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Part 2 of 7

For part 1, see barcode 00001736 30
For parts 3-7, see barcodes 00001736 32 through 00001736 36

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIR
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-1933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

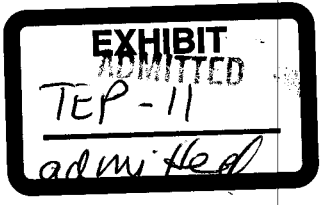
Rebuttal Testimony of

Ann E. Bulkley

on Behalf of

Tucson Electric Power Company

July 25, 2016



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EXHIBITS:

Exhibit AEB-R-1 Fair Value Rate of Return - Arizona Staff Methodology
Exhibit AEB-R-2 Correction of Mr. Gorman's Fair Value Cost Rate

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley, and I am a Vice President of Concentric Energy Advisors, Inc. ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. On whose behalf are you submitting this Rebuttal Testimony?

A. I am submitting this Rebuttal Testimony on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. Did you previously submit testimony in this proceeding?

A. Yes. I submitted Direct Testimony regarding the appropriate Return on Equity ("ROE"), capital structure, and Fair Value Rate of Return ("FVROR") for TEP in this proceeding.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to the cost of capital issues within the Direct Testimonies of Mr. David C. Parcell on behalf of the Utilities Division Staff (the "Staff") of the Arizona Corporation Commission (the "Commission"), Mr. Robert B. Mease on behalf of the Residential Utility Consumer Office ("RUCO"), Mr. Michael P. Gorman on behalf of the U.S. Department of Defense and all other Federal Executive Agencies ("DOD"), and Mr. Gregory W. Tillman on behalf of Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively, the "Opposing ROE Witnesses").

Q. Have you prepared any exhibits to support your analysis and recommendations?

A. Yes. My recommendations are supported by the data presented in Exhibits AEB-R-1 through AEB-R-2, which have been prepared by me or under my direction.

Q. How is the remainder of your Rebuttal Testimony organized?

A. The remainder of my Rebuttal Testimony is organized as follows:

- In Section II, I provide a summary and overview of my Rebuttal Testimony.
- In Section III, I provide a summary of capital market conditions and their effect on the cost of equity for TEP.
- In Section IV, I respond to Mr. Parcell's analyses and recommendations.
- In Section V, I respond to Mr. Mease's analyses and recommendations.
- In Section VI, I respond to Mr. Gorman's analyses and recommendations.
- In Section VII, I respond to Mr. Tillman's recommendations.
- Finally, in Section VIII, I summarize my conclusions and recommendations.

II. SUMMARY AND OVERVIEW

Q. Please provide an overview of the Opposing Witnesses ROE recommendations in this proceeding.

A. As shown in Table 1, the Opposing ROE witnesses have recommended ROE levels in a narrow range from 9.20 percent to 9.35 percent.[1] The FVROR recommendations of the Opposing ROE witnesses range from 5.00 percent to 5.20 percent.

[1] Mr. Tillman recommends an ROE not to exceed 9.50 percent based on the recent settlement agreement in UNS Electric.

Table 1: Recommended ROE Ranges and Point Estimates of the Opposing ROE Witnesses

Witness	Recommended ROE Range	Original Cost ROE Recommendation	FVROR Recommendation
Mr. Parcell	9.20%-9.50%	9.35%	5.00%
Mr. Mease	7.91%-9.65%	9.20%	5.20%
Mr. Gorman	8.90%-9.70%	9.30%	5.00%
Mr. Tillman	N/A	Max of 9.50%	NA

Q. Please provide a brief overview of your response to Staff witness Parcell with respect to the appropriate ROE for TEP.

A Mr. Parcell recommends an ROE of 9.35 percent and relies on a 0.70 percent Fair Value Increment for TEP.[2] Mr. Parcell performs a Discounted Cash Flow analysis, Capital Asset Pricing Model analysis, and Comparable Earnings analysis to estimate the cost of equity for TEP.[3] He contends that his ROE recommendation of 9.35 percent is reasonable based on his view that the current low interest rate environment has reduced the cost of equity for electric utility companies. As discussed in my Direct and Rebuttal testimonies, while interest rates in recent years have been at historically low levels as a result of Federal Reserve monetary policy, current and projected capital market conditions fully support an ROE above 9.35 percent. The specific areas of disagreement with Mr. Parcell's ROE analyses are summarized below:

- Mr. Parcell's ROE estimation methodologies result in a lower recommended ROE than the annual average ROEs authorized for 2014 to 2016 for vertically integrated electric companies; and, is lower than each of the individual returns authorized for vertically integrated electric utilities during that period, with the exception of one company, Kansas City Power and Light, which was authorized a return of 9.30 percent in 2015.

[2] Direct Testimony of David C. Parcell, at 3 and 49. Mr. Parcell's range of return on the Fair Value Increment is between 0.00 percent and 1.42 percent. See Direct Testimony of David C. Parcell at 45, and 48.

[3] *Ibid.*, at 2-3.

- As shown in DCP-1, Mr. Parcell provides a recommended range of equity returns of 9.2 percent, 9.35 percent and 9.5 percent. The majority of the results of Mr. Parcell's analyses fall significantly below his recommended range of equity returns. Therefore, Mr. Parcell's ROE recommendation does not appear to be directly tied to his analytical results, but rather is based on his judgment regarding the appropriate ROE for TEP. Mr. Parcell's recent ROE recommendations in other proceedings have been within a narrow range, regardless of the relative risk profile of the subject utility.[4] Mr. Parcell has not considered the additional risks that TEP is exposed to, relative to the proxy group, which are described at length in my Direct Testimony.[5]
- Mr. Parcell's CAPM analysis produces results ranging from 6.5 percent to 6.8 percent, at least 255 basis points below his final recommended ROE and 250 to 280 basis points below the lowest authorized ROE for any integrated electric utility. Despite these facts, Mr. Parcell suggests that these results should still be considered as a factor in setting the ROE for TEP.[6] Mr. Parcell acknowledges that his unreasonably low results are related to the assumptions he uses for the market risk premium of 5.75 percent. While the analysis he presents in Schedule 8 shows the market risk premium increasing since the 2008 financial market collapse, and the 2014 market risk premium at nearly 300 basis points higher than the pre-collapse levels, Mr. Parcell suggests that investors have come to expect lower equity returns and risk premiums.[7] Mr. Parcell's analysis of the equity risk premium appears inconsistent with investor expectations and the risk factors in the market since the 2008 financial market turmoil. It is not reasonable to expect

4 *See* Municipal Light and Power Department Anchorage, Docket U-13-184, filed May 2014 with recommended ROE of 9.5%; Artesian Water Company, Docket 11-132, filed September 2014 for ROE of 9.10%; United Water Pennsylvania Inc., Docket R-20152462723, filed April 2015 for ROE of 9.25%; Southwestern Public Service, Docket 43695, filed May 2015 for ROE of 9.4%; and Oklahoma Gas and Electric Company, Docket 201500273, filed March 2015 for ROE of 9.0%.

5 Direct Testimony of Ann E. Bulkley, at 44-51.

6 Direct Testimony of David C. Parcell, at 34.

7 Direct Testimony of David C. Parcell, at 33.

that in 2008, as financial institutions filed bankruptcy and returns in the stock market were negative, that the risk premium for holding equity would be *lower* than in more stable market conditions.

- In addition, Mr. Parcell's analysis does not reflect the inverse relationship between the equity risk premium and interest rates. When interest rates are anomalously low, as they are today, it is important to either use a normalized interest rate that is more characteristic of the long term average, or if one chooses to use a current interest rate, it should be used in conjunction with a forward-looking market risk premium that reflects the current interest rate environment and the inverse relationship of the market risk premium to interest rates.
- Mr. Parcell's DCF and comparable earnings analyses are heavily reliant on historical data which are subject to a host of accounting and operational issues that have no bearing on forward-looking return projections. To the extent that past historical occurrences remain relevant, they are already incorporated in analyst projections. By relying on historical data, Mr. Parcell is placing unwarranted weight on the effect of historical occurrences.
- Mr. Parcell claims that my analysis is biased upward in a manner that inflates my return recommendation. He takes exception to my use of analyst forecasts of earnings growth, claiming that analysts provide inaccurate and biased forecasts; he takes exception to my use of projected interest rates and my forward risk premium calculation, claiming that the ultimate application of those inputs results in a return that is too high. Although, Mr. Parcell criticizes my reliance on analysts' projections of earnings growth for my DCF analysis, it is solely the earnings growth rate in Mr. Parcell's DCF analysis that establishes the lower bound of his range. All of the other growth rate estimates that Mr. Parcell considered produce DCF results that range from 6.7 percent to 8.2 percent, which

are significantly below his final DCF result of 9.20 percent and his recommended ROE of 9.35 percent.

Q. Please summarize your response to Staff witness Parcell with respect to the FVROR.

A The methodology that Staff relies on to develop the FVROR is consistent with the methodology that was used in my Direct Testimony (i.e., assigning a return to the Fair Value Increment of one half the real risk-free rate). However, Staff's proposed cost rate for the Fair Value Increment is lower than what is reflective of current market conditions because of the nominal risk-free rate Mr. Parcell has relied on. Simply updating the nominal risk-free rate used in Staff's FVROR to the short-term nominal risk-free rate used in the analysis presented in my Direct Testimony increases the return on the Fair Value Increment from 0.70 percent to 1.25 percent.

Q. Please summarize your response to RUCO witness Mease's ROE recommendation for TEP.

A. As shown in Table 1 above, the range of ROE results presented by Mr. Mease is between 7.91 percent and 9.65 percent, which represents the range of results for his Constant Growth DCF model. Mr. Mease's recommended ROE of 9.20 percent is 80 basis points below the 10.00 percent return that was authorized for TEP in Docket No. E-01933A-12-0291 and 45 to 55 basis points below the average annual returns that have been authorized for integrated electric utilities since 2014. Mr. Mease's recommended ROE is not a reasonable estimate of the cost of equity for TEP for the following reasons:

- Mr. Mease's recommendation to lower TEP's currently authorized ROE by 80 basis points is based on the use of recent interest rates and fails to consider the expectation for interest rates over the period that TEP's rates will be in effect. As

discussed in my Direct Testimony, forward-looking data demonstrate that investors expect an increase in interest rates. As shown by the Bond Yield Risk Premium analysis, there is a positive relationship between interest rates and ROEs. Therefore, using forward-looking data would suggest an increase in the ROE, not the decrease proposed by Mr. Mease.

- The results of Mr. Mease's CAPM analysis range from 7.48 percent to 8.51 percent. Mr. Mease relies on the 3 month average for the 30-year Treasury bond yield for his risk free rate and a market risk premium of 6.91 percent, for which he has provided no source or explanation. As stated previously with respect to Mr. Parcell, when interest rates are anomalously low, as they are today, it is important to either use a normalized interest rate that is more characteristic of the long term average, or a current interest rate in conjunction with a forward-looking market risk premium that reflects the current interest rate environment and the inverse relationship of the market risk premium to interest rates.
- Mr. Mease's recommended FVROR is calculated by removing inflation from the Weighted Average Cost of Capital ("WACC") that would be applied to an OCRB. In order to properly calculate the FVROR, consistent with Commission precedent, one half of the real risk-free rate should be used as the cost rate that is applied to the FV increment.

Q. Please summarize your response to DOD witness Mr. Gorman's ROE and capital structure recommendations for TEP.

A. Mr. Gorman's ROE recommendation of 9.30 percent does not provide a reasonable estimate of TEP's cost of equity.

- Mr. Gorman's 9.30 percent ROE recommendation is not comparable to the average recent ROE awards for vertically-integrated electric utilities and would

not allow TEP to effectively compete for capital with other investments of comparable risk.

- The results of Mr. Gorman's DCF analysis are significantly below the range of results he establishes as reasonable. While Mr. Gorman suggests that a return of 9.30 percent is reasonable for TEP, his mean Constant Growth DCF results suggest a return of 7.72 percent (using sustainable growth rates) and 8.71 percent (using analysts' earnings per share growth rates). These results are 59 to 158 basis points below any authorized ROE for a vertically integrated electric utility and are not reasonable. In my Direct and Rebuttal testimonies, I explain how the DCF model is being affected by anomalous market conditions and propose certain adjustments within the range of results.
- Mr. Gorman's Multi-Stage DCF analysis produces a return of 7.99 percent that is within the range established by his constant growth DCF results. The unreasonably low result from this methodology is based on his forecast long-term growth rate of 4.20 percent. Using a multi-stage DCF analysis and Mr. Gorman's price and near-term growth rate assumptions, a 9.30 percent ROE, which is recommended by Mr. Gorman, would require a long-term GDP growth rate of 5.84 percent, which is 44 basis points higher than the long-term GDP growth rate relied on in my analysis.
- The low end of Mr. Gorman's range of CAPM results of 8.01 percent is substantially below any authorized ROE for a vertically integrated electric utility in the U.S. in the last 25 years, while the upper end of the range of 9.44 percent is approximately 40 basis points lower than the average authorized ROEs for integrated electric utilities since January 2015. Mr. Gorman assigns 75 percent weight to the high CAPM results and 25 percent to the low CAPM results to arrive at an average CAPM result of 9.10 percent.

- Mr. Gorman's low market risk premium of 6.0 percent does not reflect the inverse relationship between the equity risk premium and interest rates. Mr. Gorman's high market risk premium of 7.90 percent is 71 basis points lower than the low end of the forward-looking MRPs in my CAPM analysis. While Mr. Gorman criticizes my MRPs as being too high, relying on the low end MRP in my analysis and Mr. Gorman's average beta of .75 results in a return of 9.95 percent which is within the range of recently authorized ROEs.
- Mr. Gorman produces two risk premium analyses, one based on long-term Treasury yields and another based on A-rated utility bond yields. In both cases, he calculates the difference between the average awarded electric ROEs in a given year, less the respective bond yield in each year from 1986-2015. Mr. Gorman bases his risk premium estimates on an average of the rolling 5-year average for each risk premium calculation. Mr. Gorman's analysis shows that the risk premium has been steadily increasing over his analytical period. Mr. Gorman offers no evidence as to why it is appropriate or relevant to rely on an equity risk premium as dated as 1986 in establishing a forward-looking ROE.
- Mr. Gorman's range of results is framed by the average of his Constant Growth DCF analysis and his CAPM analysis on the low end and by his Risk Premium analysis on the high end. Mr. Gorman fails to recognize that the DCF model is producing results that are not corroborated by the CAPM, the Bond Yield Plus Risk Premium analysis, or ROE awards for integrated electric utilities in other jurisdictions.
- Mr. Gorman's recommended capital structure consisting of 48.69 percent common equity and 51.31 percent long-term debt should be rejected. As discussed in the Rebuttal Testimony of Company witness Kentton Grant, shortly after the test-year TEP achieved, and has since maintained, a capital structure consistent with the proposed capital structure of 50.03 percent common equity

and 49.97 percent long-term debt. The Company's proposed equity ratio is well below the proxy group average common equity ratio of 54.00 percent. [8]

- While Mr. Gorman relies on a methodology to estimate the FVROR that is similar to the methodology that I used in my Direct Testimony, Mr. Gorman's analysis relies on current and short-term projected nominal risk-free rates and a long-term projection of inflation. Since interest rates are expected to increase, the effect of using these two different time periods to estimate the real risk-free rate is that the nominal risk-free rate and the inflation factor are not consistent. Simply updating the nominal risk-free rate to be consistent with the projected time period relied on in estimating the inflation factor increases the return on the fair value increment 61 basis points above the estimate provided by Mr. Gorman.

Q. Please summarize your response to Wal-Mart witness Mr. Tillman with respect to the appropriate ROE for TEP.

A. Mr. Tillman does not recommend a specific ROE for TEP. Rather, he suggests that the Commission should examine the Company's request in light of the customer impact of the resulting revenue requirement increases and recent ROE awards for electric utilities approved by commissions nationwide.[9] Mr. Tillman testifies that the average authorized ROE for vertically-integrated electric utilities from 2013-2016 has been 9.89 percent, and that the trend in recent years has been toward declining allowed returns on equity.[10] Mr. Tillman does not take into consideration the range of those returns nor does he consider the comparative risk of TEP and the companies in his data set. Mr. Tillman ultimately recommends that the Commission not allow an ROE higher than the 9.50 percent ROE recently stipulated to by UNS Electric Inc. unless there is a showing that economic or

8 *See* Exhibit AEB-9, p. 1 of 2 proxy group average for the eight quarters ending Q1 2015.
9 Direct Testimony of Gregory Tillman, at 8.
10 *Ibid.*, at 12.

capital market conditions are significantly different from the time of the stipulation.[11] However, Mr. Tillman does not discuss the fact that this stipulated ROE was only one aspect of a complicated revenue requirement stipulation entered into by several of the parties to the UNS Electric rate case, nor does he discuss the significant difference in the risk profile between UNS Electric and TEP.

Q. Several of the Opposing ROE witnesses suggest that the Commission should consider ROE awards in other jurisdictions as a practical benchmark for assessing ROE recommendations. Do you agree?

A. I agree that ROE awards in other jurisdictions provide a useful benchmark to assist the Commission in assessing overall reasonableness and send an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, and financial growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have the incentive to direct their capital to those investments. Thus, an ROE significantly below authorized ROEs in other jurisdictions can inhibit the Company's ability to attract capital on reasonable terms for investment in Arizona.

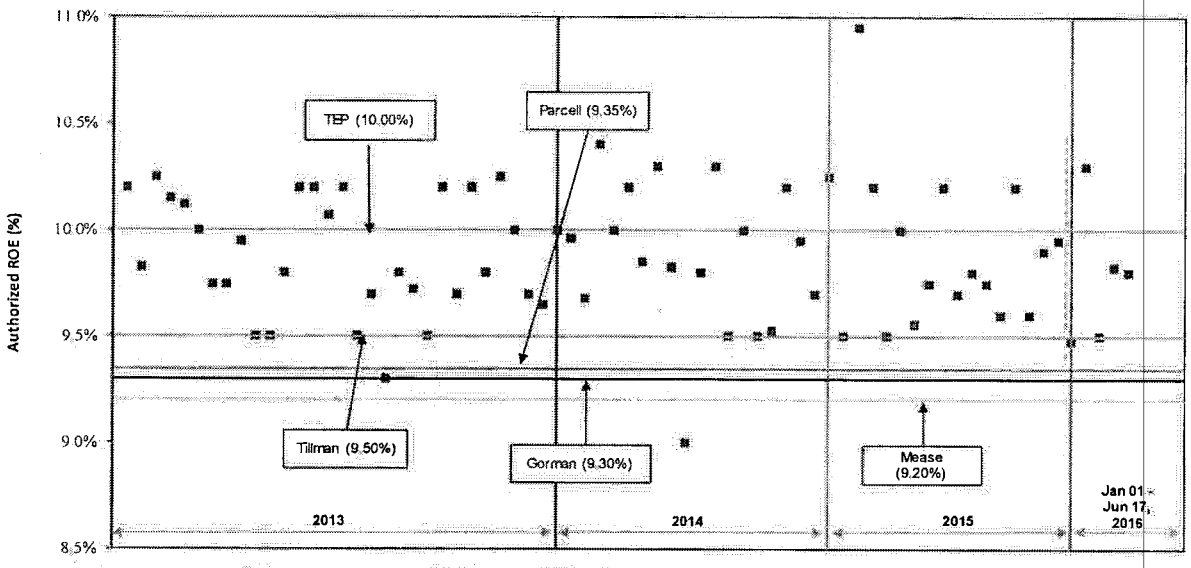
Q. How do the ROE recommendations of the Opposing ROE witnesses compare to the allowed ROEs for other integrated electric utilities?

A. As shown in Chart 1, the ROE recommendations of Mr. Mease (9.20 percent), Mr. Gorman (9.30 percent), Mr. Parcell (9.35 percent) and Mr. Tillman (no higher than 9.50

[11] *Ibid.*, at 14.

percent) are below the average authorized ROE for vertically-integrated electric utilities between January 1, 2012 and May 31, 2016.

Chart 1: Authorized ROEs for Integrated Electric Utilities
January 1, 2013 – June 17, 2016[12, 13]



Q. What is your conclusion regarding the appropriate cost of equity for the Company?

A. While the average authorized ROE has declined, there is variability in authorized ROEs. Based on the risk factors identified for TEP, I agree with the Opposing ROE witnesses that it is appropriate to set the ROE above the mean of the analytical results. As discussed in the Rebuttal Testimony of TEP witness Kentton Grant, the Company has modified its non-fuel revenue requirement to reflect an ROE of 10.00 percent, which is at the low end of my recommended range. I conclude that the Company's requested return of 10.00 percent is conservative based on the results of the ROE estimation methodologies, the recently authorized returns for vertically integrated electric utilities, company-specific risk factors and investors' expectation of market conditions over the

12 Source: SNL Energy, Inc.
13 It is important to note that the 2016 authorized ROE represents approximately 6 months of data and is a very small sample, including only four data points that provide specific authorized ROEs outside of the context of a more comprehensive settlement.

period that rates will be in effect. ROEs at the levels proposed by the Opposing ROE witnesses are not reasonable and do not meet the standards established in *Hope* and *Bluefield* for a fair return.

III. CAPITAL MARKET CONDITIONS AND THEIR EFFECT ON THE COST OF EQUITY FOR TEP

Q. How have the Opposing ROE witnesses taken into consideration the effect of economic and capital market conditions on the cost of equity for TEP?

A. Messrs. Parcell, Mease and Gorman cite the current low interest rate environment as an important consideration in the cost of equity and as support for their low ROE recommendations. Mr. Tillman cites the recent trend of declining average ROE awards for regulated electric utilities. The Opposing ROE witnesses' recommendations, however, are based on capital market conditions over the past few years, and do not adequately consider the changes that have occurred in recent months or the prospects for financial markets on a going-forward basis. In my view, it is not reasonable to dismiss current and projected market conditions or to base the authorized ROE for TEP in this proceeding on previous economic and financial market conditions.

The ROE that is authorized in this proceeding is intended to provide a reasonable return to investors over the forward-looking period during which these rates will be in effect. For that reason, it is important to consider the prospects for financial markets during that period. As discussed in my Direct Testimony, extraordinary and persistent federal intervention in capital markets has artificially lowered government bond yields since the Great Recession of 2008-09, as the Federal Reserve has used monetary policy (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage

backed securities) to stimulate the U.S. economy.[14] This highly accommodative monetary policy has resulted in government bond yields that have been artificially suppressed by the Federal Reserve. However, market data suggest that investors perceive greater risk in the current market environment, and there is a great deal of uncertainty around the path and timing of interest rate movements. Therefore, it is important to consider the current and prospective market conditions and investor expectations, all of which may put upward pressure on utility capital costs going forward.

Q. Do you agree with the Opposing ROE witnesses that changes in utility bond yields support a lower authorized ROE for TEP?

A. No, I do not. During periods of equity market volatility, as risk aversion increases, investors seek out the relative safety of Treasury securities and other relatively low-risk debt securities, essentially bidding up prices and forcing down yields. Accordingly, the current yields on U.S. Treasury securities are being driven by a temporary flight to quality by investors and the Federal Reserve's highly accommodative monetary policy. The current low bond yields are not being driven by typical bond market participants. In addition, there is a well-established inverse relationship between equity risk premiums and prevailing risk free rates.[15] Equity investors tend to require higher risk premiums during periods of lower interest rates. Thus, low interest rates set by the Federal Reserve are not reliable indicators of investment risk or the cost of capital in equity markets. The Opposing ROE witnesses fail to recognize the inverse relationship between interest rates

14 Direct Testimony of Ann E. Bulkley, at 11-12.

15 *See e.g.,* S. Keith Berry, "Interest Rate Risk and Utility Risk Premia during 1982-93," *Managerial and Decision Economics*, Vol. 19, No. 2 (March, 1998), in which the author used a regression analysis, including using allowed ROEs as the relevant data source, and concluded that there was an inverse relationship between equity risk premia and interest rates. *See* also Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholders Required Rates of Return," *Financial Management*, Spring 1986, at page 66, and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, "An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry," *Financial Management*, Volume 24, No. 3, Autumn 1995, at pages 89-95.

and the equity risk premium. As interest rates decrease, the equity risk premium increases to reflect the fact that investors are unwilling to invest in riskier equity assets, and instead prefer the relative safety of debt securities despite their current historically low yields. On that basis, I disagree that the current low level of utility bond yields indicates that the cost of equity for utilities is correspondingly low.

Q. Mr. Gorman views electric utilities as generally regarded as "safe haven" or "low risk" investments, and that investors will continue to provide an abundance of low cost capital to support utilities' capital programs.[16] What is your response?

A. There is no dispute that utilities are now, and typically have been, relatively lower risk investments than the market overall; that clearly is the case given that the proxy group Beta coefficients all are less than one.[17] However, my discussion of capital market conditions and risk sentiment indicators shows that investors are facing generally higher risks and that utilities, in particular, are not "low risk" investments. Specifically, the incremental credit spreads between Baa-rated and A-rated utility bonds, and the current level of uncertainty in global financial markets will likely result in higher credit spreads and risk premiums and may translate into higher equity capital costs for all U.S. companies, even A- and Baa-rated regulated utilities.

Q. What is the financial market's perspective on the likelihood for future increases in short-term interest rates by the Federal Reserve?

A. At present there is great uncertainty around the Federal Reserve's policy for future increases in short-term interest rates. In mid-December 2015, the Federal Reserve announced the first increase in short-term interest rates since the financial market

[16] Direct Testimony of Michael P. Gorman, at 9.
[17] *See,* Schedule AEB-4.

collapse in 2008. In its statement, the Federal Reserve indicated that further increases in short-term interest rates would be gradual as the economy strengthens further and inflation rises from undesirably low levels. The July 2016 issue of the Blue Chip Financial Forecasts ("Blue Chip") surveyed leading economists and market participants concerning their views about the likelihood of future increases in short-term interest rates by the Federal Reserve. Blue Chip reported that 43.9 percent of market participants surveyed expected the Federal Reserve to raise short-term interest rates again no later than September 2016, and forecast that yields on 30-year Treasury bonds would increase to 4.30 percent between 2018 and 2022. [18,19]

However, recent changes in the global economy with Great Britain's vote to exit the European Union ("Brexit") has resulted in unsettled markets and heightened volatility. It is unclear at this time how this development will affect export markets and the overall growth of the U.S. economy, which again serves to increase market volatility and market risk. This sort of uncertainty in global financial markets may have an effect on interest rates, risk premiums, and credit spreads, affecting the return requirements of investors.

Q. What indications are there that investor risk sentiment is increasing?

A. Even before the Brexit vote, credit spreads were increasing. As shown in Chart 2 of my Direct Testimony, credit spreads between government and utility bonds had increased to nearly 200 basis points and were wider than when the company had its last rate case. The spread between Baa-rated utility debt and 30-year Treasury bonds is now 253 basis points, an increase of 61 basis points since the filing of my Direct Testimony.

[18] Blue Chip Financial Forecasts, Volume 35, No. 7, July 1, 2016, at 14.
[19] Blue Chip Financial Forecasts, Volume 35, No. 6, June 1, 2016, at 14.

Table 2: Credit Spreads

BOND YIELDS	5/31/16 CURRENT CREDIT SPREADS	7/31/15 FILING OF DIRECT	6/27/2013 TEP 2013 RATE DECISION	GREAT RECESSION 12/3/2007-6/30/2009
Moody's Baa-Rated - Moody's A Rated Utility Bond	1.11%	0.76%	0.53%	0.80%
Moody's Baa-rated Utility Bond – 30-year U.S. Treasury	2.53%	1.92%	1.59%	3.03%
Moody's A-rated Utility Bond – 30-year U.S. Treasury	1.42%	1.16%	1.06%	2.23%

As discussed in my Direct Testimony, increasing credit spreads are an indicator that bond investors are becoming more concerned about future economic conditions.[20]

Q. Are expectations for higher interest rates, wider credit spreads, lower dividend yields, and high stock valuations for utility companies already reflected in the cost of equity produced by a DCF analysis?

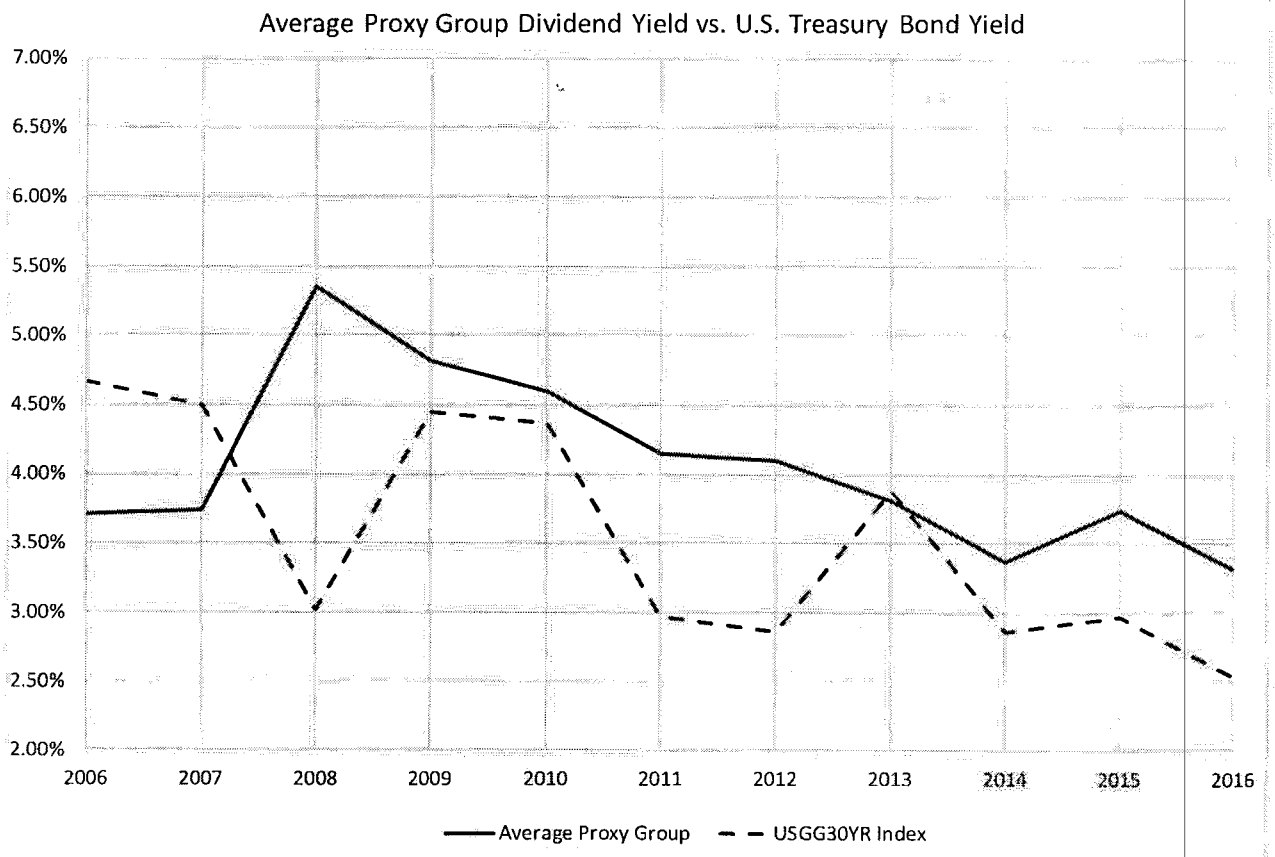
A. In theory, and during times of general economic and capital market stability, I believe that the DCF analysis reflects market conditions and investor expectations. However, in the current market environment, the DCF model results are being distorted by the uncommonly low level of interest rates. Value Line recently observed that dividend yields for electric utilities are currently well below the historical average, and that high valuations on utility shares are not expected to be sustained over the three-to-five year period.[21] In order to assess how low interest rates are affecting the dividend yields for utility stocks, I have performed an analysis comparing the current dividend yield for the electric utilities in my proxy group (excluding those companies that are currently involved in merger activity) to the historical dividend yields for these same companies

[20] Direct Testimony of Ann E. Bulkley, at 17.

[21] Value Line Investment Survey, Electric Utility (West) Industry, April 29, 2016, at 2226.

from 2006-2016, as well as to yields on 30-year Treasury bonds in each year. Chart 2 presents the results of my analysis.

Chart 2: Average Proxy Group Dividend Yields and U.S. Treasury Bond Yields 2006 - 2016



As shown in Chart 2, the average dividend yield for the companies in my proxy group is at its lowest level since 2006, driven lower by yields on 30-year Treasury bonds and federal monetary policy.

Understanding the important role that dividend yields play in the DCF model, this is evidence that anomalous capital market conditions are causing the DCF model to

understate equity costs for regulated utilities at this time. The FERC has recently recognized this phenomenon, stating:

> As is discussed, infra, the level of the dividend yield affects the reliability of the DCF process when that level is lower than the level acceptable to investors that value utility stocks based on their estimated long-term dividend growth. The record creates cause for concern that during a period including the Study Period, investors valuing utility stocks based solely or primarily on their current yield bid the prices of the proxy group stocks up to levels that rendered their Total Returns unacceptable to investors that valued such stocks based on their estimated long-term dividend growth. For reasons set out below, this record evidence creates further cause for concern that placement of the MISO TOs' Base ROE at the Midpoint may not meet the requirements of Hope.[22]

The FERC also observed that due to anomalous conditions in capital markets (i.e., low Treasury bond yields) the midpoint results of the DCF model are not a reasonable estimate of the cost of equity at this time, stating:

> The yields of 10-year Treasury Bonds during the Study Period continue to reflect economic conditions that could render inputs to the DCF analysis unrepresentative. During the study period, the yields of 10-year Treasury Bonds averaged 2.21 percent. That yield was 38 basis points higher than the average yield of those bonds during the Opinion No. 531 study period, but 79 basis points below the 3.0 percent level that so concerned the Commission in Opinion No. 531. If the average 10-year Treasury-Bond yields for the Opinion No. 531 study period reflected economic conditions that could serve to render financial inputs into the DCF model unrepresentative, the average bond yields for the study period in this proceeding are close enough to the earlier yields to reflect the same conditions. Accordingly, the level of 10-year Treasury Bond yields during the Study Period create sufficient doubt regarding the representativeness of DCF inputs to warrant an examination of alternative metrics prior to making a final determination as to the level of the MISO TOs' Base ROE.[23]

In summary, the DCF model is not adequately reflecting expectations for higher rates, wider credit spreads, lower dividend yields and high valuations on utility shares at this

[22] 155 FERC ¶ 63,030 (June 30, 2016) at para. 128.
[23] *Ibid.*, at paragraph 126.

time. Consequently, it is necessary to consider the results of other Risk Premium models and returns in other jurisdictions in order to assess the reasonableness of the DCF results and to determine where to set the appropriate return within the range of results.

Q. How should capital market conditions be considered in setting the ROE for TEP?

A. The expectations of equity investors and the overall risk sentiment in the market should be considered in setting the ROE for TEP. As a result of market uncertainty, utility share valuations are temporarily inflated due to investors' flight to quality, and correspondingly result in abnormally low dividend yields. Consequently, the DCF models will understate forward-looking equity returns, because share valuations are based on temporary circumstances. Other models, such as the Risk Premium analysis, which are sensitive to changes in interest rates, may provide better information for the utility cost of equity than that currently indicated by the DCF model. Further, as a result of higher credit spreads, increased market volatility and the potential for rising interest rates, it is reasonable to believe that the cost of capital for electric utilities such as TEP would be increasing, not decreasing. Based on similar data, regulators in other jurisdictions including the FERC, have determined that it is appropriate to consider the results of other models and to estimate the cost of equity toward the upper end of the range of results during periods of anomalous capital market conditions.

IV. RESPONSE TO STAFF WITNESS PARCELL

Q. Please summarize Staff witness Parcell's ROE recommendation.

A. Mr. Parcell recommends an ROE for TEP of 9.35 percent based on the results of his DCF, CAPM and Comparable Earnings analysis. This recommendation is 65 basis points lower than TEP's currently-authorized ROE of 10.00 percent. As support for his ROE

recommendation, Mr. Parcell cites the low interest rate environment in recent years, as well as the weak economic outlook for the next few years.

Q. What is your response to Mr. Parcell's testimony and recommendation concerning the Cost of quity?

A. Mr. Parcell's recommendation is unduly low in light of current and projected economic and capital market conditions, and is not consistent with recently-authorized ROEs for vertically-integrated electric utilities in other jurisdictions. Moreover, Mr. Parcell's recommended ROE does not appear to be the product of the vast majority of his analyses. The ranges he establishes are only loosely related to his analytical results. For example, he states that the high end of his range of 9.5 percent is based on his CE analysis; however, the highest ROE in that analysis is 9.3 percent. In summary, Mr. Parcell's recommendation appears to be highly subjective and based at least as much on his opinion as on his analyses. Furthermore, it is not clear whether Mr. Parcell has considered the full extent of TEP's operating risks, particularly those related to its generation portfolio. In his most recent testimonies, Mr. Parcell's recommendations have been within a tight range (between 9.0 and 9.4 percent), despite large differences in operating risks among the subject utilities (i.e. water utilities, vertically integrated electric utilities with differing generation portfolios, etc.).

Q. Is Mr. Parcell's ROE recommendation of 9.35 percent consistent with returns for integrated electric utilities in other jurisdictions across the U.S.?

A. No, it is not. As shown in Chart 1, Mr. Parcell's ROE recommendation of 9.35 percent is at the low end of the range of recent ROE awards for integrated electric utilities. In 2015-2016, the range of ROEs for vertically integrated electric utilities was 9.30 percent to 10.30 percent, with an average return of 9.72 percent. Forward-looking economic and

capital market conditions, as well as TEP's additional business risks, support an authorized ROE *above* the proxy group average and higher than the average for integrated electric utilities. As discussed in my Direct Testimony, TEP has higher risk associated with its generation portfolio compared to the companies in the proxy group, and also has above average regulatory risk in Arizona.[24]

Q. Mr. Parcell summarizes gas and electric utility authorized returns from 2012 to 2015 in his testimony.[25] Does this provide a reasonable benchmark for TEP's authorized return?

A. No, it does not. Although I generally agree with Mr. Parcell's figures for electric and gas utility rate case averages since 2012, he has not attempted to distinguish between vertically integrated electric utilities and electric distribution utilities. Vertically integrated utilities have much more risk than pure transmission and distribution ("T&D") utilities. The risks associated with owning generation assets include market risk, cost recovery risk, and regulatory risk associated with market forces, unplanned outages and maintenance and new environmental requirements. As shown in Table 3, authorized returns for vertically-integrated electric utilities have averaged between 25 and 60 basis points higher than returns authorized for T&D companies from 2012-2016. Mr. Parcell's recommendation does not reflect the additional risk of owning generation assets.

[24] Direct Testimony of Ann E. Bulkley, at 41-49.
[25] Direct Testimony of David C. Parcell, at 14.

Table 3: Authorized ROEs for State Jurisdictional Electric Utility Operations[26]

Year	All Electric	Distribution	Vertically Integrated	Difference
2012	10.02%	9.75%	10.10%	0.36%
2013	9.82%	9.37%	9.95%	0.58%
2014	9.76%	9.49%	9.94%	0.45%
2015	9.60%	9.17%	9.75%	0.58%
2016	9.52%	9.39%	9.65%	0.26%

Q. Please describe the differences in your proxy group from that used by Mr. Parcell.

A. While there are many proxy group differences, the screening criteria used by Mr. Parcell and me are similar in many respects and result in an overlap of seven companies in our respective proxy groups (Allete, Great Plains Energy, IDACORP, Otter Tail Corp, Portland General Electric Corp, PNM Resources and Westar). There are five companies that I have included in my proxy group that Mr. Parcell has excluded; four of these (American Electric Power, Duke Energy Corp, Eversource Energy and Pinnacle West Capital Corp) were excluded for exceeding Mr. Parcell's $5 billion market capitalization threshold, and one company (Empire District Electric) was removed as it had announced a major acquisition subsequent to my proxy group selection. Three companies in Mr. Parcell's group were excluded from my proxy group; two of these companies (Avista and Northwestern Corp) do not meet my screening criterion requiring at least 90 percent of total regulated operating income from regulated electric operations, and El Paso did not have sufficient dividend payment history. Mr. Parcell has provided evidence using both his and my proxy groups. I conclude that the proxy group one chooses has no material bearing on his results.

[26] Source: SNL Financial. The number of authorized ROEs in 2016 is very limited, with only four decided cases included in this data set. Therefore, the 2016 results should be considered with caution.

A. Constant Growth DCF Model

Q. Please summarize Mr. Parcell's Constant Growth DCF analyses.

A. Mr. Parcell performs a Constant Growth DCF analysis with several indicators of expected dividend growth, including:

1) historical earnings retention growth for years 2011-2015 (five-year average);

2) five-year average historic growth in earnings per share ("EPS"), dividends per share ("DPS") and book value per share ("BVPS");

3) projections of earnings retention growth for 2016, 2017, and 2019-2021 (Value Line);

4) projections of EPS, DPS, and BVPS (Value Line) for years 2012-2014 to 2019-2021; and

5) five-year projections of EPS growth (per First Call).

Mr. Parcell calculated mean and median returns for each individual growth rate, as well as an ROE for the average of all growth rates. Mr. Parcell's Constant Growth DCF analysis yielded mean and median ROE results of 8.0 percent, and produced a mean ROE estimate ranging from 6.9 percent (historic and prospective earnings retention growth rates) to 9.2 percent (5 year projected First Call EPS growth). All of these ROE estimates are below any authorized ROE for a vertically-integrated electric utility in the last 25 years.

Q. Do you agree with Mr. Parcell that historical measures of growth are relevant to a forward-looking evaluation of the Company's ROE?

A. No, I do not. Mr. Parcell states that because of the "vast majority of historical information available to investors, it is neither realistic nor logical to maintain that

investors only consider projected (estimated) data for a single statistic (EPS) to the exclusion of historic (actual) data and other statistics (historic and estimated)."[27] I disagree for two reasons. First, the Constant Growth DCF model is a forward-looking model that evaluates investors' required returns based on future cash flows. As such, the appropriate measure of growth is investors' expectations, not historical results. Historical growth rates are not relevant because past growth may not reflect future growth potential. Second, securities' analysts forecasted growth rates incorporate historical performance to the extent the analysts believe it is likely to continue. Additional consideration of historical growth rates provides no meaningful incremental information regarding the proxy companies' future growth potential and places unwarranted weight on historical events.

Q. Does Mr. Parcell disagree with the earnings growth estimates in your Constant Growth DCF model?

A. Yes, Mr. Parcell suggests that my recommendation is biased upward in a manner that inflates the return recommendation. He states that although I have included three measures of earnings growth in my Constant Growth DCF analyses, in reality all three focus on analysts' projections of earnings growth and exclude everything else.[28]

Q. What is your response?

A. As indicated in my Direct Testimony, dividend growth can only be sustained by earnings growth.[29] Earnings are the fundamental determinant of a company's ability to pay dividends. Further, both dividends and book value per share may be directly affected by short run management decisions. As a result, dividend growth rates and book value

27 Direct Testimony of David C. Parcell, at 36-37.
28 Direct Testimony of David C. Parcell, at 36.
29 Direct Testimony of Ann E. Bulkley, at 26.

growth rates may not accurately reflect a company's long-term growth. In contrast, earnings growth rates are not affected by short run cash management decisions and are the only forward-looking growth rates available on a consensus basis.

While Mr. Parcell criticizes my use of EPS growth projections as the only measure of growth, it is in effect the only growth rate that he relies on in establishing his final DCF result of 9.2 percent. All other growth rates that he reviews produce returns that are at least 30 basis points below the lowest authorized ROE for any integrated electric utility from 2012-2016. Despite his criticism of analyst EPS growth rates, Mr. Parcell believes that the highest value in his analysis, which is based on analyst estimates of EPS growth, represents the current DCF-derived ROE for the proxy group.

Q. Do you agree with Mr. Parcell that "analysts still have a positive earnings growth bias"?[30]

A. No, I do not. Mr. Parcell references a McKinsey study and an SEC Investor Alert to support his claim of analyst bias; however, the evidence on the topic is far from clear and there are many conflicting opinions. A 2010 article in Financial Analysts Journal, for example, found that analyst forecast bias has significantly declined or disappeared entirely since the Global Settlement:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the

[30] Direct Testimony of David C. Parcell, at 37.

recent efforts of regulators have helped neutralize analysts' conflicts of interest.[31]

Further, the Global Analysts Research Settlement of 2003 (the "Global Settlement") served to remove all incentives for bias in the financial industry. Specifically, the Global Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research. In addition, analysts covering the common stock of the proxy companies must certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation.

Q. Have other regulators offered an opinion on this issue?

A. Yes. The FERC has specifically addressed the concern about analyst growth rate forecasts in its March 2015 Order on Rehearing, Opinion 531-B, where it reaffirmed its rejection of the argument that analyst growth rates should not be used in the DCF analysis, because the analysts making those projections allegedly are overly optimistic in their projections.[32] The Commission also noted that the appropriate dividend growth rate to include in a DCF analysis is the growth rate expected by the market. While the market may be wrong in its expectations as reflected in the IBES growth projections, the cost of common equity to a regulated enterprise depends upon what the market expects, not upon precisely what is actually going to happen.[33]

[31] Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010 at 195. Please note that this appears to be the published version of the working paper cited by Mr. Parcell.

[32] FERC Order on Rehearing, Opinion No. 531-B (March 3, 2015) at para 71.

[33] *Ibid.*

Q. Do you agree with Mr. Parcell's "retention growth" DCF analysis?

A. No, I do not. The underlying premise of the "retention growth" calculation is that future earnings will increase as the retention ratio (*i.e.*, the portion of earnings not paid out in dividends) increases. There are, however, several reasons why that may not be the case. Management decisions to conserve cash for capital investments, to manage the dividend payout for the purpose of minimizing future dividend reductions, or to signal future earnings prospects can and do influence dividend payout (and therefore earnings retention) decisions in the near-term.

Q. Is there academic research that supports your position?

A. Yes. In 2006, two articles appeared in Financial Analysts Journal, which addressed the theory that high dividend payouts (*i.e.*, low retention ratios) are associated with low future earnings growth.[34] Both of those articles cite a 2003 study by Arnott and Asness[35] who found that, over the course of 130 years of data, future earnings growth is associated with high, rather than low payout ratios.[36] In essence, the findings of all three studies are that there is a negative, not a positive relationship between earnings growth rates and payout ratios. As such, I disagree with Mr. Parcell's use of the retention growth model.

Q. Do you have other concerns regarding Mr. Parcell's retention growth rates?

A. Yes. Mr. Parcell's retention growth rates are too low to be credible. In addition, these growth rates require an estimate of the earned return on common equity and are therefore

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34 Ping Zhou, William Ruland, *Dividend Payout and Future Earnings Growth*, Financial Analysts Journal, Vol. 62, No. 3, 2006. *See* also Owain ap Gwilym, James Seaton, Karina Suddason, Stephen Thomas, *International Evidence on the Payout Ratio, Earnings, Dividends and Returns*, Financial Analysts Journal, Vol. 62, No. 1, 2006.

35 Robert Arnott, Clifford Asness, *Surprise: Higher Dividends = Higher Earnings Growth*, Financial Analysts Journal, Vol. 59, No. 1, January/February 2003.

36 Since the payout ratio is the inverse of the retention ratio, the authors found that future earnings growth is negatively related to the retention ratio.

somewhat circular. By adopting Value Line's earned ROE estimates, Mr. Parcell has effectively pre-supposed the return on common equity projected by Value Line for the proxy group companies. As shown on Exhibit DCP-1, the average Value Line earned ROE estimates for the companies in Mr. Parcell's proxy group from 2011-2015 ranged from 8.3 to 8.9 percent,[37] yet for the same period he calculates a mean DCF result, using historical retention growth rates covering the same period, of 6.9 percent, a difference of 140 to 200 basis points. Similarly, his prospective retention growth rate produces a DCF result of 6.9 percent, but the implied ROEs (upon which those growth rates were calculated) actually ranged from 8.4 to 9.2 percent,[38] a difference of 150 to 230 basis points. These retention growth DCF results are unreasonably below the return on equity authorized for any electric utility that I am aware of. In fact, Mr. Parcell did not appear to consider these results reasonable based on his DCF estimate of 9.2 percent.

Q. Has the FERC recently abandoned the use of earnings retention growth rates in its electric transmission ROE methodology?

A. Yes. In Opinion No. 531, the FERC changed its approach on the DCF methodology to be applied in public utility rate cases.[39] In summary, the FERC adopted the same two-step DCF methodology it has employed in gas and oil pipeline rate proceedings since the mid-1990s, in place of the one-step methodology previously used. The FERC's two-stage DCF approach does not rely on a retention growth calculation, and instead incorporates a long-term growth projection equal to GDP. The FERC justified its change on several grounds, but as is relevant in this proceeding, it determined that both a short-term and long-term growth rate should be incorporated into the DCF calculation for public utilities. The FERC explained that its previous approach for electric utilities, using a one-stage

37 *See* DCP-1, Schedule 10, p. 1 of 2.
38 *Ibid.*
39 Opinion No. 531 147 FERC ¶ 61,234 (June 19, 2014).

DCF model, based on a short-term retention growth rate, was established at a time when electric utilities were just beginning the process of restructuring and that in the Commission's view investors would place limited weight on long-term growth projections. However, the FERC in revisiting its approach for electric utilities, finds that there is no longer reason to distinguish between gas pipelines and electric utilities in its DCF methodologies, and it has chosen to align its approach. When intervenors challenged the use of analyst earnings growth rates as the short term growth rate as opposed to a retention growth rate, the FERC responded as follows:

> We also reject Petitioners' argument that the Commission should have used the "br+sv" growth rate as the short-term growth rate in the two-step DCF methodology. While the "br+sv" growth formula relies on short-term Value Line projections of five years or less for the various inputs to the formula, it seeks to estimate a company's "sustainable growth rate."
>
> For that reason, although the Commission has stated that the formula "only produces a projection of short-term growth, similar to the IBES projections," the Commission finds the formula unreasonable for use as the short-term growth projection in the two-step DCF methodology. By seeking to estimate a "sustainable growth rate," the "br+sv" growth formula also contains some elements of a long-term growth projection, in addition to a short-term growth projection, and thus is inappropriate for use as a purely short-term growth projection in a two-step DCF methodology.
>
> The Commission adopted the two-step DCF methodology because, among other reasons, its incorporation of a long-term growth projection in the cost of equity calculation would have the effect of ascribing sustainable long-term growth to all members of a proxy group. Thus, the Commission's adoption of the two-step DCF methodology accomplishes what the use of the "br+sv" formula was intended to accomplish.[40]

[40] Opinion No. 531-B, 147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015) at para.77.

B. Multi-Stage DCF Analysis

Q. Did Mr. Parcell criticize your multi-stage DCF analysis?

A. Yes. Mr. Parcell criticizes my use of analyst EPS projections for the short-term growth rate in the Multi-Stage model filed in my Direct Testimony. I have previously addressed Mr. Parcell's concerns with the use of analyst growth rates. Mr. Parcell also takes exception to the long-term GDP growth rate used in the final stage of my Multi-Stage DCF model, claiming that the use of historical data for my GDP growth rate is inconsistent with projected growth rates used elsewhere in my DCF analyses.

Q. What is your response to Mr. Parcell's criticisms of your Multi-Stage DCF analysis?

A. The long-term growth rate used in my Multi-Stage DCF analysis is consistent with industry practice. For example, as Morningstar explains, it is appropriate to use historical real growth in GDP combined with projected inflation to calculate nominal GDP growth:

> Growth in real GDP (with only a few exceptions) has been reasonably stable over time; therefore, its historical performance is a good estimate of expected long-term future performance. By combining the inflation estimate with the real growth rate estimate, a long-term estimate of nominal growth is formed...[41]

With regard to the time period used to compute average historical growth in real GDP, Morningstar writes:

> The 87-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great

[41] Ibbotson and Associates, Stocks, Bonds, Bills and Inflation, 1926-2012, 2013 Valuation Yearbook, at 52.

deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.[42]

Q. Mr. Parcell states that economists and various government agencies are forecasting lower GDP growth rates.[43] What is your response?

A. Nominal GDP growth rates of 4.40 percent to 4.60 percent, as published in the reports cited by Mr. Parcell, are well below the average nominal GDP growth rate in the U.S. since 1926. By comparison, my historical GDP growth rate of 5.40 percent is based on a projected inflation rate of 2.09 percent (based on three sources), and actual historical growth in real GDP of 3.25 percent from 1929-2015.[44]

Moreover, as discussed in my Direct Testimony, there has been a tendency to under-estimate GDP growth in the decade after severe economic events.[45] The financial crisis and recession that began in 2007 were qualitatively different from most other U.S. economic downturns, which were followed by a rapid return to pre-recession overall output growth levels. The current U.S. economic growth situation is similar to that following the two most severe U.S. economic events in the last century (*i.e.*, the 1929 stock market crash and the 1973 oil shock).

Q. What is your conclusion regarding the appropriate GDP growth rate for the Multi-Stage DCF analysis?

A. In my view, current estimates of real GDP growth are understated relative to the long-term average because forecasters are placing too much weight on recent economic weakness. For that reason, I believe it is reasonable to use historical long-term GDP

42 *Ibid.*, at 59.
43 Direct Testimony of David C. Parcell, at 39.
44 *See* Exhibit AEB-3 filed with my Direct Testimony.
45 Direct Testimony of Ann E. Bulkley, at 29.

growth as the terminal growth rate in the Multi-Stage DCF model. However, the Multi-Stage DCF model does not directly reflect the substantial increase in interest rates that is projected over the next five years, as borrowing costs increase from the artificially low levels of the recent past.

C. CAPM Analysis

Q. Please summarize Mr. Parcell's CAPM results and explain how he uses that analysis.

A. Mr. Parcell's CAPM analysis produces mean results of 6.70 percent for the Parcell Proxy Group and 6.50 percent for the Bulkley Proxy Group. These results are based on a risk free rate of 2.23 percent, Value Line betas ranging from 0.50 to 0.85, and a market risk premium ("MRP") of 5.75 percent. Although Mr. Parcell testifies that his CAPM results should be considered as one factor in determining the cost of equity for TEP, he ultimately relies on the results set by his Constant Growth DCF model and his Comparable Earnings Analysis for his recommended range of 9.2 percent to 9.5 percent.[46] The results of Mr. Parcell's CAPM analysis are well below the authorized ROE for any U.S. electric utility company in the past 25 years.[47]

Q. What are the areas in which you disagree with Mr. Parcell's CAPM analysis?

A. I have two areas of concern with the inputs and assumptions that Mr. Parcell has relied on to derive his CAPM results. First, I do not believe that Mr. Parcell's risk free rate of 2.23 percent adequately considers projected increases in Treasury bond yields that are expected over the period that TEP's rates are likely to be in effect. Second, I disagree with Mr. Parcell's use of a MRP of 5.75 percent.

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46 Direct Testimony of David C. Parcell, at 33.

47 Source: SNL Regulatory Research Associates.

Q. Please explain your concern with the risk free rate that Mr. Parcell has used in his CAPM analysis.

A. Mr. Parcell has used a current three-month average of the 20-year Treasury bond yield for his risk-free rate in conjunction with a long-term historical average MRP. My primary concern is that when interest rates are anomalously low, as they are today, it is important to either use a normalized interest rate that is more characteristic of the long term average, or a current interest rate in conjunction with a forward-looking MRP that reflects the current interest rate environment and the inverse relationship of the market risk premium to interest rates.

The inputs and assumptions used in the ROE analysis should reflect the forward-looking cost of equity. Mr. Parcell agrees that the cost of capital is forward looking.[48] As discussed in Section III of my Rebuttal Testimony, leading economists surveyed by Blue Chip are expecting higher interest rates over the next five years. This is a very important consideration for equity investors as they assess their return requirements. Mr. Parcell makes no attempt to normalize the current anomalously low interest rates and yet pairs them with the long term average market risk premium, which is based on much higher interest rates. Mr. Parcell's risk free rate of 2.23 percent does not adequately take into consideration the effect of the market's expectation for higher interest rates on the cost of equity for TEP. For that reason, I believe that Mr. Parcell's CAPM results are significantly understated.

[48] Staff Response to TEP Data Request 2.14(B)("Mr. Parcell considers the cost of capital to be forward looking.").

Q. Mr. Parcell states that it is "not proper to use projected interest rates as the risk-free rate" and that the current yield is the proper rate because it is "known and measurable and reflects investor's collective assessment of all capital market conditions." Do you agree?

A. No, I do not. First, I disagree that current interest rates reflect investors' collective assessment of all capital market conditions. As I have stated previously in this testimony, current yields on U.S. Treasury securities are being driven by the Federal Reserve's monetary policy, not by typical bond market participants; and today's low interest rates are not reliable indicators of investment risk or the cost of capital in equity markets over the period that the rates in this case will be in effect. It is common practice for analysts to use normalized interest rates, as I have done by using a forecast bond yield, particularly in anomalous market conditions, because forecasted bond yields provide a more reliable indication of investment risk and the cost of capital over the expected rate period.

Q. What MRP does Mr. Parcell use in his CAPM analysis?

A. Mr. Parcell estimates the MRP as being in the range of 4.40 percent to 6.85 percent. From within that range, he chooses an MRP of 5.75 percent.[49]

Q. What is the basis for Mr. Parcell's MRP estimate?

A. Mr. Parcell considered several alternate measures of the equity risk premium. On Schedule 8, Mr. Parcell calculates the historical ROE of the S&P 500 for each year from 1978 to 2014 by dividing earnings per share by average book value per share for each year. He arrives at the annual risk premium by subtracting the total return on the 20-year Treasury bond. The average of all the yearly risk premiums is 6.85 percent. As an

[49] Direct Testimony of David C. Parcell, at 28.

alternative measure, he considers total returns for the S&P 500, less the total return of the 20-year Treasury as tabulated by Morningstar, using both arithmetic and geometric averages for the period from 1926-2014. That analysis resulted in risk premiums of 6.0 percent (arithmetic) and 4.4 percent (geometric).

Q. Why do you disagree with Mr. Parcell's estimate of the MRP?

A. First, the MRP that Mr. Parcell estimates is an annual historical value that is not necessarily reflective of current or projected market conditions. Second, the MRP should be a market-based input to the CAPM, entirely subject to market forces. Mr. Parcell's calculation of the annual return on book equity for the S&P 500 removes the market assessment from the model. Mr. Parcell has substituted the accounting book value for the market valuation embedded in stock returns. By calculating the annual return on book equity rather than the return on share price, he is removing the objectivity inherent in a market model and substituting accounting data and all of the idiosyncrasies associated with that data into his analysis. The CAPM is a market model, and its inputs should be derived from the equilibrium of market forces, not accounting cost and earnings information.

Q. What are your other concerns with Mr. Parcell's MRP estimate?

A. Aside from the fact that Mr. Parcell relies entirely on historical data for his MRP and provides no forward-looking risk premium estimate, his averaging of historical MRPs based on geometric means and arithmetic means is without basis. He states that, "a combination of arithmetic and geometric means is appropriate since investors have access

to both types of means presumably, both types are reflected in investment decisions and thus stock prices and the ROE."[50] I disagree.

Geometric returns serve a specific purpose, as do arithmetic returns. To simply average the two, because they are both published and available to investors is completely without basis. The only appropriate mean for this purpose is the arithmetic mean. The geometric mean is the compound rate that equates a beginning value to its ending value. It is used to determine the exact rate of compounded return between a specific starting and ending point. The arithmetic mean is the simple average of single period rates of return and best approximates the uncertainty associated with returns from year to year. The important distinction between the two methods is that the arithmetic mean assumes that each periodic return is an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. By contrast, the geometric mean does not incorporate the same degree of uncertainty because it assumes that returns remain constant from year to year. In his review of literature on the topic, Cooper noted the following rationale for using the arithmetic mean:

> Note that the arithmetic mean, not the geometric mean is the relevant value for this purpose. The quantity desired is the rate of return that investors expect over the next year for the random annual rate of return on the market. The arithmetic mean, or simple average, is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean....[The] geometric mean underestimates the expected annual rate of return.[51]

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50 Direct Testimony of David C. Parcell, at 27-28.

51 Ian Cooper, *Arithmetic versus geometric mean estimators: Setting discount rates for capital budgeting*, European Financial Management 2.2, (1996): 158.

Q. You noted earlier that Mr. Parcell computed his MRP estimates using the "total return" on the 20-year government bond yield, not the "income return." Why is it not appropriate to use the total return on government bonds to derive the MRP?

A. According to Morningstar, the historical MRP is appropriately calculated by subtracting the *income only* portion of the government bond return from the total return on large company stocks:

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return…The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[52]

By subtracting the total return on government bonds from the total return on large company stocks, Mr. Parcell has understated the historical MRP by approximately 100 basis points (using the arithmetic mean).[53] Based on Mr. Parcell's average Beta coefficient of 0.78, the effect on his mean CAPM estimate is approximately 78 basis points. Even with that correction, using a historical MRP renders results that are far too low to be reasonable estimates of TEP's cost of equity.

Q. Mr. Parcell contends that your MRPs are overstated. What is your response?

A. Mr. Parcell presumes that my forward-looking MRP is over-stated because it exceeds the average long term MRP from 1926 to present. Mr. Parcell testifies: "Ms. Bu[l]kley offered no evidence or rationale to explain why investors would expect such a large increase in risk premiums over historic levels. Again, Ms. Bu[l]kley chooses data that

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[52] Morningstar, Ibbotson SBBI 2012 Valuation Yearbook, Market Results for Stocks, Bonds, Bills, and Inflation 1926-2011, at 55.

[53] Morningstar SBBI Presentation, Morningstar Stocks, Bonds, Bills, and Inflation 1926 – 2015, at 6.

produce higher and excessive results."[54] One needs to look no further than Mr. Parcell's own Schedule 8, where he shows, by his own estimation that the MRP increased from 7.94 percent prior to the financial market collapse in 2007 to 10.85 percent in 2014, the last year of his analysis. Mr. Parcell's analysis demonstrates that investors expect higher risk premiums over historical levels. In fact, Mr. Parcell's recent estimates of the MRP are higher than those used in my analysis.

Q. Are there other regulatory agencies that have offered opinions on a forward-looking CAPM?

A. Yes. In Opinion 531-B the FERC specifically addressed the assumptions used in a projected CAPM analysis. The FERC concluded that estimates of the MRP using the same methodology that was used in my Direct Testimony were appropriate. Specifically, the FERC stated:

> ...As an initial matter, we reject EMCOS's argument that the NETOs' CAPM analysis is flawed because it used a DCF study to determine the market risk premium. As explained above, using a DCF study is the standard method of calculating the market risk premium in a forward-looking CAPM analysis. We are, therefore, unpersuaded that the use of a DCF study renders the NETOs' CAPM analysis deficient. We also disagree with Petitioners' argument that the NETOs' CAPM analysis relied on an overly optimistic growth rate input in determining the market risk premium. The growth rate in the NETOs' CAPM analysis is based on IBES data, which the Commission has long relied upon as a reliable source of growth rate data.[55]

Q. What are your conclusions regarding Mr. Parcell's CAPM analysis?

A. Mr. Parcell's inputs to the CAPM analysis are based on historical data rather than forward-looking investor expectations. Under the current interest rate environment, the

[54] Direct Testimony of David C. Parcell, at 42 [corrected spelling of Bulkley].
[55] Opinion No. 531-B, 147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015) at para 110.

CAPM does not produce reliable results without making adjustments to certain inputs and assumptions. Mr. Parcell attributes his lower CAPM results to lower interest rates and believes that investors expect lower risk premiums than in prior years as a result of lower equity market returns and a perceived decline in investor expectations of equity returns and risk premiums.[56] Mr. Parcell fails to acknowledge the well-established inverse relationship between the market risk premium and interest rates. Given the current low yields on Treasury bonds, and the inverse relationship between interest rates and the MRP, the MRP should be higher than the historical average, not lower. This is demonstrated in Mr. Parcell's annual estimate of the MRP.[57]

The average historical income only return on long-term government bonds that is used to calculate the historical MRP is 5.00 percent, while the current 30-day average risk free rate on long-term government bonds is approximately 2.65 percent. The historical MRP as reported by Ibbotson and Associates is 7.0 percent through 2015. Because interest rates on long-term government bonds are well below the historical average of 5.00 percent, the inverse relationship between interest rates and the MRP implies that the forward-looking MRP should be higher than 7.0 percent. Consequently, Mr. Parcell's interest rate and MRP in his CAPM analysis are too low and provide no meaningful insight into the cost of equity for TEP. Furthermore, while Mr. Parcell is critical of the assumptions used in my CAPM analysis, his assumptions produce a mean of 6.7 percent for his proxy group – a result that is at least 260 basis points below the lowest authorized ROE for an electric utility, that I am aware of; and 265 basis points below his own ROE recommendation in this case. These results are so low that Mr. Parcell does not even use them in setting his recommended ROE.[58]

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56 Direct Testimony of David C. Parcell, at 33.

57 Direct Testimony of David C. Parcell, Schedule 8.

58 Direct Testimony of David C. Parcell, at 33, where he states, "*This range includes my DCF result (9.2 percent), and my CE result (9.5 percent)....*"

D. Comparable Earnings Analysis

Q. Please explain your concerns with Mr. Parcell's Comparable Earnings Analysis.

A. Mr. Parcell provides a Comparable Earnings analysis that presents "realized returns" over a period that is too long (as far back as 2002) to be relevant in this proceeding. Many of the proxy companies would not have met my screening criteria during those historical periods, particularly those that have had credit ratings below investment grade. Furthermore, realized book returns are not a good proxy for the return that investors expect going forward, especially realized book returns that date back over a decade and include losses from non-electric operations. For example, according to Mr. Parcell's Schedule 10, PNM Resources earned an ROE of 3.4 percent in 2007, 0.50 percent in 2008, and 3.10 percent in 2009. According to PNM's 10-K, these disappointing returns were not attributable to ongoing utility operations, but rather impairment of goodwill, trading losses in unregulated operations, high rates of customer defaults, and significant regulatory disallowances. It makes little sense to incorporate such factors into a forward-looking return estimate, particularly when these events occurred nearly a decade ago. Similarly, low returns for Otter Tail between 2008 and 2011 appear to be entirely due to losses in non-electric operations. It is not appropriate to bring historical accounting returns into an exercise that is setting forward-looking ROE. Mr. Parcell's Comparable Earnings analysis is a backward looking measure with no consideration of or relevance to current market conditions. Alternatively, the authorized ROEs for the utility subsidiaries of the proxy companies is more reflective of the regulated ROE that investors expect for similar risk companies. Based on my analysis of the authorized returns of the utility subsidiaries of the proxy companies, those authorized returns averaged 9.98 percent.

E. Conclusions on Mr. Parcell's ROE Recommendation

Q. What is your conclusion regarding Mr. Parcell's ROE recommendation of 9.35 percent?

A. While I present several results in my testimony, I consider the effect of market conditions on certain models and weight the results accordingly. My recommended ROE is within the range established by the high end of the DCF analysis presented in my Direct Testimony as well as the low end of the range established by the results of the CAPM. In contrast, while Mr. Parcell criticizes the assumptions used in my analyses in support of his own methodologies, he discards nearly all of his own results. Specifically, Mr. Parcell offers extensive criticism of the assumptions used in my CAPM, offering instead his view on the appropriate specification of this model, then discards the results of that model.

With respect to the DCF model, Mr. Parcell spends pages criticizing my exclusive use of EPS growth rates, yet the only DCF result from the myriad of growth rates he uses in his DCF model is the one derived from EPS growth rates.

Mr. Parcell criticizes my use of forecasted interest rates in my regression risk premium analysis, claiming that resulting ROEs are too high, despite the fact that those ROEs are based solely on the historical relationship between interest rates and authorized returns. While Mr. Parcell criticizes the use of projected data in my various analyses, he relies on a Comparable Earnings methodology that produces returns, even on a projected basis, that are lower than the 9.5 percent ROE that he concludes is derived from this methodology.

F. Capital Structure

Q. Mr. Parcell rejects the adjustments TEP made to its test year capital structure and cost of debt. Is this appropriate?

A. I don't believe so. It is common practice for utilities to adjust historical test year figures for known and measurable differences. Utilities already are dealing with regulatory lag when using a historical test year, particularly in periods of significant capital investment. By disallowing adjustments for known and measureable differences, the utility's rates are based on a rate base that is obsolete by the time rates go into effect, in effect disallowing any recovery for those known and measurable differences. As I have shown in my Direct Testimony, TEP's proposed capital structure of 50.03 percent is well below the mean of the proxy group of 54 percent and toward the low end of the range of equity ratios for the proxy companies. Mr. Parcell reports in his testimony that AUS Utility Reports indicate that the average gas and electric utility equity ratio in 2015 is 47 percent. However, this is the average equity ratio for utility holding companies and is not reflective of the utility operating companies' authorized equity ratios. Given TEP's significant risk profile, I would expect it to require more equity in its capital structure than the companies in its proxy group. Accordingly, TEP's proposed capital structure should be accepted.

G. Fair Value Rate of Return

Q. Please summarize Mr. Parcell's proposed return on the FVROR and Fair Value Increment.

A. Mr. Parcell recommends a FVROR of between 0.00 percent and 1.42 percent. In support of his position that the return on the FVRB increment should be zero, Mr. Parcell states that "[s]ince the increment between the FVRB and OCRB is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that

this increment has no financing costs". [59] While Mr. Parcell provides this recommendation, he also provides a calculation of the return on the FV increment. In that calculation, Mr. Parcell estimates the real risk-free rate and the difference between the nominal risk-free rate and inflation, which results in a return on the fair value increment of 1.42 percent. That is consistent with the return that is proposed in my Direct Testimony. Mr. Parcell's third calculation of the return on the fair value increment applies 50 percent of the real risk-free rate, or 0.70 percent, to the fair value increment.[60] The resulting FVROR resulting from this final method is 5.00 percent.

Q. Do you agree with Mr. Parcell's recommendation?

A. While I generally agree that the return on the Fair Value increment should be based on the real risk-free rate, I do not agree with the approach Mr. Parcell has used to calculate that return. Mr. Parcell relies on projected Treasury bond yields for a very short-term, ending in the second quarter of 2017. With the expectation that interest rates will increase, it would be reasonable to rely on a longer projection to reflect the period that these rates may be in effect. As shown in my Direct Testimony, the average projected return on 30-year Treasury bonds for 2017-2021 was 110 basis points higher than the yield Mr. Parcell relied on.

Q. How would the return on the Fair Value Increment change if you made these modifications to Mr. Parcell's analysis?

A. Relying on an expected nominal risk-free rate of 4.80 percent and Mr. Parcell's inflation factor of 2.3 percent would result in real risk-free rate of 2.50 percent and a return on the

59 Direct Testimony of David C. Parcell, at 45.
60 *Ibid.*, at 48-49.

fair value increment of 1.25 percent, which is 55 basis points higher than Mr. Parcell's recommendation.

Q. What is the effect of this change on the FVROR?

A. While I disagree with Mr. Parcell's recommended ROE of 9.35 percent, for the purposes of illustration, maintaining that cost rate and adjusting the return on the fair value increment to reflect a projected real risk-free rate, the FVROR would be 5.16 percent. Assuming an ROE of 10.00 percent and a return on the fair value increment of 1.25 percent, the resulting FVROR would be 5.57 percent.

V. RESPONSE TO RUCO WITNESS MEASE

Q. Please summarize Mr. Mease's analyses and recommendations.

A. Based on his analyses, Mr. Mease develops a range of ROE results from 7.91 percent to 9.65 percent and recommends an ROE for TEP of 9.20 percent.[61] The high and low results of Mr. Mease's Constant Growth DCF analysis form the upper and lower boundaries of his range of results. His CAPM analyses (yielding a mean result of 7.97 percent) and his Comparable Earnings analysis (yielding a range from 8.50 percent to 9.30 percent) fall within his range. Mr. Mease indicates that his point estimate of 9.20 percent is at the high side of the range of results derived from his DCF, CAPM and Comparable Earnings ("CE") analyses.[62] Mr. Mease testifies that the economy is recovering from recession more slowly than expected and that expected investment returns have declined. He states that given the economic uncertainty going forward, interest rates will remain at or near current levels for the next several years.[63] Mr. Mease

61 Direct Testimony of Robert B. Mease, at 27.
62 *Ibid.*, at 17.
63 *Ibid.*, at 12-13.

supports the Company's proposed capital structure of 50.03 percent common equity and 49.97 percent long-term debt. He calculates the weighted average cost of capital of 7.30 percent. Further, Mr. Mease recommends a FVROR for TEP of 5.20 percent, which he derives by subtracting an inflation rate of 1.56 percent from his inflation adjusted weighted average cost of capital of 6.76 percent.

Q. Is Mr. Mease's ROE recommendation of 9.20 percent fair and reasonable for TEP?

A. No, Mr. Mease's ROE recommendation of 9.20 percent is 80 basis points below TEP's currently authorized ROE and well below returns available from other comparable-risk investments. Mr. Mease's discussion of economic and capital market conditions does not reflect the reality of higher credit spreads, or prospects for higher interest rates, or the volatility that has characterized the broader equity market in recent months. As a result, Mr. Mease's recommendation does not reflect the current and prospective market conditions that TEP will experience during the period in which rates will be in effect. Finally, Mr. Mease has failed to take into consideration additional business and regulatory risks which differentiate TEP from the proxy group companies.

Q. Mr. Mease notes that rate filings by electric utilities in 2015 were the fewest in seven years and the average awarded ROE was the lowest in three decades. Does this put his recommendation into perspective?

A. Although it is true that authorized ROEs have trended down with interest rates over the past decade and are near the lowest level in three decades, no authorized return for vertically-integrated utilities has been authorized as low as Mr. Mease's recommendation of 9.20 percent for TEP. The EEI Report Mr. Mease cites in his testimony indicates that the mean authorized return for electric utilities is 9.85 percent, or 65 basis points higher than his recommendation. That average ROE includes both T&D and vertically

integrated companies. TEP's risk related to operating an extensive generation portfolio should result in an ROE above the mean for that sample group.

Q. What are your principal areas of disagreement with Mr. Mease?

A. I disagree with the following aspects of Mr. Mease's analyses: (1) his primary reliance on a Constant Growth DCF model; (2) his use of projected dividend growth rates in the Constant Growth DCF model; (3) his application of the CAPM and the reasonableness of his CAPM results; (4) his failure to take into consideration the higher business and regulatory risks to which TEP is exposed relative to the proxy group companies; and (5) his FVROR recommendation and the method used to derive that recommendation.

A. Application of the Constant Growth DCF Model

Q. What growth rate does Mr. Mease rely on in his Constant Growth DCF analysis?

A. Mr. Mease states that dividend growth can be measured using the product of a company's retention ratio and its return on book equity.[64] This is the sustainable growth rate commonly expressed as the "b" x "r" growth rate. However, in Exhibit RBM-5, Mr. Mease's analysis relies on both projected dividend growth rates, as reported by Value Line, and analysts' projected earnings growth rates as, reported by Yahoo! Finance, not on sustainable growth, as his testimony implies.

Q. Do you agree with the growth rates that Mr. Mease relies on in his DCF analysis?

A. Not entirely. Mr. Mease relies on an average of projected dividend per share growth and earnings per share growth rates to estimate the growth rate in the DCF model. Estimates

64 *Ibid.*, at 9.

of earnings growth are more indicative of long-term investor expectations than are dividend or book value growth estimates because earnings growth is least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Furthermore, earnings are the fundamental driver of a company's ability to pay dividends. As noted by Brigham and Houston:

> Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).[65]

In the analysis presented in my Direct Testimony, the growth rate used in the Constant Growth DCF model is a projected earnings per share growth rate.

Q. Have you reviewed the Potomac Electric Power decision that Mr. Mease cites as support for relying on the DCF model?

A. Yes, I have. While the commission in that case did rely on the DCF model, there are other important factors to be noted from this decision. First, the commission indicated that while it has a preference for the DCF model, it does not preclude parties from filing other approaches and most importantly, the commission considered the entire record, "which may include actions taken by other commissions and recent changes in the law."[66] Furthermore, the commission set the upper bound of the ROE at the high end of the range of the Constant Growth DCF results, calculated based on the high earnings per share growth rates; this is similar to the calculation that Mr. Mease performed that resulted in an ROE of 9.65 percent. Finally, it is important to note that the ROE that was established by that commission in 2014 for Potomac Electric Power (a lower-risk transmission and

[65] Eugene F. Brigham and Joel F. Houston, *Fundamentals of Financial Management*, at 317 (Concise Fourth Edition, Thomson South-Western).

[66] Public Service Commission of the District of Columbia, Order and Opinion No. 17424, March 26, 2014, p. 102-103.

distribution only utility) was 9.50 percent, or 30 basis points higher than the ROE recommended by Mr. Mease.

Q. Has the FERC provided a rationale for setting the ROE at the upper end of the range of reasonable returns?

A. Yes, it has. In FERC Opinion No. 531-B, the FERC allowed a return for the NETOs that was midway between the median return and the high end of the range. The Commission found that, although it typically sets the base ROE for a group of utilities at the midpoint of the zone of reasonableness identified by the DCF methodology, a mechanical application of the DCF methodology with the use of the midpoint here would result in an ROE that does not satisfy the requirements of Hope and Bluefield. Therefore, the Commission explained that based on the record in this case, including the unusual capital market conditions, the base ROE for the NETOs should be set halfway between the midpoint of the zone of reasonableness and the top of the zone of reasonableness.

As a result of the anomalous capital market conditions reflected in the record, and their potential impact on the DCF model, the Commission found it necessary and reasonable to consider additional record evidence, including evidence of alternative benchmark methodologies and state commission-approved ROEs, to gain insight into the potential impacts of these unusual capital market conditions on the appropriateness of using the [midpoint of the zone of reasonableness identified by the DCF methodology].[67]

The Commission found the additional record evidence—specifically the NETOs' risk premium analysis, Capital Asset Pricing Model (CAPM) analysis, expected earnings analysis, and evidence of state commission-authorized ROEs—supported a finding that

[67] Opinion No. 531-B, 147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015) at para. 36-37.

an upward adjustment from the midpoint was warranted. The FERC ruled that anomalous conditions warranted an ROE at the upper end of the reasonable range. As yields on Treasury bonds have continued to decline since the FERC issued Opinion 531-B, it is reasonable to believe that conditions in capital markets remain "anomalous," which would warrant a placement of ROE above the midpoint of the DCF results. As Mr. Mease's median DCF result is 8.56 percent and the mean high result is 12.26 percent, a midpoint ROE estimate would be 10.41 percent.

B. Application of Capital Asset Pricing Model

Q. Please summarize Mr. Mease's CAPM analysis and results.

A. Mr. Mease's CAPM analysis relies on what appears to be a historical MRP of 6.91 percent, the three-month average yield on 30-year Treasury bonds of 2.64 percent as the risk-free rate, and Value Line Betas for the proxy group ranging from 0.70 to 0.85.[68] That analysis produces an ROE estimate for TEP of 7.97 percent.[69]

Q. Please comment on the reasonableness of Mr. Mease's CAPM result.

A. Mr. Mease's CAPM result of 7.97 percent is entirely inconsistent with the returns required by equity investors for companies with commensurate risk, and is 203 basis points below TEP's currently authorized ROE. Furthermore, Mr. Mease's CAPM result has never been observed as an authorized ROE for any electric utility in at least the past 25 years.

[68] Exhibit RBM-6.
[69] Direct Testimony of Robert B. Mease, at 25.

Q. Do you agree with Mr. Mease's use of only the three-month average yield on the 30-year Treasury security as the risk-free rate in his CAPM analysis?

A. No, I do not. As Mr. Mease notes, the Commission has stated that "the consideration of both historical and projected data is appropriate in evaluating the Cost of Equity".[70] Therefore, the use of only the three-month historical average yield of 2.64 percent as the risk-free rate is not reasonable, especially when considering investors' expectation for rising interest rates during the period when this return will be in effect. Furthermore, Mr. Mease fails to take into consideration the inverse relationship between interest rates and the MRP. That is, if current interest rates are approximately 250 basis points below historical levels, it is not appropriate to use the three-month average historical yield on 30-year Treasury securities as the risk-free rate in conjunction with the historical MRP. Furthermore, Mr. Mease's CAPM analysis does not consider the market's expectation for rising interest rates on the cost of equity. Projected yields on 30-year Treasury securities indicate that investors are expecting substantially higher interest rates and higher inflation over the next five years.

Q. Do you agree with the MRP of 6.91 percent that Mr. Mease has used in his CAPM analysis?

A. Mr. Mease does not provide a source for his MRP estimate; however, it is generally consistent with historical MRPs. What is clear is that it is not a forward-looking MRP, and in that case should only be used with a normalized risk-free rate that better reflects the risk-free return investors require and accordingly the cost of capital. As discussed in my response to Mr. Parcell, today's artificially low interest rates are not indicative of the true required return for investment in risk-free securities.

[70] Direct Testimony of Robert B. Mease, at 29. See also Decision No. 75268,

Q. What are your conclusions regarding Mr. Mease's CAPM analysis?

A. Mr. Mease's inputs to the CAPM analysis are based on historical data rather than forward-looking investor expectations. Under the current interest rate environment, the CAPM does not produce reliable results without making adjustments to certain inputs and assumptions. Consequently, Mr. Mease's CAPM analysis provides no meaningful insight into the cost of equity for TEP.

C. Other ROE Issues

Q. Please explain your concerns with Mr. Mease's Comparable Earnings Analysis.

A. Mr. Mease provides an identical Comparable Earnings analysis to that prepared by Mr. Parcell. My criticisms of Mr. Mease's Comparable Earnings analysis are addressed in my response to Mr. Parcell.

Q. Mr. Mease included a page of rebuttal testimony addressing the small size premium. Have you presented evidence for TEP on this topic?

A. No. I have not proposed a small size premium for TEP.

D. Fair Value Rate of Return

Q. Please summarize Mr. Mease's recommendation with respect to the FVROR for TEP.

A. Mr. Mease recommends a FVROR of 5.20 percent for TEP, which is derived by subtracting an inflation rate of 1.56 percent from his recommended WACC 6.76 percent.[71] Mr. Mease's inflation rate is based on a seven-year historical average

[71] Direct Testimony of Robert B. Mease, Schedule RBM- 3, at 1.

difference between the yield on Treasury Inflation Protected Securities ("TIPS") and comparable Treasury securities with similar liquidity and duration.

Q. Do you agree with the methodology Mr. Mease has used to derive the FVROR for TEP?

A. No, I do not. In recent rate cases for both TEP and UNS Electric, the Commission has applied a positive rate of return to the fair value increment of rate base in establishing the FVROR. Mr. Mease's analysis does not follow this approach and instead simply removes inflation from the entire cost of capital.

Q. Please explain why it is not appropriate to apply an inflation factor to the WACC.

A. Only the fair value increment of the capital structure should be reduced to reflect a lower return. The remainder of the capital structure should receive the OCROR. To reduce the return on the entire capital structure for inflation understates the return on the original cost rate base.

Q. How does your proposed methodology for estimating the FVROR address Mr. Mease's point regarding inflation in the FVRB?

A. The calculation proposed in my Direct Testimony is consistent with the methodology proposed by Staff. This approach establishes the Fair Value Increment, which is the difference between the OCRB and the FVRB and assigns a separate return to that component of the capital structure. As shown in Exhibit AEB-10 of my Direct Testimony, I calculate the FVROR by applying the Company's requested equity cost rate of 10.00 percent to the equity component of the OCRB, and the debt cost rate to the debt

component of the OCRB without adjustment. The Fair Value Increment is then assigned a cost rate equal to one half of the risk-free rate.

Q. Do you agree with the methodology used by Mr. Mease to estimate inflation?

A. No. Mr. Mease's inflation rate analysis is entirely historical and considers only the period since the Great Recession, from 2009 through 2015. Furthermore, Mr. Mease's estimate of inflation has been declining since 2011. Furthermore, as discussed in the rebuttal testimony of Company Witness Grant, the methodology relied on by Mr. Mease is very sensitive to minor changes in expected inflation. As shown in Mr. Grant's rebuttal testimony, during periods of low inflation or deflation, the methodology used by Mr. Mease would produce a large return premium for most utilities. Conversely, during periods of high inflation, his proposed methodology would impose severe return penalties on most utilities. Significant variability in the revenue requirement resulting from this methodology exposes TEP to much greater risk than the proxy companies.

Q. What is your conclusion with respect to the appropriate return on FVROR for TEP?

A. I continue to support the methodology used in my Direct Testimony to establish the FVROR. That approach suggests a return on the Fair Value Increment between the projected risk free rate and the ROE. The methodology that I have employed is consistent with the approach proposed by Staff, though the inflation factors differ. Specifically, I conclude that the minimum ROR that should be applied to the Fair Value "Increment" of rate base is the real risk free rate, which I estimate to be 2.84 percent.[72] The Company continues to advocate the use of 50.00 percent of the risk free rate in the

[72] Direct Testimony Exhibit AEB-11.

FVROR calculation in order to moderate the effect of the rate increase on customers. As discussed in my Direct Testimony, applying 50 percent of the risk free rate to the Fair Value Increment, coupled with using a 10.35 percent ROE, results in a FVROR of 5.69 percent. Based on a 10.00 percent ROE, and taking into account adjustments the Company has made to the OCRB and Fair Value Increment of rate base, I now recommend a FVROR of 5.57 percent, calculated as shown in Table 4 below:

Table 4: Revised FVROR[73]

Capital	Amount ($M)	Weighting	Weighted Amount ($M)
Original Cost Rate Base	$2,066.3	50%	$1,033.2
Replacement Cost New Less Depreciation	$3,649.4	50%	$1,824.7
Fair Value Rate Base			$2,857.9
Appreciation above OCRB			$ 791.5

Capital	Amount	Percentage	Cost Rate	Weighted Cost Rate
Long-term Debt	$1,032.6	36.13%	4.32%	1.56%
Common Equity	$1,033.8	36.17%	10.00%	3.62%
OCRB	$2,066.4	72.30%		5.18%
Appreciation above OCRB	$ 791.6	27.70%	1.42%	0.39%
Total	$2,857.9	100%		5.57%

VI. RESPONSE TO DOD WITNESS MR. GORMAN

Q. Please provide a summary of Mr. Gorman's testimony and recommendations.

A. Mr. Gorman estimates a range of returns of 8.90 percent to 9.70 percent and recommends a cost of equity at the midpoint of his estimated range, *i.e.*, 9.30 percent.[74] The upper end of Mr. Gorman's estimated range (*i.e.*, 9.70 percent) is based on his risk premium analysis,[75] and the lower end (*i.e.*, 8.90 percent) represents the midpoint of his Constant Growth DCF analysis (using analyst growth rates) and his CAPM analysis.[76] Mr.

73 See Exhibit AEB-R-1.
74 Direct Testimony of Michael P. Gorman, at 2.
75 *Ibid.*, at 26.
76 *Ibid.*, at 30, 36.

Gorman appears to recognize that his Multi-Stage DCF results of 7.99 percent and his Constant Growth DCF results based on the Sustainable Growth model of 8.06 percent fall far below the results of his other models, since these results have been excluded from his range of returns. In fact, only Mr. Gorman's Bond Yield plus Risk Premium analysis produces an ROE estimate that is generally consistent with the authorized ROEs for vertically-integrated electric utilities in 2015 and 2016. Mr. Gorman's Constant Growth DCF model using growth rates based on either analyst EPS forecasts or sustainable growth rates, his Multi-Stage DCF model, and his CAPM analysis all produce ROE estimates that are well below any authorized return on equity for a vertically-integrated electric utility in the last 25 years.

Q. What are the major areas of disagreement between you and Mr. Gorman?

A. Mr. Gorman and I disagree on the inputs and assumptions used in several analyses including: (1) the growth rates used in the Constant Growth DCF model; (2) the long-term growth rate used in the Multi-Stage DCF Model; (3) the appropriate market risk premium for the CAPM analysis; (4) the approaches used in our respective Risk Premium analyses; (5) Mr. Gorman's conclusion that a 9.30 percent ROE is supportive of TEP's financial integrity; and (6) Mr. Gorman's recommended equity ratio for TEP.

A. Proxy Group Selection

Q. Please explain areas of difference between your proxy group and Mr. Gorman's proxy group for TEP.

A. Mr. Gorman and I have each developed a proxy group to estimate the cost of equity for TEP. However, we have used somewhat different screening criteria in developing our respective proxy groups. Mr. Gorman's proxy group consists of 29 electric utility

companies, whereas my proxy group was comprised of 12 electric utilities. While many of Mr. Gorman's screening criteria are similar to mine, there are several important differences that affect the composition of our respective proxy groups. First, Mr. Gorman screens for companies that are classified as "Regulated" or "Mostly Regulated" by the Edison Electric Institute, whereas I have screened based on the percentage of regulated operating income and the percentage of regulated income derived from electric utility operations. The EEI criteria for "Regulated" is investor-owned electric companies with greater than 80 percent of total assets regulated, and for "Mostly Regulated" is 50 to 80 percent of total assets regulated.[77] By contrast, I have screened out companies that do not derive greater than 90 percent of their regulated operating income from regulated electric operations.

Q. What is your conclusion with respect to proxy group for TEP?

A. Mr. Gorman's proxy group is much less focused on regulated electric utility operations than my group. For that reason, I believe that my proxy group is comprised of more risk-comparable companies than Mr. Gorman's. When I employ my DCF and CAPM assumptions using Mr. Gorman's proxy group, there is a substantial difference in the mean results of the Constant Growth DCF analysis. As discussed later in my Rebuttal Testimony, this difference is primarily due to Mr. Gorman's inclusion of Entergy and First Energy, both of which have negative earnings per share growth rates from Zack's and Reuters consensus forecasts, and very low SNL growth rates. As shown in Table 5, the results of the Constant Growth DCF analysis using Mr. Gorman's proxy group are 44 basis points lower than the results for my proxy group.

[77] EEI, 2015 Financial Review, Annual Report of the U.S. Investor-Owned Electric Utility Industry (2015) at i, v.

Table 5: Gorman Proxy Group Results v. Bulkley Proxy Group Results

	CONSTANT GROWTH DCF			MULTI-STAGE DCF		CAPM	
				Mean Growth Rate			
	Low	Mean	High	Ver. 1	Ver. 2	B'berg	VL
Average:	-0.49%	-0.44%	-0.23%	0.10%	-0.16%	0.13%	-0.14%
Median:	-0.25%	-0.03%	0.42%	0.17%	-0.09%	0.13%	-0.15%

B. DCF Analyses

Q. Please summarize Mr. Gorman's DCF analyses.

A. Mr. Gorman conducts three DCF analyses, two forms of the Constant Growth DCF and a Multi-Stage DCF analysis. The results of Mr. Gorman's DCF analyses range from 7.89 percent to 8.71 percent.[78] Mr. Gorman concludes that his DCF studies support a return on equity of 8.70 percent based on the Constant Growth DCF results, which he considers to be a reasonable high-end DCF return estimate.[79] All of Mr. Gorman's ROE estimates are well below any authorized ROE for a vertically-integrated electric utility in the last 25 years.

i. Constant Growth DCF

Q. How did Mr. Gorman develop his Constant Growth DCF analyses?

A. Mr. Gorman's Constant Growth DCF analyses are based on the use of analysts' earnings growth estimates in the first analysis and a measure of "Sustainable Growth" in the second specification of the model.[80]

78 Direct Testimony of Michael P. Gorman, Table 4.
79 Direct Testimony of Michael P. Gorman, at 36.
80 *Ibid.*, at 25, 27.

Q. Why are Mr. Gorman's Constant Growth DCF results so much lower than recent market benchmarks?

A. Mr. Gorman's first Constant Growth DCF analysis relies on an average of the analysts' earnings growth rates and produces returns in the range of 8.70 percent. This result, which Mr. Gorman characterizes as a reasonable high-end DCF estimate, is below the low end of the range he has established for his final recommendation. The low result is largely attributable to the extremely low growth rates that Mr. Gorman has relied on for several proxy group companies. For example, as shown in Exhibit MPG-4, Mr. Gorman relies on earnings growth rates of 0.50 percent for Entergy Corporation, and 0.40 percent for FirstEnergy. Relying on these growth rates in perpetuity in the Constant Growth form of the DCF model results in estimated returns for these two companies of 5.01 percent and 4.58 percent respectively.[81] These returns, which are more consistent with a debt return, not equity, influence the mean result of 8.71 percent.

Q. Have you made any adjustments to Mr. Gorman's Constant Growth DCF analysis using consensus analyst earnings growth rates?

A. Yes, I have. In my view, it is not reasonable to believe that investors would purchase shares in companies that are expected to have negative real earnings growth over the next five years. If those results are excluded from Mr. Gorman's DCF analysis, the mean ROE increases to 9.0 percent. While this is still well below returns for comparable risk electric utilities, it is 29 basis points higher than Mr. Gorman's mean DCF result using EPS growth rates.

[81] Exhibit MPG-5.

Q. What are the results from Mr. Gorman's "Sustainable Growth" DCF model?

A. Mr. Gorman's Sustainable Growth DCF analysis produces mean and median ROE results of 8.06 percent and 7.72 percent, respectively.[82] While Mr. Gorman devotes considerable effort to the support of the sustainable growth model, he ultimately does not rely on the results of this model when setting the ROE from his DCF analyses.

Q. Do you agree with the use of the "Sustainable Growth" estimate?

A. No, I do not. As discussed in my response to Mr. Parcell, there is academic support for the theory that earnings growth may not occur along with increases in the retention ratio. This contradicts the fundamental principles of the sustainable growth rate. Furthermore, by adopting Value Line's earned ROE estimates, Mr. Gorman has effectively pre-supposed the Return on Common Equity projected by Value Line for the proxy group companies. As shown on Exhibit MPG-7, the average Value Line earned ROE estimates for the companies in Mr. Gorman's proxy group is 10.38 percent, or more than 230 basis points higher than Mr. Gorman's DCF estimate using sustainable growth rates.[83] Moreover, as discussed in my response to Mr. Parcell, in Order 531, the FERC has recently abandoned the use of sustainable growth rates in the DCF analysis and has indicated that a two-stage analysis using long term growth estimates is more appropriate for electric utilities.

Q. Does Mr. Gorman disagree with the earnings growth estimates that you used in your Constant Growth DCF model?

A. Yes, Mr. Gorman states that the DCF results presented in my Direct Testimony are overly optimistic because the earnings growth rate that I have relied on is not a reasonable

82 Direct Testimony of Michael P. Gorman, Table 4.
83 Exhibit MPG-7, column 5.

estimate of long-term sustainable growth. Mr. Gorman suggests that the growth rate used in the DCF model cannot be higher than economists' predictions of GDP growth, which he estimates to be 4.2 percent. [84]

Q. What is your response to Mr. Gorman?

A. Mr. Gorman's own DCF recommendation contradicts his concern with the earnings growth rates used in my analysis. In order to support Mr. Gorman's recommended ROE of 9.30 percent using his Constant Growth DCF model, it would be necessary to rely on an average growth rate of 5.70 percent.[85]

ii. Multi-Stage DCF Analysis

Q. Please summarize Mr. Gorman's Multi-Stage DCF analysis.

A. Mr. Gorman also performs a Multi-Stage DCF analysis. In the first stage of his analysis (years 1-5), Mr. Gorman relies on consensus analyst EPS growth projections. In the second stage (years 6-10), the EPS growth rates are increased or decreased based on the difference between the short-term growth rate in Stage 1 and the long-term growth rate in Stage 3. In the third stage (starting in year 11), the growth rate is based on Mr. Gorman's estimate of projected GDP growth of 4.20 percent.[86] Mr. Gorman's Multi-Stage DCF analysis produces ROE estimates of 7.99 percent (mean) and 7.89 percent (median). Similar to the results of the Mr. Gorman's Sustainable Growth model, these ROE estimates are well below the authorized ROE for any vertically-integrated electric utility in the past 25 years. Furthermore, Mr. Gorman does not rely on his Multi-Stage DCF results in developing his range of results or his ROE recommendation.

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84 Direct Testimony of Michael P. Gorman, at 56.

85 Derived by iteratively solving for the growth rate using the constant growth formula employed by Mr. Gorman. [((D/P)x(1+g))+g= ROE]; where D=$1.82, P=$53.47 and ROE = 9.30%.

86 Direct Testimony of Michael P. Gorman, at 30,32.

Q. Do you agree with the long-term growth rate in Mr. Gorman's Multi-Stage DCF Model?

A. No, I do not. Mr. Gorman assumes a long-term growth rate of 4.20 percent, which is the average of five and ten-year GDP growth rate estimates as reported by Blue Chip Economic Indicators ("Blue Chip").[87] Mr. Gorman's GDP growth projection is more than 110 basis points below the long-term historical growth rate in nominal GDP reported by the U.S. Bureau of Economic Analysis. As discussed in my response to Mr. Parcell, there is support in the investment community for the use of historical real GDP growth and projected inflation as an estimate of nominal GDP growth.

Q. What long-term GDP growth rate would Mr. Gorman need to use in his Multi-Stage DCF analysis to support his ROE recommendation of 9.30 percent?

A. While Mr. Gorman is critical of my long-term GDP growth rate of 5.40 percent as being too high, in order to arrive at his 9.30 percent ROE recommendation, he would need to use a GDP growth rate of 5.84 percent[88] in his Multi-Stage DCF analysis. This implied growth rate is 164 basis points higher than the 4.20 percent GDP growth rate Mr. Gorman uses, and 44 basis points higher than my long-term GDP growth rate that Mr. Gorman criticizes as being too high.

87 *Ibid.*, at 27, and Schedule MPG-10.

88 Derived by using Schedule MPG-10 to solve for the long-term growth rate that would result in an ROE of 9.30 percent using Mr. Gorman's multi-stage DCF model.

Q. What is your conclusion regarding the appropriate GDP growth rate for the Multi-Stage DCF analysis?

A. In my view, current estimates of real GDP growth are understated relative to the long-term average because recent economic weakness is over-emphasized in current projections. For that reason, I believe it is reasonable to use historical long-term real GDP growth in conjunction with projected inflation as the terminal growth rate in the Multi-Stage DCF model.

C. CAPM Analyses

Q. Please summarize Mr. Gorman's CAPM analyses.

A. Mr. Gorman develops a range of CAPM estimates of 8.01 percent to 9.44 percent, based on an average of two estimates of the MRP. Mr. Gorman's first estimate of the MRP (7.90 percent) is based on the long-term historical arithmetic average real market return over the 1926-2014 period as reported by Morningstar, which he then adjusts for current inflation forecasts.[89] The second estimate of the MRP (*i.e.*, 6.00 percent) is based on the historical difference between the return on the S&P 500 and the total return on long-term government bonds.[90] Finally, Mr. Gorman uses the Blue Chip projected yield on 30-year Treasury bonds of 3.50 percent as his risk free rate, together with Beta coefficients provided by Value Line to calculate his CAPM result.[91] Mr. Gorman's CAPM analysis produces a return of 8.01 percent to 9.44 percent and yields an average ROE estimate of 9.10 percent.[92]

89 *Ibid.*, at 46,47.
90 *Ibid.*, at 47.
91 *Ibid.*, at 45,46.
92 *Ibid.*, at 49.

Q. Do you agree with the historical market risk premiums Mr. Gorman has used in his CAPM analysis?

A. No, I do not. As discussed in my response to Mr. Parcell, Mr. Gorman's CAPM analysis fails to reflect the inverse relationship between interest rates and market risk premia. That is, as interest rates decrease, the market risk premium increases, and vice versa. Mr. Gorman's use of a historical MRP fails to accurately reflect current market conditions.

Q. Why do you believe that the historical estimate of the MRP does not properly reflect current capital market dynamics?

A. Mr. Gorman employs an MRP based on the historical relationship between the returns on the S&P 500 and long-term government bonds. Table 6 shows that from 2007-2009 the historical MRP decreased even as market volatility (the primary statistical measure of risk) significantly increased. As discussed previously, Mr. Parcell's Schedule 8, which estimates historical MRPs, also demonstrates this.

Table 6: Historical Market Risk Premium and Market Volatility

	Market Volatility	Annual Market Return	Historical Market Risk Premium[93]
2009	31.48	26.46%	6.70%
2008	32.69	-37.00%	6.50%
2007	17.54	5.49%	7.10%

The assumption that investors would expect or require a lower risk premium during periods of increased volatility is counter-intuitive and leads to unreliable analytical results. The relevant objective in the application of the CAPM is to ensure that all three components of the model (*i.e.*, the risk-free rate, Beta, and the market risk premium) are

93 *Ibid.*, at 59. The Historical Market Risk Premium equals total return on large company stocks less income only return on long-term government securities. Data is as reported by Ibbotson for each year.

consistent with market conditions and investor perceptions. Assuming a lower market risk premium during periods when interest rates are artificially suppressed by Federal Reserve monetary policy is at odds with that premise.

Q. Does Mr. Gorman have any objections to your specification of the CAPM?

A. Yes, Mr. Gorman asserts that my DCF-derived MRP estimate is based on a growth rate component that is "far too high" to be an outlook for "sustainable" long-term market growth.[94]

Q. How do you respond to Mr. Gorman's conclusion on your estimated market return and MRP?

A. The MRP developed in my Direct Testimony is forward-looking and is based on the required return on the S&P 500 Index less the 30-year Treasury Bond Yield. The required return on the S&P 500 is calculated using the Constant Growth DCF model applied to the companies in the S&P 500 index for which long-term earnings projections are available. As I discussed more fully in my response to witness Parcell, the same method was endorsed by the FERC in Opinion No. 531-B as the appropriate manner to calculate the forward-looking MRP in the CAPM analysis.[95]

Q. Is Mr. Gorman's position regarding your DCF-derived market return consistent with his own approach to the CAPM analysis?

A. No, it is not. In his own CAPM analysis, Mr. Gorman uses a market return estimate of 12.10 percent.[96] Assuming that his market return estimate includes a dividend yield

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94 Direct Testimony of Michael P. Gorman, at 62.
95 Opinion No. 531-B,147 FERC ¶ 61,234 Order on Rehearing (March 3, 2015) at para.109-111,
96 *Ibid.*, at 47.

component equal to the value in my DCF-derived market return (*i.e.*, 2.07 percent), Mr. Gorman's market return estimates imply earnings growth rates of 9.93 percent,[97] or more than twice the long-term nominal GDP growth rate (*i.e.*, 4.20 percent) that Mr. Gorman uses in his Multi-Stage DCF Model. Mr. Gorman does not explain the inconsistency between his use of a market return growth rate in the CAPM that is materially higher than his long-term GDP growth rate estimate on the one hand, and his rejection of the DCF-derived market return used in my CAPM analysis (based solely on his observation that my value is higher than estimates of long-term GDP growth) on the other.

As a practical matter, it is unclear why Mr. Gorman asserts that 4.20 percent is an appropriate benchmark of long-term growth when his reliance on this growth projection in his Multi-Stage DCF analysis resulted in estimated returns that he ultimately could not rely on.

D. Risk Premium Model

Q. Please summarize Mr. Gorman's Risk Premium analyses.

A. In addition to his CAPM analysis, Mr. Gorman performs two additional Risk Premium analyses to estimate the Company's cost of equity. Mr. Gorman's first approach calculates the equity risk premium by taking the difference between regulatory commission-authorized equity returns for electric utilities and long-term Treasury bond yields from 1986-2015. Mr. Gorman determines that the rolling five-year average equity risk premia is 5.40 percent within a range of 4.25 percent and 6.71 percent.[98] Based on the projected 30-year Treasury yield of 3.50 percent, and the equity risk premium range

[97] Note that, based on my DCF-derived market return calculation, the earnings growth rate equals ([market return] – [dividend yield]) / (1 + 0.5 x [dividend yield]).

[98] Exhibit MPG-12.

noted above, Mr. Gorman calculates a range of risk premium results from 7.75 percent (3.50 percent plus 4.25 percent) to 10.21 percent (3.50 percent plus 6.71 percent). Mr. Gorman arrives at an ROE of 9.60 percent by giving 75 percent weight to the high end of his range and 25 percent weight to the low end.[99]

Mr. Gorman's second Risk Premium approach calculates the average risk premium for the period 1986 through 2015 as the difference between the average authorized equity returns for electric utility companies and the concurrent A-rated utility bond yields. Mr. Gorman determines that the rolling five-year average equity risk premia is 4.03 percent within a range of 2.88 percent and 5.53 percent.[100] Mr. Gorman then develops a range of ROE estimates by adding the 2.88 percent and 5.53 percent equity risk premia to the 13-week average Baa-rated utility bond yield of 4.91 percent, to arrive at a range of 7.79 percent to 10.44 percent. Mr. Gorman arrives at an overall ROE estimate of 9.78 percent by giving 75 percent weight to the high end of his range and 25 percent weight to the low end.[101] Based on those two approaches (*i.e.*, the risk premium as a function of Treasury yields and of utility bond yields), Mr. Gorman calculates a range of ROE results from 9.60 percent to 9.80 percent and determines that the midpoint of 9.70 percent represents a reasonable ROE estimate.[102]

Q. Does Mr. Gorman rely upon his risk premium model in making his ROE recommendation?

A. Yes. The high end of Mr. Gorman's range (*i.e.*, 9.70 percent) is based on the results of his Risk Premium analysis.[103]

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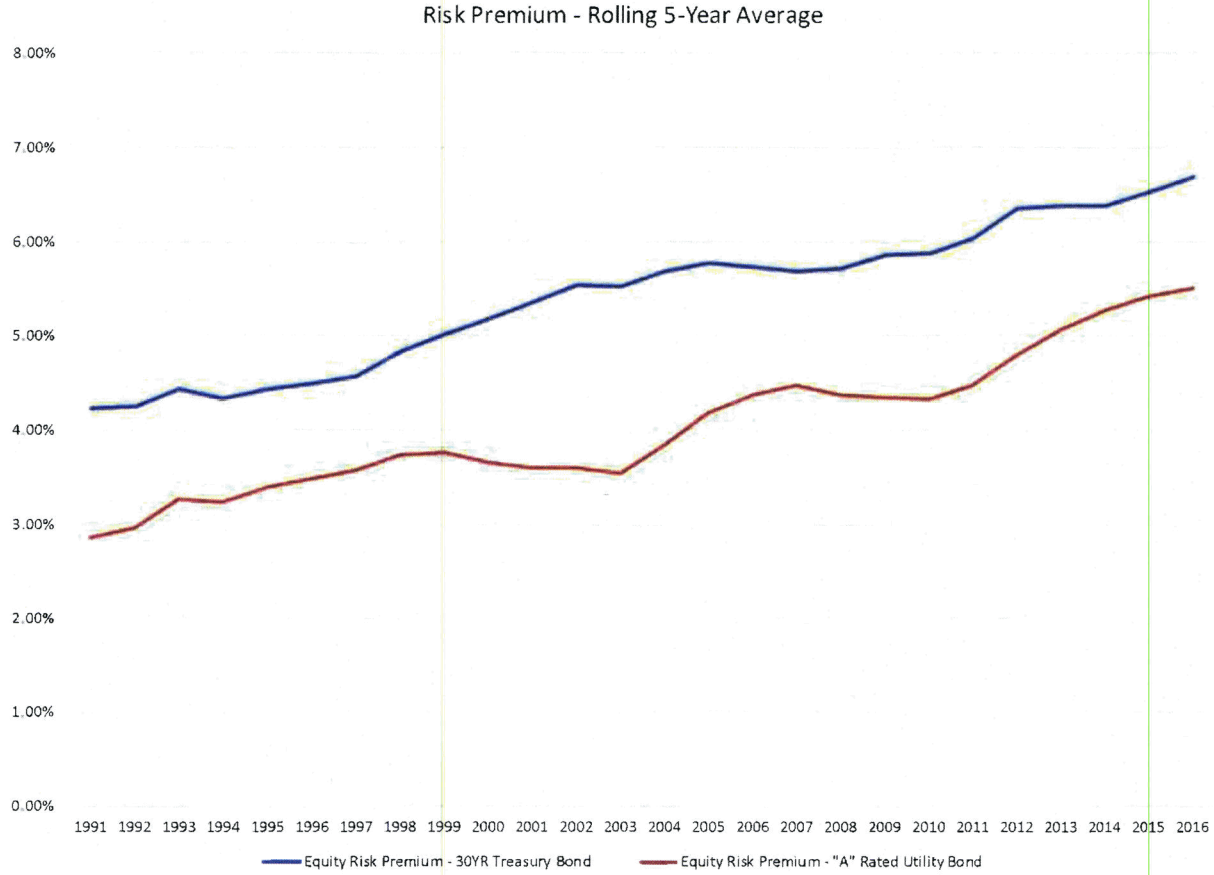
99 Direct Testimony of Michael P. Gorman, at 43.
100 Exhibit MPG-13.
101 Direct Testimony of Michael P. Gorman, at 43.
102 *Ibid.*
103 *Ibid.*, at 50.

Q. What are your specific concerns with Mr. Gorman's risk premium analyses?

A. Mr. Gorman creates a range of ROE estimates based on the rolling five year average risk premium as compared to Treasury bonds and A-rated utility bonds. However, as shown in Chart 33, the equity risk premium has been steadily increasing during the time period covered by Mr. Gorman's analysis. The low end of his range is represented by the five year rolling average equity risk premium in 1991, while the high end of his range is based on the five year rolling average equity risk premium in 2016.

Chart 3: Equity Risk Premium – 1991-2016 Rolling Five Year Average



Mr. Gorman offers no evidence as to why the average equity risk premium in 1991 is at all meaningful in establishing forward-looking ROE estimates in 2016. The high end of Mr. Gorman's range of Risk Premium estimates is 10.21 percent (based on Treasury yields) and 10.44 percent (based on utility bond yields). These are based on the average MRP for the five years ended 2016. Of the historical MRPs considered by Mr. Gorman, the most recent period would be most reflective of current and near term projected market conditions.

Q. What are the average results of Mr. Gorman's risk premium analysis using the most recent risk premium data?

A. Relying on the most recent five-year rolling average historical MRP, Mr. Gorman's estimated returns are 10.21 percent to 10.44 percent, the mean of which is 10.33 percent.

Q. Does Mr. Gorman's Direct Testimony address the inverse relationship between interest rates and risk premia?

A. Yes, Mr. Gorman disputes the inverse relationship between interest rates and risk premia.[104] In particular, Mr. Gorman claims that, while academic studies have shown that in the past there has been such an inverse relationship, the relationship has changed over time, particularly since interest rate volatility is lower now than it was in the 1980s. Mr. Gorman further suggests that I have ignored investment risk differentials in my regression analyses.

[104] Direct Testimony of Michael P. Gorman, at 54-55.

Q. Do you agree with Mr. Gorman's conclusions regarding your Risk Premium approach?

A. No, I do not. First, Mr. Gorman fails to recognize that a large body of research in addition to my own statistical analyses supports the inverse relationship between interest rates and equity risk premia. In addition, several of these studies were published after those that Mr. Gorman cites as evidence that this inverse relationship is a relic of the 1980s. As summarized in *New Regulatory Finance*:

> Published studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carelton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates—rising when rates fell and declining when interest rates rose. The reason for this relationship is that when interest rates rise, bondholders suffer a capital loss. This is referred to as interest rate risk.... Conversely in low interest rate environments, when bondholders' interest rate fears subside and shareholders' fears of loss of earning power dominate, the risk differential will widen and hence the risk premium will increase.[105]

Furthermore, Mr. Gorman's critique of my risk premium analysis is inconsistent with his own approach. Mr. Gorman states that the relationship between interest rates and equity risk premia "changes over time".[106] However, Mr. Gorman fails to account for any relationship between interest rates and equity risk premia in his own analysis. Further, he concludes that "current market perceptions of utility risk is about average relative to the historical time period," by reviewing credit spreads of utility bond yields. However, he comes to this conclusion by subtracting a projected bond yield of 3.5 percent from a 13-week average utility bond yield to calculate his credit spreads. One cannot infer the current state of market risk by subtracting a projected bond yield from historical bond yield information. If he wishes to derive any meaningful information from historical bond yields, he must use data from the same time periods. When he performed this

105 Morin, Roger A., *New Regulatory Finance*, Public Utilities Reports, Inc. (2006), at 128.
106 Direct Testimony of Michael P. Gorman, at 54-55.

analysis, it revealed that bond spreads were actually increasing for all but the very highest credit ratings, and indicates that there is more risk in today's market than the long term average.

E. Financial Integrity

Q. Does Mr. Gorman address whether his ROE recommendation will preserve the financial integrity of TEP?

A. Yes. Mr. Gorman assesses the reasonableness of his ROE recommendation by evaluating the *pro forma* effect that his recommended ROE would have on three of the Company's key financial ratios with the goal of ascertaining whether those ratios would still fall within S&P's guideline ranges sufficient for an investment grade rating.[107] Specifically, Mr. Gorman estimates the following financial ratios assuming that the Company earns his recommended ROE: (1) Total Debt to Total Capital; (2) Debt to Earnings Before Interest, Taxes, Depreciation, and Amortization ("EBITDA"); and (3) Funds From Operations ("FFO") to Total Debt. In his Schedule MPG-18, Mr. Gorman develops his *pro forma* financial ratio calculations based on TEP's retail cost of service as presented in this case and his recommended ROE of 9.30 percent. Mr. Gorman notes that TEP has an overall financial risk profile rating of "Significant" from S&P and proceeds to demonstrate that, assuming all other inputs to his *pro forma* financial analysis remain unchanged, his recommended ROE of 9.30 percent would be sufficient to maintain those three key financial ratios within the S&P guideline ranges for "Significant" or "Intermediate" financial risk. Based on that analysis, Mr. Gorman concludes that his recommendation would support an investment grade bond rating.[108]

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107 *Ibid.*, at 51-52.
108 *Ibid.*, at 52-53.

Q. Do you agree with Mr. Gorman's analysis and conclusion?

A. No, I do not. The fact that Mr. Gorman's ROE recommendation produces credit metrics that fall within a certain ratings category does not mean that the Company necessarily would achieve or maintain that rating because rating agencies consider factors other than financial ratios in the development of credit ratings. Moreover, Mr. Gorman's analysis assumes that TEP will earn its authorized ROE despite the persistent regulatory lag that is created in Arizona by the use of a historical test year. Lastly, from the standpoint of equity investors, the relevant consideration is whether the authorized ROE for TEP offers investors a comparable return as compared to prevailing returns available to investors in other utilities with commensurate risk. In that regard, Mr. Gorman's ROE recommendation of 9.30 percent is significantly lower than the average authorized ROE for integrated electric utilities of 9.73 percent for 2015 and 2016.

F. Capital Structure Recommendation

Q. Please summarize Mr. Gorman's proposed capital structure for TEP.

A. Mr. Gorman proposes a capital structure consisting of 48.69 percent common equity and 51.31 percent long-term debt, as compared to TEP's proposed capital structure of 50.03 percent common equity and 49.97 percent long-term debt.[109] In particular, Mr. Gorman testifies that the average common equity ratio for the companies in his proxy group is 47.9 percent based on data published by Value Line and 45.6 percent based on data provided by SNL (including short term debt).[110] Mr. Gorman states that his recommended capital structure is slightly higher than but comparable to the proxy group.[111]

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109 Direct Testimony of Michael P. Gorman, at 5.
110 Direct Testimony of Michael P. Gorman, at 23.
111 *Ibid.*

Q. Have you reviewed the analysis of proxy company capital structures that Mr. Gorman relies on?

A. Yes. Mr. Gorman relies on two data sources for his analysis: Value Line and SNL. Value Line only reports the capital structures of the holding companies, not the regulated utility subsidiaries. As shown in my Direct Testimony (Exhibit AEB-9), SNL does report the capital structures of the proxy companies. It appears, however, that the data that Mr. Gorman relied on from SNL was the capital structure at the holding company level, including short-term debt.

Q. Do you agree with the analysis prepared by Mr. Gorman?

A. No, I do not. The relevant capital structure for comparison purposes is at the operating company level, not the holding company, as used by Mr. Gorman. The Commission in this case will be setting the capital structure for TEP, the operating company, which will be used to finance investments in rate base that provides electric utility service to customers. Mr. Gorman's analysis includes corporate-level debt that is not part of the regulated or financial capital structure of the operating utilities.

As discussed in my Direct Testimony, TEP's proposed common equity ratio of 50.03 percent is below the mean common equity ratio of the operating companies in my proxy group of 54.00 percent.[112] The Company's proposed capital structure is based on the test year actual capital structure and pro forma adjustments for a pending bond redemption for the period ending June 20, 2015. In addition, it is consistent with the range of equity ratios at the operating company level for the electric utility companies in my proxy

[112] Direct Testimony of Ann E. Bulkley, at Exhibit AEB-9.

group, and with the requirements to maintain the Company's current credit rating. For those reasons, I continue to support TEP's proposed capital structure as reasonable.

G. Mr. Gorman's Adjustments to Ms. Bulkley's Analysis

Q. Mr. Gorman provides adjustments to the assumptions used in the ROE analyses you provided in Direct Testimony in this proceeding, the results of which are summarized in Table 7 of his testimony. Do you agree with the proposed adjustments?

A. No, I do not. Mr. Gorman's adjustments to the assumptions used in my analyses appear to be arbitrary and are not consistent with his own testimony. While Mr. Gorman criticizes my Constant Growth DCF analysis stating that it is based on excessive, unstainable growth rates, Mr. Gorman makes no adjustment to my Constant Growth DCF results, but instead indicates that they should be considered at the high end of the range of results.

Mr. Gorman criticizes the GDP growth estimate used in my Multi-Stage DCF analysis and adjusts the long-term growth rate to rely on the 4.2 percent growth rate that he uses in his Multi-Stage model. As discussed in my response to Mr. Gorman's analysis, the long-term GDP growth rate he uses in his analysis is unreasonably low and produces results that he ultimately does not rely on in developing his recommended ROE. As noted in my response to his Multi-Stage DCF analysis, in order to derive an ROE of 9.3 percent, which is his recommendation, it would be necessary to use a GDP growth rate of 5.83 percent. Therefore, since Mr. Gorman implicitly does not rely on his long-term GDP growth rate to determine his ROE recommendation, I do not believe it is appropriate to adjust my analysis to reflect his lower long-term growth rate.

Regarding my CAPM, Mr. Gorman suggests that this analysis is based on inflated market risk premiums and reduces my risk premium estimates, stating that they are inflated and updates my risk free rate. As discussed in my response to Mr. Gorman, the methodology used to develop the MRP estimates that I have relied on has been supported by the FERC and is more reasonable than relying on the historical MRP.

Finally, Mr. Gorman suggests that my bond yield risk premium analysis is based on inflated utility equity risk premiums and stale Treasury yields. I have already addressed our differing opinions regarding these analyses in my response to Mr. Gorman.

Q. Mr. Gorman indicates that based on credit rating, TEP and both your proxy group and Mr. Gorman's proxy groups are risk-comparable. Do you agree?

A. No, I do not. Though I do agree that ratings agencies perform a thorough review of risk, they do so with the focus of determining to what extent those risks are likely to impact the company's ability to repay its debt obligations. However, in this case, we are attempting to assess how those risks would impact the returns available for equity holders. Though the credit ratings may indicate a broad measure of risk, they do not address the risks that are applicable to equity holders.

H. Fair Value Rate of Return

Q. Please briefly summarize Gorman's testimony as it relates to the Company's FVROR.

A. Mr. Gorman's position regarding the FVROR is that the net operating income should be approximately the same using a FVRB as it would be using the OCRB.

Q. How does Mr. Gorman calculate the FVROR?

A. Mr. Gorman calculates the return on the Fair Value increment by estimating inflation and subtracting that from the nominal risk-free rate to estimate an implied real risk-free rate. Mr. Gorman then relies on 50 percent of the real risk-free rate as the return on the fair value increment. This methodology is similar to the methodology that I relied on in my Direct Testimony.

Q. Do you agree with Mr. Gorman's calculation?

A. No I do not. Mr. Gorman has not relied on consistent data to perform his calculation. Mr. Gorman suggests that it is more appropriate to use current observable yields on Treasury bonds and projected Treasury yield over the next two years, because this period of Treasury bond yields is likely to reflect TEP's actual capital costs during the period rates will be in effect.[113] Mr. Gorman states that the five and 10 year Treasury bond yields that I have relied on "will not impact TEP's cost of capital when the rates are in effect".[114] Despite that concern, Mr. Gorman relies on those long-term estimates of inflation to estimate his inflation rate. As shown in MPG-22, Mr. Gorman updates the inflation measures that I relied on in my Direct Testimony, extending the forecast period for an

[113] Direct Testimony of Michael P. Gorman, at 74.
[114] *Ibid.*

additional year to 2027. This has the effect of increasing the inflation factor that is used to convert the nominal risk-free rate to the real risk-free rate. While Mr. Gorman's schedule demonstrates that interest rates are projected to increase, even from the filing of my Direct Testimony, Mr. Gorman relies on the average of a historical nominal risk-free rate and a projected nominal risk-free rate through the third quarter of 2014. His estimate of the real risk-free rate is then developed by reducing the historical and short-term nominal risk-free rate by inflation expectations that are projected through 2027.

Q. How would you adjust Mr. Gorman's calculation?

A. The development of the nominal risk-free rate and the inflation factor that is used to estimate the real risk-free rate should be based on similar projected periods. As shown in my Direct Testimony and in Mr. Gorman's MPG-22, the estimate of the return on the fair value increment that was developed in my recommendation is internally consistent with respect to forecast periods.

Q. Have you calculated the effect of this change on Mr. Gorman's estimated return on the fair value increment?

A. Yes, I have. As shown in Exhibit AEB-R-2, relying only on the projected analysis, because it is the relevant analysis in a forward-looking estimate of the cost of capital, the average inflation projection is 2.27 percent and the average nominal Treasury bond yield is 4.45 percent. The resulting implied real risk-free rate is 2.13 percent. The return on the fair value increment would be 1.07 percent, or 61 basis points higher than Mr. Gorman's estimated return. Applying a cost rate of 1.07 percent to the fair value increment in the calculation of the FVROR presented in my Direct Testimony would result in a FVROR of 5.60 percent.

VII. RESPONSE TO WAL-MART WITNESS TILLMAN

Q. Please briefly summarize Mr. Tillman' testimony as it relates to the Company's ROE.

A. Mr. Tillman does not recommend a specific ROE. Rather, he observes that the proposed recommendation exceeds recently authorized ROEs across the country which, according to Mr. Tillman, have averaged 9.74 percent for all electric utilities from 2013 through 2016, and 9.89 percent for vertically-integrated electric utilities.[115] Mr. Tillman also testifies that the industry trend has been toward declining ROEs for electric utilities over this time period.[116] Mr. Tillman concludes that the Commission should approve an ROE no higher than the currently allowed ROE of 9.50 percent unless the Commission "determines that UNSE has sufficiently and substantially demonstrated a significant change in the economic environment faced by the Company"[117] since the Commission's decision in the 2012 rate case.

Q. What are your responses to Mr. Tillman on those points?

A. Mr. Tillman observes that the recommended ROE is higher than returns authorized for electric utilities by other regulatory commissions. He reports that authorized returns for electric utilities have ranged from 8.72 percent to 10.95 percent from 2013-2016 (to date); and that the average authorized ROE for that period is 9.74 percent. Mr. Tillman recommends an allowed ROE of no more than 9.50 percent for TEP, which is 24 basis points below the average ROE of all electric utilities included in Mr. Tillman's analysis. However, TEP is a vertically integrated electric utility with substantial generation assets. As I discussed in my response to Mr. Parcell, TEP has greater risk than most utilities,

115 Direct Testimony of Gregory Tillman, at 12.
116 *Ibid.*
117 *Ibid at 14.*

including other vertically integrated electric utilities, and as a result should be authorized a higher return. Mr. Tillman does report that the average for vertically-integrated electric utilities over the same time period (2013-2016) was 9.89 percent,[118] which is nearly 40 basis points above Mr. Tillman's recommendation.

Furthermore, though ROE has been trending down from 2013-2016, there is no justification for lowering the allowed return further, particularly given expectations for interest rate increases. Both my Direct and Rebuttal Testimony explain how current economic and forward-looking capital market conditions are evolving and how wider credit spreads and investor expectations for higher interest rates provide support for the conclusion that the cost of equity will be trending higher from current levels.

If the Commission finds recently authorized ROEs to be a useful benchmark in this proceeding, of the Company's revised requested ROE of 10.00 is within the range of ROEs (from 9.00 percent to 10.95 percent) authorized for vertically integrated electric utilities from 2013-2016 on a nationwide basis, while Mr. Mease's and Mr. Parcell's recommended ROEs of 9.30 percent and 9.35 percent, respectively, are lower than all but one such authorization for integrated electric utilities, as shown in Chart 1.

Q. Mr. Tillman believes the UNSE stipulation to a 9.5 percent ROE should be considered by the Commission in its decision regarding the authorized ROE for TEP. Do you agree?

A. No, I do not. As Mr. Tillman notes, the stipulation was negotiated between UNSE and several parties. Stipulations are based on a balancing of issues, where there are many

[118] SNL Database.

trade-offs to reach agreement across many parties. It is inappropriate to select one element of a negotiated agreement, in isolation and which was based on specific circumstances, and attribute the results of that agreement to TEP, a company with a completely separate set of circumstances.

VIII. CONCLUSIONS AND RECOMMENDATION

Q. Please summarize your conclusions regarding the appropriate ROE for TEP.

A. While the average authorized ROE declined in 2015, there is considerable variability in the range of authorized ROEs. Based on the risk factors identified for TEP, I believe that it is appropriate to set the ROE above the mean of the analytical results. As described in the Rebuttal Testimony of TEP witness Grant, the Company has updated its non-fuel revenue requirement using a 10.00 percent ROE, a value at the low end of my recommended range. I conclude that the Company's requested ROE of 10.00 percent is conservative based on the results of the ROE estimation methodologies, recently authorized ROEs for other vertically integrated electric utilities, the risk factors identified for TEP, and investors' expectation of market conditions over the period that rates will be in effect. ROEs at the levels proposed by the Opposing ROE witnesses are not reasonable and do not meet the standards established in *Hope* and *Bluefield* for a fair return.

Q. What is your recommendation for the FVROR for TEP?

A. Based on a 10.00 percent ROE, and a 1.42 percent return on the Fair Value Increment of rate base, I believe that a FVROR of 5.57 percent is reasonable and appropriate for TEP.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit AEB – R – 1

UNS ELECTRIC
FAIR VALUE RATE OF RETURN
ARIZONA STAFF METHODOLOGY

	Amount ($M)	Weighting	Weighted Amount ($M)	
Original Cost Rate Base (OCRB)	$ 2,066.3	50.00%	$ 1,033.2	[1]
Replacement Cost New, Depreciated Rate Base (RCND)	$ 3,649.4	50.00%	1,824.7	[2]
Fair Value Rate Base (FVRB)			2,857.9	[3]
Appreciation Above OCRB			$ 791.5	[4]
FVRB / OCRB Multiple			1.38	

Capital	Amount ($M)	Percent	Cost Rate		Weighted Cost Rate	
Long-Term Debt	$ 1,032.5	36.13%	4.32%	[5]	1.56%	
Common Equity	1,033.8	36.17%	10.00%	[6]	3.62%	
Capital Financing OCRB	$ 2,066.3	72.30%			5.18%	
Appreciation Above OCRB Not Recognized on Utility's Books	791.5	27.70%	1.42%		0.39%	
Total	$ 2,857.9	100.00%			5.57%	[7]

[1] Exhibit DJL-R-1 attached to the testimony of TEP witness David J. Lewis.
[2] Exhibit DJL-R-1 attached to the testimony of TEP witness David J. Lewis.
[3] Equals [1] + [2]
[4] Equals [3] – OCRB
[5] Schedule D-1
[6] Equals Recommended ROE on OCRB
[7] Capital Financing OCRB + Return on Fair Value Increment

Exhibit AEB – R – 2

Tucson Electric Power Company

Correction of Mr. Gorman's Fair Value Cost Rate

Line	As Filed by Ms. Bulkley[1]		Corrected	
	Step 1		**Step 1**	
	Consumer Price Index		**Consumer Price Index[2]**	
1	2017-2021	2.30%	2018-2022	2.30%
2	2022-2026	2.30%	2023-2027	2.30%
3	Average	2.30%	Average	2.30%
	Consumer Price Index (All-Urban)		**Consumer Price Index (All-Urban)[3]**	
4	2015	2.37	2016	2.392
5	2026	2.94	2027	3.123
6	Compound Annual Growth Rate	1.98%	Compound Annual Growth Rate	2.46%
	GDP Chain-type Price Index		**GDP Chain-type Price Index[3]**	
7	2015	1.11	2016	1.119
8	2026	1.34	2027	1.398
9	Compound Annual Growth Rate	1.74%	Compound Annual Growth Rate	2.05%
			Market-Based Breakeven Inflation	
10			13-Week Average Nominal Yield[4]	4.30%
11			13-Week Average TIPS Yield[5]	0.92%
12			Breakeven Inflation[6]	3.34%
13	**Average Inflation Forecast**	**2.01%**	**Average Inflation Forecast**	**2.27%**
	Step 2		**Step 2**	
	Nominal U.S. Treasury Bond Yield, 30-Year		**Nominal U.S. Treasury Bond Yield, 30-Year**	
14	2017-2021	4.80%	2018-2022[7]	4.30%
15	2022-2026	5.00%	2023-2027[7]	4.60%
16	Average	4.90%	Average	4.45%
17	Implied Real Risk Free Rate	2.84%	Implied Real Risk Free Rate[8]	2.13%
18			13-Week Average 30-Year TIPS Yield[5]	0.92%
19			Average Real Risk Free Rate	1.53%
20	50.0% of Real Risk Free Rate	1.42%	**50.0% of Real Risk Free Rate**	**1.07%**

Sources & Notes:

[1] Exhibit AEB-10, page 2.

[2] *Blue Chip Economic Indicators*, March 10, 2016, page 14.

[3] EIA, *Annual Energy Outlook 2016: Early Release*, Table 20.

[4] Exhibit MPG-15, page 1.

[5] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.

[6] (1+2.64%) / (1+0.92%) - 1.

[7] *Blue Chip Financial Forecasts*, June 1, 2016, page 14.

[8] (1+3.07%) / (1+2.13%) - 1.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIR
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Rejoinder Testimony of

Ann E. Bulkley

on Behalf of

Tucson Electric Power Company

September 1, 2016

EXHIBIT
ADMITTED
TEP-12
admitted

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Exhibit AEB-Rejoinder-1 **EEI 2016 Q1 Credit Ratings Update**

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley, and I am a Vice President of Concentric Energy Advisors, Inc. ("Concentric"). My business address is 293 Boston Post Road West, Suite 500, Marlborough, MA 01752.

Q. On whose behalf are you submitting this Rejoinder Testimony?

A. I am submitting this Rejoinder Testimony on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. Did you previously submit testimony in this proceeding?

A. Yes. I submitted Direct and Rebuttal testimonies regarding the appropriate Return on Equity ("ROE"), capital structure, and Fair Value Rate of Return ("FVROR") for TEP in this proceeding.

Q. What is the purpose of your Rejoinder Testimony?

A. The purpose of my Rejoinder Testimony is to respond to the cost of capital issues raised by Mr. Michael P. Gorman on behalf of the U.S. Department of Defense and all other Federal Executive Agencies ("DOD") with respect to the Settlement Agreement filed with the Commission on August 15, 2016 ("Settlement Agreement").

Q. Have you prepared any exhibits to your Rejoinder Testimony?

A. Yes. I have included Exhibit AEB-Rejoinder-1 to this testimony, which has been prepared under my direction.

II. REJOINDER RESPONSE TO MR. GORMAN

Q. Please provide a brief overview of Mr. Gorman's Rebuttal Testimony and his recommendations.

A. Mr. Gorman opposes the Settlement Agreement filed with the Commission on August 15, 2016, and urges the Commission to reject it.[1] He states that the settlement is unreasonable and exceeds fair compensation for TEP's investment risk; and that the FVROR and OCRB increment exceeds a fair return on the value of TEP's rate base. Mr. Gorman, instead, recommends an ROE of 9.5 percent and a capital structure of 48.69 percent, which represents the company's test year capital structure before any adjustment for known and measurable changes. Mr. Gorman's ROE recommendation results in a FVROR of 5.10 percent. Mr. Gorman also levels several criticisms against my testimony and dismisses many of the issues raised in my testimony as being without merit, e.g. my challenges to his inclusion of proxy companies with negative growth rates in his DCF analyses and to his use of sustainable growth rates that create results that are substantially lower than the Value Line ROE forecasts that he bases his sustainable growth estimates on. We also have differing perspectives on the current market risk environment. Mr. Gorman also takes issue with my forward-looking market return and the resulting market risk premium; and to my calculation of the FVROR increment.

[1] The agreement was signed and authorized by the Residential Utility Consumer Office, Arizonans for Electric Choice and Competition, Freeport Minerals Corporation, Sierra Club, Western Resource Advocates, Noble Americas Energy Solutions, LLC, The Kroger Co., Wal-Mart Stores, Inc. and Sam's West, Inc., and the Arizona Investment Council.

Q. What has been agreed upon by parties to the Settlement Agreement.

A The Settlement provided for a 9.75 percent ROE and an embedded cost of long-term debt of 4.32 percent, resulting in a weighted average cost of capital of 7.04 percent. It also provided for a fair value rate of return of 5.34 percent.

Q. Please provide a brief overview of your response to Mr. Gorman with respect to his testimony and the appropriate ROE for TEP.

A There are many methodological and theoretical areas where Mr. Gorman and I significantly disagree. However, setting aside the methodological and theoretical differences, the ROE that is stipulated in the Settlement Agreement is 25 basis points above the ROE that Mr. Gorman suggests as a maximum return for TEP. While Mr. Gorman suggests that 9.50 is the maximum return the Commission should authorize for TEP, the range that he recommends in his rebuttal testimony as well as the litigated authorized returns in other regulatory jurisdictions that he relies on in his surrebuttal testimony support an ROE at the stipulated level of 9.75 percent. In addition, the Value Line projected ROEs for his proxy companies, which Mr. Gorman uses to develop the sustainable growth rate used in his DCF analysis supports an ROE that is consistent with my original recommendation of 10.35 percent. As shown in Mr. Gorman's Exhibit MPG-7, p. 1 of 2 to his direct testimony, the Value Line projected ROE estimates for the proxy group averaged 10.38 percent. Regarding the Company's capital structure, Mr. Gorman's recommendation to use the Company's test year capital structure of 48.69 percent ignores proforma adjustments allowed by this Commission for pending bond redemptions, to the test year actual capital structure. Finally, Mr. Gorman's criticisms of my estimated rate of return on the Fair Value increment are without merit, as each component of the calculation is based on investor expectations of market conditions.

Q. Mr. Gorman states that market evidence clearly shows that the market is embracing returns on equity of 9.5 percent and lower for electric utilities. Do you agree?

A No. There is no such "clear" evidence. Mr. Gorman himself states that investors should expect an ROE of 9.69, which is intended to reflect a measure of central tendency in the 2015 and 2016 authorized ROEs for vertically integrated electric utilities.[2] That return is closer to the stipulated ROE of 9.75 percent than his initial recommendation of 9.30 percent or his revised recommendation of 9.5 percent.

Q. How does Mr. Gorman derive the 9.69 percent expected return for vertically integrated utilities?

A. Reviewing the data Mr. Gorman relied on for this analysis, that return is calculated by taking the midpoint of the average litigated ROEs for both 2015 and 2016. I see no reason why it would be beneficial to rely on the midpoint of the average of these two periods rather than taking the midpoint or simple average over the entire time period. Furthermore, Mr. Gorman's 2016 average authorized ROE consists of only two data points. Mr. Gorman's data ranges from 9.3 percent to 10.35 percent for the period 2015-2016. If one were to take the midpoint of the high and low data points for that period, the result would be 9.8 percent. Calculating the simple average of each observation, the result is 9.73 percent. Regardless, any of these measures of central tendency (ranging from 9.69 percent to 9.8 percent) are supportive of a 9.75 percent ROE.

Q. Do you agree with Mr. Gorman that authorized ROEs are trending down in 2016?

A. No, I do not. As noted previously, there have only been two data points for litigated ROEs in 2016. As presented on Mr. Gorman's MPG-24, one case was above the

[2] Rebuttal Testimony of Michael P. Gorman, at 7, lines 17-18.

stipulated ROE (Indianapolis Power and Light at 9.85 percent) and one was below (El Paso Electric – New Mexico at 9.48 percent).[3] This data does not make a compelling case that utility ROEs are trending down.

Q. Do you agree with Mr. Gorman's conclusion that ROEs that were established in settlement should not be considered among evidence of recently authorized ROEs?

A. I recognize that settlements represent an agreed upon set of terms that all parties can accept. Therefore, it is possible that some elements may not be agreeable to all parties in the case. However, while that is the case, including settled ROEs in the 2015 to 2016 period has very little impact on the overall average. Mr. Gorman's evidence indicates that there is a 2 basis point difference between the average including settlements (9.70 percent) and the average excluding settlements (9.72 percent).

Q. What conclusion can be reached from review of Mr. Gorman's evidence on authorized returns for vertically integrated electric utilities?

A. Mr. Gorman's evidence supports TEP's stipulated ROE of 9.75 percent. Though the data shows that there have been instances of ROEs at or very close to 9.5 percent issued for vertically integrated utilities, the vast majority are in the upper 9 percent to the lower 10 percent range. In light of the additional perceived risk that TEP carries for its heavy reliance on coal-fired generation assets and its large capital expenditure program, I find an ROE upwards of 10 percent to continue to be reasonable. However, the Stipulated ROE of 9.75 percent as shown by Mr. Gorman's own evidence, is representative of an integrated electric utility of average risk and is a reasonable compromise for parties in the settlement.

[3] Surrebuttal Testimony of Michael P. Gorman, Exhibit MPG-24, p. 2 of 2.

Q. Has Mr. Gorman presented other evidence that supports an ROE of 9.75 percent?

A. Yes. In his rebuttal testimony, the high end of the range established by Mr. Gorman's analysis was 9.7 percent.

Q Mr. Gorman states on p. 10 of his Rebuttal that "authorized returns on equity have been declining but utilities' bond ratings have been improving..." Do you agree?

A. No. I do not agree with either portion of this statement. As I have discussed above, utility ROE determinations do not appear to be trending lower in 2016. Furthermore, Value Line is projecting ROEs for Mr. Gorman's proxy group to be significantly higher than the ROE that he recommends, demonstrating the expectation that authorized returns will trend higher in the near term. Furthermore, I find no recent evidence that bond ratings are improving for the electric utility segment.

Q. What is the basis of Mr. Gorman's statement that bond ratings have been improving?

A. Mr. Gorman based his comments on credit rating analysts' reports he cites in his direct testimony. Specifically, he cites a December 9, 2015, S&P report titled, "The Outlook For U.S. Regulated Utilities Remains Stable On Increasing Capital Spending And Robust Financial Performance." Interestingly, that report describes the ratings outlook for regulated utilities as "Stable with a slight bias toward the negative."[4] This is not exactly a ringing endorsement for an improving credit outlook. Similarly, Mr. Gorman cites a Fitch report from September 2015, that characterizes the industry outlook as "Stable"[5]; and a Moody's report from November 2015 that also characterizes the "outlook for the US regulated utilities industry [as] stable."[6] None of these reports indicate that bond

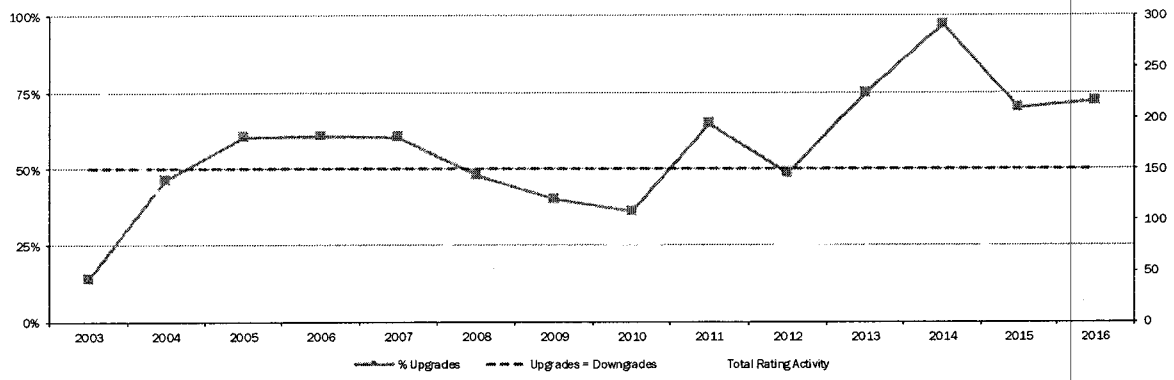
[4] Direct Testimony of Michael P. Gorman, at 5 line 12.
[5] *Ibid.*, at 6, line 25.
[6] *Ibid.*, at 6, line 32.

ratings are improving, but rather reveal that the outlook for regulated utilities is stable to slightly negative.

Q. Have you reviewed more recent studies regarding bond ratings?

A. Yes. EEI recently prepared a report that summarizes electric utility bond ratings and rating changes for 2016 to date. That study indicates that the ratio of positive to negative ratings actions have remained generally consistent with 2015 yields after having declined rather substantially over the past several years. Chart 1 below summarizes the data shown in EEI's Q1 2016 Update – Electric Utility Industry Financial Data and Trend Analysis, which I have also attached as Exhibit AEB-Rejoinder-1. The chart shows the number of ratings actions in each year (the lavender line and right vertical axis) and the ratio of upgrades to downgrades (the grey line and the left vertical axis). Based on the data shown in Chart 1, there has been no appreciable improvement in electric utility credit ratings.

Chart 1: Direction of Ratings Actions – U.S. Shareholder -Owned Electric Utility Industry



Source: EEI 2016 Q1 Credit Ratings Update, IV. Direction of Rating Action, derived from Fitch Ratings, Moody's, and Standard & Poor's.

Q. Has Mr. Gorman effectively presupposed the return on equity as projected by Value Line to be 10.38 percent for his proxy group in his calculation of the sustainable growth rate?

A. Yes, he has. The calculation of sustainable growth rates is in part premised on Value Line 3-5 year projections of ROE. As Mr. Gorman presents in his direct testimony at MPG-7, Value Line has estimated an ROE for each member of his proxy group that averages 10.38 percent for the group. He has made no attempt to reconcile this with the fact that when he uses the same data to reverse-engineer sustainable growth rates for his proxy group companies, the resulting ROEs for the same proxy group averaged 8.06 (mean) and 7.76 (median), more than 200 basis points lower. Mr. Gorman has not provided any reasonable explanation for such a large difference in ROE. Since he essentially abandons his sustainable growth ROE results, it is evident that Mr. Gorman even finds his sustainable growth results to be too low. In my opinion, the Value Line estimates of ROE for his proxy group provide another meaningful data point for this Commission to consider in its decision to set a just and reasonable ROE for TEP.

Q. Please summarize your response to DOD witness with respect to his capital structure recommendations for TEP.

A. Mr. Gorman recommends that the Commission adopt TEP's test year capital structure without allowing for adjustments for pending bond redemptions at the time of the test year end, but that have actually occurred. The test year capital structure Mr. Gorman recommends is already over a year old. This Commission has regularly considered adjustments for known and measurable changes to the test year capital structure. These adjustments are not allowed for items that "may" or "may not" occur, as Mr. Gorman states in his testimony, but in fact have occurred or will definitely occur and are measurable. It is appropriate for this Commission to approve TEP's proposed capital structure, adjusted for these known and measurable changes, of 50.03 percent equity and to reject Mr. Gorman's attempt to deny recovery for the higher amount of equity TEP already carries in its capital structure. I have shown in my analysis that TEP's proposed capital structure is reasonable in relation to the proxy group companies and should be accepted. The analysis provided by Mr. Gorman at Exhibit MPG-3 also shows that TEP's proposed capital structure is reasonable and within the range of proxy group company capital structures.

Q. Mr. Gorman states that a major flaw in your FVROR methodology is that you are not relying on observable market evidence to measure a fair rate of return on a fair value rate base, and that rather you are using a projected interest rate to capture a higher FVROR. Please explain your reasoning for using the projected interest rate.

A. I have estimated the nominal risk free rate for the FVROR calculation by taking the average of the forecast yield for the U.S. 30-year Treasury for two time periods, 2017-2021 and 2022-2026. I have relied on these long term averages as they incorporate investors expectation of movement in government interest rates. To use only today's

anomalous and artificially low interest rate environment would result in an understatement of TEP's FVROR over the time period that these rates will be in effect. As discussed in my direct and rebuttal testimonies, due to the anomalous market conditions that have resulted in abnormally low yields on Treasury bonds, and the prospects that those conditions will change in the near term, it is appropriate to rely on forward looking estimates of interest rates in setting the return on the FV increment.

Q. Are there other ideological or methodological differences with Mr. Gorman that you have not addressed either in this testimony or in your Rebuttal Testimony?

A. The majority of the differences between Mr. Gorman's analysis and the analysis presented in my direct testimony have been discussed in my direct and rebuttal testimonies. However, Mr. Gorman provides a few additional criticisms of my analysis in his Surrebuttal testimony that I will address. Specifically, the exclusion of low outlier data from the DCF results, and the market risk premium calculation used in my CAPM.

Q. Mr. Gorman devotes a considerable portion of his Surrebuttal Testimony discussing your proposal to remove the results of Entergy and First Energy from his DCF results. He claims that to do so would "not produce an unbiased legitimate estimate of the current market cost of equity based on a DCF model." Do you concur?

A. No. Mr. Gorman suggests that it is inappropriate to exclude Entergy and First Energy from my proxy group and that he appropriately included them. I excluded these companies because they did not satisfy my screening criteria, i.e. did not have positive long-term earnings growth forecasts from at least two equity analysts. Both companies had negative growth rates by Zacks and Yahoo, and very low SNL growth rates. However, Mr. Gorman has included them in his proxy group, and the DCF results for these companies were 5.01 percent and 4.58 percent, respectively. Mr. Gorman suggests

that removing two unreasonably low DCF results requires that you remove the same number of DCF results at the upper end of the range. I disagree. There were no extreme outliers that defied economic logic at the upper end of Mr. Gorman's data. In SoCal Edison, Opinion No. 445, the FERC acknowledged that "... investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return..."[7] In that same 2010 SoCal Edison proceeding the FERC found it to be "reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more, taking into account the extent to which the excluded low-end ROEs are outliers from the low-end ROEs of other proxy group companies. This gives the Commission flexibility to exclude proxy company results when the low-end ROE is somewhat above the average bond yield, but is still sufficiently low that an investor would consider the stock to yield essentially the same return as debt." This practice was affirmed in FERC Opinion Nos. 531[8] and 531-B.[9] With long term utility bonds very near to 4 percent, I believe it continues to be reasonable to remove Entergy and First Energy as low outliers from Mr. Gorman's DCF results.

Q. How do you respond to Mr. Gorman's criticism that your CAPM analysis is based on a forward-looking return on the market that is simply unjustified?

A. Mr. Gorman asserts that the estimated forward-looking market return used in my CAPM is based on a growth rate that cannot be sustained indefinitely. He claims the effect of this is to overstate the market DCF and correspondingly to overstate my calculation of the market risk premium. What Mr. Gorman is missing is that the market, as measured by the S&P 500 Index, is comprised of the largest companies on the New York Stock Exchange which are continually replaced when companies no longer fit the criteria for inclusion in the Index. So the concept of whether the companies in the Index "will

7 FERC Opinion No. 445, 92 FERC ¶61,070, SoCal Edison Opinion (July 26, 2000) at 21.
8 FERC Opinion No. 531, 147 FERC ¶61,234, NETOs Order on Initial Decision (June 19, 2014), para. 122.
9 FERC Opinion No. 531-B, 150 FERC ¶61,165, NETOs Order on Rehearing (March 3, 2015), para. 60.

sustain their respective growth rates indefinitely" is misplaced since this occurs by replacing low performing companies with higher performing companies. In developing the S&P forward-looking market return, we are assuming that current growth rates will be sustained or will be substituted with others that are equally robust. Accordingly, my calculation of the forward market return and forward-looking market risk premium are appropriate. As indicated in my rebuttal testimony, the use of a constant growth DCF analysis for the S&P 500 companies to estimate the market return has been embraced by the FERC.[10]

III. CONCLUSIONS

Q. Please summarize your conclusions regarding the appropriate ROE for TEP.

A. I believe that the proposed settlement ROE of 9.75 percent is conservative based on the results of my ROE estimation methodologies, recently authorized ROEs for other vertically integrated electric utilities, the risk factors identified for TEP, and investors' expectation of market conditions over the period that rates will be in effect. However, it does provide a reasonable compromise to settle the matters in this case. Further, the Commission should uphold its policy of allowing certain known and measurable changes to TEP's test year capital structure and reject Mr. Gorman's attempt to deprive the company recovery for its higher equity costs.

Q. What is your recommendation for the FVROR for TEP?

A. Based on a 9.75 percent ROE, and a 1.00 percent return on the Fair Value Increment of rate base, I believe that a FVROR of 5.34 percent is within the range of reasonable returns for TEP.

[10] Rebuttal Testimony of Ann E. Bulkley, at 39 and 65.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

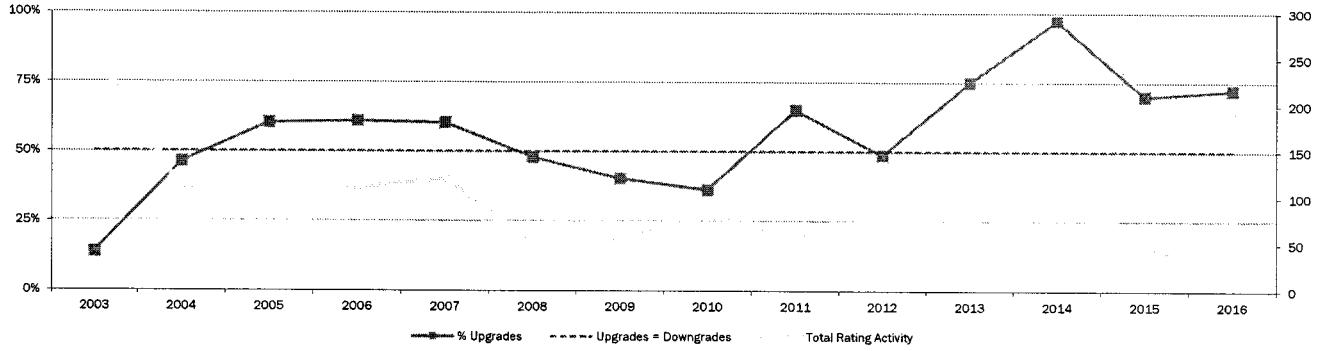
Exhibit AEB-Rejoinder-1

IV. Direction of Ratings Actions

Direction of Ratings Actions

U.S. Shareholder-Owned Electric Utility Industry

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Upgrades	21	35	51	73	67	73	24	23	29	39	37	60	103	35	13
Downgrades	279	218	59	48	43	48	26	34	51	21	39	20	3	15	5
% Upgrades	7.0%	13.8%	46.4%	60.3%	60.9%	60.3%	48.0%	40.4%	36.3%	65.0%	48.7%	75.0%	97.2%	70.0%	72.2%
Total Rating Activity	**300**	**253**	**110**	**121**	**110**	**121**	**50**	**57**	**80**	**60**	**76**	**80**	**106**	**50**	**18**
Upgrades = Downgrades	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%	50%



Source: Fitch Ratings, Moody's, Standard & Poor's

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-_____

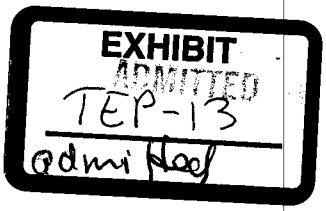
Direct Testimony of

Frank P. Marino

on Behalf of

Tucson Electric Power Company

November 5, 2015



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I. INTRODUCTION.

Q. Please state your name and business address.

A. Frank P. Marino. My business address is 88 E Broadway Blvd, Tucson, AZ 85701.

Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?

A. I serve as TEP's Vice President and Controller. My responsibilities include all accounting, tax, and financial reporting functions at TEP. I serve in the same capacity for UNS Energy Corporation and its subsidiaries.

Q. Please describe your background and work experience.

A. I have 28 years of experience working with electric and gas utilities and power generation companies in accounting, finance, regulatory and general management roles. I hold a Bachelor of Science in Accounting from the State University of New York and a Masters of Business Administration in Finance from Fairleigh Dickinson University. I am licensed as a Certified Public Accountant in New Jersey.

I joined TEP in January 2013 as Assistant Controller and was appointed Vice President and Controller in August 2013. Prior to joining TEP, I was a Vice President at The AES Corporation ("AES") in financial and project management roles, and I also held senior leadership financial roles at its electric utility subsidiary Indianapolis Power & Light Company. Prior to AES, I was employed by Xcel Energy ("Xcel") in its accounting and financial reporting department.

My career began in 1987 with Orange and Rockland Utilities, Inc. ("O&R") where I held progressively expanding roles in financial reporting and regulatory affairs. I ultimately

held the title Director of Compliance when O&R was acquired by Consolidated Edison Company of New York, Inc. ("Con Edison") in 1999. At Con Edison, I held the role of Assistant Controller until I joined Xcel in 2003. While with O&R and Con Edison, I testified in rate case and other regulatory proceedings in New York, New Jersey and Pennsylvania on numerous occasions. In addition, I submitted direct testimony before the Federal Energy Regulatory Commission.

Q. What is the purpose of your Direct Testimony?

A. My testimony is in support of the Company's rate case filing. I am sponsoring the historical information for the twelve month period ending June 30, 2015 (the "Test Year") presented on the following schedules:

- C-3
- E-1 through E-9

I address the early retirement of generation plant assets, and I support in my testimony various pro forma adjustments made to the Test Year on Schedules B-2 and C-2. Specifically, I am sponsoring the rate base pro forma adjustments on Schedule B-2 listed below:

- Sundt Coal Handling Facilities
- San Juan Unit 2
- Sundt and San Juan Materials and Supplies
- Accumulated Deferred Income Taxes ("ADIT")
- Accumulated Deferred Investment Tax Credit ("ITC")
- Fortis Merger Rate Base Adjustment

I am also sponsoring the pro forma adjustments reflected on Schedule C-2 listed below:

- Payroll Expense

- Payroll Tax Expense
- Pension & Benefits
- Post-Retirement Benefits
- Short-Term Incentive Compensation
- Long-Term Incentive Compensation
- San Juan Unit 2 Operating Costs
- Sundt and San Juan Materials and Supplies
- San Juan Unit 1 SNCR O&M Expense
- Depreciation and Amortization Expense Annualization
- Property Tax Expense
- Income Tax Expense
- Fortis Merger Operating Income Adjustment

Finally, I will address the Company's compliance with the Fortis merger conditions.

II. SUMMARY OF SCHEDULES.

A. "C" Schedules.

Q. Please describe the information contained on summary Schedule C-3.

A. Schedule C-3 calculates the revenue conversion factor. That factor is used to convert the computed Test Year return deficiency to an equivalent annual revenue increase amount. It effectively recognizes that there will be additional bad debt expense and income taxes associated with any adjustment to annual revenue requirements.

B. "E" Schedules.

Q. Please summarize Schedules E-1 through E-9.

A. Schedules E-1 through E-9 were prepared in accordance with the filing requirements contained in Arizona Administrative Code ("A.A.C.") R14-2-103. These schedules contain historical financial and accounting information, key operating statistics and notes to the financial statements using information in the Company's regulatory books of account.

Q. Are TEP's regulatory books of account maintained in accordance with the FERC Uniform System of Accounts as required under A.A.C. R14-2-212.G.2?

A. Yes.

Q. Please describe Schedule E-1.

A. Schedule E-1 contains the comparative TEP balance sheets at the end of the Test Year and the two prior periods ended December 31, 2014, and December 31, 2013.

Q. Please describe Schedule E-2.

A. This schedule sets forth comparative income statements for the Test Year and the two prior calendar years. The income statement for the Test Year is the starting point for the Adjusted Test Year income statement shown on Schedule C-1.

Q. Please describe Schedule E-3.

A. This Schedule presents the comparative statements of cash flows for the Test Year and the two prior calendar years.

Q. Please describe Schedule E-4.

A. This Schedule reports the changes in stockholders' equity from December 31, 2012 through the end of the Test Year.

Q. Please describe Schedule E-5.

A. Page 1 of Schedule E-5 presents a summary of the balances in the various electric utility plant account categories and accumulated depreciation and amortization at June 30, 2015 and December 31, 2014. Pages 2 and 3 of Schedule E-5 present the same information on a more detailed basis, by individual electric plant account. Pages 4 and 5 of Schedule E-5 present the balances for acquisition discounts at December 31, 2014 and at the end of the Test Year.

Q. Please describe Schedule E-6.

A. Schedule E-6 contains operating income statements for the Test Year and two previous calendar years. Retail revenues are reported by rate class. Operating expenses are reported by major category.

Q. Please describe Schedule E-7.

A. This Schedule reports key electric operating statistics, in a comparative format, for the Test Year and the two prior calendar years.

Q. Please describe Schedule E-8.

A. This Schedule shows the taxes charged to operating expenses by type for the Test Year and the two prior calendar years.

Q. Please describe Schedule E-9.

A. This Schedule contains a reference to FERC's website for TEP's FERC Form 3-Q for the period ended June 30, 2015 and the FERC Form 1 for the period ended December 31, 2014 which includes the footnotes to the financial statements for the twelve months ended December 31, 2014, the most recent calendar year period for which footnotes were prepared. The footnotes disclose important facts required for a proper understanding of the financial statements.

III. PRO FORMA ADJUSTMENTS.

Q. Please explain what a pro forma adjustment is.

A. Public utility rates are established based on prudently incurred costs of providing safe, reliable service. The Company's revenue requirement is based on a historical Test Year that reflects a level of operating revenues, expenses and net plant investment in that period. Because a historical Test Year is being used, it creates a need to adjust for occurrences not expected to recur or for events that are expected to occur but did not during the Test Year. Such adjustments may be in the form of eliminations, annualizations or normalizations.

Elimination adjustments are made to remove out-of-period or non-recurring transactions that are not properly included in Test Year revenue requirements. For example, the Company has eliminated the costs associated with the Fortis merger that were incurred during the Test Year.

Annualization adjustments are made to reflect the full, twelve-month, revenue or expense level of components of operating income. Annualization adjustments recognize that certain events that happen in a Test Year are ongoing and must be spread over the entire

Test Year period. An example of an annualization adjustment is the depreciation expense adjustment to reflect end of Test Year investments. The annualization adjustments synchronize Test Year investments, revenue and expense relationships.

Normalization adjustments reflect that the recorded Test Year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequently than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the Test Year may not be viewed as normal thus requiring an adjustment for ratemaking purposes.

IV. GENERATION PLANT EARLY RETIREMENTS.

Q. Did the Commission address early generation plant retirements in TEP's last rate case?

A. Yes. The Settlement Agreement approved in the most recent TEP Rate Order, Decision No. 73912 (June 27, 2013) ("2013 TEP Rate Order"), states at Section 20.3 that "if TEP makes any filing with the ACC related to the early retirement of any production asset, TEP will propose that any then-existing excess depreciation reserve for production plant be applied to the unrecovered book value of the retiring asset."

Q. Is TEP expected to retire early any generation plant assets?

A. Yes. There are two generation stations that will have certain early plant retirements due, in both cases, to environmental regulations. These include the coal handling facilities at H. Wilson Sundt Generating Station ("Sundt") and Unit 2 of the San Juan Generating Station ("San Juan"). These early retirements will be complete by the end of the first

year that new rates are effective as a result of this rate case. I will address each separately.

Q. Please describe the Sundt coal handling facilities.

A. Sundt Unit 4 is a steam generation facility capable of generating electricity from multiple fuels, including coal and natural gas. It is the only unit at Sundt capable of burning coal. The coal related assets include a rail spur, a rotary car dumper, pulverizers, and coal conveyors with a net book value of $16 million as of June 30, 2015. These assets entered service in 1988 and were built in response to a 1981 order of the U.S. Department of Energy requiring the use of coal as the primary boiler fuel at Sundt.

Q. What environmental regulations are causing the early retirement of the Sundt coal handling facilities?

A. There are two regulations related to Regional Haze and mercury emissions that are impacting Sundt. The combination of the Regional Haze and mercury emission rules are causing the early retirement of the coal handling facility assets.

Q. Please describe the Regional Haze Rules requirements related to Sundt.

A. The Environmental Protection Agency's ("EPA") Regional Haze Rules require emission controls known as Best Available Retrofit Technology ("BART") for certain industrial facilities emitting air particulate that reduce visibility in national parks and wilderness areas. The EPA issued a final rule for Sundt that would require TEP to either (i) install, by mid-2017, Selective Non-Catalytic Reduction ("SNCR") and dry sorbent injection at Sundt Unit 4 if it continues to use coal as a fuel source, or (ii) permanently eliminate coal as a fuel source as a better-than-BART alternative by the end of 2017. Under this rule, TEP is required to notify the EPA of its decision by March 2017. Installing SNCR and dry sorbent injection on Sundt Unit 4 is inconsistent with TEP's resource diversification

strategy addressed by TEP witness Hutchens. TEP has exhausted its coal inventory at Sundt and is currently fueling Sundt Unit 4 primarily with natural gas.

Q. Please address the mercury rules as they relate to Sundt.

A. In February 2012, the EPA issued final rules for the control of mercury and other power plant emissions. These rules require additional control equipment that would need to be installed at Sundt by April 2016. Although the U.S. Supreme Court reversed and remanded the mercury rule in June 2015, the rules remain in force and effect. Additionally, Arizona has an Arizona-specific mercury rule in place that will become effective and applicable to Sundt in the event the Federal rule is struck down.

Q. Please summarize TEP's proposal related to the early retirement of the Sundt coal handling facilities.

A. Sundt Unit 4 is capable of burning coal until it can no longer comply with the mercury rules in April 2016. At that time, the coal handling facilities will no longer be used and useful and must be removed from plant in service. As these facilities are still being recovered in TEP's rates, the investment will be transferred to a regulatory asset account and amortized at the same rate it would otherwise have been depreciated as plant in service, until the remaining unrecovered cost is offset against an equivalent amount of the generation depreciation reserve as addressed later in my testimony. Upon approval of this treatment by the ACC, TEP will record the offset of the remaining unrecovered investment against the excess generation depreciation reserve.

Q. Please address San Juan.

A. San Juan is a four-unit coal-fired steam generation facility located in New Mexico and operated by Public Service Company of New Mexico ("PNM"). TEP has a 50% interest in both coal-fired units 1 and 2 each having a nominal capacity rating of 340 MW

resulting in TEP's ownership of 170 MW for each unit.

Q. What environmental regulations are causing the early retirement of assets at San Juan?

A. The same Regional Haze Rules that are causing the early retirement of Sundt coal handling facilities are causing the early retirement of assets at San Juan. In October 2014, the EPA published a final rule approve a New Mexico state plan for San Juan which includes the closure of Units 2 and 3 by December 2017 and the installation of SNCR technology on units 1 and 4 by January 2016.

Given the closure of two units and the desire of certain participants to end their ownership interests in San Juan, PNM and the other owner participants, including TEP, negotiated restructured ownership agreements. As a result, following the closure of San Juan Units 2 and 3, TEP's ownership interest will consist of a 50% interest in San Juan Unit 1.

In August 2015, PNM filed a settlement agreement with the New Mexico Public Regulation Commission ("NMPRC") for approval of the ownership changes and to retire San Juan units 2 and 3 in December 2017. The NMPRC is expected to rule on this settlement agreement in late 2015 or early 2016. TEP's proposed treatment of San Juan Unit 2 in this case assumes NMPRC approval to early retire Unit 2 in December 2017.

Q. Please summarize TEP's proposed treatment of the early retirement of the San Juan Unit 2.

A. Although San Juan Unit 2 is not expected to be retired until the end of the first year that new rates will be in effect as a result of this rate case, TEP proposes to reflect the retirement of the asset consistent with the rate treatment specified for early generation

plant retirements in TEP's last rate case as addressed later in my testimony. I will also address the proposed treatment of capital, spare parts and operating expenses that will be incurred prior to the retirement of the assets.

Q. Are there other costs related to the Regional Haze compliance plan for San Juan that need to be addressed in this case?

A. Yes. The Company proposes pro forma adjustments related to remaining spare parts inventory for San Juan Unit 2 and the operating costs related to the SNCR that need to be reflected in the Test Year operating expenses. In addition, TEP invested approximately $1.7 million in Selective Catalytic Reduction ("SCR") technology based on an initial EPA order requiring the installation of SCR on all four units at San Juan. TEP proposes to record these costs to a regulatory asset for recovery in its next rate base rate case filing.

V. RATE BASE PRO FORMA ADJUSTMENTS.

A. Sundt Coal Handling Facilities.

Q. Please address the rate base pro forma adjustment for Sundt coal handling facilities.

A. TEP is reflecting the early retirement of the coal handling facilities at the Sundt by reducing plant assets for the original book value and correspondingly reducing accumulated depreciation for the equivalent amount. This is an appropriate way of presenting the ultimate disposition of the remaining book value of the Sundt coal handling facilities in this case in accordance with the Settlement Agreement in TEP's last rate case.

Q. What are the impacts of this adjustment?

A. The adjustment results in the elimination of depreciation expense, property tax expense

and any direct costs associated with the coal handling facilities formerly recognized as fuel costs.

B. San Juan Unit 2.

Q. Please summarize TEP's proposed treatment of the expected early retirement of San Juan Unit 2.

A. As addressed earlier in my testimony, San Juan Unit 2 is expected to be removed from service in December 2017. TEP is reflecting its early retirement by reducing plant assets for its book value and correspondingly reducing accumulated depreciation for the equivalent amount. The depreciation rates sponsored by Dr. White do not include depreciation expense for San Juan Unit 2. I would note that Dr. White's depreciation study shows that while there is inadequate excess generation depreciation reserve to cover both Sundt coal handling facilities and San Juan Unit 2, there is a sufficient level of total excess reserves when combining both generation and distribution excess reserves to nearly offset all of these remaining unrecovered costs associated with these assets.

Q. Are there any differences between the rate treatment of San Juan Unit 2 and the Sundt coal handling facilities?

A. Yes. Unlike the coal handling facilities that will be out of service prior to when rates become effective as a result of this case, San Juan Unit 2 will continue to supply system electricity to TEP in 2017. As a result, there will be costs incurred during 2017 including operation and maintenance expenses, capital expenditures, and property taxes that need to be addressed in this rate case.

Q. Please describe how TEP proposes to recover 2017 operating costs of San Juan Unit 2.

A. Since San Juan Unit 2 will continue to be used and useful during the first full year rates are expected to be effective as a result of this case, TEP could include all the costs associated with operating Unit 2 in the Test Year. Accordingly, the Company could benefit from regulatory lag as an offset to its typical adverse impact. However, TEP is not proposing such treatment and is only requesting cost recovery that reflects the anticipated costs for 2017. TEP proposes to include one-third of the 2017 operating cost for San Juan Unit 2 in Test Year expenses based on the assumption that new base rates from this case will remain in effect for approximately three years before TEP's next base rate case. For accounting purposes, TEP will reflect in its financial statements one-third of the 2017 operating costs for San Juan Unit 2 to match the revenue allowance and defer the remaining two-thirds of the 2017 operating costs which will then be amortized over the subsequent two year period.

Q. Please describe how TEP proposes to recover any post Test Year capital costs related to San Juan Unit 2.

A. TEP is requesting to record post Test Year capital costs related to San Juan Unit 2 as a regulatory asset for inclusion in its rates at TEP's next rate case.

Q. Are there benefits to customers by reflecting the retirement of San Juan Unit 2 in this proceeding in the manner proposed by TEP?

A. Yes. Base rates will be reflect a lower level of recovery for operation, maintenance and depreciation expense as proposed due to pro forma Test Year costs that are less than actual costs incurred in the Test Year.

C. **Sundt and San Juan Materials and Supplies.**

Q. Please address the treatment of any remaining materials and supplies for Sundt coal handling facilities and San Juan Unit 2.

A. TEP proposes to record any remaining inventory related to the Sundt coal handling facilities and San Juan Unit 2 to a regulatory asset and amortize the cost over a three year period starting in the Test Year. The inventory specific to the coal handling facilities will no longer be necessary once a decision is made to no longer burn coal at the Sundt Unit 4. Those items were purchased to assure the continued service of Unit 4 and, had they been installed, would have been recovered as depreciation expense charged to fuel. This adjustment will also include any remaining San Juan spare parts inventory after assessing what inventory from Unit 2 can be utilized at Unit 1 which will remain in operation, as the units consist of similar technology.

D. **Accumulated Deferred Income Tax ("ADIT").**

Q. Please explain what ADIT is.

A. ADIT represents the balance of deferred income taxes recorded over time based on the difference between when an item of income or expense is recognized for financial reporting purposes and when it is recognized for income tax purposes. There are many items that are subject to such timing differences, however, the most significant differences arise from the accelerated depreciation methods used for income tax purposes.

Q. Can you provide an example of how deferred income taxes arise?

A. Yes. Let's assume that TEP makes a $1 million investment in a distribution line that is placed in service in 2015 and has a 40-year straight-line depreciable life for financial

reporting purposes. For simplicity, I will ignore cost of removal and salvage values and assume that the investment qualifies for 100% bonus depreciation for tax purposes. The distribution line's book depreciation rate would be 2.5% and TEP's electric rates would be set to recover $25,000 in depreciation expense per year for 40 years. For tax purposes, however, the entire investment in the line would be deducted in the year it is placed in service. Thus, in 2015 TEP would collect $25,000 of taxable revenue and claim tax depreciation of $1 million. As a result, TEP would have a net depreciation timing difference of $975,000 which, when it offsets TEP's other taxable income, would produce an incremental cash benefit as a reduction in income taxes paid of $341,350 assuming a 35% Federal income tax rate ($975,000 x 35%).

The $341,250 cash benefit to TEP represents funds available to finance utility operations. However, the cash will need to be repaid to the government over time as the depreciation timing difference for the distribution line reverses. In effect, the accelerated depreciation for income tax purposes gives rise to an interest-free loan from the government. This timing difference results in an ADIT balance of $341,350 at the end of 2015, which is deducted from rate base.

Q. Please describe how deferred income tax balances for the distribution line reverse.

A. In each of the next 39 years, TEP will collect $25,000 of depreciation expense from its customers which will be taxable for income tax purposes. However, since the entire investment in the line was deducted in 2014 for tax purposes, TEP has $0 tax depreciation to claim for the remaining life of the line. Thus, TEP will include on its tax return $25,000 of taxable income upon which it will incur $8,750 of income tax ($25,000 x 35%). This difference between book depreciation and tax depreciation will result in an annual reduction in ADIT of $8,750 per year until the $341,250 ADIT balance in 2015 is fully amortized in year 40 ($8,750 x 39 = $341,250).

Q. Please explain the ADIT Adjustment.

A. The adjustment reduces rate base for the computed balance of ADIT. A rate base deduction is appropriate to reflect the interest free source of capital for timing differences reflected in rate base (e.g., accelerated tax depreciation on plant in service, whether through regular or bonus depreciation) consistent with the Commission's historical normalization rate treatment for TEP which I will address later in my testimony. As a result of this rate base deduction, the customer is not paying a rate of return on the interest free source of capital.

Q. In order to better understand deferred income taxes, can you briefly describe the accounting for income taxes under GAAP?

A. Yes. Accounting for income taxes under GAAP is contained in the Accounting Standards Codification ("ASC") in Section 740 (formerly SFAS No. 109 *Accounting for Income Taxes* ("SFAS109")). The income tax calculation has three components: income taxes currently payable, deferred income taxes, and deferred investment tax credit ("ITC"). Taxes currently payable represents the income taxes payable to the U.S. Treasury for the current period as computed under the provisions of the Internal Revenue Code ("IRC"). There are differences between how certain items are treated under the IRC and GAAP. These differences are listed on Schedule M of the filed income tax return. Such differences between income tax treatment and book accounting treatment are either timing differences or permanent differences.

As I stated earlier, the most common and largest timing difference is depreciation. Depreciation is a timing difference because both book and tax depreciation amounts are limited, over time, to the cost of the utility plant. Thus, in the early years tax depreciation will exceed book depreciation, but in the later years, book depreciation will exceed tax depreciation.

while others only permit the recognition of certain timing/temporary differences required by the IRC to be recognized in utility ratemaking ("partial normalization"). To the extent that normalization is permitted in ratemaking, the resulting deferred income taxes are reflected as a component of income tax expense – with the corresponding balance sheet reserve for accumulated deferred taxes deducted from rate base as non-investor capital. This treatment reflects the availability of such amounts for plant investment or operating purposes between the time they are collected from customers and ultimately remitted to taxing authorities.

The other ratemaking approach to timing differences is when regulators do not permit deferred income tax expense as a recoverable cost in the ratemaking process. This approach is known as flow through since, under this approach, the income tax reducing benefits of tax return deductions are flowed-through to the retail customer by a reduction of current income tax expense, without the offsetting deferred income tax expense. Because flow-through only applies to book-tax timing differences, any reduction in income taxes payable when a timing difference originates is offset by higher income taxes payable when the timing difference reverses. Of course, under a flow-through approach, there is no ADIT to reduce rate base as the interest-free loan has been provided to retail customers.

Q. What income tax rate-making authority has been granted to TEP?

A. Prior to 1979, TEP was a flow-through entity for ratemaking purposes, meaning that it was not permitted to reflect deferred income taxes in rate-making. In Decision No. 50430 (1979), the Arizona Corporation Commission ("Commission" or "ACC") authorized the Company to begin rate recovery of deferred income taxes relating to the benefits (shorter lives and accelerated methods) of accelerated depreciation, starting with production plant placed in service during 1979, transmission plant installed in 1980, and

distribution plant added in 1981. Then, the Commission issued Decision No. 56659 (October 24, 1989), which expanded the Company's normalization authority prospectively to include all originating book-tax timing differences. The Commission ruled that "we will allow full tax normalization at this time." (Decision No. 56659 at 38). This authority included the differences between the manner in which salvage and removal costs are recognized for book and tax purposes, as well as the effect of the debt component of the Allowance for Funds Used During Construction ("AFUDC") and taxable Contributions in Aid of Construction. In Decision No. 58497 (January 13, 1994) at 95, the Commission authorized TEP to implement *SFAS No. 109* (now known as ASC740), for regulatory accounting purposes.

To the extent ASC740 requires the recording of certain deferred tax assets that do not actually reflect the prepayment of tax and certain deferred tax liabilities that do not represent the collection of taxes prior to their remittance to taxing authorities, we effectively exclude these amounts recorded on the Company's balance sheet in determining the appropriate amount of deferred tax assets and ADIT for ratemaking purposes. An example of this treatment is the equity component of AFUDC. The equity component of AFUDC is capitalized for book purposes but is excluded from our income tax return. Under ASC740, the amount capitalized for books (the amount capitalized in the work order and depreciated) compared to the amount capitalized for income tax purposes (zero) represents a temporary difference that requires ADIT. For book purposes, we offset the ADIT on the equity component of AFUDC with a regulatory asset, thus recognizing we have not included such amounts on the tax return.

Q. Has there been a substantial change in ADIT since TEP's last rate case?

A. Yes. TEP's last rate case used a test year ending December 31, 2011. Since the last test year, the ADIT relating to accelerated depreciation has increased as a result of recent

bonus depreciation legislation. On January 3, 2013, the "American Taxpayer Relief Act of 2012" was passed extending 50% bonus depreciation through December 31, 2013. On December 22, 2014, the "Tax Increase Prevention Act of 2014" was passed extending 50% bonus depreciation through December 31, 2014. At the time of this filing, Congress has not acted to further extend bonus depreciation beyond December 31, 2014.

Q. Did TEP elect bonus depreciation on all eligible property placed in service since the last rate case?

A. Yes. TEP has claimed bonus depreciation on all eligible assets since the last rate case.

Q. Is bonus depreciation beneficial to customers?

A. Yes. By claiming bonus depreciation, TEP ensures that it receives the maximum amount of interest-free capital on behalf of its customers, therefore it results in the maximum amount rate base deduction. To illustrate this, using the same $1 million distribution line assumptions I discussed earlier, and a 7.34% return on rate base, the customer benefits are over $200,000 larger by claiming bonus depreciation over the regular tax depreciation schedule. See **Exhibit FPM-1**.

Q. Did all of the bonus depreciation deductions result in a cash benefit to TEP through reduced Federal income tax payments?

A. No, not yet. The deductions for bonus depreciation exceeded the amount that could be used to offset taxable income and have created a Net Operating Loss Carryforward (NOLC).

Q. Please explain the concept of NOLC.

A. In comparison to my previous example of the distribution line, a NOLC reflects a loan that has not been made to the Company. A NOLC is recorded as an asset balance in the

deferred income tax accounts. The cash benefit of the loan will be realized when the NOLC is used against a future year's taxable income.

TEP's ADIT balance represents the tax benefits of all timing differences regardless of whether or not they have produced a cash benefit. Therefore, when there is a NOLC, the ADIT credit balance overstates the amount of the interest-free loan made to the Company. These deductions did not defer any Federal income tax liability and thus, under the tax depreciation normalization rules of IRC §168, such excess deductions should not be included in the Company's deferred income taxes.

Q. What are the tax depreciation normalization rules?

A. The tax depreciation normalization rules were enacted by Congress to prevent accelerated tax depreciation incentives from being flowed directly to customers through the rate setting process. The normalization rule requires that, where a utility claims accelerated depreciation it must make an adjustment to a reserve to reflect the amount of deferral of Federal income tax liability resulting from the use of such a depreciation method. In addition, the utility's ADIT that can reduce rate base cannot exceed the amount of such reserve (i.e., resulting from that adjustment) used in computing a utility's cost of service in ratemaking. By excluding the bonus depreciation deductions that were not used to offset taxable income from the computation of deferred income taxes, TEP is in compliance with the normalization rules.

Q. Why doesn't Congress allow the flow-through of accelerated tax depreciation incentives?

A. Accelerated depreciation was enacted for the purpose of promoting investment in plant and equipment by businesses. Congress was concerned that, in the case of regulated utilities whose rates are set by reference to their costs, these incentives could be flowed

directly to customers through the rate-setting process. If this were to occur, then the benefits Congress had intended to promote investment by businesses in plant and equipment would be taken from them and converted into consumption incentives for regulated utility customers. As this was not Congress' intent, it included the depreciation normalization rules in the tax law to prevent this from happening.

Q. What is the impact to TEP and its customers if the tax depreciation normalization rules are not followed?

A. If the normalization rules are not followed, TEP would be unable to claim accelerated tax depreciation. Instead, the Company would be required to use regulatory depreciation methods for tax purposes. This would cause a substantial increase in TEP's income tax payable and a substantial decrease in the ADIT balance that is included as a reduction to rate base. As a consequence, TEP customers benefit when normalization rules are followed.

Q. Has the IRS ruled on the normalization rules when a company has a NOLC?

A. Yes. In Private Letter Rulings (PLRs) 201438003, 201436037, 201436038, 201519021, and 201534001 the IRS ruled that a reduction of a taxpayer's rate base by the full amount of its ADIT balance unreduced by the balance of its NOLC ADIT would be inconsistent with the normalization rules.

Q. Has TEP reduced its ADIT rate base reduction by its NOLC ADIT?

A. Yes. To be consistent with the normalization rules TEP has offset its ADIT rate base reduction by its NOLC ADIT.

Q. What other deferred tax assets not attributable to timing differences have you included in rate base?

A. Similar to the ADIT associated with NOLs, we have also included in rate base the deferred tax asset for Minimum Tax Credit Carryforwards ("MTCC").

Q. What is a MTCC?

A. TEP incurred alternative minimum tax ("AMT") in a number of years. AMT is an amount of tax imposed on a taxpayer over and above its "normal" income tax. The payment of AMT gave rise to a MTCC. MTCCs are credits that can be used to reduce a company's future tax liability. This system of tax effectively reduces the cash benefit of certain tax deductions in the year that they are claimed but, through the MTCC feature, permits that benefit to be realized at a later point in time. The economics of the AMT regime are very similar to those of an NOLC and, as a result, are properly treated in the same fashion.

Q. Generally, how does the AMT work?

A. The AMT rules provide that each corporation adjust its regular taxable income for a number of adjustments and preferences to arrive at alternative minimum taxable income ("AMTI"). A tentative AMT ("TAMT") is computed by applying the 20% AMT tax rate to AMTI. To the extent that this TAMT exceeds the corporation's tax computed in the regular way, it pays the regular tax and an amount equal to the excess. This excess is the AMT. The amount of AMT paid in any year is generally creditable against a corporation's tax liability in future years, but only to the extent that its regular tax exceeds its TAMT in that subsequent year.

Q. What adjustments and preferences are most relevant to TEP?

A. Accelerated depreciation and amortization.

Q. Please provide a simple example of how the AMT operates.

A. Assume TEP, in year 1, has $1 million of pre-tax book income and $900,000 of tax depreciation in excess of book depreciation. TEP reports regular taxable income of $100,000 ($1 million of book income less $900,000 of accelerated tax depreciation) and, assuming a 35% tax rate, incurs a regular tax liability of $35,000. The $900,000 of accelerated depreciation reduces TEP's tax liability by $315,000 ($900,000 x 35%). Thus, TEP has $315,000 of cost-free capital available to it before considering any effects of the AMT. This amount would be reflected as an ADIT credit that is available to reduce rate base.

Q. How does AMT impact TEP's tax liabilities?

A. Assume that TEP has an AMT adjustment which reduces accelerated depreciation deductions by $500,000. AMTI is computed by adding regular taxable income of $100,000 to the amount of the adjustment of $500,000 to produce AMTI of $600,000. At the 20% AMT rate, TEP's TAMT will equal $120,000. Since that amount exceeds its $35,000 regular tax liability, TEP will incur both the $35,000 regular tax liability and $85,000 more in AMT, or a total of $120,000. This $85,000 AMT produces a MTCC which is available to offset taxes payable in the future. Due to the AMT, TEP did not realize the entire $900,000 benefit of its accelerated depreciation. The AMT caused a portion (i.e., $85,000) of the benefit to be deferred until such time as the MTCC is used.

Q. How does TEP reflect AMT on its balance sheet?

A. TEP reflects the full, pre-AMT benefit of the accelerated depreciation ($315,000 in the above example) as a deferred tax credit (*i.e.*, a governmental loan) in FERC Account 282. It then reflects the $85,000 benefit reduction as a deferred tax debit *(i.e.,* a future tax benefit) in FERC Account 190.

Q. What is the amount of cost-free capital available to TEP in the example above?

A. As a result of the AMT benefit reduction, TEP has only $230,000 of cost-free capital available to it. Reducing rate base by $315,000 overstates the amount of the governmental loan. The rate base reduction, in this example, should be $230,000. This is precisely how TEP reflected its MTCC in this proceeding.

Q. What gives rise to the Accumulated Deferred Income Tax Liability for Excess Deferred State Income Taxes ("EDIT") that is included in ADIT?

A. On February 17, 2011, the Arizona legislature passed a bill reducing the state corporate income tax rate from the then effective rate of 6.968% to an ultimate rate of 4.9%. This reduction is being phased in beginning in 2014 with a reduction of approximately 0.5% per year until the income tax rate reaches 4.9% for 2017 and later years.

In 2013, New Mexico adopted similar legislation which reduces the then effective rate of 7.6% to an ultimate rate of 5.9%. The reduction is being phased in beginning in 2014 with a reduction of approximately 0.3% per year until the income tax rate reaches 5.9% for 2018 and later years.

For purposes of ADIT presented in this case, the balance of Arizona deferred income taxes is presented at the rates in effect at the time the timing differences originated.

Q. How does TEP treat the EDIT collected in prior years for ratemaking purposes?

A. The EDIT is amortized as a reduction to deferred income tax expense as the underlying timing differences reverse.

Q. Is the treatment of ADIT and including the impact of NOLC, MTCC and EDIT you are proposing in this case consistent with the treatment approved in TEP's last rate case?

A. Yes.

E. Accumulated Deferred Investment Tax Credit ("ITC").

Q. You previously mentioned a third tax component to the income tax calculation, Accumulated Deferred ITC. Please explain the adjustment for Accumulated Deferred ITC.

A. Unlike deferred taxes, which can be likened to an interest-free loan from the U.S. Treasury, the ITC can be likened to a grant or rebate. The ITC is a direct reduction of income taxes otherwise payable. It is calculated by multiplying a qualifying investment times a statutory credit percentage.

As explained below, for rate-making purposes TEP shares the ITC in accordance with IRC §46(f)(1), whereby the rate-making treatment for Accumulated Deferred ITC is a reduction to rate base that reflects the provision of non-investor capital due to a reduction in income taxes payable (benefitting the customer) with below-the-line amortization (benefitting the shareholder) each year. TEP has claimed ITC under IRC §48(a)(2) that provides for a 30% ITC for investment in qualifying solar facilities placed in service prior to January 1, 2017. Further, IRC §50(c)(3)(A) requires that the depreciable tax basis of the underlying property be reduced by an amount equal to 50% of the energy credit taken with regard to the property.

Q. What are the rules governing the accounting for ITC for public utilities?

A. The tax normalization rules are contained in IRC §46(f) (as in effect prior to the Revenue Reconciliation Act of 1990). IRC §50(d)(2) requires that these normalization rules be applied to the §48 Energy Credit when elected by a regulated utility. The normalization rules require all public utilities to elect one of the two available normalization methods. The method used by TEP is described in §46(f)(1) (as in effect prior to the Revenue Reconciliation Act of 1990).

Q. Please explain the requirements of IRC §46(f)(1).

A. This section provides that a regulated utility shall not reduce the base to which rate of return is applied by any portion of the credit unless the reduction is restored not less rapidly than ratably. "Ratably" is defined as the life used by the public utility for purposes of calculating book depreciation for the qualified property.

Q. How do the normalization rules apply to taxpayers that have generated ITC, but have not yet realized the ITC benefit through lower income tax payments?

A. PLR 8326081 addresses the issue of when the benefits of ITC should be reflected in rates and concluded that if the ITC is used to reduce revenue requirements before actually realized on the income tax return, a normalization violation would occur. While this ruling is for a utility that elected the ITC sharing method provided for in §46(f)(2) (ratable amortization in cost of service), similar guidance should apply for utilities who elected to share ITC under §46(f)(1). In this ruling, the IRS clearly states "the credit cannot be used to reduce the cost of service until it has been allowed for federal income tax purposes". Thus, the taxpayer was prohibited from reducing cost of service for ratemaking purposes. In the case of a company subject to the normalization provisions of §46(f)(1), such as TEP, the same rule would apply to prohibit the reduction of rate base for credits not yet realized on the taxpayer's federal tax return.

Q. What is the amortization period used by TEP to amortize ITC?

A. TEP amortizes the ITC over the tax life of the assets that generated the ITC. This treatment was authorized by the Commission Director of Utilities in a letter to TEP dated July 21, 1983 (attached as Exhibit FPM-2). In the case of solar generating facilities, the property is classified for depreciation purposes in IRC §168(e)(1) and qualifies for a five-year life for tax depreciation purposes. As the book life of the solar generating assets proposed in this case is 28 years, the use of the shorter life is in compliance with the normalization provisions of IRC §46(f)(1).

Q. How is ITC amortization computed?

A. In accordance with the amortization period granted TEP in **Exhibit FPM-2**, the credits are amortized over the tax life of the qualifying property. Since the five-year tax depreciation recovery period authorized by IRC §167 is spread over six years, TEP uses a straight-line amortization period of six years with a half-year of amortization in the first and last years.

Q. Please discuss the ITC that TEP has generated and whether it has been realized.

A. The ITC that TEP has generated is attributable to qualified solar facilities placed in service from 2010-2014. The ITC related to 2010 and 2011 was realized and has been included as a reduction to rate base, net of accumulated amortization. The ITC generated from 2012-2014 has not been realized and consistent with the normalization rules is not included as a reduction to rate base.

Q. Is there a corresponding adjustment to current or deferred income tax expense as a result of the ITC?

A. Yes, there is an adjustment to deferred income tax expense as a result of the ITC discussed later in my testimony.

Q. Is the treatment of ITC in this case consistent with that approved by the ACC in TEP's last rate case?

A. Yes.

F. Fortis Rate Base Adjustment.

Q. Please explain the Fortis Rate Base Adjustment.

A. On August 12, 2014, the Commission issued an order that approved the merger of UNS Energy with Fortis Inc. (Decision No. 74689). A condition of the order specifies that no merger-related cost would be borne by the ratepayers. This adjustment eliminates all merger-related cost allocated to TEP and included in plant in service through overhead allocations. Specifically, this adjustment removes the portion of merger-related costs that were capitalized as part of the Administrative & General loading applied to capital projects.

VI. OPERATING INCOME PRO FORMA ADJUSTMENTS.

A. Payroll Expense.

Q. Before addressing the specific compensation-related pro forma adjustments, please describe the Company's overall employee compensation strategy.

A. The Company has a balanced total compensation program that incorporates performance-based elements for all non-union employees. The Company's compensation policies include the following objectives:

- Attracting, motivating and retaining highly-skilled employees;
- Linking the payment of compensation to the achievement of short and long-term financial and strategic objectives, including providing safe, reliable and affordable electric service; and

- Aligning performance objectives of executive management with those of other employees by using similar performance measures for each group.

The table below summarizes the three components of the total compensation program for non-union employees.

Compensation Component	Key Features	Purpose
Base Salary	Adjustments made annually based on market data and to remain near the median of relevant market data	Provide a fixed amount of compensation
Short-term Incentive Compensation (Performance Enhancement Plan or "PEP")	Goals are identical for executive and non-union employees; Must achieve a minimum threshold of financial performance or payout for other measures capped at 50%.	Motivate and reward achieving or exceeding the Company's short-term objectives, while reinforcing pay-for-performance; Focus employees on key customer, operational and financial metrics.
Long-term Incentive Compensation[1]	Delivered in a combination of performance shares and restricted stock units	Supports retention and ensures focus on long-term performance objectives

Q. How does the Company ensure that total non-union compensation levels are reasonable?

A. With respect to non-executive employees, the Company periodically commissions market studies for a sampling of jobs in order to ensure that total compensation (i.e., the sum of base salary, short-term incentive and long-term incentive compensation) is near the median. For executive management, the Company has established a peer group of other electric and gas utility companies of comparable size and complexity, including electric

[1] Only executive officers and senior director employees are eligible for Long-Term Incentive Compensation.

and gas utility companies thought to be competitors for talent. Total compensation for executive management is similarly targeted at median of market, in this case using a peer group. These approaches enable the Company to successfully hire, motivate and retain talented employees and executives while ensuring a reasonable overall compensation cost structure relative to market.

Q. How does the Company ensure that union employee compensation levels are reasonable?

A. The Company's union employees are represented by a local union which bargains with the Company on wages, benefits and other work related matters on behalf of the represented employees. The Company and the union periodically negotiate Collective Bargaining Agreements that are subject to ratification by the union members. Thus, there is an established process in place to ensure the reasonableness of union employee compensation.

Q. Please explain the Payroll Expense Adjustment.

A. The Payroll Expense Adjustment is necessary to reflect the proper level of salaries and wages in Test Year operating expenses. The Payroll Expense Adjustment was computed based on an average of operations and maintenance ("O&M") wages for the 12 month periods ended June 30, 2015 and June 30, 2014, and reflects the known and measurable wage increase for 2016 and the estimated wage increase for 2017, the year in which rates established in this proceeding will go into effect.

Q. Does the Payroll Expense Adjustment exclude capitalized payroll costs?

A. Yes. The adjustment only includes the amount directly recorded to O&M expenses and excludes the A&G labor cost allocated to capital projects.

Q. Is the Payroll Expense Adjustment consistent with the 2013 TEP Rate Order?

A. Yes.

B. Payroll Tax Expense.

Q. Please explain the Payroll Tax Expense Adjustment.

A. The Payroll Tax Expense Adjustment reflects the Company's taxes (Social Security and Medicare) that correspondingly increase as a result of the increased expense from the Payroll Expense Adjustment. The Company's effective employer's tax rate for 2015 was applied to the increased payroll expense reflected in the Payroll Expense Adjustment.

C. Pension and Benefits.

Q. Please explain the Pension and Benefits adjustment.

A. The Pension and Benefits adjustment is intended to include in operating expenses a level of pension and benefits expense reflecting the Test Year work force and the current pension and medical, dental, vision, life and long-term disability benefit expense level. The benefit costs covered by this adjustment include the qualified retirement pension plans as determined in the most recent actuarial study, the Company's share of contributions to the employees' 401(k) plan, and medical, dental, vision, life and long-term disability costs. The adjustment includes the current cost of the Supplemental Executive Retirement Plan ("SERP") for the Company's executives. The SERP is a normal and recurring business practice.

Q. What is the purpose of a SERP?

A. The qualified pension retirement plan, which covers all TEP employees, is subject to IRC limitations on the amount of compensation that can be taken into account on the amount

of benefits that can be provided. The non-qualified SERP provides the retirement benefits to executive officers that would have been provided under the qualified retirement plan had the limitations not applied.

Q. Is the Pension and Benefits adjustment consistent with the 2013 TEP Rate Order?

A. The pension adjustment, except for the SERP, was prepared and calculated in the same manner as was approved by the Commission as part of the Settlement Agreement in the last TEP rate case. Although the Company did not request recovery of SERP costs in the last rate case, it reserved the right to request it in this rate case.

Q. Why should the revenue requirement in this case reflect the cost of the SERP?

A. Because it is a common business practice and is necessary to keep TEP competitive in attracting and retaining executive talent.

D. <u>Post-Retirement Benefits.</u>

Q. Please explain the Post-Retirement Benefits adjustment.

A. The Post-Retirement Benefits adjustment is necessary to reflect in operating expenses a level of Post-Retirement Benefits expense reflecting the Test Year work force level and the current Post-Retirement Benefits actuarial expense level. In addition, the adjustment includes a component for the 15-year amortization of incremental expense representing the difference between accrual expense and cash cost basis that was recorded between the time when TEP adopted accrual accounting of Post-Retirement Benefits expense for financial reporting purposes and the time when accrual based expense was recognized for ratemaking purposes.

Q. Please explain the change to accrual accounting and the 15-year amortization of the incremental expense.

A. In January 1993, TEP adopted Statement of Financial Accounting Standards No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions ("FAS 106")*, which requires accrual based accounting, for financial reporting purposes. However, the Commission continued to allow only cash basis recovery for ratemaking purposes until 2008 (Decision No. 70628). The Post-Retirement Benefits adjustment includes a 15-year amortization of the incremental expense incurred by using the cash basis for ratemaking between 1993, when the company adopted FAS 106, and 2008 when the Commission allowed a change to accrual basis for ratemaking purposes. Since Decision No. 70628, TEP's rates have been set to recover Post-Retirement Benefits costs on an accrual basis, including a 15-year amortization of the incremental difference.

Q. Is the Post-Retirement Benefits adjustment consistent with the 2013 TEP Rate Order?

A. Yes.

Q. Is the treatment of the 15-year amortization consistent with the 2013 TEP Rate Order?

A. Yes.

E. <u>Short-Term Incentive Compensation.</u>

Q. Please Explain the Company's Short-Term Incentive Compensation program.

A. The Company's short-term incentive compensation, called the Performance Enhancement Plan ("PEP"), is a program that holds a portion of non-union employee's total cash compensation "at risk". As such, a percentage of a non-union employee's base salary is

linked to the Company's performance. As a performance-based component of total compensation, PEP links compensation to metrics and outcomes that benefit customers in the areas of reliability, safety, customer satisfaction, and financial performance which ultimately benefits customers through lower rate levels. The same metrics are used to determine incentive compensation payouts for non-executive employees and executive management.

Q. How is the "at risk" portion of an employee's compensation determined?

A. The "at risk" portion is reflected as a percentage of base salary depending on an employee's position in the Company and their ability to influence the metrics and outcomes. Performance targets are established each year, typically before the end of the first quarter. The objectives are tailored to drive behavior that supports the Company's strategy for delivering safe and reliable service to customers at reasonable rates while maintaining the financial health of the Company.

Having an "at risk" component of compensation allows the Company to focus its effort toward achieving measurable, meaningful goals and compensating employees when those goals are met. The 2015 PEP goals are as follows:

Metric	Criteria	Weighting	Benefit to Customers
Net Income	Actual Net Income	40%	Efforts to increase net income result in lower rates
Operation and Maintenance ("O&M") Expenses	Actual O&M expense	20%	Lower O&M expense which results in lower rates
Equivalent Availability Factor ("EAF")	Percentage of time that a generation unit is available to provide power at its maximum rating	10%	Increased generation reliability which reduces purchased power costs
System Average Interruption Duration Index ("SAIDI")	Average number of minutes of interruption experienced by customers	10%	Reduced length of outages
Customer Satisfaction	As measured by J.D. Power surveys	10%	Increased customer satisfaction
OSHA Recordables	OSHA Recordable Incident Rate	10%	Improved employee, customer and community safety

The 2014 PEP goals had similar metrics and weightings.

Q. How does the customer benefit from PEP?

A. There are clear benefits to customers through improved reliability, satisfaction, safety and financial performance that ultimately results in lower rates. Moreover, using an incentive compensation program is less costly than higher base salaries because incentive compensation does not automatically drive increases in other employee costs such as: vacation pay, sick pay, long-term disability and 401(K) employer matching contributions. As a result, PEP is less costly than increasing base salaries.

Q. How does a Net Income goal benefit customers?

A. A net income PEP goal places an emphasis on revenue generation and cost reduction efforts. TEP actively seeks out opportunities to increase non-jurisdictional revenues (e.g., long-term wholesale sales) which allow the Company to generate incremental

margin that can offset other increases in costs of providing utility services. The Company also has a focus on cost containment activities that are not captured by the O&M expense PEP goal, such as property and sales tax reductions. These efforts allow the Company to delay requests for retail rate adjustments and also, in the case of long-term wholesale sales, result in larger allocations of costs to non-jurisdictional operations both of which benefit customers through lower rates.

Q. Which employees are eligible for PEP?

A. All non-union employees are eligible for PEP. Any form of compensation provided to the union work force must be collectively bargained. In September 2015, a union that represents IBEW 1116 members bargained for a pay for performance component of compensation for call center employees. While the collective bargaining agreement is still subject to ratification by the union employees, this is the first instance where TEP's union has agreed to tie employee performance to the achievement of goals that directly benefit customers. Similar to the PEP program for non-union employees, the union's inclusion of this pay for performance compensation element in their total compensation program is evidence of its routine nature.

Q. Please explain the PEP Adjustment.

A. The adjustment produces a pro forma Test Year expense level reflecting the average of the PEP expense for the Test Year and the prior year ended June 30, 2014. Since PEP payments are subject to payroll taxes, a portion of the adjustment reflects the incremental effect of payroll taxes. The PEP adjustment is calculated in the same manner as the payroll expense adjustment.

Q. Is the Incentive Compensation adjustment consistent with the 2013 TEP Rate order?

A. No. The Commission approved an adjustment that reflected only 50% PEP for all employees.

Q. Why is TEP asking for 100% of PEP in this case?

A. As I discussed earlier in my testimony, the PEP performance targets are based on factors that are critical to the success of the Company. These targets put a portion of employee's compensation "at risk" which, in effect, ties employee performance to the achievement of goals that directly benefit customers. Whether the goals are financial or service driven, the customer ultimately benefits from the improved performance associated with the cost of the program. Additionally, features of the PEP program ensure that payouts are made only when benefits are produced.

The Company ensures that compensation costs are reasonable by targeting total compensation inclusive of PEP at the median of market. An alternative would be to include this "at risk" portion of compensation in base salary, however, that would not achieve the benefits of linking a portion of cash compensation to specific outcomes that benefit customers. Finally, as I discussed earlier, TEP's compensation structure is less costly than if cash compensation were comprised only of base salary which would be increased in order to meet the compensation programs other objectives related to attracting and retaining talent while targeting median of market compensation levels.

Q. Has the Commission allowed 100% recovery of Short-Term Incentive Compensation before?

A. Yes. In Decision No. 69663 (issued June 28, 2007), page 37, the Commission adopted Staff's position to allow recovery of 100% of Arizona Public Service Company ("APS")

Cash-Based Incentive Compensation Program expense because the "at risk" pay program ties employee performance to the customer's benefit. APS' variable incentive program is an "at risk" pay program where a part of an employee's annual cash compensation is put at risk and expectations are established for the employee at the start of the year. If certain performance results are achieved, a predictable award will be earned based upon objective criteria. The actual amount of the award depends upon the achieved results. The intent of the plan is to link pay with business performance and personal contributions to results; motivate participants to achieve higher levels of performance; communicate and focus on critical success measures; reinforce desired business behaviors, as well as results; and to reinforce an employee ownership culture (APS Exhibit No. 51, Gordon Rebuttal, p. 8). Staff did not oppose inclusion of the Test Year variable incentive compensation expense in cost of service, noting that although corporate earnings serve as a threshold or precondition to the payout, the Test Year level of expense is tied primarily to performance measures that directly benefit APS customers (Staff Exhibit No. 43, Dittmer Direct, p. 110).

More recently, in Decision No. 75268 (issued September 8, 2015), the Commission adopted the Administrative Law Judge's Recommended Opinion and Order in the EPCOR Water Arizona, Inc.'s ("EPCOR") rate case to allow recovery in rates of incentive compensation so long as total compensation costs were reasonable. In that case, EPCOR removed a portion of the incentive compensation attributable to financial performance based on Commission treatment in its prior rate case. For the reasons explained above, I believe the financial portions of TEP's PEP provide direct benefits to customers through lower rates and should be included in Test Year expenses.

Q. How does TEP ensure that total compensation levels, including PEP, are reasonable?

A. The company targets total compensation, including PEP, at the median of market. This helps TEP remain competitive in attracting and retaining highly skilled employees at a reasonable cost.

Q. Is there an alternative to TEP using PEP while continuing to remain competitive in attracting and retaining a talented workforce?

A. Yes. TEP could raise base salaries and not have an "at risk" pay compensation component. However, this approach would omit the pay-for-performance feature of the compensation program that benefits customers.

Q. Can you provide an example?

A. Yes. Assume we determine that the median total compensation for an employee is $60,000. We can choose to pay that employee $60,000 in base salary or we could choose to pay that employee $55,000 in base salary and offer a target incentive compensation payment of $5,000 tied to the achievement of certain measurable goals related to safety, customer service, reliability, the reduction of costs and TEP's financial soundness. To the extent the performance goals are achieved and the employee is awarded a $5,000 incentive payment, the total amount paid to the employee would be the same $60,000 necessary for TEP to remain competitive in market for talent.

F. <u>Long-Term Incentive Compensation.</u>

Q. Please explain the Company's Long-Term Incentive Compensation program.

A. The Long-Term Incentive Compensation ("LTI") program is comprised of Performance Units ("PU") and Restricted Stock Units ("RSU"). The program is designed to: (1) place

a focus on long-term performance, linking a portion of the compensation of executive officers to the achievement of multi-year financial results, and (2) serve as a retention tool for executive talent. These objectives are achieved by a three-year vesting schedule inherent in each annual LTI award. The PUs will result in cash compensation to the extent that the three-year cumulative financial target is achieved. RSUs also pay out in cash and vest over three years to serve as a retention tool.

Q. How is the LTI portion of total compensation determined?

A. LTI is reflected as a percentage of base salary depending on an executive's position in the Company and their ability to influence financial outcomes.

Q. How does LTI benefit customers?

A. First, LTI allows the Company to attract and retain the executive talent needed to manage a business of the Company's size and complexity. Second, LTI ensures a focus on the long-term performance of the Company which reduces its financing and operating costs that are ultimately reflected in electric rates.

Q. Please explain the LTI Adjustment.

A. The adjustment produces a pro forma Test Year expense level reflecting the average of the LTI expense for the Test Year and the prior year ended June 30, 2014. Since LTI payments are subject to payroll taxes, a portion of the adjustment reflects the incremental effect of payroll taxes.

Q. Does the combination of PEP and LTI result in labor costs that exceed the market?

A. No. The total compensation approximates the median of the market, based on the most recent benchmark studies. The benchmarking information demonstrates that the amounts are reasonable.

Q. Is the LTI adjustment consistent with the 2013 TEP Rate order?

A. No. TEP did not request recovery of this cost in its last rate case, but reserved the right to request it in this case.

G. San Juan Unit 2 Operating Costs.

Q. Please describe the San Juan Unit 2 adjustment to Test Year operating costs.

A. This adjustment is needed to include in Test Year expenses one-third of the 2017 San Juan Unit 2 operating costs as addressed earlier in my testimony.

H. Sundt and San Juan Materials and Supplies.

Q. What is the purpose of the Sundt and San Juan Materials and Supplies adjustment?

A. This adjustment is necessary to reflect in Test Year expenses a three-year amortization of materials and supplies inventory related to the Sundt coal handling facilities and San Juan Unit 2, as addressed earlier in my testimony.

I. San Juan Unit 1 SNCR Operating Costs.

Q. Please explain the San Juan Unit 1 SNCR Operating Costs adjustment.

A. TEP has a 50% interest in San Juan Unit 1 which is operated by Public Service New Mexico ("PNM"). The same environmental compliance matters that are causing the early retirement of San Juan Unit 2 also dictate the environmental controls needed for San Juan Unit 1 to continue to operate. PNM is currently in the process of installing Selective Non-Catalytic Reduction ("SNCR") technology at Unit 1. In accordance with an U.S. Environmental Protection Agency ("EPA") ruling, the SNCR is required to be operational in 2016, prior to the effectiveness of new rates in this rate case. TEP witness

Dukes addresses the post Test Year rate base adjustment associated with these investments. This adjustment reflects the additional operation and maintenance expense that will also be incurred. Additional information about the environmental regulations and their impact on San Juan can be found later in my testimony in the section titled Accounting for Generation Plant Early Retirements.

J. Depreciation and Amortization Expense Annualization.

Q. Please explain your proposed Depreciation and Amortization Expense Annualization Adjustment.

A. TEP witness Dr. Ronald White performed a 2015 Depreciation Study using data provided by the Company from its FERC Form 1. Using Dr. White's study, the Company updated the depreciation rates from the rates authorized in the 2013 TEP Rate Order.

Q. Why is this adjustment necessary?

A. The amount of depreciation expense recorded by TEP during the Test Year reflects less than a full year of depreciation for assets placed in service during the period and that are included in rate base. Moreover, it includes depreciation recorded on assets retired during the Test Year, and thus, not included in rate base. This adjustment produces an annual depreciation expense consistent with the level of depreciable plant in rate base, based on known and measurable changes.

Q. How was the adjustment computed?

A. The adjustment was calculated by first computing the pro forma annualized depreciation expense and then deducting Test Year recorded depreciation expense. For generation assets pro forma annual depreciation was computed by multiplying the end-of-Test Year plant balance in rate base at each generating location and related depreciable FERC plant

account, by the respective current or proposed depreciation rate. For other accounts, annual depreciation was computed using the end-of-Test Year balance in the respective accounts multiplied by the approved current depreciation or amortization rate. For certain assets, a portion of depreciation is capitalized as part of the cost of constructing new assets; thus, such amounts were excluded from the calculation.

K. Property Tax Expense.

Q. Please explain the Property Tax adjustment.

A. The Property Tax adjustment is a pro forma adjustment to Test Year operating expense to reflect the final, adjusted plant in service at the end of the Test Year, using the 2017 statutory assessment ratios, and average property tax rates in effect for the 2015 property tax year. To the extent more current tax rate information becomes available during this rate case proceeding, the Company will update the property tax adjustment.

L. Income Tax Expense.

Q. Please explain the Income Tax Expense adjustment.

A. The Income Tax Expense adjustment is a pro forma adjustment to Test Year operating expenses to reflect income taxes based on final adjusted operating revenues, operating expenses, and rate base. It is computed in two parts. The first part is pro forma current income tax expense, with the tax liability computed as though an actual income tax return was being prepared on final adjusted Test Year taxable operating income. For this purpose, it was necessary to identify all operating book-tax differences ("Schedule M items"), both timing and permanent, and then re-compute current tax expense based on adjusted Test Year operating revenues and expenses as necessary. The tax deduction for

interest was computed using a synchronization methodology reflecting final adjusted rate base and the weighted cost of debt in the capital structure.

The second part of the income tax adjustment is deferred income tax expense. Deferred income taxes are computed on the Schedule M items representing timing differences for which TEP has obtained normalization ratemaking authority from the Commission as previously described in my direct testimony.

Q. What is the adjustment to Deferred Income Tax Expense as a result of the basis adjustment associated with the IRC §48 Energy Credit?

A. As previously discussed in my direct testimony, the election to take the §48 Energy Credit on qualifying property requires a reduction in the basis of the qualifying property for purposes of calculating tax depreciation. The result of this basis reduction is that future tax depreciation deductions will be reduced by an amount equal to one-half of the §48 Energy Credit, or 15% of the basis of the qualifying property.

This basis reduction effectively reduces the value of the §48 Energy Credit from 30% of the cost of the asset (the amount of the unamortized rate-base reduction) to 24.75% (assuming a 35% tax rate applied to the 15% basis reduction). This loss of benefit is reflected as an increase to deferred income tax expense each year as the basis difference reverses through the book depreciation timing difference.

Q. What is the adjustment to Deferred Income Tax Expense for Excess Deferred State Income Taxes?

A. As previously discussed, TEP reduces state deferred income tax expense (and the revenue requirement) for the excess deferred state income taxes associated with utility operations

as the underlying timing differences reverse. Income tax expense has been reduced by the estimated 2015 amortization.

M. Fortis Merger Operating Income Adjustment.

Q. Please explain the Fortis Merger Costs Adjustment.

A. This adjustment removes all merger related costs from the Test Year income statement.

VII. COMPLIANCE WITH FORTIS MERGER CONDITIONS.

Q. Please describe the Fortis merger conditions.

A. The Fortis/UNS Energy merger settlement agreement, which was approved by Decision No. 74689 (August 12, 2014), contains various conditions. The ACC order requires the Company to submit an annual compliance filing addressing the conditions with the first such annual report due April 1, 2016. That said, there are several conditions that need to be addressed in this rate case. I will address most of those conditions, while TEP witness Susan Gray will addresses Conditions 28 and 29 regarding best efforts to maintain or improve quality of service

Q. In Condition 5 of the settlement agreement, Fortis, UNS Energy and the Regulated Utilities (including TEP) agreed that they will not seek recovery of or on any acquisition premium or goodwill amount in any future rate proceeding. Can you confirm that TEP is not seeking such recovery?

A. Yes, TEP is not seeking such recovery.

Q. In Condition 6, the Companies agreed that Fortis shall not allocate any Fortis specific costs to the Regulated Utilities (including TEP) for possible recovery in a future rate proceeding for five years after closing. Can you confirm that TEP is not seeking such recovery in this rate case?

A. Yes, our revenue requirement does not include any Fortis specific costs.

Q. In Condition 7, Fortis, UNS Energy and the Regulated Utilities agreed that they will not pass any costs of the shareholder litigation related to the merger to ratepayers. Does the revenue requirement include any shareholder litigation costs?

A. No, it does not.

Q. In Condition 8, Fortis, UNS Energy and the Regulated Utilities agreed that they would not seek recovery of or on the transaction and transition costs associated with the merger. Does the revenue requirement include any such costs?

A. No, it does not.

Q. Condition 8 also precludes recovery of any Change of Control and Retention payments related to the merger. Can you confirm that TEP is not seeking any recovery of those payments?

A. Yes, the Company is not seeking any such recovery and its customers will not bear the cost of any of such payments.

Q. Condition 9 provides that Fortis shall hold the TEP's ratepayers harmless from the impacts of any fluctuations in foreign exchange rates and any incremental taxes arising from its international ownership structure. Does the revenue requirement include any such impacts?

A. No, the revenue requirement does not include impacts of any fluctuations in foreign

exchange rates or any incremental taxes arising from its international ownership structure.

Q. With respect to Condition 10, has Fortis made an acquisition since the approval of the Fortis/UNS Energy merger that has had any material adverse impact on TEP?

A. No, it has not.

Q. With respect to Condition 11, can you confirm that the revenue requirement in this case does not include any increase in the total compensation of the Senior Management Personnel?

A. The revenue requirement does not include any such increase. As of the end of the Test Year there were 10 executive officers of UNS Energy. This is one less than the number of executive officers as of August 12, 2014, the date of Decision No. 74689 approving the merger. Therefore, pursuant to Condition 11, the portion of the compensation for those Senior Management Personnel that is allocable to TEP has not increased.

Q. With respect to Condition 12, has Fortis completed any merger or acquisition within the United States since the approval of the Fortis/UNS Energy merger?

A. No, it has not.

Q. In Condition 13, Fortis, UNS Energy and the Regulated Utilities agreed that the goodwill and transaction costs of the Fortis/UNS Energy transaction would be excluded from the rate base, expenses and capitalization in the determination of rates and earned returns of TEP. Can you confirm that the rate base, expenses and capitalization excludes the goodwill and transaction costs of the merger?

A. Yes, the revenue requirement does not include those items.

Q. Pursuant to Condition 15, have UNS Energy and the Regulated Utilities prepared a final schedule of the external costs to achieve the merger?

A. Yes, they have. I can confirm that the revenue requirement sought in this docket does not reflect any recovery or recognition of any legal or financial advisory fees, or other external costs associated with the acquisition.

Q. As contemplated in Condition 17, is the proposed capital structure in this docket separate from that of Fortis?

A. Yes, it is. As set forth in TEP witness Kentton Grant's testimony, we are proposing to use TEP's actual capital structure in this rate case.

Q. Under Condition 62, TEP is required to disclose in its rate case filing "each service function (i.e., accounting, treasury, human resources, information technology, risk management, etc.) that it does not fully staff, or which it relies in whole or in part upon Fortis and/or UNS Energy." Please set forth those service functions for which TEP relies on Fortis and/or UNS Energy.

A. Following the closing of the Fortis merger, there are two services for which TEP relies in whole or in part on Fortis. First, while TEP continues to raise debt capital funds through its in-house treasury function, equity capital financing is performed entirely by Fortis. The costs incurred by Fortis for this function are allocated to UNS Energy and TEP and those costs incurred during the Test Year have been removed. Second, TEP coordinates with Fortis on procuring the majority of its insurance coverage to take advantage of scale discounts that would otherwise be unavailable to TEP. TEP contracts with the insurance broker directly and is direct charged for such coverage.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

FPM-1

Tucson Electric Power Company
Bonus Depreciation Ratepayer Benefit Example

Assumptions

Investment	1,000,000
Federal Tax Rate	35.0%
Return on Rate Base	7.34%

Year	Book Depreciation	Regular MACRS Tax Rates	Regular Tax Depreciation	ADIT Reduction to Rate Base	Ratepayer Benefit	100% Bonus Tax Depreciation	ADIT Reduction to Rate Base	Ratepayer Benefit
1	25,000	0.0375	37,500	(4,375)	(321)	1,000,000	(341,250)	(25,048)
2	25,000	0.07219	72,190	(20,892)	(1,533)	-	(332,500)	(24,406)
3	25,000	0.06677	66,770	(35,511)	(2,607)	-	(323,750)	(23,763)
4	25,000	0.06177	61,770	(48,381)	(3,551)	-	(315,000)	(23,121)
5	25,000	0.05713	57,130	(59,626)	(4,377)	-	(306,250)	(22,479)
6	25,000	0.05285	52,850	(69,374)	(5,092)	-	(297,500)	(21,837)
7	25,000	0.04888	48,880	(77,732)	(5,705)	-	(288,750)	(21,194)
8	25,000	0.04522	45,220	(84,809)	(6,225)	-	(280,000)	(20,552)
9	25,000	0.04462	44,620	(91,676)	(6,729)	-	(271,250)	(19,910)
10	25,000	0.04461	44,610	(98,539)	(7,233)	-	(262,500)	(19,268)
11	25,000	0.04462	44,620	(105,406)	(7,737)	-	(253,750)	(18,625)
12	25,000	0.04461	44,610	(112,270)	(8,241)	-	(245,000)	(17,983)
13	25,000	0.04462	44,620	(119,137)	(8,745)	-	(236,250)	(17,341)
14	25,000	0.04461	44,610	(126,000)	(9,248)	-	(227,500)	(16,699)
15	25,000	0.04462	44,620	(132,867)	(9,752)	-	(218,750)	(16,056)
16	25,000	0.04461	44,610	(139,731)	(10,256)	-	(210,000)	(15,414)
17	25,000	0.04462	44,620	(146,598)	(10,760)	-	(201,250)	(14,772)
18	25,000	0.04461	44,610	(153,461)	(11,264)	-	(192,500)	(14,130)
19	25,000	0.04462	44,620	(160,328)	(11,768)	-	(183,750)	(13,487)
20	25,000	0.04461	44,610	(167,192)	(12,272)	-	(175,000)	(12,845)
21	25,000	0.02231	22,310	(166,250)	(12,203)	-	(166,250)	(12,203)
22	25,000		-	(157,500)	(11,561)	-	(157,500)	(11,561)
23	25,000		-	(148,750)	(10,918)	-	(148,750)	(10,918)
24	25,000		-	(140,000)	(10,276)	-	(140,000)	(10,276)
25	25,000		-	(131,250)	(9,634)	-	(131,250)	(9,634)
26	25,000		-	(122,500)	(8,992)	-	(122,500)	(8,992)
27	25,000		-	(113,750)	(8,349)	-	(113,750)	(8,349)
28	25,000		-	(105,000)	(7,707)	-	(105,000)	(7,707)
29	25,000		-	(96,250)	(7,065)	-	(96,250)	(7,065)
30	25,000		-	(87,500)	(6,423)	-	(87,500)	(6,423)
31	25,000		-	(78,750)	(5,780)	-	(78,750)	(5,780)
32	25,000		-	(70,000)	(5,138)	-	(70,000)	(5,138)
33	25,000		-	(61,250)	(4,496)	-	(61,250)	(4,496)
34	25,000		-	(52,500)	(3,854)	-	(52,500)	(3,854)
35	25,000		-	(43,750)	(3,211)	-	(43,750)	(3,211)
36	25,000		-	(35,000)	(2,569)	-	(35,000)	(2,569)
37	25,000		-	(26,250)	(1,927)	-	(26,250)	(1,927)
38	25,000		-	(17,500)	(1,285)	-	(17,500)	(1,285)
39	25,000		-	(8,750)	(642)	-	(8,750)	(642)
40	25,000		-	-	-	-	-	-
	1,000,000	1	1,000,000		(265,444)	1,000,000		(500,955)

Increase in Ratepayer Benefits By Claiming Bonus Depreciation (235,511)

EXHIBIT

FPM-2

Tucson Electric Power Company

220 West Sixth Street
P. O. Box 711
Tucson, Arizona 85702

Kenneth L. Saul
Vice President
and Controller

(602) 884-3630

July 20, 1983

Mr. Neill Dimmick
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Dear Mr. Dimmick:

The Economic Recovery Tax Act of 1981 included a number of changes in the law which directly affected the treatment of depreciation and investment tax credit by investor-owned utility companies. These included the replacement of the Class Life ADR System of depreciation with the Accelerated Cost Recovery System (ACRS), the elimination of the repair allowance on ACRS additions, the revised treatment of the dispositions of ACRS property, the required normalization of depreciation on ACRS property, and the changes in the investment tax credit rates and recapture provisions. In addition, the Tax Equity and Fiscal Responsibility Act of 1982 was responsible for further changes. These included the reduction of future depreciation rates under ACRS, the decrease in the depreciation benefits for facilities financed by industrial development bonds, the required capitalization of construction period interest and taxes, further changes in the investment tax credit rates and recapture provisions, the allowance of a deduction for unused investment tax credit, and the change in the investment tax credit limitation.

As the above changes in the law were enacted, Tucson Electric Power Company analyzed the changes to determine whether further action was required by the Arizona Corporation Commission to insure compliance with the law. In this connection the Company plans to amortize investment tax credits over 15 years the new tax life of public utility property, because we believe that the investment tax credit tax benefits should be spread over the tax life of the equipment generating the credit, and that such amortization is consistent with current tax law and the Uniform Systems of Accounts and as such requires no further regulatory approval.

Should you have any questions please do not hesitate to call, and in that regard if we have not heard from you within ten days, we will assume that the procedure outlined is acceptable to you.

Thank you for your consideration in this matter.

Very truly yours,

KLS/nj

DIANE E. McCARTHY
CHAIRMAN

BUD TIMS
COMMISSIONER

RICHARD KIMBALL
COMMISSIONER

LORRIE DROSNY
EXECUTIVE SECRETARY

ARIZONA CORPORATION COMMISSION

July 21, 1983

Mr. Kenneth L. Saul
Vice President and Controller
Tucson Electric Power Company
P. O. Box 711
Tucson, Arizona 85702

Dear Mr. Saul:

We have received your letter of July 20, 1983 regarding the amortization of investment tax credits and find that the procedure you outlined is consistent with our understanding of the law and the Uniform System of Accounts. Therefore, we have no objection to your company implementing same.

Thank you for advising us of your changes.

Very truly yours,

Neill T. Dimmick
Director of Utilities

NTD/nd

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

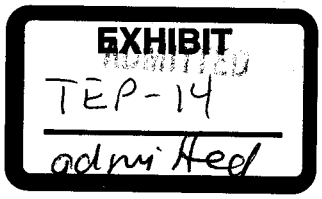
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-1933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

REBUTTAL TESTIMONY OF FRANK P. MARINO

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016



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Exhibits:

Exhibit FPM-R-1 TEP's response to AECC's data request AECC 1.3

Exhibit FPM-R-2 TEP's supplemental response to UDR 1.001, dated March 18, 2016

Exhibit FPM-R-3 Decision No. 75033

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Frank P. Marino and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you present direct testimony in this case?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony?

A. I will respond to a variety of topics addressed in the Direct Testimonies of Commission Staff ("Staff"), the Residential Utility Consumers Office ("RUCO"), Arizonans for Electric Choice and Competition ("AECC"), and the International Brotherhood of Electrical Workers Local 1116 ("IBEW"). Specifically, I will address the following topics:

- Bonus Depreciation
- Accumulated Deferred Income Taxes Related to Intervenor Plant Adjustments
- Updates to Pro-Forma Adjustments in Direct Testimony
- Payroll Expense
- Short-Term Incentive Compensation
- Long-Term Incentive Compensation, SERP
- D&O Insurance and Severance Pay
- IBEW Allegation of Cross Subsidization

II. BONUS DEPRECIATION.

Q. Have there been any changes in tax law since TEP filed its rate case?

A. Yes. On December 18, 2015, the Protecting Americans from Tax Hikes Act of 2015 was signed into law. The Act extends 50 percent bonus tax depreciation through December 31, 2017, and includes a phase down to 40 percent bonus depreciation in 2018 and 30 percent in 2019.

Q. How does the extension of bonus depreciation impact this rate case?

A. Under prior law, 50 percent bonus tax depreciation expired December 31, 2014. As a result, in TEP's initial filing ADIT on post-test year plant and asset additions from January 1, 2015 to June 30, 2015 was calculated without the impact of 50 percent bonus depreciation. In TEP's Supplemental Response to AECC Data Request 1.3 attached as **Exhibit FPM-R-1**, TEP provided updated ADIT calculations, reflecting the extension of 50 percent bonus depreciation.

Q. Did Intervenor's file Direct Testimony reflecting the updated ADIT provided by TEP?

A. Yes. Staff and AECC included the updated ADIT amounts provided by TEP.

Q. Do you have any corrections to post-test year plant adjustments proposed by Staff and AECC?

A. Yes. The updated ADIT amounts provided by TEP reflect post-test year plant additions. Staff and AECC made adjustments to post-test year plant included in rate base without making the associated and offsetting ADIT adjustment. I discuss this in more detail in the next section.

III. ACCUMULATED DEFERRED INCOME TAXES RELATED TO INTERVENOR PLANT ADJUSTMENTS.

Q. Please explain how TEP determines whether the ADIT related to particular assets should be included in rate base?

A. TEP includes ADIT in rate base whenever the associated asset cost and accumulated depreciation are included in rate base.

Q. Did Staff and the Interveners accurately reflect this relationship in their Direct Testimony?

A. No. There are a number of Staff and Intervenor proposals to remove assets from rate base. However, in nearly all cases, the ADIT associated with the adjustment was not likewise removed resulting in an overstated adjustment and understated rate base. TEP witness Lewis has reflected the corrections to rate base that would need to accompany such adjustments.

IV. UPDATES TO PRO-FORMA ADJUSTMENTS IN DIRECT TESTIMONY.

Q. Please summarize the updates you made to the pro-forma adjustments you sponsor.

A. During the discovery process, I have identified errors related to certain pro-forma adjustments in my Direct Testimony that require correction. These include:

- Pension and Benefits
- Sundt Coal Handling Facilities Materials and Supplies
- Short-Term Incentive Compensation

Q. Please address the update to the Pension and Benefits pro-forma adjustment.

A. The update to the Pension and Benefits pro-forma adjustment captures certain benefit costs that were excluded from the initial adjustment addressed in my Direct Testimony at

page 32 lines 14 - 23. This was identified by TEP when responding to Data Request STF 7.15. The corrected information was provided as a supplemental response to UDR 1.001 on March 18, 2016 (the pertinent excerpt of the response to UDR 1.001 is attached as **Exhibit FPM-R-2**). Staff witness Mullinax acknowledged the need to correct the initial pro-forma adjustment in her Direct Testimony.

Q. **Please address the update to the Sundt Coal Handling Facilities Materials and Supplies pro-forma adjustment.**

A. My Direct Testimony at page 42, lines 13 – 16, addresses the recovery of remaining materials and supplies related to both the Sundt Coal Handling Facilities and San Juan Unit 2, which are both being retired early. After further review, we have determined that the amount of materials and supplies related to Sundt Coal Handling Facilities were understated in our initial filing.

Q. Please address the update to the Short-Term Incentive Compensation pro-forma adjustment.

A. In response to a RUCO data request, the Company discovered that the amount reported as test year short-term incentive compensation expense did not exclude the amount capitalized as A&G. The pro-forma adjustment proposed in my Direct Testimony at page 37, lines 19 – 24, was designed to produce a certain amount of recovery of Short-Term Incentive Compensation ("PEP"). The pro-forma adjustment has been corrected.

Q. **Have these three updates been included in TEP's updated revenue requirement calculation?**

A. Yes. TEP witness Lewis has included updates to these pro-forma adjustments as reflected in Exhibit DJL-R-1 to his Rebuttal Testimony.

V. PAYROLL EXPENSE.

Q. Please summarize the Staff and Intervenor proposals related to Payroll Expense.

A. Both Staff witness Mullinax and AECC witness Higgins propose to eliminate the increase in payroll costs of 2% for 2017 because it is an estimate and not known and measurable. IBEW witness Northrup supports the proposed 2% increase for 2017 for union employees, but opposes a similar adjustment for non-union personnel because the terms and conditions of their employment can change.

Q. Do you agree that the 2017 payroll increase should be removed?

A. No. Payroll increases are reasonable and necessary in order for TEP to remain competitive in the market for talent. Also the payroll changes are known and measurable with the exception of the 2017 non-union increase.

Q. Why is a 2% union increase for 2017 reasonable?

A. Since TEP filed this rate case, TEP and IBEW Local 1116 entered into a new collective bargaining agreement covering the three-year period January 2016 through December 2018. The agreement includes 2% annual increases in 2016 and 2017 and 2.5% increase in 2018. The agreement became effective January 4, 2016. Thus, this cost increase is in fact known and measurable. It is also representative of market pay increases.

Q. Why is a 2% non-union increase for 2017 reasonable?

A. Non-union increases have averaged approximately 2% per year for the past 6 years. The non-union increases are of the same magnitude of the negotiated union increases. This is a reasonable adjustment to test year expenses as 2017 represents the first full year that new rates will be in effect.

Q. **Which pro-forma adjustments does the 2% payroll increase impact?**

A. It impacts the following pro-forma adjustments:

- Payroll Expense
- Short-Term Incentive Compensation
- Long-Term Incentive Compensation
- Payroll Tax Expense

Q. **Please explain the Payroll Tax Expense adjustment.**

A. TEP's initial filing included a pro-forma adjustment to Payroll Tax Expense related to the pro-forma payroll increases. AECC witness Higgins identified an adjustment to Payroll Tax Expense related to his proposal to remove the 2% payroll increase for 2017. To the extent the 2% payroll increase for 2017 is removed from test year expense, I agree that Payroll Tax Expense should be adjusted accordingly.

VI. SHORT-TERM INCENTIVE COMPENSATION.

Q. **Please describe the adjustment you initially proposed for Short-Term Incentive Compensation.**

A. I proposed an adjustment that sets test year expense at a level equal to the average Short-Term Incentive Compensation ("PEP") expense for the test year ended June 30, 2015 and the prior year ended June 30, 2014. I then escalated the result by 2% for 2016 and 2017.

Q. **In what ways do the Staff and Intervenor proposals differ from that approach?**

A. Aside from the 2% payroll increase for 2017 that I addressed above, Staff witness Mullinax and RUCO witness Michlik each propose excluding 50% of PEP expense from test year expenses based on the premise that customers and shareholders both benefit from the program. AECC witness Higgins proposes to exclude 40% of the cost to

remove the portion of the expense attributable to the net income component of the program.

Q. **Do you agree with these proposals?**

A. I do not. My Direct Testimony at pages 34 - 40 addresses why PEP expense is a reasonable cost of providing service and how each component of PEP benefits customers. There is no basis to exclude elements of PEP in the ratemaking process. The financial performance of a utility sets the foundation for its ability to provide safe, reliable and affordable service. All of the components of PEP ensure that employees strive to provide the highest quality service at the lowest cost to customers. PEP is an integral component of TEP's compensation program which is designed to attract, retain and motivate a workforce while producing measurable benefits to customers at an overall cost that is comparable to market.

VII. LONG-TERM INCENTIVE COMPENSATION AND SERP.

Q. **Please summarize the Staff and Intervenor proposals related to Long-Term Incentive Compensation and SERP.**

A. Staff witness Mullinax, RUCO witness Michlik and AECC witness Higgins each propose to remove 100% of both LTI and SERP expense from the test year.

Q. **Do you agree with these proposals?**

A. No. My Direct Testimony at pages 40 – 42 addresses why these expenses are a reasonable cost of providing electric service.

Q. **Are you proposing any concessions with respect to the ratemaking treatment of LTI and SERP expense?**

A. Yes. While LTI and SERP are both reasonable and necessary components of TEP's compensation program, I propose as a concession in this case to remove these costs from test year expenses. The related adjustments have been included in TEP's revised revenue requirement as addressed by TEP witness Lewis. These concessions are made in the spirit of compromise, but TEP retains its right to request and receive recovery of LTI and SERP in future rate cases.

VIII. D&O INSURANCE AND SEVERANCE PAY.

Q. Please summarize the Staff and Intervenor proposals related to D&O insurance and severance pay.

A. Both Staff witness Mullinax and RUCO witness Michlik propose a 50/50 sharing of test year D&O insurance cost and they both propose to remove 100% of test year severance pay expense. I would note that Staff witness Mullinax removed from her calculation of pro-forma operating income the portion of severance pay that was capitalized.

Q. Are you willing to accept both of their proposed adjustments?

A. Yes, as a compromise for purposes of this rate case and while reserving TEP's right to request and receive full recovery of D&O insurance and severance costs in future rates. TEP witness Lewis has reflected the correct adjustment to both operating income and rate base associated with accepting these adjustments.

IX. IBEW ALLEGATION OF CROSS SUBSIDIZATION.

Q. Please summarize the allegation made by IBEW witness Northrup.

A. Mr. Northrup alleges that TEP cross-subsidizes UNS Energy and he asks that the Commission "focus its attention on this issue" and "pay special attention to whether UNS is being inappropriately enriched at the expense of TEP and, in turn, its patrons."

Q. Are you aware of any cross-subsidization of UNS Energy by TEP?

A. No. In my capacity of Vice President and Controller, I ensure that UNS Energy and its affiliates have appropriate policies and procedures in place to prevent cross-subsidization. These procedures use a fully-distributed costing methodology for assigning costs between regulated and non-regulated activities with an emphasis on direct assignment and cost causation whenever possible.

Q. Does UNS Energy and its affiliates have a Code of Conduct on file with the Commission?

A. Yes. UNS Energy and its affiliates, including TEP, have complied with a Code of Conduct which has been on file with the Commission since 2000 (see Decision No. 62767 (August 2, 2000)). The Code of Conduct sets forth the procedures for valuing and allocating intercompany transactions related to the transfer of assets and the provision of goods and services between UNS Energy affiliates. The Code of Conduct ensures that utility customers of TEP and its regulated utility affiliates are not impacted by cross-subsidization as it sets the methods upon which costs are allocated among regulated and non-regulated affiliates. In compliance with the ACC order approving Fortis' acquisition of UNS Energy, UNS Energy submitted a revised Code of Conduct to include all Fortis affiliates. See Decision No. 74689 (August 12, 2014) (Settlement Agreement Conditions

6 and 58). The Commission approved the revised Code of Conduct in Decision No. 75033 (April 23, 2015) attached as **Exhibit FPM-R-3**.

Q. Do UNS Energy's policies and procedures related to the Code of Conduct set forth any objectives?

A. Yes. UNS Energy and its affiliates utilize cost allocation procedures consistent with the Code of Conduct which have the principle objectives "to prevent or minimize, to the extent practicable, the potential for cross-subsidization of one activity or entity by another" while achieving "a proper balance between the desired precision of the cost allocation process with the cost of attaining such accuracy." See Attachment B, page 2 of **Exhibit FPM-R-3**.

Q. Does that conclude your Rebuttal Testimony?

A. Yes.

Exhibit FPM – R – 1

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO AECC FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322
January 14, 2016

AECC 1.3

Bonus tax depreciation. Using TEP's direct case as a starting point, what is the impact on the TEP's revenue requirement resulting from the five year extension of bonus tax depreciation in H.R. 2029 (as signed into law by President Obama on December 18, 2015)? Please provide the adjustments necessary on both a Total Company and ACC Jurisdictional basis necessary to reflect the impact of this extension on TEP's requested revenue increase. Please provide the workpapers used to support this response in Excel format with formulas intact.

RESPONSE: **January 4, 2016**

TEP is in the process of evaluating the H.R. 2029 through its year end close process and will respond as soon as possible.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

SUPPLEMENTAL RESPONSE: **January 14, 2016**

For an updated Accumulated Deferred Income Tax pro forma adjustment that includes the impacts of the extension of bonus depreciation, see AECC 1.3 Bonus - Rate Base - Accumulated Deferred Income Taxes.xlsm. This update would reduce the overall revenue requirement by approximately $1.5 million. The Excel file is not identified by Bates numbers.

RESPONDENT:

Jason Rademacher

WITNESS:

Frank Marino

Exhibit FPM – R – 2

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 18, 2016

WORKPAPERS:

UDR 1.001

Workpapers. Please provide a complete set of supporting workpapers for all schedules, analysis, calculations and witness testimony in TEP's filing. Provide all in Excel format with formulas and cross references intact where applicable.

SUPPLEMENTAL RESPONSE: March 18, 2016

- The adjustment for the Company's share of contributions to the employees' benefits expense (including 401(k) plan, medical, dental, vision, life and long-term disability benefit) was inadvertently omitted from the rate case filing. Please see revised pro-forma "Income – Pension & Benefits Revised.xlsm", as listed above.
- There was an inadvertent mathematical error in the working capital proforma adjustment. Please see Rate Base – Working Capital Revised.xlsm, as listed above.
- Please see Income-Payroll Expense-Revised.xlsm for the updated file which replaces linked numbers with values eliminating the errors when links are not activated, and adds page 10.
- Please see Income - Long Term Incentive Compensation-Revised.xlsm. The amount listed as Fortis Merger LTC Compensation Expense has been corrected.

RESPONDENT:

Regulatory Department

Exhibit FPM – R – 3

0000161735

BEFORE THE ARIZONA CORPORATION COMMISSION

SUSAN BITTER SMITH
Chairman
BOB STUMP
Commissioner
BOB BURNS
Commissioner
DOUG LITTLE
Commissioner
TOM FORESE
Commissioner

Arizona Corporation Commission
DOCKETED
APR 23 2015
DOCKETED BY

IN THE MATTER OF THE APPLICATION FOR APPROVAL OF THE REORGANIZATION OF UNS ENERGY CORPORATION ON BEHALF OF ITSELF AND ITS AFFILIATES UNISOURCE ENERGY SERVICES AND TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-04230A-14-0011 & E-01933A-14-0011

DECISION NO. 75033

ORDER

Open Meeting
April 14-15, 2015
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. On October 9, 2014, in compliance with Conditions 6 and 58 of the Settlement Agreement approved in Decision No. 74689 dated August 12, 2014, UNS Energy Corporation ("UNS Energy") and Fortis Inc. ("Fortis") submitted its proposed code of conduct regarding UNS Energy's and its regulated utility subsidiaries' affiliate transactions ("Code of Conduct") and the related proposed procedures for valuing and allocating intercompany transactions related to the transfer of assets and the provision of goods and services between affiliates ("Policies and Procedures"). The Code of Conduct updates UNS Energy's previously approved Code of Conduct to reflect the current conditions, including the acquisition of UNS Energy by Fortis.

2. UNS Energy and Fortis state that the Policies and Procedures reflect the long-standing valuation and cost allocation practices that have been in place since UNS Energy's acquisition of the Citizens Utilities' assets in 2002. They underlie the rates approved by the Commission for Tucson

Electric Power Company, UNS Electric, Inc. and UNS Gas, Inc. The Policies and Procedures also have been updated to reflect the current conditions in Arizona, including the acquisition of UNS Energy by Fortis.

3. Fortis and UNS Energy request Commission approval of the Code of Conduct and the Policies and Procedures to the extent required by Decision No. 74689 and the related Settlement Agreement.

4. Staff has reviewed the Code of Conduct and the Policies and Procedures and has made some clarifications as shown on the attached. Staff recommends that the Commission approve the Code of Conduct and the Policies and Procedures as contained in Attachments A and B.

CONCLUSIONS OF LAW

1. UNS Energy and its regulated affiliates are public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-250 and 40-251.

2. The Commission has jurisdiction over UNS Energy and its regulated affiliates and of the subject matter of the Docket.

ORDER

IT IS THEREFORE ORDERED that UNS Energy Corporation Code of Conduct and Policies and Procedures, attached hereto as Attachment A and Attachment B, respectively, are hereby approved.

BY THE 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 Capitol, in the City of Phoenix, this 23rd day of April, 2015.

JODI JERICH
EXECUTIVE DIRECTOR

DISSENT: _____

DISSENT: _____

SMO:GB:sms/BES

SERVICE LIST FOR: UNS Energy Corporation
DOCKET NOS. E-04230A-14-0011 & E-01933A-14-0011

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Ms. Lyn Farmer
Chief Administrative Law Judge,
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Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007

Attachment A

Docket No. E-04230A-14-0011 & E-01933A-14-0011

Code of Conduct

UNS Energy Corporation

and

Regulated Utilities

October 2014

Decision No. 75033

I. Purpose.

The purpose of this Code of Conduct is to govern the transactions between and among UNS Energy, the Regulated Utilities and their Affiliates. The Code of Conduct sets forth the procedures for managing intercompany transactions, including procedures for valuing and allocating intercompany transactions related to the transfer of assets and to the provision of goods and services between and among UNS Energy, the Regulated Utilities and their Affiliates. This Code of Conduct and related Policies and Procedures are intended to implement Conditions 6 and 58 of the Settlement Agreement approved by Decision No. 74689 (August 12, 2014). The Code of Conduct is not intended to supersede the obligations of UNS Energy or its Affiliates under Arizona statutes and/or the Commission's rules, regulations and orders.

II. Definitions.

"Affiliate" means a separate legal entity that is controlled by, controls, or is under common control with a Regulated Utility.

"Assets" means real property, depreciable personal property and intangible property.

"Commission" means the Arizona Corporation Commission.

"Confidential Customer Information" means any non-public customer specific information obtained by a Regulated Utility as a result of providing regulated services to the customer.

"Depreciable personal property" means vehicles, machinery, furniture, fixtures not attached to land, equipment, computer hardware and related software applications and any other tangible property, which are not goods or real property.

"Depreciated Cost" means the Fully Allocated Cost of an asset less appropriate depreciation.

"Fully Allocated Costs" means the sum of direct costs plus an appropriate share of indirect costs.

"Goods" means non-depreciable personal property, such as inventory, materials and supplies.

"Intangible property" means any asset having no physical existence, its value being set by the rights and anticipated benefits that an owner obtains by possessing it.

"Policies and Procedures" means those policies and procedures developed by UNS Energy and the Regulated Utilities to implement this Code of Conduct.

"Regulated Utilities" means TEP, UNS Electric, and UNS Gas (individually "Regulated Utility").

"TEP" means Tucson Electric Power Company as it currently exists, as its name may be changed, or as any successor enterprise.

"UNS Electric" means UNS Electric, Inc. as it currently exists, as its name may be changed, or as any successor enterprise.

"UNS Energy" means UNS Energy Corporation as it currently exists, as its name may be changed, or as any successor enterprise.

"UNS Gas" means UNS Gas, Inc. as it currently exists, as its name may be changed, or as any successor enterprise.

III. Applicability of Code of Conduct.

The Code of Conduct applies to UNS Energy and its interactions with Affiliates and the Regulated Utilities and their interactions with Affiliates.

All employees and authorized agents of UNS Energy and the Regulated Utilities shall comply with this Code of Conduct. Failure to comply with this Code of Conduct will subject the employee to disciplinary actions as described in Section VII.

IV. Affiliate Transactions.

A. Transfer of Assets between Affiliates.

1. All transfers of assets between the Regulated Utilities shall be at Depreciated Cost.

2. All transfers of assets from the Regulated Utilities to their Affiliates (other than Regulated Utilities) shall be at the higher of Depreciated Cost or fair market value.

3. All transfers of assets to the Regulated Utilities from their Affiliates (other than Regulated Utilities) shall be at the lower of Depreciated Cost or fair market value.

B. Transfer of Goods and Services between Affiliates.

1. The Regulated Utilities' tariffed goods and services shall be provided to their Affiliates and third parties at the rates and under the terms and conditions set forth in the tariff.

2. All transfers of non-tariffed goods and services between the Regulated Utilities shall be at Fully Allocated Costs.

3. All transfers of non-tariffed goods and services from the Regulated Utilities to their Affiliates (other than Regulated Utilities) shall be at the higher of Fully Allocated Costs or fair market value.

4. All transfers of goods and services to the Regulated Utilities from their Affiliates (other than Regulated Utilities) shall be at the lower of Fully Allocated Costs or fair market value.

V. Accounting for and Allocation of Costs between Affiliates.

A. UNS Energy and the Regulated Utilities shall account for and allocate costs in compliance with the Policies and Procedures attached hereto as Exhibit B.

B. UNS Energy and the Regulated Utilities may not make and implement any material change to the Policies and Procedures without seeking the prior approval of the Commission. Once notification is made of an intended modification, if no action is taken by the Commission within 30 days of its filing, the modification shall be deemed approved.

VI. Use of Customer Information.

The Regulated Utilities shall not provide Confidential Customer Information to any Affiliate or third party except in compliance with applicable Commission rules, regulations or orders.

VII. Dissemination, Education, and Compliance.

A. Copies of this Code of Conduct shall be provided to employees of UNS Energy and the Regulated Utilities, and those authorized agents of UNS Energy and the Regulated Utilities. A copy of the Code of Conduct shall be maintained on UNS Energy's Intranet.

B. Training on the provisions of the Code of Conduct and its implementation shall be provided to all employees of UNS Energy and the Regulated Utilities.

C. Compliance with the Code of Conduct is mandatory. An employee's or agent's failure or refusal to abide by or to act according to such standards may subject the employee or agent to disciplinary action, up to and including discharge from employment or termination of the agent's relationship with UNS Energy and the Regulated Utilities.

D. Questions regarding this Code of Conduct should be directed to the UNS Energy Legal Department.

VIII. Procedure to Modify the Code of Conduct.

UNS Energy, the Regulated Utilities or Commission Staff may request modifications to the Code of Conduct by filing an application with the Commission. The application shall set forth the proposed modifications and the reasons supporting them.

Attachment B

UNS Energy Corporation

Code of Conduct Policies and Procedures

October 2014

Background

UNS Energy Corporation ("UNS Energy")[1] is a wholly-owned subsidiary of Fortis, Inc. UNS Energy provides regulated electric utility and natural gas distribution service, and conducts non-regulated energy-related business activities through a number of affiliated entities. See **Exhibit 1** (the entities identified in Exhibit 1 are referred to as the "UNS System"). Tucson Electric Power Company ("TEP") provides retail electric service to customers in Pima and Cochise Counties, and wholesale power to other utilities and power marketers. UniSource Energy Services ("UES") provides retail electric service through UNS Electric, Inc. to customers in Mohave and Santa Cruz Counties, and local natural gas distribution service through UNS Gas, Inc. to customers located across Northern Arizona and in Santa Cruz County. The regulated utility operations of TEP, UNS Electric, Inc. and UNS Gas, Inc. (the "Regulated Utilities") are subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and the Arizona Corporation Commission ("Commission" or "ACC").

The Regulated Utilities incur costs, both capital and operating, in connection with the provision of administrative support and other services to their electric and gas utility and non-utility business activities (to the extent offered), as well as to Affiliates. It is, therefore, necessary to develop, implement, and effectively administer an adequate and effective cost

[1] Capitalized terms not otherwise defined in these Policies and Procedures have the same definitions as set forth in the Code of Conduct.

allocation policy. The principal objectives of the intra-and inter-company cost allocation procedures are to:

- Prevent or minimize, to the extent practical, the potential for cross-subsidization of one activity or entity by another, and
- Achieve a proper balance between the desired precision of the cost allocation process with the cost of attaining such accuracy.

Rates charged for regulated energy utility service provided by the Regulated Utilities will be based solely on the reasonable and necessary costs incurred in connection with the provision of safe, reliable service to customers. Because the Regulated Utilities routinely incur administrative and other costs that benefit regulated and non-regulated operations and Affiliates, an appropriate cost allocation methodology is required. The cost assignment and allocation methodology described herein provides for the equitable assignment and allocation of costs to businesses, activities, and Affiliates, and prevents cross-subsidization.

The code of conduct and these cost allocation policies and procedures are intended to produce reasonable results that are consistent with applicable Arizona law, the reporting requirements of the Securities and Exchange Commission and FERC, and the Internal Revenue Code.

Cost Accounting Principles

As a general principal, UNS Energy and the Regulated Utilities support the use of an equitable, fully-distributed costing methodology for assigning costs between regulated and non-regulated business activities and between Affiliates, with emphasis on direct assignment and cost causation to the extent possible. The overriding goals of the cost accounting and

allocation process are to limit the possibility of cross-subsidization of any entity or activity by another, and to achieve the desired objectives as best as practicable.

Presently, most UNS System corporate services in Arizona (i.e. accounting, information systems, etc.) are performed by TEP, as needed by its regulated electric utility and its non-utility business activities, as well as by its other Affiliates located in Arizona. The objectives and procedures described herein, however, would apply equally to the extent that Affiliates of the UNS System provide services to TEP or other Affiliates.

Costs should be directly assigned to the benefiting activity or entity to the extent possible. Costs benefiting multiple activities or entities that cannot be directly assigned will be considered as common costs, and accumulated in homogeneous cost pools. Where possible, common costs should be allocated to the beneficiaries on the basis of causal relationships, identified by determining the factor which gives rise to the incurrence of the cost. Common costs for which a specifically identifiable causal relationship cannot be established should be allocated on a residual basis using the allocation methodology described later herein.

Utility Plant in Service and other fixed assets that benefit both regulated and non-regulated activities or Affiliates are considered in the cost allocation process through the inclusion of a return on the net investment, computed using the current authorized regulated rate of return. For this purpose, the net investment represents the gross original fixed asset cost less accumulated depreciation and related accumulated deferred income taxes.

Direct Costing

All incurred costs that directly and solely benefit a specific business activity or Affiliate are charged directly to the beneficiary. Costs may be directly assignable to: construction activities, utility operations, non-utility operations, or the business of other Affiliates in the UNS System. Directly assignable costs include such items as payroll and payroll related overhead costs, as well as identifiable non-labor costs. Employees are required to directly charge their time and expenses that they may identify as directly assignable in accordance with this reporting policy.

For accounting and billing purposes, directly assignable costs will be handled as follows:

- Basic payroll costs of both operating and administrative employees, and related payroll taxes, will be charged as follows:
  - Labor costs applicable to construction will be charged to the appropriate work order.
  - Labor costs applicable to non-utility operations will be charged to the appropriate below-the-line account.
  - Labor costs chargeable to Affiliates will be charged to the appropriate inter-company receivable account.
- Employee benefits and other costs relating to directly assignable labor costs will be charged to the same work orders, below-the-line accounts, or inter-company receivable to which such labor was charged.
- Directly assignable non-labor costs shall be charged to the appropriate work order, below-the-line accounts, or inter-company receivable account.

Fixed Labor Cost Distributions

Vice Presidents, Senior Vice Presidents, and the President of UNS Energy and of TEP will account for their time on an "exception" time basis. In connection therewith, each of the affected officers will use the same payroll cost account distribution (intra- and inter-company) percentages for all payroll periods throughout the year, unless there is a significant change in the individual's responsibilities or activities, at which time the distribution factors would be revised. To arrive at the respective fixed payroll allocation factors, an annual time study is prepared for the purpose of identifying the normal, recurring activities of each affected employee and the benefiting entities, with percentages derived therefrom being the basis for future fixed payroll cost assignment.

Allocated Costs

Incurred costs that cannot be directly assigned, but which benefit multiple activities and entities, both regulated and non-regulated, will be assigned to homogeneous cost pools for allocation. Where a sufficient degree of correlation can be reasonably identified, such allocations will be based on factors representing elements of cost causation. Detailed procedures for specific allocations by the Regulated Utilities based on cost causative factors shall be maintained by the Regulated Utilities and provided to the Commission upon request.

Where elements of cost causation cannot be reasonably or economically identified as the basis for cost allocation, a residual allocator will be applied to the allocation pool. The residual allocator used by members of the UNS System is a three-factor allocation methodology based on a weighted average of annual revenues, payroll costs, and plant

investment. It is widely-used and has been accepted by the FERC and state regulatory commissions.

General Office Buildings

Administrative and general corporate activities benefiting TEP and other members of the UNS System are performed by TEP employees located at the UNS Energy Headquarters Building ("HQ") and in the Operating Headquarters Building ("OH") and other facilities located at the Sundt Generating Station that are owned by TEP.

Since TEP's regulated and non-regulated operations and other UNS System Affiliates benefit from such services, there needs to be an accurate and equitable allocation of the capital and operating costs being incurred to the benefiting activities and entities. A key element of the cost allocation process is to equitably assign an appropriate portion of the capital and operating costs applicable to the general office buildings to benefiting activities and Affiliates. The allocation of building costs will be made via a per employee hourly payroll loading charge, based on an annual revenue requirement.

Fair Market Value

In transactions potentially requiring the determination of a fair market value, the Regulated Utilities shall act in a commercially reasonable and prudent manner in determining the fair market value of an asset, good or service, to the extent practicable, given the specific circumstances of the transaction.

Tariffed Services

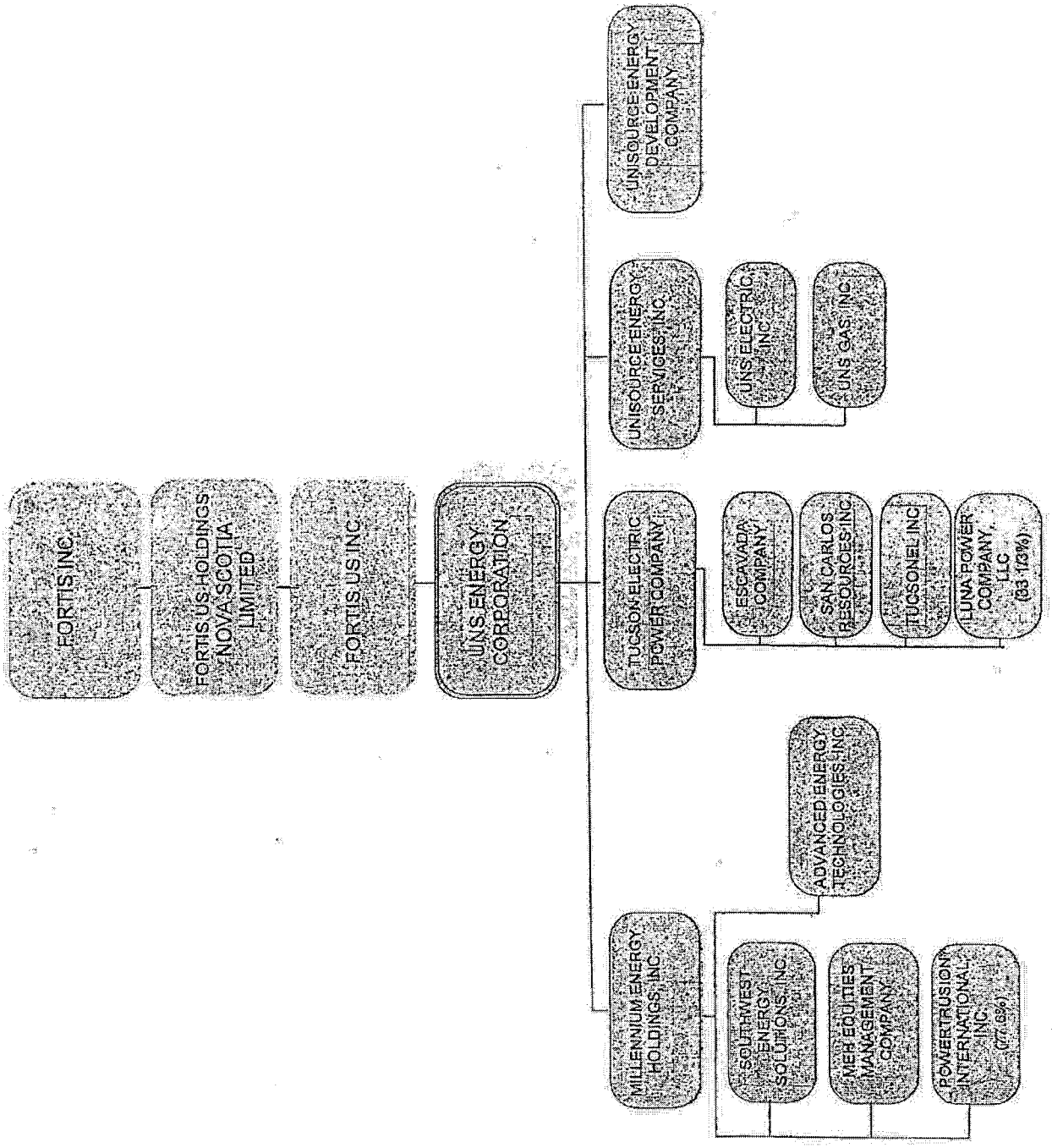
Regulated utility services provided by any Regulated Utility will be priced at the existing tariffed rate for that service.

Revisions and Updating

These policies and code of conduct will be updated as necessary in the event of major changes in operations or regulatory conditions such as retail competition.

Exhibit 1

UNS System



Decision No. 75033

BEFORE THE
ARIZONA CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF
DR. RONALD E. WHITE
IN DOCKET NO. E-01933A-15-____

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

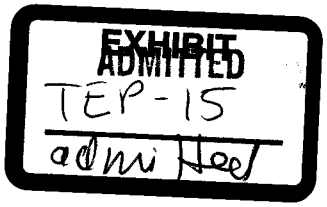
Q. WHAT IS YOUR OCCUPATION?

A. I am President of Foster Associates Consultants, LLC. Foster Associates is a public utility economic consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property service-life forecasting, depreciation estimation, and valuation of industrial property.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND.

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. degree in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Direc-



tors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the Midwest Finance Association, and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Before joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over 30 jurisdictions, including several appearances in Arizona. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communications Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is contained in Appendix REW–1.

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

A. Foster Associates was engaged by Tucson Electric Power Company (TEP), a wholly–owned subsidiary of UNS Energy Corporation ("UNS Energy"), to conduct a 2015 depreciation rate study for electric plant subject to the jurisdiction of the Arizona Corporation Commission (ACC). The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates. The scope, findings and recommendations of the study are contained in Exhibit REW–1.

II. Development of Depreciation Rates

Q. PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. The service potential (or future economic benefit) of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other noncash expenses) or cash inflows attributable to the use of that asset alone. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life system) of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation,

deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of an accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated entity. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. PLEASE DESCRIBE THE PRINCIPAL ACTIVITIES INVOLVED IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life and

curve descriptive of the parent population from which a plant account is viewed as a random sample. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is most often obtained from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current recorded reserve balance with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the sum of all reserves is the most important indicator of the adequacy (or inadequacy) of recorded depreciation reserves. Differences between theoretical and recorded reserves will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments requiring an identification of reserves at a different level from that main-

tained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute or rebalance recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and net salvage rates. A redistribution of recorded reserves will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Table 1 below.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

The above elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

III. 2015 Depreciation Rate Study

Q. PLEASE DESCRIBE THE SOURCE OF DEPRECIATION RATES CURRENTLY USED BY TEP.

A. Depreciation rates currently used by TEP were adopted pursuant to a Settlement Agreement in Docket No. E–01933A–12–0291 (Decision No. 73912 Approving Set-

tlement Agreement dated June 27, 2013). The parties to the Agreement consented to adopt depreciation rates proposed by TEP in a 2012 depreciation study, based on December 31, 2011 plant and reserve balances..

Q. DID TEP PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2015 DEPRECIATION STUDY?

A. Yes. The database used in conducting the current study was obtained by appending plant and net salvage transactions for activity years 2012–2014 and age distributions of surviving plant at December 31, 2014 to the database used in conducting the 2012 study. The accuracy and completeness of the assembled database was verified for activity years 2012 through 2014 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2007 were verified in the 2007 and 2012 studies. Age distributions of surviving plant at December 31, 2014 were reconciled to the CPR.

Reserve transactions recorded over the period 1989–2014 were used in the 2015 study to derive appropriate net salvage rates for distribution facilities. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR TEP PLANT AND EQUIPMENT?

A. Yes. As discussed in Exhibit REW–1, distribution plant accounts were analyzed using a technique in which first, second and third degree orthogonal polynomials were fitted to a set of observed retirement ratios. The resulting functions were expressed as survivorship functions and numerically integrated to obtain an estimate of the projection life of a plant category. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life and

curve for each plant category. Plant accounts classified in Steam and Other Production were identified by unit and treated as life–span categories in the 2015 study.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS IN THE 2015 STUDY?

A. Yes. Five–year moving averages of the ratio of realized salvage and cost of removal to the associated retirements were used in the study for distribution and general plant categories to a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. Cost of removal and salvage opinions obtained from TEP operating personnel were blended with judgment and historical net salvage indications in developing estimates of the future. Independent contractors were retained by TEP to develop cost estimates for demolition and abatement of steam and other production generating stations.

Average net salvage rates for depreciable plant accounts were estimated using direct dollar weighting of historical retirements with historical net salvage rates, and future retirements (*i.e.*, surviving plant) with estimated future net salvage rates.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes. Statement C of Exhibit REW–1 provides a comparison of computed, recorded and rebalanced reserves at December 31, 2014. The sum of recorded reserves was $1,526,654,221 or 37.7 percent of the depreciable plant investment. The corresponding computed reserve is $1,549,014,457 or 38.3 percent of the depreciable plant investment. A proportionate amount of the measured reserve shortfall of $22,360,236 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates recommended in this study. Statement D of Exhibit REW–1 provides an estimate of the investment and net salvage components of the rebalanced reserves.

Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES?

A. Yes. A redistribution of recorded reserves is again considered appropriate for TEP. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserve to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Q. PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED FOR TEP.

A. Current depreciation rates were developed for each primary account using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. The formulation of an account accrual rate using the currently approved system is given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

A remaining–life rate is equivalent to the sum of a whole–life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category. Stated as an equation, a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where both computed and recorded reserves are expressed as ratios to the plant in service.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM USED BY TEP?

A. No. Depreciation rates recommended in the 2015 study were developed using the currently approved system. It is the opinion of Foster Associates that this system will

remain appropriate for TEP, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

Q. ARE YOU GENERALLY FAMILIAR WITH THE NEAR–TERM PLANS FOR SAN JUAN UNIT 2 AND SUNDT COAL HANDLING FACILITIES?

A. Yes. It is my understanding that San Juan Unit 2 is scheduled to cease production by the end of 2017 and Sundt Unit 4 is scheduled to cease burning coal prior to the end of 2017. San Juan Unit 2 and the Sundt coal handling facilities will then be retired from service.

Q. WERE THESE NEAR–TERM RETIREMENTS CONSIDERED IN THE DEPRECIATION STUDY?

A. Yes. At the request of TEP, both San Juan Unit 2 and the Sundt coal handling facilities were treated as pro–forma retirements at December 31, 2014 and associated primary account recorded reserves were reduced by the pro–forma retirements. In the case of San Juan, the resulting debit reserve balances (totaling $110.1 million) were redistributed to Unit 1 and Common primary accounts in proportion to the distribution of computed reserves. The debit reserve balances for Sundt (totaling $24.7 million) were redistributed to Units 1 through 4 in proportion to the distribution of computed reserves. No reserve was redistributed to the Sundt solar booster (Areva).

IV. SUMMARY

Q. PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS RECOMMENDED FOR TEP IN THE 2015 STUDY.

A. Table 2 below provides a summary of the changes in annual rates and accruals resulting from an application of the service life and net salvage parameters recommended in the study.

Function	Accrual Rate			2015 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.56%	3.65%	0.09%	$ 63,233,113	$ 64,730,459	$ 1,497,346
Other Production	3.27%	2.89%	-0.38%	18,005,482	15,925,600	(2,079,882)
Distribution	1.80%	1.80%	0.00%	25,066,136	25,101,719	35,583
General Plant	5.83%	5.89%	0.06%	19,194,724	19,383,557	188,833
Net Salvage (Dist.)	0.27%	0.25%	-0.02%	3,762,756	3,484,034	(278,722)
Total	3.19%	3.18%	-0.01%	$129,262,211	$128,625,369	($636,842)

Table 2. Current and Proposed Rates and Accruals

The composite accrual rate recommended for TEP electric operations is 3.18 percent. The current equivalent rate is 3.19 percent. The recommended change in the composite rate is a reduction of 0.01 percentage points.

A continued application of current rates would provide annualized depreciation expense of $129,262,211 compared with an annualized expense of $128,625,369 using the recommended accrual rates. The resulting 2015 expense reduction is $636,842.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

2015 - Present Foster Associates Consultants, LLC
President

2007 - Present Foster Associates, Inc.
Chairman

1996 - 2007 Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February,

1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

Testifying Witness

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01933A–12–0126, Tucson Electric Power Company.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc, testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842,

District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. RP14-118-000, WBI Energy Transmission, Inc.; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC*Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power

Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 12-KGSG-835-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City

Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9385, Potomac Electric Power Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State

Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New York Public Service Commission, Case No. 12–G–0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 201500213, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

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Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues,

sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee.

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

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Speaker

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Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

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Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

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An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

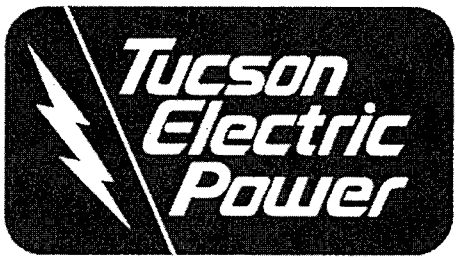
The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

Exhibit REW-1

Exhibit REW–1

2015 Depreciation Rate Study



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EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a 2015 Depreciation Rate Study conducted by Foster Associates Consultants, LLC (Foster Associates) for electric plant owned and operated by Tucson Electric Power Company (TEP), a wholly–owned subsidiary of UNS Energy Corporation ("UNS Energy"). Work on the study commenced in June 2015 and progressed through late October at which time the project was completed.

Foster Associates is a public utility economic consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by TEP were adopted pursuant to a Settlement Agreement in Docket No. E–01933A–12–0291 (Decision No. 73912 Approving Settlement Agreement dated June 27, 2013). The parties to the Agreement consented to adopt depreciation rates proposed by TEP in a 2012 depreciation study, based on December 31, 2011 plant and reserve balances.

The principal findings and recommendations of the 2015 study are summarized in the Statements section of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a summary of the investment and net salvage components of rebalanced reserves. Statement E provides a summary of the components used to obtain weighted–average net salvage rates. Statement F provides a computation of the estimated future net salvage rate for steam and other production facilities. Statement G contains the computation of terminal dismantlement costs for steam and other production facilities. Statement H provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. The statement also contains current and proposed statistics including average service lives, average remaining lives, and average net salvage rates.

SCOPE OF REVIEW

The principal activities undertaken in conducting the 2015 study included:

- Collection of plant and reserve data;
- Discussions with TEP plant accounting and operating personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been approved, TEP is currently using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is "retired" (*i.e.*, credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period. Any realized net salvage for amortizable accounts is netted against current–year vintage additions.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the approved amortization categories.

RECOMMENDED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the service life and net salvage parameters recommended in the current study.

Function	Accrual Rate			2015 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Steam Production	3.56%	3.65%	0.09%	$63,233,113	$64,730,459	$1,497,346
Other Production	3.27%	2.89%	-0.38%	18,005,482	15,925,600	(2,079,882)
Distribution	1.80%	1.80%	0.00%	25,066,136	25,101,719	35,583
General Plant	5.83%	5.89%	0.06%	19,194,724	19,383,557	188,833
Net Salvage (Dist.)	0.27%	0.25%	-0.02%	3,762,756	3,484,034	(278,722)
Total	3.19%	3.18%	-0.01%	$129,262,211	$128,625,369	($636,842)

Table 1. Current and Proposed Rates and Accruals

The composite accrual rate recommended for TEP electric operations is 3.18 percent. The current equivalent rate is 3.19 percent. The recommended change in the composite rate is a reduction of 0.01 percentage points.

A continued application of current rates would provide annualized depreciation expense of $129,262,211 compared with an annualized expense of $128,625,369 using the recommended accrual rates. The resulting 2015 expense reduction is $636,842.

Of the 214 plant accounts included in the 2015 study, Foster Associates is recommending accrual rate reductions for 85 accounts, rate increases for 92 accounts and no change for 37 accounts.

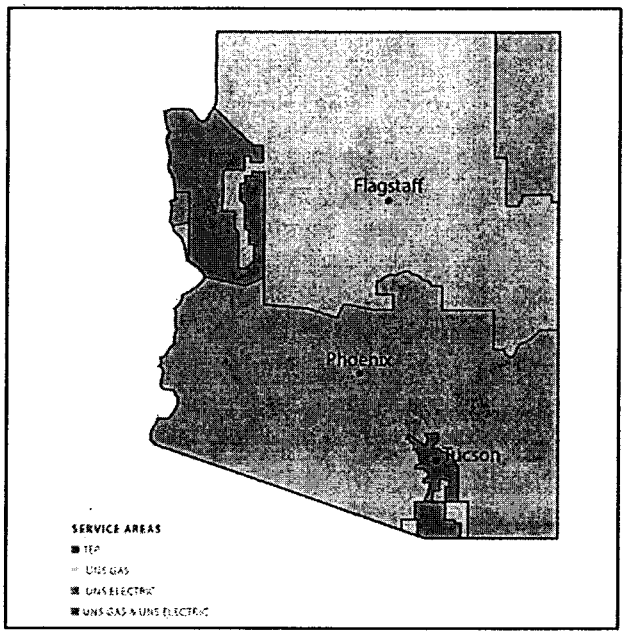
COMPANY PROFILE

GENERAL

Tucson Electric Power Company (TEP) is a vertically integrated, regulated utility that generates, transmits and distributes electricity. TEP also sells electricity to other utilities and power marketing entities located primarily in the western United States. TEP is a wholly owned subsidiary of UNS Energy Corporation (UNS Energy), a utility services holding company. UNS Energy is an indirect wholly owned subsidiary of Fortis Inc. (Fortis) which is the largest investor-owned gas and electric distribution utility holding company in Canada.

SERVICE AREA

TEP's service territory covers 1,155 square miles with service to approximately 415,000 retail electric customers and includes a population of approximately one million people in the greater Tucson metropolitan area in Pima County, as well as parts of Cochise County. TEP also sells wholesale electricity to other entities in the western United States.



DISTRIBUTION SYSTEM

The overhead electric distribution system is comprised of 2,600 circuit–miles of lower voltage primary lines. TEP owns approximately 77% of the poles on which the lower voltage lines are located. The underground electric distribution system includes 4,461 cable–miles of lines. Electric substation capacity consisted of 106 substations with a total installed transformer capacity of 15,809,050 kilovolt amperes.

GENERATING RESOURCES

At December 31, 2014, TEP owned or leased 2,448 MW of net generating capability, as set forth in Table 2 below.

Generating Source	Unit No.	Date in Service	Fuel Type	MW	Operating Agent	TEP's Share %	TEP's Share MW
Springerville Station [1]	1	1985	Coal	387	TEP	49.5	192
Springerville Station	2	1990	Coal	390	TEP	100.0	390
San Juan Station	1	1976	Coal	340	PNM	50.0	170
San Juan Station	2	1973	Coal	340	PNM	50.0	170
Navajo Station	1	1974	Coal	750	SRP	7.5	56
Navajo Station	2	1975	Coal	750	SRP	7.5	56
Navajo Station	3	1976	Coal	750	SRP	7.5	56
Four Corners Station	4	1969	Coal.	785	APS	7.0	55
Four Corners Station	5	1970	Coal	785	APS	7.0	55
Gila River Power Station	3	2003	Gas	550	Ethos	75.0	413
Luna Generating Station	1	2006	Gas	555	PNM	33.0	185
Sundt Station	1	1958	Gas/Oil	81	TEP	100.0	81
Sundt Station	2	1960	Gas/Oil	81	TEP	100.0	81
Sundt Station	3	1962	Gas/Oil	104	TEP	100.0	104
Sundt Station [2]	4	1967	Coal	120	TEP	100.0	120
Sundt Combustion Turbines		1972-1973	Gas/Oil	50	TEP	100.0	50
DeMoss Petrie		2001	Gas/Oil	75	TEP	100.0	75
North Loop		2001	Gas	94	TEP	100.0	94
Springerville Solar Station		2002-2014	Solar	16	TEP	100.0	16
Tucson Solar Projects		2010-2014	Solar	12	TEP	100.0	12
Ft. Huachuca Project		2014	Solar	17	TEP	100.0	17
Total TEP Capacity [3]							2,448

Table 2. Generating Resources

[1]At December 31, 2014, TEP owned 96 MW of capacity at Springerville Unit 1 and continued to lease the remaining 291 MW of capacity. In January 2015, TEP purchased 96 MW of capacity bringing the total owned capacity to 192 MW. TEP's lease of the remaining 195 MW expired in January 2015.

[2]Sundt Station Unit 4 can be operated on either coal or natural gas. The table above reflects the nominal generating capacity assuming the unit is fueled by coal. If the Unit burns natural gas, it has a nominal capacity of 156 MW.

[3]Excludes 932 MW of additional resources, which consist of certain capacity purchases and interruptible retail load

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This study provides the foundation and documentation for recommended changes in depreciation rates used by TEP. The proposed rates are subject to approval by the Arizona Corporation Commission.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2015 study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. Age distributions of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of a study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in a life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a data base. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to a company's official plant records.

The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system currently used by TEP provides aged transactions over the period 1989–2014 for all plant accounts.

The database used in conducting the current study was obtained by appending plant and net salvage transactions for activity years 2012–2014 and age distributions of surviving plant at December 31, 2014 to the database used in conducting the 2012 study.[1] The accuracy and completeness of the assembled database was verified for activity years 2012 through 2011 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Activity years prior to 2007 were verified in the 2007 and 2012 studies. Age distributions of surviving plant at December 31, 2014 were reconciled to the CPR.

Reserve transactions recorded over the period 1989–2014 were used in the 2015 study to derive appropriate net salvage rates for distribution facilities. Realized net salvage was blended with future net salvage estimates to derive average net salvage rates used in the computation of theoretical reserves.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of an account. Mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

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[1] The database used in the 2015 study was initially constructed in 2004 when depreciation rates were developed by Foster Associates for non–local generation operations. The database was constructed to provide a reverse calculation of plant activity recorded over the period 1989–2003. Age distributions of plant exposed to retirement at the beginning of each activity year were derived by adding (or subtracting) transaction amounts to the coded age distributions of surviving plant at December 31, 2003.
The reverse–flow database was converted to a forward–flow file by a) coding December 31, 1998 derived age distributions as opening plant balances; b) coding post–1998 derived additions as recorded additions; and c) removing December 31, 2003 age distributions from the database. The conversion of the database from a reverse construction to a forward construction was undertaken to facilitate appending future activity years without removing or adjusting prior coded transactions.
The 2004 database was updated in the 2007 and 2012 studies by appending additional plant and net salvage transactions to the prior databases. The accuracy and completeness of the assembled databases were verified for each appended activity year by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance to the official plant records of the Company. Age distributions of surviving plant were reconciled to the CPR.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

Analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2015 study.

An actuarial life analysis program designed and developed by Foster Associates was used in the 2015 study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally contains the age of each survivor and the age of each retirement from a group of property units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. The ratio of retirements to exposures—called a "retirement ratio"—is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in the 2015 study are the Iowa–type curves mathematically

described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting functions were expressed as survivorship functions and numerically integrated to obtain an estimate of the projection life of a plant category. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life and curve for each plant category.

The set of computer programs used in the NJNG study provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life analysis program designed and developed by Foster Associates include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides both tabular and graphics output to aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters and services), retirement dispersion is also exhibited in plant categories composed of major items of plant that will most likely be retired as a single unit. Property units retired from an integrated system prior to the retirement of the entire facility are viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span

method with interim retirements described by an appropriate survivor curve. Plant accounts classified in Steam and Other Production were identified by unit and treated as life–span categories in the 2015 study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a basis for estimating future salvage and cost of removal. However, consideration should be given to events that may cause deviations from net salvage realized in the past. Factors that should be considered include: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

Five–year moving averages of the ratio of realized salvage and cost of removal to the associated retirements were used in the 2015 study for distribution and general plant categories to: a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) provide a basis for estimating a future net salvage rates. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

Average net salvage rates were estimated using direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with estimated future net salvage rates. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as the weighting of future net salvage estimates changes from the installation of subsequent plant additions.

Independent contractors were retained by TEP to develop cost estimates at December 31, 2011 for demolition and abatement of steam and other production planta.[2] Statement G provides a computation of terminal dismantlement costs used in Statement F to derive future net salvage rates for these production facili-

ties. The blending of interim and final net salvage rates is shown in Statement E.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve, which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant currently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifica-

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[2]The firm of Burns & McDonnell was retained to estimate the cost of dismantling steam generating units at Sundt, and Springerville (Units 1 and 2, Common Facilities, and Fuel Handling Facilities), as well as gas turbines at DeMoss Petrie, Sundt, North Loop, and Luna (in which TEP has a 1/3 interest).

The firm of Black & Veatch was retained in 2013 by Public Service Company of New Mexico to update dismantlement costs estimated in 2011 for San Juan Generating Station in which TEP holds 50 percent ownership interest in Units 1 and 2, and 19.8% ownership of Common Facilities.

The firm of Sargent & Lundy was retained to conduct dismantlement studies at the Navajo Generating Station in which TEP holds 7.5 percent ownership interest in Units 1, 2, 3 and the Common Facilities.

Shaw Environmental Inc. was retained by Arizona Public Service Company to estimate demolition costs in 2015 dollars for the Four Corners Generating Station of which TEP holds 7 percent ownership interest in Units 4 and 5, and 5.07 percent ownership of Common Facilities.

tions, total recorded reserves in relation to the sum of account computed reserves provides a meaningful indicator of the adequacy (or inadequacy) of recorded reserves. If statistical life studies have not been conducted or retirement dispersion has been overlooked in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences can also arise from plant accounting activity such as transfers and adjustments that may require an identification of reserves at a level lower than maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A redistribution of recorded reserves is considered appropriate for TEP. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of the recorded reserve for depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function (or generating plant unit) by the ratio of the function (or unit) total recorded reserve to the function (or unit) total calculated reserve. The sum of the redistributed reserves within a function (or generating unit) is, therefore, equal to the function (or unit) total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of computed, recorded and rebalanced reserves at December 31, 2014. The sum of recorded reserves was $1,526,654,221 or 37.7 percent of the depreciable plant investment. The corresponding computed reserve is $1,549,014,457 or 38.3 percent of the depreciable plant investment. A proportionate amount of the measured reserve shortfall of $22,360,236 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates recommended in this study. Statement D provides an estimate of the investment and net salvage components of the rebalanced reserves.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less

expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of a time–based method is that it does not require an estimate of the remaining amount of service potential an asset will produce or the amount of service potential actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole–life and remaining–life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2015 study were developed using the currently approved system composed of the straight–line method, vintage group procedure, remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure, whole–life technique with amortization of reserve imbalances over the estimated remaining life of each rate category. It is the opinion of Foster Associates that the current system will remain appropriate for TEP, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring and performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting and remains appropriate for these plant categories.

The treatment of amortization accounts in the current study was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Applying a rate equal to the reciprocal of the amortization period to plant balanc-

es prior to posting retirements would overstate the annualized amortization expense. Accrual rates contained in Statement A have been applied to plant balances containing vintages that will be retired upon approval of the proposed amortization periods. Accrual rates contained in Statement A should be applied to current plant balances. Accrual rates equal to the reciprocal of the amortization period should be applied to these categories after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life and net salvage statistics recommended for a) steam production; b) other production; c) distribution plant; and d) general plant categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2015 depreciation accruals derived from an application of the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2014.
- Statement D provides a summary of the investment and net salvage components of rebalanced reserves.
- Statement E provides a summary of the components used to obtain weighted average net salvage rates.
- Statement F provides a computation of the estimated future net salvage rate for steam and other production facilities.
- Statement G contains the computation of terminal dismantlement costs for steam and other production facilities.
- Statement H provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by TEP for the mix of investments recorded at December 31, 2014. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Both current and proposed accrual rates are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

The formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION							
310.00	Rights-of-Way	3.03%		3.03%	2.85%		2.85%
311.00	Structures and Improvements	3.37%	0.33%	3.70%	3.17%	0.67%	3.84%
312.00	Boiler Plant Equipment	2.89%	0.38%	3.27%	3.03%	0.52%	3.55%
314.00	Turbogenerator Units	3.27%	0.72%	3.99%	3.29%	0.54%	3.83%
315.00	Accessory Electric Equipment	3.72%	0.94%	4.66%	3.07%	0.70%	3.77%
316.00	Miscellaneous Power Plant Equipment	3.34%	0.40%	3.74%	2.96%	0.41%	3.37%
	Total Steam Production Plant	3.09%	0.47%	3.56%	3.09%	0.56%	3.65%
OTHER PRODUCTION							
Non-Solar							
341.00	Structures and Improvements	2.51%	0.31%	2.82%	2.58%	0.38%	2.96%
342.00	Fuel Holders, Products and Accessories	2.71%	0.31%	3.02%	2.66%	0.37%	3.03%
343.00	Prime Movers	2.36%	0.04%	2.40%	2.49%	0.22%	2.71%
344.00	Generators and Devices	2.13%	0.15%	2.28%	1.95%	0.18%	2.13%
345.00	Accessory Electric Equipment	2.34%	0.08%	2.42%	2.10%	0.17%	2.27%
346.00	Miscellaneous Power Plant Equipment	2.45%	0.27%	2.72%	2.51%	0.35%	2.86%
	Total Non-Solar	2.33%	0.11%	2.44%	2.34%	0.23%	2.57%
Solar							
344.00	Generators and Devices	5.13%		5.13%	3.44%	0.17%	3.61%
	Total Solar	5.13%		5.13%	3.44%	0.17%	3.61%
	Total Other Production Plant	3.19%	0.08%	3.27%	2.68%	0.21%	2.89%
DISTRIBUTION PLANT							
360.RW	Rights-of-Way	1.43%		1.43%	1.41%		1.41%
361.00	Structures and Improvements	1.63%		1.63%	1.71%		1.71%
362.00	Station Equipment	1.46%		1.46%	1.66%		1.66%
364.00	Poles, Towers and Fixtures	1.63%		1.63%	1.66%		1.66%
365.00	Overhead Conductors and Devices	1.47%		1.47%	1.64%		1.64%
366.00	Underground Conduit	1.42%		1.42%	1.36%		1.36%
367.00	Underground Conductors and Devices	1.89%		1.89%	1.78%		1.78%
368.OH	Line Transformers - Overhead	1.84%		1.84%	1.75%		1.75%
368.UG	Line Transformers - Underground	2.52%		2.52%	1.97%		1.97%
369.OH	Services - Overhead	1.62%		1.62%	1.83%		1.83%
369.UG	Services - Underground	1.50%		1.50%	1.52%		1.52%
370.00	Meters	2.99%		2.99%	4.61%		4.61%
373.00	Street Lighting and Signal Systems	1.74%		1.74%	1.76%		1.76%
	Total Distribution Plant	1.80%		1.80%	1.80%		1.80%
GENERAL PLANT							
	Depreciable						
390.00	Structures and Improvements	2.49%	0.15%	2.64%	2.53%	0.15%	2.68%
392.C0	Transportation - Class 0	4.96%	-0.73%	4.23%	5.14%	-0.86%	4.28%
392.C1	Transportation - Class 1	12.43%	-1.81%	10.62%	12.97%	-2.20%	10.77%
392.C2	Transportation - Class 2	12.25%	-1.78%	10.47%	12.88%	-2.23%	10.65%
392.C3	Transportation - Class 3	10.71%	-1.56%	9.15%	11.49%	-2.02%	9.47%
392.C4	Transportation - Class 4	7.03%	-1.02%	6.01%	7.59%	-1.35%	6.24%
392.C5	Transportation - Class 5	7.31%	-1.08%	6.23%	7.87%	-1.31%	6.56%
392.C6	Transportation - Class 6	6.65%	-1.00%	5.65%	6.78%	-1.01%	5.77%
392.C7	Transportation - Class 7	6.98%	-1.04%	5.94%	7.20%	-1.08%	6.12%
392.C8	Transportation - Class 8	7.50%	-1.13%	6.37%	7.85%	-1.19%	6.66%
392.C9	Transportation - Class 9	4.66%	-0.70%	3.96%	4.02%	-0.61%	3.41%
396.00	Power Operatied Equipment	6.48%	-0.24%	6.24%	6.72%	-0.06%	6.66%
397.EM	EMS and SCADA Equipment	4.96%		4.96%	5.12%		5.12%
	Total Depreciable	4.12%	-0.17%	3.95%	4.25%	-0.21%	4.04%

TUCSON ELECTRIC POWER COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
	Amortizable						
391.00	Furniture and Office Equipment	← 24 Year Amortization →		4.15%	← 24 Year Amortization →		4.15%
391.20	Network and Data Equipment	← 5 Year Amortization →		18.68%	← 5 Year Amortization →		18.68%
393.00	Stores Equipment	← 15 Year Amortization →		6.35%	← 15 Year Amortization →		6.35%
394.00	Tools, Shop and Garage Equipment	← 17 Year Amortization →		5.72%	← 17 Year Amortization →		5.72%
395.00	Laboratory Equipment	← 17 Year Amortization →		5.78%	← 17 Year Amortization →		5.78%
397.20	Telecommunications Equipment	← 15 Year Amortization →		6.59%	← 15 Year Amortization →		6.59%
398.00	Miscellaneous Equipment	← 20 Year Amortization →		5.00%	← 20 Year Amortization →		5.00%
	Total Amortizable	8.75%		8.75%	8.75%		8.75%
	Total General Plant	5.94%	-0.11%	5.83%	6.01%	-0.12%	5.89%
	SUBTOTAL	2.89%	0.21%	3.10%	2.83%	0.26%	3.09%
	NET SALVAGE						
108.02	Distribution		0.28%	0.28%		0.25%	0.25%
	Total Net Salvage		0.27%	0.27%		0.25%	0.25%
	TOTAL UTILITY	2.89%	0.30%	3.19%	2.83%	0.35%	3.18%
	STEAM PRODUCTION (by Unit)						
	Four Corners						
310.00	Rights-of-Way						
311.00	Structures and Improvements	2.19%	0.17%	2.36%	2.47%	0.15%	2.62%
312.00	Boiler Plant Equipment	1.60%	0.15%	1.75%	1.57%	0.13%	1.70%
314.00	Turbogenerator Units	2.33%	0.14%	2.47%	2.06%	0.10%	2.16%
315.00	Accessory Electric Equipment	3.48%	0.19%	3.67%	4.04%	0.20%	4.24%
316.00	Miscellaneous Power Plant Equipment	2.39%	0.17%	2.56%	2.31%	0.13%	2.44%
	Total Four Corners	1.82%	0.15%	1.97%	1.80%	0.12%	1.92%
	Four Corners Unit 4						
310.00	Rights-of-Way						
311.00	Structures and Improvements	2.13%	0.16%	2.29%	2.35%	0.13%	2.48%
312.00	Boiler Plant Equipment	1.50%	0.16%	1.66%	1.43%	0.14%	1.57%
314.00	Turbogenerator Units	2.44%	0.12%	2.56%	2.08%	0.09%	2.17%
315.00	Accessory Electric Equipment	3.87%	0.17%	4.04%	3.91%	0.15%	4.06%
316.00	Miscellaneous Power Plant Equipment	2.34%	0.15%	2.49%	2.20%	0.11%	2.31%
	Total Four Corners Unit 4	1.78%	0.15%	1.93%	1.68%	0.13%	1.81%
	Four Corners Unit 5						
310.00	Rights-of-Way						
311.00	Structures and Improvements	2.26%	0.19%	2.45%	2.60%	0.17%	2.77%
312.00	Boiler Plant Equipment	1.70%	0.13%	1.83%	1.73%	0.10%	1.83%
314.00	Turbogenerator Units	2.17%	0.16%	2.33%	2.03%	0.12%	2.15%
315.00	Accessory Electric Equipment	3.07%	0.22%	3.29%	4.18%	0.25%	4.43%
316.00	Miscellaneous Power Plant Equipment	2.45%	0.20%	2.65%	2.43%	0.14%	2.57%
	Total Four Corners Unit 5	1.86%	0.14%	2.00%	1.93%	0.11%	2.04%
	Navajo						
310.00	Rights-of-Way	0.29%	0.02%	0.31%	0.77%	0.04%	0.81%
311.00	Structures and Improvements	1.43%	0.10%	1.53%	2.57%	0.14%	2.71%
312.00	Boiler Plant Equipment	1.66%	0.10%	1.76%	3.15%	0.16%	3.31%
314.00	Turbogenerator Units	1.51%	0.10%	1.61%	3.17%	0.16%	3.33%
315.00	Accessory Electric Equipment	1.87%	0.13%	2.00%	3.89%	0.21%	4.10%
316.00	Miscellaneous Power Plant Equipment	1.58%	0.11%	1.69%	2.85%	0.16%	3.01%
	Total Navajo	1.63%	0.10%	1.73%	3.14%	0.17%	3.31%

TUCSON ELECTRIC POWER COMPANY Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	Current (at 12/31/2014)			Proposed (at 12/31/2014)		
	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Navajo Unit 1						
310.00 Rights-of-Way						
311.00 Structures and Improvements	0.69%	0.05%	0.74%	4.13%	0.20%	4.33%
312.00 Boiler Plant Equipment	1.75%	0.12%	1.87%	6.00%	0.30%	6.30%
314.00 Turbogenerator Units	1.58%	0.09%	1.67%	6.04%	0.28%	6.32%
315.00 Accessory Electric Equipment	1.51%	0.09%	1.60%	8.48%	0.40%	8.88%
316.00 Miscellaneous Power Plant Equipment	0.67%	0.05%	0.72%	4.01%	0.19%	4.20%
Total Navajo Unit 1	1.61%	0.11%	1.72%	6.05%	0.30%	6.35%
Navajo Unit 2						
310.00 Rights-of-Way						
311.00 Structures and Improvements	0.99%	0.07%	1.06%	1.42%	0.09%	1.51%
312.00 Boiler Plant Equipment	1.52%	0.09%	1.61%	1.70%	0.10%	1.80%
314.00 Turbogenerator Units	1.60%	0.12%	1.72%	1.82%	0.12%	1.94%
315.00 Accessory Electric Equipment	1.62%	0.11%	1.73%	2.05%	0.13%	2.18%
316.00 Miscellaneous Power Plant Equipment	0.88%	0.06%	0.94%	0.97%	0.06%	1.03%
Total Navajo Unit 2	1.51%	0.10%	1.61%	1.73%	0.10%	1.83%
Navajo Unit 3						
310.00 Rights-of-Way						
311.00 Structures and Improvements	0.99%	0.07%	1.06%	1.12%	0.06%	1.18%
312.00 Boiler Plant Equipment	1.58%	0.08%	1.66%	1.83%	0.08%	1.91%
314.00 Turbogenerator Units	1.22%	0.07%	1.29%	1.42%	0.06%	1.48%
315.00 Accessory Electric Equipment	1.33%	0.11%	1.44%	1.57%	0.11%	1.68%
316.00 Miscellaneous Power Plant Equipment	0.73%	0.08%	0.81%	0.96%	0.09%	1.05%
Total Navajo Unit 3	1.44%	0.08%	1.52%	1.67%	0.08%	1.75%
Navajo Common						
310.00 Rights-of-Way	0.29%	0.02%	0.31%	0.77%	0.04%	0.81%
311.00 Structures and Improvements	1.91%	0.14%	2.05%	2.81%	0.17%	2.98%
312.00 Boiler Plant Equipment	2.19%	0.17%	2.36%	2.87%	0.20%	3.07%
314.00 Turbogenerator Units	3.86%	0.28%	4.14%	4.89%	0.29%	5.18%
315.00 Accessory Electric Equipment	3.49%	0.24%	3.73%	4.37%	0.25%	4.62%
316.00 Miscellaneous Power Plant Equipment	2.00%	0.13%	2.13%	3.34%	0.19%	3.53%
Total Navajo Common	2.23%	0.16%	2.39%	3.12%	0.20%	3.32%
San Juan						
310.00 Rights-of-Way						
311.00 Structures and Improvements	1.72%	0.15%	1.87%	7.58%	0.72%	8.30%
312.00 Boiler Plant Equipment	2.45%	0.74%	3.19%	7.64%	0.89%	8.53%
314.00 Turbogenerator Units	2.06%	0.18%	2.24%	7.58%	0.73%	8.31%
315.00 Accessory Electric Equipment	2.09%	0.19%	2.28%	7.63%	0.73%	8.36%
316.00 Miscellaneous Power Plant Equipment	1.58%	0.12%	1.70%	7.61%	0.70%	8.31%
Total San Juan	2.30%	0.56%	2.86%	7.62%	0.84%	8.46%
San Juan Unit 1						
310.00 Rights-of-Way						
311.00 Structures and Improvements	1.72%	0.15%	1.87%	7.57%	0.73%	8.30%
312.00 Boiler Plant Equipment	2.38%	0.25%	2.63%	7.63%	0.74%	8.37%
314.00 Turbogenerator Units	2.06%	0.18%	2.24%	7.58%	0.73%	8.31%
315.00 Accessory Electric Equipment	2.09%	0.19%	2.28%	7.63%	0.73%	8.36%
316.00 Miscellaneous Power Plant Equipment	1.59%	0.12%	1.71%	7.60%	0.72%	8.32%
Total San Juan Unit 1	2.25%	0.23%	2.48%	7.62%	0.73%	8.35%

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
San Juan Common							
310.00	Rights-of-Way						
311.00	Structures and Improvements	1.66%	0.16%	1.82%	8.09%	0.02%	8.11%
312.00	Boiler Plant Equipment	3.76%	9.71%	13.47%	7.74%	3.76%	11.50%
314.00	Turbogenerator Units	2.30%	0.20%	2.50%			
315.00	Accessory Electric Equipment	2.10%	0.20%	2.30%			
316.00	Miscellaneous Power Plant Equipment	1.36%	0.12%	1.48%	8.09%		8.09%
	Total San Juan Common	3.70%	9.46%	13.16%	7.75%	3.66%	11.41%
Springerville							
310.00	Rights-of-Way	3.04%		3.04%	2.85%		2.85%
311.00	Structures and Improvements	3.72%	0.05%	3.77%	2.84%	0.60%	3.44%
312.00	Boiler Plant Equipment	3.16%	0.07%	3.23%	2.12%	0.39%	2.51%
314.00	Turbogenerator Units	2.97%	0.08%	3.05%	2.18%	0.14%	2.32%
315.00	Accessory Electric Equipment	3.30%	0.08%	3.38%	1.90%	0.19%	2.09%
316.00	Miscellaneous Power Plant Equipment	3.99%	0.06%	4.05%	2.25%	0.24%	2.49%
	Total Springerville	3.22%	0.07%	3.29%	2.22%	0.36%	2.58%
Springerville Unit 1							
310.00	Rights-of-Way						
311.00	Structures and Improvements	7.97%	0.01%	7.98%	2.06%	0.08%	2.14%
312.00	Boiler Plant Equipment	6.15%	0.03%	6.18%	1.98%	0.08%	2.06%
314.00	Turbogenerator Units	5.77%	-0.05%	5.72%	1.97%	0.08%	2.05%
315.00	Accessory Electric Equipment	6.08%	0.01%	6.09%	1.73%	0.08%	1.81%
316.00	Miscellaneous Power Plant Equipment	8.69%		8.69%	2.14%	0.07%	2.21%
	Total Springerville Unit 1	6.24%	0.01%	6.25%	1.97%	0.08%	2.05%
Springerville Unit 1 Common							
310.00	Rights-of-Way				2.03%		2.03%
311.00	Structures and Improvements	3.00%	0.01%	3.01%	2.04%	0.24%	2.28%
312.00	Boiler Plant Equipment	4.24%		4.24%	2.00%	0.26%	2.26%
314.00	Turbogenerator Units	1.83%		1.83%	1.93%	0.26%	2.19%
315.00	Accessory Electric Equipment	4.35%		4.35%	1.81%	0.30%	2.11%
316.00	Miscellaneous Power Plant Equipment	3.72%		3.72%	1.83%	0.28%	2.11%
	Total Springerville Unit 1 Common	3.34%	0.01%	3.35%	2.00%	0.25%	2.25%
Springerville Unit 2							
310.00	Rights-of-Way						
311.00	Structures and Improvements	1.86%	0.15%	2.01%	2.16%	0.15%	2.31%
312.00	Boiler Plant Equipment	1.88%	0.14%	2.02%	2.12%	0.15%	2.27%
314.00	Turbogenerator Units	1.84%	0.14%	1.98%	2.25%	0.15%	2.40%
315.00	Accessory Electric Equipment	1.69%	0.13%	1.82%	1.88%	0.12%	2.00%
316.00	Miscellaneous Power Plant Equipment	1.71%	0.11%	1.82%	2.14%	0.13%	2.27%
	Total Springerville Unit 2	1.85%	0.14%	1.99%	2.13%	0.15%	2.28%
Springerville Unit 2 Common (Leasehold Imp.)							
310.00	Rights-of-Way	2.80%		2.80%	3.86%		3.86%
311.00	Structures and Improvements	4.34%	0.01%	4.35%	5.38%	2.00%	7.38%
312.00	Boiler Plant Equipment	5.50%		5.50%	6.45%	2.16%	8.61%
314.00	Turbogenerator Units	4.06%		4.06%	4.69%	1.85%	6.54%
315.00	Accessory Electric Equipment	3.06%		3.06%	4.01%	1.58%	5.59%
316.00	Miscellaneous Power Plant Equipment	4.37%		4.37%	5.19%	2.01%	7.20%
	Total Springerville Unit 2 Common	4.34%	0.01%	4.35%	5.36%	1.89%	7.25%

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
Springerville Coal Handling							
310.00	Rights-of-Way	5.44%		5.44%	2.04%		2.04%
311.00	Structures and Improvements						
312.00	Boiler Plant Equipment	1.65%		1.65%	2.14%	1.24%	3.38%
314.00	Turbogenerator Units						
315.00	Accessory Electric Equipment						
316.00	Miscellaneous Power Plant Equipment						
	Total Springerville Coal Handling	1.70%		1.70%	2.14%	1.22%	3.36%
Sundt							
310.00	Rights-of-Way						
311.00	Structures and Improvements	3.91%	2.04%	5.95%	3.03%	1.45%	4.48%
312.00	Boiler Plant Equipment	3.73%	1.76%	5.49%	2.81%	1.19%	4.00%
314.00	Turbogenerator Units	6.15%	3.63%	9.78%	3.66%	2.01%	5.67%
315.00	Accessory Electric Equipment	5.67%	3.17%	8.84%	3.73%	1.94%	5.67%
316.00	Miscellaneous Power Plant Equipment	6.31%	3.45%	9.76%	4.00%	2.10%	6.10%
	Total Sundt	4.58%	2.42%	7.00%	3.17%	1.51%	4.68%
Sundt Unit 1							
310.00	Rights-of-Way						
311.00	Structures and Improvements	9.95%	5.37%	15.32%	4.99%	2.77%	7.76%
312.00	Boiler Plant Equipment	10.40%	5.02%	15.42%	4.54%	2.37%	6.91%
314.00	Turbogenerator Units	11.68%	6.16%	17.84%	4.98%	2.71%	7.69%
315.00	Accessory Electric Equipment	13.14%	7.13%	20.27%	6.15%	3.39%	9.54%
316.00	Miscellaneous Power Plant Equipment	12.19%	6.50%	18.69%	5.82%	3.28%	9.10%
	Total Sundt Unit 1	11.26%	5.81%	17.07%	5.04%	2.72%	7.76%
Sundt Unit 2							
310.00	Rights-of-Way						
311.00	Structures and Improvements	8.40%	5.33%	13.73%	5.00%	3.05%	8.05%
312.00	Boiler Plant Equipment	8.25%	5.37%	13.62%	4.08%	2.62%	6.70%
314.00	Turbogenerator Units	8.22%	5.19%	13.41%	3.91%	2.44%	6.35%
315.00	Accessory Electric Equipment	10.07%	6.35%	16.42%	5.61%	3.58%	9.19%
316.00	Miscellaneous Power Plant Equipment	9.57%	5.95%	15.52%	5.36%	3.37%	8.73%
	Total Sundt Unit 2	8.62%	5.51%	14.13%	4.43%	2.80%	7.23%
Sundt Unit 3							
310.00	Rights-of-Way						
311.00	Structures and Improvements	6.64%	4.90%	11.54%	4.13%	2.90%	7.03%
312.00	Boiler Plant Equipment	6.17%	4.67%	10.84%	3.88%	2.80%	6.68%
314.00	Turbogenerator Units	6.82%	5.09%	11.91%	4.05%	2.86%	6.91%
315.00	Accessory Electric Equipment	7.15%	5.16%	12.31%	3.98%	2.76%	6.74%
316.00	Miscellaneous Power Plant Equipment	7.90%	5.55%	13.45%	4.62%	3.17%	7.79%
	Total Sundt Unit 3	6.66%	4.95%	11.61%	3.99%	2.83%	6.82%
Sundt Unit 4							
310.00	Rights-of-Way						
311.00	Structures and Improvements	1.47%	0.36%	1.83%	2.13%	0.69%	2.82%
312.00	Boiler Plant Equipment	1.47%	0.35%	1.82%	2.09%	0.65%	2.74%
314.00	Turbogenerator Units	1.73%	0.43%	2.16%	2.54%	0.76%	3.30%
315.00	Accessory Electric Equipment	1.53%	0.36%	1.89%	2.32%	0.73%	3.05%
316.00	Miscellaneous Power Plant Equipment	1.78%	0.31%	2.09%	2.41%	0.68%	3.09%
	Total Sundt Unit 4	1.52%	0.36%	1.88%	2.19%	0.69%	2.88%

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
Sundt Solar Booster (Areva)							
310.00	Rights-of-Way						
311.00	Structures and Improvements	3.34%		3.34%			
312.00	Boiler Plant Equipment	3.34%		3.34%	3.11%	0.01%	3.12%
314.00	Turbogenerator Units						
315.00	Accessory Electric Equipment						
316.00	Miscellaneous Power Plant Equipment						
	Total Sundt Solar Booster (Areva)	3.34%		3.34%	3.11%	0.01%	3.12%
OTHER PRODUCTION (by Unit)							
DeMoss Petrie Gas Unit 1							
341.00	Structures and Improvements	2.46%	0.19%	2.65%	2.64%	0.18%	2.82%
342.00	Fuel Holders, Products and Accessories	2.30%	0.21%	2.51%	2.23%	0.20%	2.43%
343.00	Prime Movers	2.90%	0.27%	3.17%	2.86%	0.01%	2.87%
344.00	Generators and Devices	2.30%	0.21%	2.51%	2.24%	0.19%	2.43%
345.00	Accessory Electric Equipment	2.30%	0.21%	2.51%	2.29%	0.05%	2.34%
346.00	Miscellaneous Power Plant Equipment	2.38%	0.22%	2.60%	2.36%	0.21%	2.57%
	Total DeMoss Petrie Gas Unit 1	2.31%	0.21%	2.52%	2.25%	0.19%	2.44%
Gila River							
341.00	Structures and Improvements	2.26%		2.26%	2.42%	0.20%	2.62%
342.00	Fuel Holders, Products and Accessories	2.26%		2.26%	2.40%	0.20%	2.60%
343.00	Prime Movers	2.26%		2.26%	2.44%	0.20%	2.64%
344.00	Generators and Devices	2.26%		2.26%	2.37%	0.20%	2.57%
345.00	Accessory Electric Equipment	2.26%		2.26%	2.39%	0.20%	2.59%
346.00	Miscellaneous Power Plant Equipment	2.26%		2.26%	2.41%	0.20%	2.61%
	Total Gila River	2.26%		2.26%	2.42%	0.20%	2.62%
Gila River Unit 3							
341.00	Structures and Improvements	2.26%		2.26%	2.38%	0.20%	2.58%
342.00	Fuel Holders, Products and Accessories	2.26%		2.26%	2.45%	0.20%	2.65%
343.00	Prime Movers	2.26%		2.26%	2.43%	0.20%	2.63%
344.00	Generators and Devices	2.26%		2.26%	2.37%	0.20%	2.57%
345.00	Accessory Electric Equipment	2.26%		2.26%	2.38%	0.20%	2.58%
346.00	Miscellaneous Power Plant Equipment	2.26%		2.26%	2.41%	0.20%	2.61%
	Total Gila River Unit 3	2.26%		2.26%	2.42%	0.20%	2.62%
Gila River Common							
341.00	Structures and Improvements	2.26%		2.26%	2.42%	0.20%	2.62%
342.00	Fuel Holders, Products and Accessories	2.26%		2.26%	2.40%	0.20%	2.60%
343.00	Prime Movers	2.26%		2.26%	2.59%	0.22%	2.81%
344.00	Generators and Devices	2.26%		2.26%			
345.00	Accessory Electric Equipment	2.26%		2.26%	2.41%	0.20%	2.61%
346.00	Miscellaneous Power Plant Equipment	2.26%		2.26%	2.41%	0.20%	2.61%
	Total Gila River Common	2.26%		2.26%	2.45%	0.21%	2.66%
Luna							
341.00	Structures and Improvements	2.63%	0.51%	3.14%	2.78%	0.52%	3.30%
342.00	Fuel Holders, Products and Accessories	2.62%	0.52%	3.14%	2.78%	0.52%	3.30%
343.00	Prime Movers	2.65%	0.51%	3.16%	2.84%	0.51%	3.35%
344.00	Generators and Devices	2.63%	0.50%	3.13%	2.80%	0.49%	3.29%
345.00	Accessory Electric Equipment	2.57%		2.57%	2.86%	0.54%	3.40%
346.00	Miscellaneous Power Plant Equipment	2.62%	0.52%	3.14%	2.78%	0.52%	3.30%
	Total Luna	2.63%	0.51%	3.14%	2.80%	0.51%	3.31%

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
North Loop Gas							
341.00	Structures and Improvements	3.17%	0.35%	3.52%	1.18%	0.13%	1.31%
342.00	Fuel Holders, Products and Accessories	2.22%	0.13%	2.35%	2.23%	0.13%	2.36%
343.00	Prime Movers	10.88%	1.39%	12.27%	5.74%	0.66%	6.40%
344.00	Generators and Devices	2.21%	0.18%	2.39%	1.49%	0.08%	1.57%
345.00	Accessory Electric Equipment	2.96%	0.30%	3.26%	1.84%	0.17%	2.01%
346.00	Miscellaneous Power Plant Equipment	2.69%	0.29%	2.98%	0.85%	0.07%	0.92%
	Total North Loop Gas	2.85%	0.27%	3.12%	1.77%	0.13%	1.90%
North Loop Gas Unit 1							
341.00	Structures and Improvements	4.39%	0.49%	4.88%	1.44%	0.20%	1.64%
342.00	Fuel Holders, Products and Accessories						
343.00	Prime Movers	9.60%	1.06%	10.66%	3.78%	0.50%	4.28%
344.00	Generators and Devices	2.65%	0.29%	2.94%	0.22%	0.01%	0.23%
345.00	Accessory Electric Equipment	4.10%	0.45%	4.55%	1.51%	0.19%	1.70%
346.00	Miscellaneous Power Plant Equipment	4.26%	0.48%	4.74%	1.19%	0.16%	1.35%
	Total North Loop Gas Unit 1	3.88%	0.43%	4.31%	0.95%	0.12%	1.07%
North Loop Gas Unit 2							
341.00	Structures and Improvements	1.98%	0.31%	2.29%	0.83%	0.15%	0.98%
342.00	Fuel Holders, Products and Accessories						
343.00	Prime Movers	5.30%	0.82%	6.12%	13.27%	0.69%	13.96%
344.00	Generators and Devices	1.85%	0.26%	2.11%	0.70%	0.10%	0.80%
345.00	Accessory Electric Equipment	2.68%	0.39%	3.07%	1.75%	0.28%	2.03%
346.00	Miscellaneous Power Plant Equipment	0.89%	0.13%	1.02%	0.13%	0.02%	0.15%
	Total North Loop Gas Unit 2	2.13%	0.31%	2.44%	1.58%	0.15%	1.73%
North Loop Gas Unit 3							
341.00	Structures and Improvements	2.17%	0.29%	2.46%	0.48%	0.08%	0.56%
342.00	Fuel Holders, Products and Accessories						
343.00	Prime Movers	13.34%	1.78%	15.12%	5.06%	0.76%	5.82%
344.00	Generators and Devices	1.99%	0.22%	2.21%	0.30%		0.30%
345.00	Accessory Electric Equipment	2.85%	0.37%	3.22%	1.44%	0.21%	1.65%
346.00	Miscellaneous Power Plant Equipment	1.09%	0.15%	1.24%	-0.26%	-0.04%	-0.30%
	Total North Loop Gas Unit 3	4.30%	0.54%	4.84%	1.35%	0.18%	1.53%
North Loop Gas Unit 4							
341.00	Structures and Improvements	2.29%	-0.10%	2.19%	2.33%	-0.09%	2.24%
342.00	Fuel Holders, Products and Accessories	2.22%	0.13%	2.35%	2.23%	0.13%	2.36%
343.00	Prime Movers						
344.00	Generators and Devices	2.22%	0.13%	2.35%	2.24%	0.12%	2.36%
345.00	Accessory Electric Equipment	2.27%	0.11%	2.38%	2.32%	0.10%	2.42%
346.00	Miscellaneous Power Plant Equipment	2.22%	0.06%	2.28%	2.23%	0.06%	2.29%
	Total North Loop Gas Unit 4	2.22%	0.13%	2.35%	2.25%	0.11%	2.36%
Solar Units (Generators and Devices)							
344.00	DeMoss Petrie	5.13%		5.13%	3.05%	0.15%	3.20%
344.00	Fort Huachuca	5.13%		5.13%	3.56%	0.18%	3.74%
344.00	HQ Rooftop	5.13%		5.13%	3.50%	0.18%	3.68%
344.00	OH Rooftop	5.13%		5.13%	3.47%	0.17%	3.64%
344.00	OH Test Yard	5.13%		5.13%	3.10%	0.15%	3.25%
344.00	Prairie Fire	5.13%		5.13%	3.50%	0.18%	3.68%
344.00	Springerville Sites 1-3 (Legacy)	5.13%		5.13%	3.05%	0.15%	3.20%
344.00	Springerville Site 4	5.13%		5.13%	3.43%	0.18%	3.61%
344.00	Tucson	5.13%		5.13%	2.60%	0.13%	2.73%
344.00	U of A Tech Park Site 1	5.13%		5.13%	3.43%	0.18%	3.61%
344.00	U of A Tech Park Site 2	5.13%		5.13%	3.47%	0.17%	3.64%
344.00	White Mountain	5.13%		5.13%	3.56%	0.18%	3.74%
	Total Solar Units	5.13%		5.13%	3.44%	0.17%	3.61%

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Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
Sundt Gas							
341.00	Structures and Improvements	0.26%	0.01%	0.27%	-0.13%	-0.01%	-0.14%
342.00	Fuel Holders, Products and Accessories	8.51%	0.15%	8.66%	3.63%	0.09%	3.72%
343.00	Prime Movers	3.64%	0.06%	3.70%	1.79%	0.04%	1.83%
344.00	Generators and Devices	0.16%		0.16%	-0.37%	-0.02%	-0.39%
345.00	Accessory Electric Equipment	1.37%	0.03%	1.40%	0.17%		0.17%
346.00	Miscellaneous Power Plant Equipment				-1.25%	-0.02%	-1.27%
Total Sundt Gas		0.96%	0.01%	0.97%	0.02%	-0.01%	0.01%
Sundt Gas Unit 1							
341.00	Structures and Improvements	0.10%		0.10%	-0.08%	-0.01%	-0.09%
342.00	Fuel Holders, Products and Accessories	8.42%	0.14%	8.56%	3.66%	0.08%	3.74%
343.00	Prime Movers	3.51%	0.06%	3.57%	1.83%	0.04%	1.87%
344.00	Generators and Devices				-0.39%	-0.02%	-0.41%
345.00	Accessory Electric Equipment	1.06%	0.02%	1.08%	0.13%	-0.01%	0.12%
346.00	Miscellaneous Power Plant Equipment				-1.21%	-0.02%	-1.23%
Total Sundt Gas Unit 1		0.77%	0.01%	0.78%	-0.01%	-0.01%	-0.02%
Sundt Gas Unit 2							
341.00	Structures and Improvements	0.41%	0.01%	0.42%	-0.18%	-0.01%	-0.19%
342.00	Fuel Holders, Products and Accessories	8.59%	0.16%	8.75%	3.61%	0.08%	3.69%
343.00	Prime Movers	3.77%	0.06%	3.83%	1.76%	0.03%	1.79%
344.00	Generators and Devices	0.32%		0.32%	-0.34%	-0.02%	-0.36%
345.00	Accessory Electric Equipment	1.65%	0.03%	1.68%	0.21%		0.21%
346.00	Miscellaneous Power Plant Equipment				-1.28%	-0.02%	-1.30%
Total Sundt Gas Unit 2		1.15%	0.02%	1.17%	0.05%	-0.01%	0.04%

TUCSON ELECTRIC POWER COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual			Proposed 2015 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
STEAM PRODUCTION								
310.00 Rights-of-Way	$ 5,106,662	$ 154,751	$ 2	$ 154,753	$ 145,417	$ 5	$ 145,422	$ (9,331)
311.00 Structures and Improvements	205,277,689	6,925,225	672,414	7,597,639	6,508,604	1,383,704	7,892,308	294,669
312.00 Boiler Plant Equipment	1,091,953,161	31,609,169	4,124,981	35,734,150	33,091,364	5,676,033	38,767,397	3,033,247
314.00 Turbogenerator Units	303,041,923	9,895,445	2,168,057	12,063,502	9,960,460	1,660,521	11,620,981	(442,521)
315.00 Accessory Electric Equipment	144,581,471	5,383,758	1,355,199	6,738,957	4,437,440	1,015,739	5,453,179	(1,285,778)
316.00 Miscellaneous Power Plant Equipment	25,222,863	842,395	101,717	944,112	746,073	105,099	851,172	(92,940)
Total Steam Production Plant	$ 1,775,183,769	$ 54,810,743	$ 8,422,370	$ 63,233,113	$ 54,889,358	$ 9,841,101	$ 64,730,459	$ 1,497,346
OTHER PRODUCTION								
Non-Solar								
341.00 Structures and Improvements	$ 23,403,461	$ 587,238	$ 72,042	$ 659,280	$ 603,985	$ 88,395	$ 692,380	$ 33,100
342.00 Fuel Holders, Products and Accessories	19,977,187	541,762	62,185	603,947	530,626	75,123	605,749	1,802
343.00 Prime Movers	202,005,134	4,774,207	83,405	4,857,612	5,028,029	448,274	5,476,303	618,691
344.00 Generators and Devices	105,487,225	2,241,822	156,008	2,397,830	2,059,197	189,494	2,248,691	(149,139)
345.00 Accessory Electric Equipment	13,809,819	322,600	10,605	333,205	289,354	23,496	312,850	(20,355)
346.00 Miscellaneous Power Plant Equipment	15,307,160	374,821	41,324	416,145	384,096	53,510	437,606	21,461
Total Non-Solar	$ 379,989,986	$ 8,842,450	$ 425,569	$ 9,268,019	$ 8,895,287	$ 878,292	$ 9,773,579	$ 505,560
Solar								
344.00 Generators and Devices	$ 170,320,932	$ 8,737,463	$ -	$ 8,737,463	$ 5,856,756	$ 295,265	$ 6,152,021	$ (2,585,442)
Total Solar	$ 170,320,932	$ 8,737,463	$ -	$ 8,737,463	$ 5,856,756	$ 295,265	$ 6,152,021	$ (2,585,442)
Total Other Production Plant	$ 550,310,918	$ 17,579,913	$ 425,569	$ 18,005,482	$ 14,752,043	$ 1,173,557	$ 15,925,600	$ (2,079,882)
DISTRIBUTION PLANT								
360.RW Rights-of-Way	$ 7,865,073	$ 112,471	$ -	$ 112,471	$ 110,898	$ -	$ 110,898	$ (1,573)
361.00 Structures and Improvements	11,402,474	196,123		196,123	194,982		194,982	(1,141)
362.00 Station Equipment	157,067,530	2,403,133		2,403,133	2,607,321		2,607,321	204,188
364.00 Poles, Towers and Fixtures	222,006,967	3,862,921		3,862,921	3,685,316		3,685,316	(177,605)
365.00 Overhead Conductors and Devices	175,675,966	2,863,518		2,863,518	2,881,086		2,881,086	17,568
366.00 Underground Conduit	58,725,355	792,792		792,792	798,665		798,665	5,873
367.00 Underground Conductors and Devices	297,183,135	5,557,325		5,557,325	5,289,860		5,289,860	(267,465)
368.OH Line Transformers - Overhead	103,657,922	1,938,403		1,938,403	1,814,014		1,814,014	(124,389)
368.UG Line Transformers - Underground	172,890,932	3,613,420		3,613,420	3,405,951		3,405,951	(207,469)
369.OH Services - Overhead	17,542,236	324,531		324,531	321,023		321,023	(3,508)
369.UG Services - Underground	112,947,714	1,716,805		1,716,805	1,716,805		1,716,805	
370.00 Meters	44,869,823	1,476,217		1,476,217	2,068,499		2,068,499	592,282
373.00 Street Lighting and Signal Systems	11,778,362	208,477		208,477	207,299		207,299	(1,178)
Total Distribution Plant	$ 1,393,613,489	$ 25,066,136	$ -	$ 25,066,136	$ 25,101,719	$ -	$ 25,101,719	$ 35,583

TUCSON ELECTRIC POWER COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual			Proposed 2015 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$ 135,680,348	$ 3,378,441	$ 203,521	$ 3,581,962	$ 3,432,713	$ 203,521	$ 3,636,234	$ 54,272
392.C0 Transportation - Class 0	1,238,946	61,452	(9,044)	52,408	63,682	(10,655)	53,027	619
392.C1 Transportation - Class 1	7,718,183	959,370	(139,699)	819,671	1,001,048	(169,800)	831,248	11,577
392.C2 Transportation - Class 2	3,839,907	470,389	(68,350)	402,039	494,580	(85,630)	408,950	6,911
392.C3 Transportation - Class 3	2,076,936	222,440	(32,400)	190,040	238,640	(41,954)	196,686	6,646
392.C4 Transportation - Class 4	2,935,027	206,332	(29,937)	176,395	222,769	(39,623)	183,146	6,751
392.C5 Transportation - Class 5	7,982,715	583,536	(86,213)	497,323	628,240	(104,574)	523,666	26,343
392.C6 Transportation - Class 6	365,200	24,286	(3,652)	20,634	24,761	(3,689)	21,072	438
392.C7 Transportation - Class 7	1,047,216	73,096	(10,891)	62,205	75,400	(11,310)	64,090	1,885
392.C8 Transportation - Class 8	9,957,500	746,813	(112,520)	634,293	781,664	(118,494)	663,170	28,877
392.C9 Transportation - Class 9	4,252,286	198,157	(29,766)	168,391	170,942	(25,939)	145,003	(23,388)
396.00 Power Operatied Equipment	11,860,940	768,589	(28,466)	740,123	797,055	(7,117)	789,938	49,815
397.EM EMS and SCADA Equipment	11,304,371	560,697		560,697	578,784		578,784	18,087
Total Depreciable	$ 200,259,575	$ 8,253,598	$ (347,417)	$ 7,906,181	$ 8,510,278	$ (415,264)	$ 8,095,014	$ 188,833
Amortizable								
391.00 Furniture and Office Equipment	$ 23,964,411	$ 993,514	$ -	$ 993,514	$ 993,514	$ -	$ 993,514	$ -
391.20 Network and Data Equipment	29,359,636	5,484,102		5,484,102	5,484,102		5,484,102	
393.00 Stores Equipment	1,852,479	117,635		117,635	117,635		117,635	
394.00 Tools, Shop and Garage Equipment	6,934,368	396,576		396,576	396,576		396,576	
395.00 Laboratory Equipment	5,091,270	294,185		294,185	294,185		294,185	
397.20 Telecommunications Equipment	57,456,141	3,785,287		3,785,287	3,785,287		3,785,287	
398.00 Miscellaneous Equipment	4,348,209	217,244		217,244	217,244		217,244	
Total Amortizable	$ 129,006,514	$ 11,288,543	$ -	$ 11,288,543	$ 11,288,543	$ -	$ 11,288,543	$ -
Total General Plant	$ 329,266,089	$ 19,542,141	$ (347,417)	$ 19,194,724	$ 19,798,821	$ (415,264)	$ 19,383,557	$ 188,833
SUBTOTAL	$ 4,048,374,265	$ 116,998,933	$ 8,500,522	$ 125,499,455	$ 114,541,941	$ 10,599,394	$ 125,141,335	$ (358,120)
NET SALVAGE								
108.02 Distribution	$ 1,393,613,489	$ -	$ 3,762,756	$ 3,762,756	$ -	$ 3,484,034	$ 3,484,034	$ (278,722)
Total Net Salvage	$ 1,393,613,489	$ -	$ 3,762,756	$ 3,762,756	$ -	$ 3,484,034	$ 3,484,034	$ (278,722)
TOTAL UTILITY	$ 4,048,374,265	$ 116,998,933	$ 12,263,278	$ 129,262,211	$ 114,541,941	$ 14,083,428	$ 128,625,369	$ (636,842)
STEAM PRODUCTION (by Unit)								
Four Corners								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	2,982,777	65,429	5,210	70,639	73,741	4,461	78,202	7,563
312.00 Boiler Plant Equipment	76,402,061	1,219,616	111,205	1,330,821	1,202,927	92,246	1,295,173	(35,648)
314.00 Turbogenerator Units	12,359,480	287,585	16,903	304,488	254,487	12,677	267,164	(37,324)
315.00 Accessory Electric Equipment	4,390,980	153,002	8,523	161,525	177,401	8,702	186,103	24,578
316.00 Miscellaneous Power Plant Equipment	3,832,234	91,767	6,700	98,467	88,687	4,786	93,473	(4,994)
Total Four Corners	$ 99,967,532	$ 1,817,399	$ 148,541	$ 1,965,940	$ 1,797,243	$ 122,872	$ 1,920,115	$ (45,825)

TUCSON ELECTRIC POWER COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual			Proposed 2015 Annualized Accrual			Difference
	Investment	Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Four Corners Unit 4								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	1,524,414	32,470	2,439	34,909	35,824	1,982	37,806	2,897
312.00 Boiler Plant Equipment	39,609,538	594,143	63,375	657,518	566,416	55,453	621,869	(35,649)
314.00 Turbogenerator Units	7,179,362	175,176	8,615	183,791	149,331	6,461	155,792	(27,999)
315.00 Accessory Electric Equipment	2,274,836	88,036	3,867	91,903	88,946	3,412	92,358	455
316.00 Miscellaneous Power Plant Equipment	1,929,161	45,142	2,894	48,036	42,442	2,122	44,564	(3,472)
Total Four Corners Unit 4	$ 52,517,311	$ 934,967	$ 81,190	$ 1,016,157	$ 882,959	$ 69,430	$ 952,389	$ (63,768)
Four Corners Unit 5								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	1,458,363	32,959	2,771	35,730	37,917	2,479	40,396	4,666
312.00 Boiler Plant Equipment	36,792,523	625,473	47,830	673,303	636,511	36,793	673,304	1
314.00 Turbogenerator Units	5,180,118	112,409	8,288	120,697	105,156	6,216	111,372	(9,325)
315.00 Accessory Electric Equipment	2,116,144	64,966	4,656	69,622	88,455	5,290	93,745	24,123
316.00 Miscellaneous Power Plant Equipment	1,903,073	46,625	3,806	50,431	46,245	2,664	48,909	(1,522)
Total Four Corners Unit 5	$ 47,450,221	$ 882,432	$ 67,351	$ 949,783	$ 914,284	$ 53,442	$ 967,726	$ 17,943
Navajo								
310.00 Rights-of-Way	$ 12,229	$ 35	$ 2	$ 37	$ 94	$ 5	$ 99	$ 62
311.00 Structures and Improvements	18,655,156	266,935	19,407	286,342	479,050	27,179	506,229	219,887
312.00 Boiler Plant Equipment	88,544,201	1,470,251	90,473	1,560,724	2,789,739	144,143	2,933,882	1,373,158
314.00 Turbogenerator Units	20,255,526	305,780	19,622	325,402	642,358	32,069	674,427	349,025
315.00 Accessory Electric Equipment	14,829,858	277,041	19,470	296,511	576,222	31,388	607,610	311,099
316.00 Miscellaneous Power Plant Equipment	4,518,597	71,350	4,862	76,212	128,777	7,365	136,142	59,930
Total Navajo	$ 146,815,567	$ 2,391,392	$ 153,836	$ 2,545,228	$ 4,616,240	$ 242,149	$ 4,858,389	$ 2,313,161
Navajo Unit 1								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	3,190,563	22,015	1,595	23,610	131,770	6,381	138,151	114,541
312.00 Boiler Plant Equipment	27,198,582	475,975	32,638	508,613	1,631,915	81,596	1,713,511	1,204,898
314.00 Turbogenerator Units	6,860,989	108,404	6,175	114,579	414,404	19,211	433,615	319,036
315.00 Accessory Electric Equipment	3,544,300	53,519	3,190	56,709	300,557	14,177	314,734	258,025
316.00 Miscellaneous Power Plant Equipment	471,227	3,157	236	3,393	18,896	895	19,791	16,398
Total Navajo Unit 1	$ 41,265,661	$ 663,070	$ 43,834	$ 706,904	$ 2,497,542	$ 122,260	$ 2,619,802	$ 1,912,898
Navajo Unit 2								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	1,802,685	17,847	1,262	19,109	25,598	1,622	27,220	8,111
312.00 Boiler Plant Equipment	26,882,286	408,611	24,194	432,805	456,999	26,882	483,881	51,076
314.00 Turbogenerator Units	6,926,050	110,817	8,311	119,128	126,054	8,311	134,365	15,237
315.00 Accessory Electric Equipment	3,172,330	51,392	3,490	54,882	65,033	4,124	69,157	14,275
316.00 Miscellaneous Power Plant Equipment	515,874	4,540	310	4,850	5,004	310	5,314	464
Total Navajo Unit 2	$ 39,299,225	$ 593,207	$ 37,567	$ 630,774	$ 678,688	$ 41,249	$ 719,937	$ 89,163

TUCSON ELECTRIC POWER COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account	Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Current 2015 Annualized Accrual Net Salvage	Current 2015 Annualized Accrual Total	Proposed 2015 Annualized Accrual Investment	Proposed 2015 Annualized Accrual Net Salvage	Proposed 2015 Annualized Accrual Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Navajo Unit 3									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	3,681,511	36,447	2,577	39,024	41,233	2,209	43,442	4,418
312.00	Boiler Plant Equipment	27,718,514	437,953	22,175	460,128	507,249	22,175	529,424	69,296
314.00	Turbogenerator Units	6,178,944	75,383	4,325	79,708	87,741	3,707	91,448	11,740
315.00	Accessory Electric Equipment	5,139,872	68,360	5,654	74,014	80,696	5,654	86,350	12,336
316.00	Miscellaneous Power Plant Equipment	549,362	4,010	439	4,449	5,274	494	5,768	1,319
	Total Navajo Unit 3	$ 43,268,203	$ 622,153	$ 35,170	$ 657,323	$ 722,193	$ 34,239	$ 756,432	$ 99,109
Navajo Common									
310.00	Rights-of-Way	$ 12,229	$ 35	$ 2	$ 37	$ 94	$ 5	$ 99	$ 62
311.00	Structures and Improvements	9,980,397	190,626	13,973	204,599	280,449	16,967	297,416	92,817
312.00	Boiler Plant Equipment	6,744,819	147,712	11,466	159,178	193,576	13,490	207,066	47,888
314.00	Turbogenerator Units	289,543	11,176	811	11,987	14,159	840	14,999	3,012
315.00	Accessory Electric Equipment	2,973,356	103,770	7,136	110,906	129,936	7,433	137,369	26,463
316.00	Miscellaneous Power Plant Equipment	2,982,134	59,643	3,877	63,520	99,603	5,666	105,269	41,749
	Total Navajo Common	$ 22,982,478	$ 512,962	$ 37,265	$ 550,227	$ 717,817	$ 44,401	$ 762,218	$ 211,991
San Juan									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	14,437,744	248,228	21,674	269,902	1,093,818	104,193	1,198,011	928,109
312.00	Boiler Plant Equipment	154,506,908	3,788,408	1,148,165	4,936,573	11,797,736	1,386,578	13,184,314	8,247,741
314.00	Turbogenerator Units	44,295,673	912,491	79,732	992,223	3,357,612	323,358	3,680,970	2,688,747
315.00	Accessory Electric Equipment	10,063,526	210,328	19,121	229,449	767,847	73,464	841,311	611,862
316.00	Miscellaneous Power Plant Equipment	2,009,555	31,839	2,411	34,250	152,968	14,113	167,081	132,831
	Total San Juan	$ 225,313,406	$ 5,191,294	$ 1,271,103	$ 6,462,397	$ 17,169,981	$ 1,901,706	$ 19,071,687	$ 12,609,290
San Juan Unit 1									
310.00	Rights-of-Way	$ -	$ -	$ -		$ -	$ -	$ -	$ -
311.00	Structures and Improvements	14,268,404	245,417	21,403	266,820	1,080,118	104,159	1,184,277	917,457
312.00	Boiler Plant Equipment	146,453,029	3,485,582	366,133	3,851,715	11,174,366	1,083,752	12,258,118	8,406,403
314.00	Turbogenerator Units	44,295,673	912,491	79,732	992,223	3,357,612	323,358	3,680,970	2,688,747
315.00	Accessory Electric Equipment	10,063,526	210,328	19,121	229,449	767,847	73,464	841,311	611,862
316.00	Miscellaneous Power Plant Equipment	1,960,172	31,167	2,352	33,519	148,973	14,113	163,086	129,567
	Total San Juan Unit 1	$ 217,040,804	$ 4,884,985	$ 488,741	$ 5,373,726	$ 16,528,916	$ 1,598,846	$ 18,127,762	$ 12,754,036
San Juan Common									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	169,340	2,811	271	3,082	13,700	34	13,734	10,652
312.00	Boiler Plant Equipment	8,053,879	302,826	782,032	1,084,858	623,370	302,826	926,196	(158,662)
314.00	Turbogenerator Units								
315.00	Accessory Electric Equipment								
316.00	Miscellaneous Power Plant Equipment	49,383	672	59	731	3,995		3,995	3,264
	Total San Juan Common	$ 8,272,602	$ 306,309	$ 782,362	$ 1,088,671	$ 641,065	$ 302,860	$ 943,925	$ (144,746)

TUCSON ELECTRIC POWER COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual			Proposed 2015 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Springerville								
310.00 Rights-of-Way	$ 5,094,433	$ 154,716	$ -	$ 154,716	$ 145,323	$ -	$ 145,323	$ (9,393)
311.00 Structures and Improvements	141,726,641	5,270,099	65,329	5,335,428	4,028,521	849,209	4,877,730	(457,698)
312.00 Boiler Plant Equipment	641,687,365	20,250,799	469,997	20,720,796	13,625,822	2,489,675	16,115,497	(4,605,299)
314.00 Turbogenerator Units	173,649,915	5,159,622	146,103	5,305,725	3,783,448	240,492	4,023,940	(1,281,785)
315.00 Accessory Electric Equipment	75,864,618	2,506,161	57,172	2,563,333	1,444,701	138,955	1,583,656	(979,677)
316.00 Miscellaneous Power Plant Equipment	12,528,984	500,165	7,287	507,452	282,408	29,809	312,217	(195,235)
Total Springerville	$ 1,050,551,956	$ 33,841,562	$ 745,888	$ 34,587,450	$ 23,310,223	$ 3,748,140	$ 27,058,363	$ (7,529,087)
Springerville Unit 1								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	20,076,015	1,600,058	2,008	1,602,066	413,566	16,061	429,627	(1,172,439)
312.00 Boiler Plant Equipment	185,682,490	11,419,473	55,705	11,475,178	3,676,513	148,546	3,825,059	(7,650,119)
314.00 Turbogenerator Units	49,547,312	2,858,880	(24,774)	2,834,106	976,082	39,638	1,015,720	(1,818,386)
315.00 Accessory Electric Equipment	21,214,167	1,289,821	2,121	1,291,942	367,005	16,971	383,976	(907,966)
316.00 Miscellaneous Power Plant Equipment	3,277,742	284,836		284,836	70,144	2,294	72,438	(212,398)
Total Springerville Unit 1	$ 279,797,726	$ 17,453,068	$ 35,060	$ 17,488,128	$ 5,503,310	$ 223,510	$ 5,726,820	$ (11,761,308)
Springerville Unit 1 Common								
310.00 Rights-of-Way	$ 1,143,496	$ -	$ -	$ -	$ 23,213	$ -	$ 23,213	$ 23,213
311.00 Structures and Improvements	52,492,826	1,574,785	5,249	1,580,034	1,070,854	125,983	1,196,837	(383,197)
312.00 Boiler Plant Equipment	14,854,799	629,843		629,843	297,096	38,622	335,718	(294,125)
314.00 Turbogenerator Units	1,264,322	23,137		23,137	24,401	3,287	27,688	4,551
315.00 Accessory Electric Equipment	9,627,097	418,779		418,779	174,250	28,881	203,131	(215,648)
316.00 Miscellaneous Power Plant Equipment	1,959,012	72,875		72,875	35,850	5,485	41,335	(31,540)
Total Springerville Unit 1 Common	$ 81,341,552	$ 2,719,419	$ 5,249	$ 2,724,668	$ 1,625,664	$ 202,258	$ 1,827,922	$ (896,746)
Springerville Unit 2								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	36,540,030	679,645	54,810	734,455	789,265	54,810	844,075	109,620
312.00 Boiler Plant Equipment	295,922,545	5,563,344	414,292	5,977,636	6,273,558	443,884	6,717,442	739,806
314.00 Turbogenerator Units	122,055,348	2,245,818	170,877	2,416,695	2,746,245	183,083	2,929,328	512,633
315.00 Accessory Electric Equipment	42,346,939	715,663	55,051	770,714	796,122	50,816	846,938	76,224
316.00 Miscellaneous Power Plant Equipment	6,624,669	113,282	7,287	120,569	141,768	8,612	150,380	29,811
Total Springerville Unit 2	$ 503,489,531	$ 9,317,752	$ 702,317	$ 10,020,069	$ 10,746,958	$ 741,205	$ 11,488,163	$ 1,468,094
Springerville Unit 2 Common (Leasehold Imp.)								
310.00 Rights-of-Way	$ 2,280,838	$ 63,863	$ -	$ 63,863	$ 88,040	$ -	$ 88,040	$ 24,177
311.00 Structures and Improvements	32,617,770	1,415,611	3,262	1,418,873	1,754,836	652,355	2,407,191	988,318
312.00 Boiler Plant Equipment	6,282,729	345,550		345,550	405,236	135,707	540,943	195,393
314.00 Turbogenerator Units	782,933	31,787		31,787	36,720	14,484	51,204	19,417
315.00 Accessory Electric Equipment	2,676,415	81,898		81,898	107,324	42,287	149,611	67,713
316.00 Miscellaneous Power Plant Equipment	667,561	29,172		29,172	34,646	13,418	48,064	18,892
Total Springerville Unit 2 Common	$ 45,308,246	$ 1,967,881	$ 3,262	$ 1,971,143	$ 2,426,802	$ 858,251	$ 3,285,053	$ 1,313,910

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Current 2015 Annualized Accrual Net Salvage	Current 2015 Annualized Accrual Total	Proposed 2015 Annualized Accrual Investment	Proposed 2015 Annualized Accrual Net Salvage	Proposed 2015 Annualized Accrual Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Springerville Coal Handling									
310.00	Rights-of-Way	$ 1,670,099	$ 90,853	$ -	$ 90,853	$ 34,070	$ -	$ 34,070	$ (56,783)
311.00	Structures and Improvements								
312.00	Boiler Plant Equipment	138,944,802	2,292,589		2,292,589	2,973,419	1,722,916	4,696,335	2,403,746
314.00	Turbogenerator Units								
315.00	Accessory Electric Equipment								
316.00	Miscellaneous Power Plant Equipment								
	Total Springerville Coal Handling	$ 140,614,901	$ 2,383,442	$ -	$ 2,383,442	$ 3,007,489	$ 1,722,916	$ 4,730,405	$ 2,346,963
Sundt									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	27,475,371	1,074,534	560,794	1,635,328	833,474	398,662	1,232,136	(403,192)
312.00	Boiler Plant Equipment	130,812,626	4,880,095	2,305,141	7,185,236	3,675,140	1,563,391	5,238,531	(1,946,705)
314.00	Turbogenerator Units	52,481,329	3,229,967	1,905,697	5,135,664	1,922,555	1,051,925	2,974,480	(2,161,184)
315.00	Accessory Electric Equipment	39,432,489	2,237,226	1,250,913	3,488,139	1,471,269	763,230	2,234,499	(1,253,640)
316.00	Miscellaneous Power Plant Equipment	2,333,493	147,274	80,457	227,731	93,233	49,026	142,259	(85,472)
	Total Sundt	$ 252,535,308	$ 11,569,096	$ 6,103,002	$ 17,672,098	$ 7,995,671	$ 3,826,234	$ 11,821,905	$ (5,850,193)
Sundt Unit 1									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	3,926,062	390,643	210,830	601,473	195,910	108,752	304,662	(296,811)
312.00	Boiler Plant Equipment	13,782,181	1,433,347	691,865	2,125,212	625,711	326,638	952,349	(1,172,863)
314.00	Turbogenerator Units	10,237,507	1,195,741	630,630	1,826,371	509,828	277,436	787,264	(1,039,107)
315.00	Accessory Electric Equipment	6,536,315	858,872	466,039	1,324,911	401,983	221,581	623,564	(701,347)
316.00	Miscellaneous Power Plant Equipment	490,578	59,801	31,888	91,689	28,552	16,091	44,643	(47,046)
	Total Sundt Unit 1	$ 34,972,643	$ 3,938,404	$ 2,031,252	$ 5,969,656	$ 1,761,984	$ 950,498	$ 2,712,482	$ (3,257,174)
Sundt Unit 2									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	2,812,689	236,266	149,916	386,182	140,634	85,787	226,421	(159,761)
312.00	Boiler Plant Equipment	14,371,609	1,185,658	771,755	1,957,413	586,362	376,536	962,898	(994,515)
314.00	Turbogenerator Units	8,451,923	694,748	438,655	1,133,403	330,470	206,227	536,697	(596,706)
315.00	Accessory Electric Equipment	6,205,700	624,914	394,062	1,018,976	348,140	222,164	570,304	(448,672)
316.00	Miscellaneous Power Plant Equipment	383,824	36,732	22,838	59,570	20,573	12,935	33,508	(26,062)
	Total Sundt Unit 2	$ 32,225,745	$ 2,778,318	$ 1,777,226	$ 4,555,544	$ 1,426,179	$ 903,649	$ 2,329,828	$ (2,225,716)
Sundt Unit 3									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	2,762,012	183,398	135,339	318,737	114,071	80,098	194,169	(124,568)
312.00	Boiler Plant Equipment	11,980,831	739,217	559,505	1,298,722	464,856	335,463	800,319	(498,403)
314.00	Turbogenerator Units	14,830,615	1,011,448	754,878	1,766,326	600,640	424,156	1,024,796	(741,530)
315.00	Accessory Electric Equipment	6,140,139	439,020	316,831	755,851	244,378	169,468	413,846	(342,005)
316.00	Miscellaneous Power Plant Equipment	404,717	31,973	22,462	54,435	18,698	12,830	31,528	(22,907)
	Total Sundt Unit 3	$ 36,118,314	$ 2,405,056	$ 1,789,015	$ 4,194,071	$ 1,442,643	$ 1,022,015	$ 2,464,658	$ (1,729,413)

TUCSON ELECTRIC POWER COMPANY
Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account Description	12/31/14 Investment	Current 2015 Annualized Accrual			Proposed 2015 Annualized Accrual			Difference
	Investment	Investment	Net Salvage	Total	Investment	Net Salvage	Total	
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
Sundt Unit 4								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements	17,974,608	264,227	64,709	328,936	382,859	124,025	506,884	177,948
312.00 Boiler Plant Equipment	80,576,055	1,184,468	282,016	1,466,484	1,684,040	523,744	2,207,784	741,300
314.00 Turbogenerator Units	18,961,284	328,030	81,534	409,564	481,617	144,106	625,723	216,159
315.00 Accessory Electric Equipment	20,550,335	314,420	73,981	388,401	476,768	150,017	626,785	238,384
316.00 Miscellaneous Power Plant Equipment	1,054,374	18,768	3,269	22,037	25,410	7,170	32,580	10,543
Total Sundt Unit 4	$ 139,116,656	$ 2,109,913	$ 505,509	$ 2,615,422	$ 3,050,694	$ 949,062	$ 3,999,756	$ 1,384,334
Sundt Solar Booster (Areva)								
310.00 Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00 Structures and Improvements								
312.00 Boiler Plant Equipment	10,101,950	337,405		337,405	314,171	1,010	315,181	(22,224)
314.00 Turbogenerator Units								
315.00 Accessory Electric Equipment								
316.00 Miscellaneous Power Plant Equipment								
Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 337,405	$ -	$ 337,405	$ 314,171	$ 1,010	$ 315,181	$ (22,224)
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00 Structures and Improvements	$ 761,988	$ 18,745	$ 1,448	$ 20,193	$ 20,116	$ 1,372	$ 21,488	$ 1,295
342.00 Fuel Holders, Products and Accessories	750,386	17,259	1,576	18,835	16,734	1,501	18,235	(600)
343.00 Prime Movers	76,766	2,226	207	2,433	2,196	8	2,204	(229)
344.00 Generators and Devices	30,772,866	707,776	64,623	772,399	689,312	58,468	747,780	(24,619)
345.00 Accessory Electric Equipment	861,492	19,814	1,809	21,623	19,728	431	20,159	(1,464)
346.00 Miscellaneous Power Plant Equipment	376,605	8,963	829	9,792	8,888	791	9,679	(113)
Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 774,783	$ 70,492	$ 845,275	$ 756,974	$ 62,571	$ 819,545	$ (25,730)
Gila River								
341.00 Structures and Improvements	$ 8,508,950	$ 192,303	$ -	$ 192,303	$ 205,534	$ 17,018	$ 222,552	$ 30,249
342.00 Fuel Holders, Products and Accessories	6,783,045	153,296		153,296	162,882	13,566	176,448	23,152
343.00 Prime Movers	188,744,730	4,265,631		4,265,631	4,597,974	378,924	4,976,898	711,267
344.00 Generators and Devices	32,783,434	740,906		740,906	776,967	65,567	842,534	101,628
345.00 Accessory Electric Equipment	9,030,698	204,094		204,094	215,581	18,061	233,642	29,548
346.00 Miscellaneous Power Plant Equipment	6,799,960	153,679		153,679	163,879	13,600	177,479	23,800
Total Gila River	$ 252,650,817	$ 5,709,909	$ -	$ 5,709,909	$ 6,122,817	$ 506,736	$ 6,629,553	$ 919,644

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Net Salvage	Total	Proposed 2015 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Gila River Unit 3									
341.00	Structures and Improvements	$ 957,417	$ 21,638	$ -	$ 21,638	$ 22,787	$ 1,915	$ 24,702	$ 3,064
342.00	Fuel Holders, Products and Accessories	178,424	4,032		4,032	4,371	357	4,728	696
343.00	Prime Movers	181,571,712	4,103,521		4,103,521	4,412,193	363,143	4,775,336	671,815
344.00	Generators and Devices	32,783,434	740,906		740,906	776,967	65,567	842,534	101,628
345.00	Accessory Electric Equipment	6,860,554	155,049		155,049	163,281	13,721	177,002	21,953
346.00	Miscellaneous Power Plant Equipment	135,558	3,064		3,064	3,267	271	3,538	474
	Total Gila River Unit 3	$ 222,487,099	$ 5,028,210	$ -	$ 5,028,210	$ 5,382,866	$ 444,974	$ 5,827,840	$ 799,630
Gila River Common									
341.00	Structures and Improvements	$ 7,551,533	$ 170,665	$ -	$ 170,665	$ 182,747	$ 15,103	$ 197,850	$ 27,185
342.00	Fuel Holders, Products and Accessories	6,604,621	149,264		149,264	158,511	13,209	171,720	22,456
343.00	Prime Movers	7,173,018	162,110		162,110	185,781	15,781	201,562	39,452
344.00	Generators and Devices								
345.00	Accessory Electric Equipment	2,170,144	49,045		49,045	52,300	4,340	56,640	7,595
346.00	Miscellaneous Power Plant Equipment	6,664,402	150,615		150,615	160,612	13,329	173,941	23,326
	Total Gila River Common	$ 30,163,718	$ 681,699	$ -	$ 681,699	$ 739,951	$ 61,762	$ 801,713	$ 120,014
Luna									
341.00	Structures and Improvements	$ 13,232,832	$ 348,023	$ 67,487	$ 415,510	$ 367,873	$ 68,811	$ 436,684	$ 21,174
342.00	Fuel Holders, Products and Accessories	11,352,383	297,432	59,032	356,464	315,596	59,032	374,628	18,164
343.00	Prime Movers	11,151,074	295,503	56,870	352,373	316,691	56,870	373,561	21,188
344.00	Generators and Devices	9,486,694	249,500	47,433	296,933	265,627	46,485	312,112	15,179
345.00	Accessory Electric Equipment	9,647	248		248	276	52	328	80
346.00	Miscellaneous Power Plant Equipment	7,424,592	194,524	38,608	233,132	206,404	38,608	245,012	11,880
	Total Luna	$ 52,657,222	$ 1,385,230	$ 269,430	$ 1,654,660	$ 1,472,467	$ 269,858	$ 1,742,325	$ 87,665
North Loop Gas									
341.00	Structures and Improvements	$ 888,601	$ 28,138	$ 3,106	$ 31,244	$ 10,476	$ 1,196	$ 11,672	$ (19,572)
342.00	Fuel Holders, Products and Accessories	303,037	6,727	394	7,121	6,758	394	7,152	31
343.00	Prime Movers	1,890,946	205,693	26,244	231,937	108,626	12,423	121,049	(110,888)
344.00	Generators and Devices	24,062,187	530,628	43,952	574,580	357,948	20,650	378,598	(195,982)
345.00	Accessory Electric Equipment	2,829,171	83,689	8,524	92,213	51,917	5,004	56,921	(35,292)
346.00	Miscellaneous Power Plant Equipment	656,253	17,655	1,887	19,542	5,548	521	6,069	(13,473)
	Total North Loop Gas	$ 30,630,195	$ 872,530	$ 84,107	$ 956,637	$ 541,273	$ 40,188	$ 581,461	$ (375,176)
North Loop Gas Unit 1									
341.00	Structures and Improvements	$ 411,070	$ 18,046	$ 2,014	$ 20,060	$ 5,919	$ 822	$ 6,741	$ (13,319)
342.00	Fuel Holders, Products and Accessories								
343.00	Prime Movers	678,545	65,140	7,193	72,333	25,649	3,393	29,042	(43,291)
344.00	Generators and Devices	3,582,271	94,930	10,389	105,319	7,881	358	8,239	(97,080)
345.00	Accessory Electric Equipment	790,955	32,429	3,559	35,988	11,943	1,503	13,446	(22,542)
346.00	Miscellaneous Power Plant Equipment	306,369	13,051	1,471	14,522	3,646	490	4,136	(10,386)
	Total North Loop Gas Unit 1	$ 5,769,210	$ 223,596	$ 24,626	$ 248,222	$ 55,038	$ 6,566	$ 61,604	$ (186,618)

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Net Salvage	Total	Proposed 2015 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
North Loop Gas Unit 2									
341.00	Structures and Improvements	$ 196,078	$ 3,882	$ 608	$ 4,490	$ 1,627	$ 294	$ 1,921	$ (2,569)
342.00	Fuel Holders, Products and Accessories								
343.00	Prime Movers	263,450	13,963	2,160	16,123	34,960	1,818	36,778	20,655
344.00	Generators and Devices	3,239,719	59,935	8,423	68,358	22,678	3,240	25,918	(42,440)
345.00	Accessory Electric Equipment	504,895	13,531	1,969	15,500	8,836	1,414	10,250	(5,250)
346.00	Miscellaneous Power Plant Equipment	128,559	1,144	167	1,311	167	26	193	(1,118)
	Total North Loop Gas Unit 2	$ 4,332,701	$ 92,455	$ 13,327	$ 105,782	$ 68,268	$ 6,792	$ 75,060	$ (30,722)
North Loop Gas Unit 3									
341.00	Structures and Improvements	$ 196,078	$ 4,255	$ 569	$ 4,824	$ 941	$ 157	$ 1,098	$ (3,726)
342.00	Fuel Holders, Products and Accessories								
343.00	Prime Movers	948,951	126,590	16,891	143,481	48,017	7,212	55,229	(88,252)
344.00	Generators and Devices	3,030,531	60,308	6,667	66,975	9,092		9,092	(57,883)
345.00	Accessory Electric Equipment	503,907	14,361	1,864	16,225	7,256	1,058	8,314	(7,911)
346.00	Miscellaneous Power Plant Equipment	128,559	1,401	193	1,594	(334)	(51)	(385)	(1,979)
	Total North Loop Gas Unit 3	$ 4,808,026	$ 206,915	$ 26,184	$ 233,099	$ 64,972	$ 8,376	$ 73,348	$ (159,751)
North Loop Gas Unit 4									
341.00	Structures and Improvements	$ 85,375	$ 1,955	$ (85)	$ 1,870	$ 1,989	$ (77)	$ 1,912	$ 42
342.00	Fuel Holders, Products and Accessories	303,037	6,727	394	7,121	6,758	394	7,152	31
343.00	Prime Movers								
344.00	Generators and Devices	14,209,666	315,455	18,473	333,928	318,297	17,052	335,349	1,421
345.00	Accessory Electric Equipment	1,029,414	23,368	1,132	24,500	23,882	1,029	24,911	411
346.00	Miscellaneous Power Plant Equipment	92,766	2,059	56	2,115	2,069	56	2,125	10
	Total North Loop Gas Unit 4	$ 15,720,258	$ 349,564	$ 19,970	$ 369,534	$ 352,995	$ 18,454	$ 371,449	$ 1,915
Solar Units (Generators and Devices)									
344.00	DeMoss Petrie	$ 1,146,081	$ 58,794	$ -	$ 58,794	$ 34,955	$ 1,719	$ 36,674	$ (22,120)
344.00	Fort Huachuca	36,709,538	1,883,199		1,883,199	1,306,860	66,077	1,372,937	(510,262)
344.00	HQ Rooftop	303,184	15,553		15,553	10,611	546	11,157	(4,396)
344.00	OH Rooftop	2,594,590	133,102		133,102	90,032	4,411	94,443	(38,659)
344.00	OH Test Yard	388,459	19,928		19,928	12,042	583	12,625	(7,303)
344.00	Prairie Fire	19,036,520	976,573		976,573	666,278	34,266	700,544	(276,029)
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	1,475,727		1,475,727	877,381	43,150	920,531	(555,196)
344.00	Springerville Site 4	7,873,874	403,930		403,930	270,074	14,173	284,247	(119,683)
344.00	Tucson	87,198	4,473		4,473	2,267	113	2,380	(2,093)
344.00	U of A Tech Park Site 1	7,723,832	396,233		396,233	264,927	13,903	278,830	(117,403)
344.00	U of A Tech Park Site 2	19,191,952	984,547		984,547	665,961	32,626	698,587	(285,960)
344.00	White Mountain	46,499,099	2,385,404		2,385,404	1,655,368	83,698	1,739,066	(646,338)
	Total Solar Units	$ 170,320,932	$ 8,737,463	$ -	$ 8,737,463	$ 5,856,756	$ 295,265	$ 6,152,021	$ (2,585,442)

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current 2015 Annualized Accrual Investment	Current 2015 Annualized Accrual Net Salvage	Current 2015 Annualized Accrual Total	Proposed 2015 Annualized Accrual Investment	Proposed 2015 Annualized Accrual Net Salvage	Proposed 2015 Annualized Accrual Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Sundt Gas									
341.00	Structures and Improvements	$ 11,090	$ 29	$ 1	$ 30	$ (14)	$ (2)	$ (16)	$ (46)
342.00	Fuel Holders, Products and Accessories	788,336	67,048	1,183	68,231	28,656	630	29,286	(38,945)
343.00	Prime Movers	141,618	5,154	84	5,238	2,542	49	2,591	(2,647)
344.00	Generators and Devices	8,382,044	13,012		13,012	(30,657)	(1,676)	(32,333)	(45,345)
345.00	Accessory Electric Equipment	1,078,811	14,755	272	15,027	1,852	(52)	1,800	(13,227)
346.00	Miscellaneous Power Plant Equipment	49,750				(623)	(10)	(633)	(633)
	Total Sundt Gas	$ 10,451,649	$ 99,998	$ 1,540	$ 101,538	$ 1,756	$ (1,061)	$ 695	$ (100,843)
Sundt Gas Unit 1									
341.00	Structures and Improvements	$ 5,545	$ 6	$ -	$ 6	$ (4)	$ (1)	$ (5)	$ (11)
342.00	Fuel Holders, Products and Accessories	394,168	33,189	552	33,741	14,427	315	14,742	(18,999)
343.00	Prime Movers	70,809	2,485	42	2,527	1,296	28	1,324	(1,203)
344.00	Generators and Devices	4,315,668				(16,831)	(863)	(17,694)	(17,694)
345.00	Accessory Electric Equipment	516,231	5,472	103	5,575	671	(52)	619	(4,956)
346.00	Miscellaneous Power Plant Equipment	19,906				(241)	(4)	(245)	(245)
	Total Sundt Gas Unit 1	$ 5,322,327	$ 41,152	$ 697	$ 41,849	$ (682)	$ (577)	$ (1,259)	$ (43,108)
Sundt Gas Unit 2									
341.00	Structures and Improvements	$ 5,545	$ 23	$ 1	$ 24	$ (10)	$ (1)	$ (11)	$ (35)
342.00	Fuel Holders, Products and Accessories	394,168	33,859	631	34,490	14,229	315	14,544	(19,946)
343.00	Prime Movers	70,809	2,669	42	2,711	1,246	21	1,267	(1,444)
344.00	Generators and Devices	4,066,376	13,012		13,012	(13,826)	(813)	(14,639)	(27,651)
345.00	Accessory Electric Equipment	562,580	9,283	169	9,452	1,181		1,181	(8,271)
346.00	Miscellaneous Power Plant Equipment	29,844				(382)	(6)	(388)	(388)
	Total Sundt Gas Unit 2	$ 5,129,322	$ 58,846	$ 843	$ 59,689	$ 2,438	$ (484)	$ 1,954	$ (57,735)

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STEAM PRODUCTION							
310.00 Rights-of-Way	$ 5,106,662	$ 3,694,243	72.34%	$ 2,875,801	56.31%	$ 2,447,153	47.92%
311.00 Structures and Improvements	205,277,689	105,373,653	51.33%	108,874,331	53.04%	97,248,235	47.37%
312.00 Boiler Plant Equipment	1,091,953,161	430,944,377	39.47%	540,470,593	49.50%	446,282,641	40.87%
314.00 Turbogenerator Units	303,041,923	108,786,141	35.90%	133,946,536	44.20%	108,151,958	35.69%
315.00 Accessory Electric Equipment	144,581,471	67,267,210	46.53%	68,934,846	47.68%	62,107,925	42.96%
316.00 Miscellaneous Power Plant Equipment	25,222,863	11,455,994	45.42%	11,404,754	45.22%	11,283,704	44.74%
Total Steam Production Plant	$ 1,775,183,769	$ 727,521,616	40.98%	$ 866,506,861	48.81%	$ 727,521,616	40.98%
OTHER PRODUCTION							
Non-Solar							
341.00 Structures and Improvements	$ 23,403,461	$ 4,517,794	19.30%	$ 5,824,666	24.89%	$ 3,626,965	15.50%
342.00 Fuel Holders, Products and Accessories	19,977,187	3,821,601	19.13%	4,890,928	24.48%	2,958,341	14.81%
343.00 Prime Movers	202,005,134	45,871,980	22.71%	48,215,536	23.87%	45,970,311	22.76%
344.00 Generators and Devices	105,487,225	42,523,497	40.31%	39,253,861	37.21%	44,592,063	42.27%
345.00 Accessory Electric Equipment	13,809,819	5,672,963	41.08%	4,932,963	35.72%	5,718,985	41.41%
346.00 Miscellaneous Power Plant Equipment	15,307,160	3,234,180	21.13%	3,997,542	26.12%	2,775,348	18.13%
Total Non-Solar	$ 379,989,986	$ 105,642,014	27.80%	$ 107,115,497	28.19%	$ 105,642,014	27.80%
Solar							
344.00 Generators and Devices	$ 170,320,932	$ 26,892,332	15.79%	$ 22,416,079	13.16%	$ 26,892,332	15.79%
Total Solar	$ 170,320,932	$ 26,892,332	15.79%	$ 22,416,079	13.16%	$ 26,892,332	15.79%
Total Other Production Plant	$ 550,310,918	$ 132,534,346	24.08%	$ 129,531,575	23.54%	$ 132,534,346	24.08%
DISTRIBUTION PLANT							
360.RW Rights-of-Way	$ 7,865,073	$ 3,685,111	46.85%	$ 2,967,754	37.73%	$ 3,720,941	47.31%
361.00 Structures and Improvements	11,402,474	2,440,911	21.41%	1,927,786	16.91%	2,417,039	21.20%
362.00 Station Equipment	157,067,530	44,816,223	28.53%	38,291,794	24.38%	48,009,871	30.57%
364.00 Poles, Towers and Fixtures	222,006,967	71,565,728	32.24%	53,853,971	24.26%	67,521,575	30.41%
365.00 Overhead Conductors and Devices	175,675,966	59,385,788	33.80%	50,923,833	28.99%	63,847,797	36.34%
366.00 Underground Conduit	58,725,355	23,125,320	39.38%	18,680,394	31.81%	23,421,293	39.88%
367.00 Underground Conductors and Devices	297,183,135	119,413,016	40.18%	92,262,153	31.05%	115,677,372	38.92%
368.OH Line Transformers - Overhead	103,657,922	45,498,501	43.89%	31,691,984	30.57%	39,735,096	38.33%
368.UG Line Transformers - Underground	172,890,932	71,195,629	41.18%	52,540,781	30.39%	65,875,110	38.10%
369.OH Services - Overhead	17,542,236	8,133,240	46.36%	6,372,839	36.33%	7,990,202	45.55%
369.UG Services - Underground	112,947,714	35,019;387	31.00%	28,664,832	25.38%	35,939,682	31.82%
370.00 Meters	44,869,823	(225,711)	-0.50%	8,648,279	19.27%	10,843,126	24.17%
373.00 Street Lighting and Signal Systems	11,778,362	4,929,241	41.85%	3,992,908	33.90%	5,006,268	42.50%
Total Distribution Plant	$ 1,393,613,489	$ 488,982,384	35.09%	$ 390,819,309	28.04%	$ 490,005,372	35.16%

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GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 135,680,348	$ 22,140,915	16.32%	$ 23,121,989	17.04%	$ 21,696,815	15.99%
392.C0 Transportation - Class 0	1,238,946	537,462	43.38%	430,858	34.78%	404,302	32.63%
392.C1 Transportation - Class 1	7,718,183	3,370,156	43.67%	3,085,389	39.98%	2,895,214	37.51%
392.C2 Transportation - Class 2	3,839,907	1,471,770	38.33%	1,512,999	39.40%	1,419,742	36.97%
392.C3 Transportation - Class 3	2,076,936	1,040,386	50.09%	982,304	47.30%	921,757	44.38%
392.C4 Transportation - Class 4	2,935,027	748,506	25.50%	1,119,503	38.14%	1,050,500	35.79%
392.C5 Transportation - Class 5	7,982,715	2,758,719	34.56%	3,223,932	40.39%	3,025,218	37.90%
392.C6 Transportation - Class 6	365,200	71,788	19.66%	72,748	19.92%	68,264	18.69%
392.C7 Transportation - Class 7	1,047,216	431,484	41.20%	371,401	35.47%	348,508	33.28%
392.C8 Transportation - Class 8	9,957,500	3,320,461	33.35%	3,285,253	32.99%	3,082,759	30.96%
392.C9 Transportation - Class 9	4,252,286	1,578,200	37.11%	1,139,077	26.79%	1,068,867	25.14%
396.00 Power Operatied Equipment	11,860,940	2,437,035	20.55%	2,664,204	22.46%	2,499,990	21.08%
397.EM EMS and SCADA Equipment	11,304,371	3,197,149	28.28%	3,314,518	29.32%	3,110,221	27.51%
Total Depreciable	$ 200,259,575	$ 43,104,031	21.52%	$ 44,324,175	22.13%	$ 41,592,158	20.77%
Amortizable							
391.00 Furniture and Office Equipment	$ 23,964,411	$ 7,694,941	32.11%	$ 7,698,753	32.13%	$ 7,698,753	32.13%
391.20 Network and Data Equipment	29,359,636	14,970,053	50.99%	14,913,970	50.80%	14,913,970	50.80%
393.00 Stores Equipment	1,852,479	820,258	44.28%	840,197	45.36%	840,197	45.36%
394.00 Tools, Shop and Garage Equipment	6,934,368	2,860,187	41.25%	2,858,589	41.22%	2,858,589	41.22%
395.00 Laboratory Equipment	5,091,270	2,395,517	47.05%	2,395,826	47.06%	2,395,826	47.06%
397.20 Telecommunications Equipment	57,456,141	18,113,523	31.53%	19,662,636	34.22%	19,662,636	34.22%
398.00 Miscellaneous Equipment	4,348,209	1,818,966	41.83%	1,815,347	41.75%	1,815,347	41.75%
Total Amortizable	$ 129,006,514	$ 48,673,445	37.73%	$ 50,185,318	38.90%	$ 50,185,318	38.90%
Total General Plant	$ 329,266,089	$ 91,777,476	27.87%	$ 94,509,493	28.70%	$ 91,777,476	27.87%
SUBTOTAL	$ 4,048,374,265	$ 1,440,815,822	35.59%	$ 1,481,367,238	36.59%	$ 1,441,838,810	35.62%
NET SALVAGE							
108.02 Distribution	$ 1,393,613,489	$ 85,838,400	6.16%	$ 67,647,219	4.85%	$ 84,815,412	6.09%
Total Net Salvage	$ 1,393,613,489	$ 85,838,400	6.16%	$ 67,647,219	4.85%	$ 84,815,412	6.09%
TOTAL UTILITY	$ 4,048,374,265	$ 1,526,654,221	37.71%	$ 1,549,014,457	38.26%	$ 1,526,654,221	37.71%

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A	B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION (by Unit)							
Four Corners							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	2,982,777	1,813,087	60.79%	1,407,310	47.18%	1,908,245	63.98%
312.00 Boiler Plant Equipment	76,402,061	60,687,020	79.43%	44,493,936	58.24%	60,345,088	78.98%
314.00 Turbogenerator Units	12,359,480	8,806,344	71.25%	6,490,155	52.51%	8,830,514	71.45%
315.00 Accessory Electric Equipment	4,390,980	1,422,016	32.38%	1,224,683	27.89%	1,663,472	37.88%
316.00 Miscellaneous Power Plant Equipment	3,832,234	2,573,936	67.17%	1,885,490	49.20%	2,555,084	66.67%
Total Four Corners	$ 99,967,532	$ 75,302,403	75.33%	$ 55,501,573	55.52%	$ 75,302,403	75.33%
Four Corners Unit 4							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	1,524,414	957,081	62.78%	717,080	47.04%	1,004,130	65.87%
312.00 Boiler Plant Equipment	39,609,538	32,129,841	81.12%	22,819,676	57.61%	31,954,492	80.67%
314.00 Turbogenerator Units	7,179,362	5,095,340	70.97%	3,640,615	50.71%	5,097,969	71.01%
315.00 Accessory Electric Equipment	2,274,836	782,000	34.38%	655,647	28.82%	918,105	40.36%
316.00 Miscellaneous Power Plant Equipment	1,929,161	1,331,723	69.03%	943,572	48.91%	1,321,288	68.49%
Total Four Corners Unit 4	$ 52,517,311	$ 40,295,985	76.73%	$ 28,776,589	54.79%	$ 40,295,985	76.73%
Four Corners Unit 5							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	1,458,363	856,006	58.70%	690,230	47.33%	904,116	62.00%
312.00 Boiler Plant Equipment	36,792,523	28,557,180	77.62%	21,674,260	58.91%	28,390,596	77.16%
314.00 Turbogenerator Units	5,180,118	3,711,004	71.64%	2,849,540	55.01%	3,732,544	72.06%
315.00 Accessory Electric Equipment	2,116,144	640,016	30.24%	569,037	26.89%	745,368	35.22%
316.00 Miscellaneous Power Plant Equipment	1,903,073	1,242,213	65.27%	941,918	49.49%	1,233,795	64.83%
Total Four Corners Unit 5	$ 47,450,221	$ 35,006,419	73.78%	$ 26,724,984	56.32%	$ 35,006,419	73.78%
Navajo							
310.00 Rights-of-Way	$ 12,229	$ 12,671	103.62%	$ 9,126	74.62%	$ 11,451	93.64%
311.00 Structures and Improvements	18,655,156	13,989,522	74.99%	11,536,575	61.84%	13,565,143	72.72%
312.00 Boiler Plant Equipment	88,544,201	67,034,406	75.71%	59,294,347	66.97%	67,573,826	76.32%
314.00 Turbogenerator Units	20,255,526	16,002,717	79.00%	14,005,570	69.14%	15,851,652	78.26%
315.00 Accessory Electric Equipment	14,829,858	9,777,819	65.93%	8,446,290	56.95%	9,853,980	66.45%
316.00 Miscellaneous Power Plant Equipment	4,518,597	2,967,546	65.67%	2,438,444	53.96%	2,928,630	64.81%
Total Navajo	$ 146,815,567	$ 109,784,682	74.78%	$ 95,730,352	65.20%	$ 109,784,682	74.78%

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Navajo Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	3,190,563	3,081,399	96.58%	2,941,499	92.19%	2,732,322	85.64%
312.00	Boiler Plant Equipment	27,198,582	20,390,194	74.97%	22,499,824	82.72%	20,899,807	76.84%
314.00	Turbogenerator Units	6,860,989	5,372,911	78.31%	5,669,140	82.63%	5,265,994	76.75%
315.00	Accessory Electric Equipment	3,544,300	2,315,538	65.33%	2,491,890	70.31%	2,314,686	65.31%
316.00	Miscellaneous Power Plant Equipment	471,227	458,551	97.31%	436,850	92.70%	405,785	86.11%
	Total Navajo Unit 1	$ 41,265,661	$ 31,618,592	76.62%	$ 34,039,203	82.49%	$ 31,618,592	76.62%
Navajo Unit 2								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	1,802,685	1,519,996	84.32%	1,182,807	65.61%	1,509,362	83.73%
312.00	Boiler Plant Equipment	26,882,286	21,334,917	79.36%	16,714,013	62.17%	21,328,503	79.34%
314.00	Turbogenerator Units	6,926,050	5,347,290	77.21%	4,189,462	60.49%	5,346,110	77.19%
315.00	Accessory Electric Equipment	3,172,330	2,305,054	72.66%	1,828,615	57.64%	2,333,469	73.56%
316.00	Miscellaneous Power Plant Equipment	515,874	478,584	92.77%	367,057	71.15%	468,397	90.80%
	Total Navajo Unit 2	$ 39,299,225	$ 30,985,841	78.85%	$ 24,281,955	61.79%	$ 30,985,841	78.85%
Navajo Unit 3								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	3,681,511	3,289,429	89.35%	2,564,640	69.66%	3,240,677	88.03%
312.00	Boiler Plant Equipment	27,718,514	21,206,074	76.51%	16,877,474	60.89%	21,326,362	76.94%
314.00	Turbogenerator Units	6,178,944	5,218,613	84.46%	4,083,695	66.09%	5,160,153	83.51%
315.00	Accessory Electric Equipment	5,139,872	4,138,011	80.51%	3,272,439	63.67%	4,135,051	80.45%
316.00	Miscellaneous Power Plant Equipment	549,362	503,918	91.73%	390,790	71.14%	493,802	89.89%
	Total Navajo Unit 3	$ 43,268,203	$ 34,356,045	79.40%	$ 27,189,038	62.84%	$ 34,356,045	79.40%
Navajo Common								
310.00	Rights-of-Way	$ 12,229	$ 12,671	103.62%	$ 9,126	74.62%	$ 11,451	93.64%
311.00	Structures and Improvements	9,980,397	6,098,698	61.11%	4,847,630	48.57%	6,082,782	60.95%
312.00	Boiler Plant Equipment	6,744,819	4,103,220	60.84%	3,203,036	47.49%	4,019,154	59.59%
314.00	Turbogenerator Units	289,543	63,903	22.07%	63,273	21.85%	79,395	27.42%
315.00	Accessory Electric Equipment	2,973,356	1,019,217	34.28%	853,346	28.70%	1,070,774	36.01%
316.00	Miscellaneous Power Plant Equipment	2,982,134	1,526,493	51.19%	1,243,747	41.71%	1,560,647	52.33%
	Total Navajo Common	$ 22,982,478	$ 12,824,203	55.80%	$ 10,220,157	44.47%	$ 12,824,203	55.80%

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San Juan								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	14,437,744	3,437,723	23.81%	9,119,596	63.16%	1,087,211	7.53%
312.00	Boiler Plant Equipment	154,506,908	6,056,700	3.92%	87,767,581	56.80%	10,463,387	6.77%
314.00	Turbogenerator Units	44,295,673	6,542,378	14.77%	27,834,853	62.84%	3,318,387	7.49%
315.00	Accessory Electric Equipment	10,063,526	(132,385)	-1.32%	5,754,151	57.18%	685,993	6.82%
316.00	Miscellaneous Power Plant Equipment	2,009,555	(208,748)	-10.39%	1,180,121	58.73%	140,690	7.00%
	Total San Juan	$ 225,313,406	$ 15,695,668	6.97%	$ 131,656,301	58.43%	$ 15,695,668	6.97%
San Juan Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	14,268,404	3,436,921	24.09%	9,113,095	63.87%	1,086,436	7.61%
312.00	Boiler Plant Equipment	146,453,029	1,499,790	1.02%	82,646,788	56.43%	9,852,901	6.73%
314.00	Turbogenerator Units	44,295,673	6,542,378	14.77%	27,834,853	62.84%	3,318,387	7.49%
315.00	Accessory Electric Equipment	10,063,526	(132,385)	-1.32%	5,754,151	57.18%	685,993	6.82%
316.00	Miscellaneous Power Plant Equipment	1,960,172	(209,009)	-10.66%	1,178,229	60.11%	140,465	7.17%
	Total San Juan Unit 1	$ 217,040,804	$ 11,137,695	5.13%	$ 126,527,116	58.30%	$ 15,084,182	6.95%
San Juan Common								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	169,340	803	0.47%	6,501	3.84%	775	0.46%
312.00	Boiler Plant Equipment	8,053,879	4,556,910	56.58%	5,120,792	63.58%	610,485	7.58%
314.00	Turbogenerator Units							
315.00	Accessory Electric Equipment							
316.00	Miscellaneous Power Plant Equipment	49,383	261	0.53%	1,892	3.83%	226	0.46%
	Total San Juan Common	$ 8,272,602	$ 4,557,973	55.10%	$ 5,129,185	62.00%	$ 611,486	7.39%
Springerville								
310.00	Rights-of-Way	$ 5,094,433	$ 3,681,571	72.27%	$ 2,866,675	56.27%	$ 2,435,702	47.81%
311.00	Structures and Improvements	141,726,641	69,753,908	49.22%	71,141,108	50.20%	68,092,765	48.05%
312.00	Boiler Plant Equipment	641,687,365	245,587,975	38.27%	271,651,601	42.33%	245,899,655	38.32%
314.00	Turbogenerator Units	173,649,915	50,485,589	29.07%	54,177,144	31.20%	54,881,825	31.60%
315.00	Accessory Electric Equipment	75,864,618	36,828,958	48.55%	35,289,604	46.52%	35,259,694	46.48%
316.00	Miscellaneous Power Plant Equipment	12,528,984	5,054,564	40.34%	4,860,135	38.79%	4,822,925	38.49%
	Total Springerville	$ 1,050,551,956	$ 411,392,565	39.16%	$ 439,986,266	41.88%	$ 411,392,565	39.16%

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Springerville Unit 1							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	20,076,015	8,646,215	43.07%	7,999,339	39.85%	8,571,789	42.70%
312.00 Boiler Plant Equipment	185,682,490	82,449,685	44.40%	78,377,007	42.21%	83,985,834	45.23%
314.00 Turbogenerator Units	49,547,312	24,720,176	49.89%	21,082,315	42.55%	22,591,011	45.59%
315.00 Accessory Electric Equipment	21,214,167	10,429,780	49.16%	10,377,254	48.92%	11,119,872	52.42%
316.00 Miscellaneous Power Plant Equipment	3,277,742	1,342,432	40.96%	1,231,642	37.58%	1,319,781	40.26%
Total Springerville Unit 1	$ 279,797,726	$ 127,588,287	45.60%	$ 119,067,557	42.55%	$ 127,588,287	45.60%
Springerville Unit 1 Common							
310.00 Rights-of-Way	$ 1,143,496	$ 878,769	76.85%	$ 472,348	41.31%	$ 463,859	40.57%
311.00 Structures and Improvements	52,492,826	26,956,787	51.35%	26,686,185	50.84%	26,206,572	49.92%
312.00 Boiler Plant Equipment	14,854,799	7,017,428	47.24%	7,679,618	51.70%	7,541,597	50.77%
314.00 Turbogenerator Units	1,264,322	677,581	53.59%	677,066	53.55%	664,897	52.59%
315.00 Accessory Electric Equipment	9,627,097	4,747,620	49.32%	5,395,718	56.05%	5,298,744	55.04%
316.00 Miscellaneous Power Plant Equipment	1,959,012	968,707	49.45%	1,090,827	55.68%	1,071,222	54.68%
Total Springerville Unit 1 Common	$ 81,341,552	$ 41,246,892	50.71%	$ 42,001,761	51.64%	$ 41,246,892	50.71%
Springerville Unit 2							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	36,540,030	11,419,075	31.25%	10,676,565	29.22%	10,436,182	28.56%
312.00 Boiler Plant Equipment	295,922,545	90,766,387	30.67%	90,279,732	30.51%	88,247,082	29.82%
314.00 Turbogenerator Units	122,055,348	24,457,076	20.04%	31,729,403	26.00%	31,015,014	25.41%
315.00 Accessory Electric Equipment	42,346,939	19,274,032	45.51%	16,893,181	39.89%	16,512,831	38.99%
316.00 Miscellaneous Power Plant Equipment	6,624,669	2,247,196	33.92%	1,997,634	30.15%	1,952,657	29.48%
Total Springerville Unit 2	$ 503,489,531	$ 148,163,767	29.43%	$ 151,576,515	30.11%	$ 148,163,767	29.43%
Springerville Unit 2 Common (Leasehold Imp.)							
310.00 Rights-of-Way	$ 2,280,838	$ 1,997,938	87.60%	$ 1,638,561	71.84%	$ 1,454,181	63.76%
311.00 Structures and Improvements	32,617,770	22,731,831	69.69%	25,779,019	79.03%	22,878,221	70.14%
312.00 Boiler Plant Equipment	6,282,729	3,192,901	50.82%	4,142,503	65.93%	3,676,366	58.52%
314.00 Turbogenerator Units	782,933	630,756	80.56%	688,361	87.92%	610,903	78.03%
315.00 Accessory Electric Equipment	2,676,415	2,377,526	88.83%	2,623,452	98.02%	2,328,247	86.99%
316.00 Miscellaneous Power Plant Equipment	667,561	496,229	74.33%	540,032	80.90%	479,264	71.79%
Total Springerville Unit 2 Common	$ 45,308,246	$ 31,427,182	69.36%	$ 35,411,927	78.16%	$ 31,427,182	69.36%

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Springerville Coal Handling								
310.00	Rights-of-Way	$ 1,670,099	$ 804,864	48.19%	$ 755,766	45.25%	$ 517,662	31.00%
311.00	Structures and Improvements							
312.00	Boiler Plant Equipment	138,944,802	62,161,574	44.74%	91,172,741	65.62%	62,448,776	44.95%
314.00	Turbogenerator Units							
315.00	Accessory Electric Equipment							
316.00	Miscellaneous Power Plant Equipment							
	Total Springerville Coal Handling	$ 140,614,901	$ 62,966,438	44.78%	$ 91,928,507	65.38%	$ 62,966,438	44.78%
Sundt								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	27,475,371	16,379,412	59.61%	15,669,743	57.03%	12,594,871	45.84%
312.00	Boiler Plant Equipment	130,812,626	51,578,275	39.43%	77,263,130	59.06%	62,000,685	47.40%
314.00	Turbogenerator Units	52,481,329	26,949,112	51.35%	31,438,814	59.90%	25,269,581	48.15%
315.00	Accessory Electric Equipment	39,432,489	19,370,802	49.12%	18,220,117	46.21%	14,644,787	37.14%
316.00	Miscellaneous Power Plant Equipment	2,333,493	1,068,696	45.80%	1,040,564	44.59%	836,375	35.84%
	Total Sundt	$ 252,535,308	$ 115,346,298	45.68%	$ 143,632,368	56.88%	$ 115,346,298	45.68%
Sundt Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	3,926,062	2,175,028	55.40%	2,719,293	69.26%	2,185,686	55.67%
312.00	Boiler Plant Equipment	13,782,181	10,318,349	74.87%	11,489,965	83.37%	9,235,291	67.01%
314.00	Turbogenerator Units	10,237,507	6,554,053	64.02%	7,221,727	70.54%	5,804,608	56.70%
315.00	Accessory Electric Equipment	6,536,315	2,644,455	40.46%	2,607,154	39.89%	2,095,552	32.06%
316.00	Miscellaneous Power Plant Equipment	490,578	230,468	46.98%	231,107	47.11%	185,757	37.86%
	Total Sundt Unit 1	$ 34,972,643	$ 21,922,353	62.68%	$ 24,269,245	69.39%	$ 19,506,895	55.78%
Sundt Unit 2								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	2,812,689	1,133,428	40.30%	1,541,596	54.81%	1,239,089	44.05%
312.00	Boiler Plant Equipment	14,371,609	9,423,263	65.57%	11,547,538	80.35%	9,281,566	64.58%
314.00	Turbogenerator Units	8,451,923	5,713,503	67.60%	7,330,945	86.74%	5,892,395	69.72%
315.00	Accessory Electric Equipment	6,205,700	1,836,537	29.59%	2,063,839	33.26%	1,658,852	26.73%
316.00	Miscellaneous Power Plant Equipment	383,824	148,170	38.60%	160,202	41.74%	128,766	33.55%
	Total Sundt Unit 2	$ 32,225,745	$ 18,254,901	56.65%	$ 22,644,120	70.27%	$ 18,200,667	56.48%

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Sundt Unit 3							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	2,762,012	1,386,818	50.21%	1,907,128	69.05%	1,532,893	55.50%
312.00 Boiler Plant Equipment	11,980,831	6,673,757	55.70%	9,168,428	76.53%	7,369,308	61.51%
314.00 Turbogenerator Units	14,830,615	8,326,645	56.14%	10,599,263	71.47%	8,519,371	57.44%
315.00 Accessory Electric Equipment	6,140,139	4,200,198	68.41%	4,614,792	75.16%	3,709,232	60.41%
316.00 Miscellaneous Power Plant Equipment	404,717	182,169	45.01%	212,154	52.42%	170,523	42.13%
Total Sundt Unit 3	$ 36,118,314	$ 20,769,587	57.50%	$ 26,501,764	73.37%	$ 21,301,327	58.98%
Sundt Unit 4							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	17,974,608	11,684,139	65.00%	9,501,726	52.86%	7,637,204	42.49%
312.00 Boiler Plant Equipment	80,576,055	25,148,847	31.21%	44,913,910	55.74%	36,100,460	44.80%
314.00 Turbogenerator Units	18,961,284	6,354,911	33.52%	6,286,881	33.16%	5,053,207	26.65%
315.00 Accessory Electric Equipment	20,550,335	10,689,612	52.02%	8,934,333	43.48%	7,181,150	34.94%
316.00 Miscellaneous Power Plant Equipment	1,054,374	507,889	48.17%	437,102	41.46%	351,329	33.32%
Total Sundt Unit 4	$ 139,116,656	$ 54,385,398	39.09%	$ 70,073,951	50.37%	$ 56,323,350	40.49%
Sundt Solar Booster (Areva)							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements							
312.00 Boiler Plant Equipment	10,101,950	14,059	0.14%	143,289	1.42%	14,059	0.14%
314.00 Turbogenerator Units							
315.00 Accessory Electric Equipment							
316.00 Miscellaneous Power Plant Equipment							
Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 14,059	0.14%	$ 143,289	1.42%	$ 14,059	0.14%
OTHER PRODUCTION (by Unit)							
DeMoss Petrie Gas Unit 1							
341.00 Structures and Improvements	$ 761,988	$ 154,938	20.33%	$ 161,792	21.23%	$ 180,486	23.69%
342.00 Fuel Holders, Products and Accessories	750,386	261,338	34.83%	239,586	31.93%	267,269	35.62%
343.00 Prime Movers	76,766	8,524	11.10%	15,312	19.95%	17,081	22.25%
344.00 Generators and Devices	30,772,866	11,025,994	35.83%	9,790,963	31.82%	10,922,248	35.49%
345.00 Accessory Electric Equipment	861,492	268,405	31.16%	295,020	34.25%	329,108	38.20%
346.00 Miscellaneous Power Plant Equipment	376,605	115,469	30.66%	106,205	28.20%	118,476	31.46%
Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 11,834,668	35.22%	$ 10,608,878	31.57%	$ 11,834,668	35.22%

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Gila River							
341.00 Structures and Improvements	$ 8,508,950	$ 2,126,825	25.00%	$ 2,212,050	26.00%	$ 2,085,222	24.51%
342.00 Fuel Holders, Products and Accessories	6,783,045	1,695,243	24.99%	1,804,242	26.60%	1,695,857	25.00%
343.00 Prime Movers	188,744,730	45,163,873	23.93%	46,375,817	24.57%	44,920,085	23.80%
344.00 Generators and Devices	32,783,434	8,295,028	25.30%	8,803,240	26.85%	8,534,905	26.03%
345.00 Accessory Electric Equipment	9,030,698	2,242,691	24.83%	2,382,547	26.38%	2,292,546	25.39%
346.00 Miscellaneous Power Plant Equipment	6,799,960	1,679,659	24.70%	1,781,996	26.21%	1,674,704	24.63%
Total Gila River	$ 252,650,817	$ 61,203,319	24.22%	$ 63,359,892	25.08%	$ 61,203,319	24.22%
Gila River Unit 3							
341.00 Structures and Improvements	$ 957,417	$ 259,052	27.06%	$ 252,492	26.37%	$ 244,796	25.57%
342.00 Fuel Holders, Products and Accessories	178,424	40,583	22.75%	43,014	24.11%	41,702	23.37%
343.00 Prime Movers	181,571,712	43,892,641	24.17%	44,985,975	24.78%	43,614,738	24.02%
344.00 Generators and Devices	32,783,434	8,295,028	25.30%	8,803,240	26.85%	8,534,905	26.03%
345.00 Accessory Electric Equipment	6,860,554	1,703,384	24.83%	1,809,283	26.37%	1,754,133	25.57%
346.00 Miscellaneous Power Plant Equipment	135,558	32,986	24.33%	34,451	25.41%	33,400	24.64%
Total Gila River Unit 3	$ 222,487,099	$ 54,223,675	24.37%	$ 55,928,454	25.14%	$ 54,223,675	24.37%
Gila River Common							
341.00 Structures and Improvements	$ 7,551,533	$ 1,867,772	24.73%	$ 1,959,557	25.95%	$ 1,840,426	24.37%
342.00 Fuel Holders, Products and Accessories	6,604,621	1,654,660	25.05%	1,761,228	26.67%	1,654,154	25.05%
343.00 Prime Movers	7,173,018	1,271,232	17.72%	1,389,842	19.38%	1,305,347	18.20%
344.00 Generators and Devices							
345.00 Accessory Electric Equipment	2,170,144	539,307	24.85%	573,264	26.42%	538,413	24.81%
346.00 Miscellaneous Power Plant Equipment	6,664,402	1,646,673	24.71%	1,747,545	26.22%	1,641,303	24.63%
Total Gila River Common	$ 30,163,718	$ 6,979,644	23.14%	$ 7,431,437	24.64%	$ 6,979,644	23.14%
Luna							
341.00 Structures and Improvements	$ 13,232,832	$ 1,357,037	10.26%	$ 2,822,621	21.33%	$ 511,943	3.87%
342.00 Fuel Holders, Products and Accessories	11,352,383	1,178,720	10.38%	2,459,029	21.66%	445,998	3.93%
343.00 Prime Movers	11,151,074	(115,314)	-1.03%	1,256,464	11.27%	227,887	2.04%
344.00 Generators and Devices	9,486,694	(1,277,620)	-13.47%	2,264,984	23.88%	410,803	4.33%
345.00 Accessory Electric Equipment	9,647	114	1.18%	149	1.55%	27	0.28%
346.00 Miscellaneous Power Plant Equipment	7,424,592	744,049	10.02%	1,600,734	21.56%	290,327	3.91%
Total Luna	$ 52,657,222	$ 1,886,985	3.58%	$ 10,403,980	19.76%	$ 1,886,985	3.58%

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North Loop Gas								
341.00	Structures and Improvements	$ 888,601	$ 867,104	97.58%	$ 620,584	69.84%	$ 837,793	94.28%
342.00	Fuel Holders, Products and Accessories	303,037	104,139	34.37%	93,618	30.89%	103,998	34.32%
343.00	Prime Movers	1,890,946	675,327	35.71%	493,389	26.09%	692,530	36.62%
344.00	Generators and Devices	24,062,187	15,675,191	65.14%	12,469,534	51.82%	15,767,332	65.53%
345.00	Accessory Electric Equipment	2,829,171	2,090,869	73.90%	1,541,327	54.48%	2,017,633	71.32%
346.00	Miscellaneous Power Plant Equipment	656,253	639,873	97.50%	469,883	71.60%	633,217	96.49%
	Total North Loop Gas	$ 30,630,195	$ 20,052,503	65.47%	$ 15,688,335	51.22%	$ 20,052,503	65.47%
North Loop Gas Unit 1								
341.00	Structures and Improvements	$ 411,070	$ 406,569	98.90%	$ 269,119	65.47%	$ 383,441	93.28%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	678,545	506,913	74.71%	289,463	42.66%	412,426	60.78%
344.00	Generators and Devices	3,582,271	3,792,993	105.88%	2,778,957	77.58%	3,959,451	110.53%
345.00	Accessory Electric Equipment	790,955	763,625	96.54%	513,422	64.91%	731,523	92.49%
346.00	Miscellaneous Power Plant Equipment	306,369	313,164	102.22%	208,046	67.91%	296,423	96.75%
	Total North Loop Gas Unit 1	$ 5,769,210	$ 5,783,263	100.24%	$ 4,059,007	70.36%	$ 5,783,263	100.24%
North Loop Gas Unit 2								
341.00	Structures and Improvements	$ 196,078	$ 215,565	109.94%	$ 162,333	82.79%	$ 207,598	105.88%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	263,450	(327,630)	-124.36%	(111,031)	-42.14%	(141,991)	-53.90%
344.00	Generators and Devices	3,239,719	3,643,451	112.46%	2,738,191	84.52%	3,501,707	108.09%
345.00	Accessory Electric Equipment	504,895	505,786	100.18%	366,742	72.64%	469,004	92.89%
346.00	Miscellaneous Power Plant Equipment	128,559	148,230	115.30%	116,577	90.68%	149,084	115.97%
	Total North Loop Gas Unit 2	$ 4,332,701	$ 4,185,401	96.60%	$ 3,272,812	75.54%	$ 4,185,401	96.60%
North Loop Gas Unit 3								
341.00	Structures and Improvements	$ 196,078	$ 212,395	108.32%	$ 159,855	81.53%	$ 214,232	109.26%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	948,951	496,044	52.27%	314,956	33.19%	422,094	44.48%
344.00	Generators and Devices	3,030,531	3,333,807	110.01%	2,542,347	83.89%	3,407,168	112.43%
345.00	Accessory Electric Equipment	503,907	493,376	97.91%	360,401	71.52%	482,997	95.85%
346.00	Miscellaneous Power Plant Equipment	128,559	144,847	112.67%	114,895	89.37%	153,978	119.77%
	Total North Loop Gas Unit 3	$ 4,808,026	$ 4,680,469	97.35%	$ 3,492,454	72.64%	$ 4,680,469	97.35%

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North Loop Gas Unit 4								
341.00	Structures and Improvements	$ 85,375	$ 32,575	38.16%	$ 29,277	34.29%	$ 32,523	38.09%
342.00	Fuel Holders, Products and Accessories	303,037	104,139	34.37%	93,618	30.89%	103,998	34.32%
343.00	Prime Movers							
344.00	Generators and Devices	14,209,666	4,904,940	34.52%	4,410,039	31.04%	4,899,007	34.48%
345.00	Accessory Electric Equipment	1,029,414	328,082	31.87%	300,762	29.22%	334,109	32.46%
346.00	Miscellaneous Power Plant Equipment	92,766	33,632	36.26%	30,365	32.73%	33,732	36.36%
	Total North Loop Gas Unit 4	$ 15,720,258	$ 5,403,369	34.37%	$ 4,864,061	30.94%	$ 5,403,369	34.37%
Solar Units (Generators and Devices)								
344.00	DeMoss Petrie	$ 1,146,081	$ 334,209	29.16%	$ 509,290	44.44%	$ 610,990	53.31%
344.00	Fort Huachuca	36,709,538	73,938	0.20%	688,304	1.88%	825,751	2.25%
344.00	HQ Rooftop	303,184	45,437	14.99%	28,424	9.38%	34,099	11.25%
344.00	OH Rooftop	2,594,590	399,653	15.40%	340,540	13.13%	408,542	15.75%
344.00	OH Test Yard	388,459	233,584	60.13%	162,716	41.89%	195,208	50.25%
344.00	Prairie Fire	19,036,520	1,980,433	10.40%	1,784,674	9.38%	2,141,054	11.25%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	17,515,266	60.89%	12,826,310	44.59%	15,387,588	53.49%
344.00	Springerville Site 4	7,873,874	1,606,533	20.40%	1,328,716	16.88%	1,594,047	20.24%
344.00	Tucson	87,198	71,385	81.86%	52,907	60.68%	63,472	72.79%
344.00	U of A Tech Park Site 1	7,723,832	1,576,302	20.41%	1,303,397	16.88%	1,563,671	20.24%
344.00	U of A Tech Park Site 2	19,191,952	2,956,201	15.40%	2,518,944	13.13%	3,021,950	15.75%
344.00	White Mountain	46,499,099	99,392	0.21%	871,858	1.88%	1,045,959	2.25%
	Total Solar Units	$ 170,320,932	$ 26,892,332	15.79%	$ 22,416,079	13.16%	$ 26,892,332	15.79%
Sundt Gas								
341.00	Structures and Improvements	$ 11,090	$ 11,891	107.22%	$ 7,620	68.71%	$ 11,521	103.89%
342.00	Fuel Holders, Products and Accessories	788,336	582,161	73.85%	294,454	37.35%	445,221	56.48%
343.00	Prime Movers	141,618	139,570	98.55%	74,554	52.64%	112,728	79.60%
344.00	Generators and Devices	8,382,044	8,804,904	105.04%	5,925,140	70.69%	8,956,775	106.86%
345.00	Accessory Electric Equipment	1,078,811	1,070,884	99.27%	713,919	66.18%	1,079,672	100.08%
346.00	Miscellaneous Power Plant Equipment	49,750	55,130	110.81%	38,725	77.84%	58,624	117.84%
	Total Sundt Gas	$ 10,451,649	$ 10,664,539	102.04%	$ 7,054,412	67.50%	$ 10,664,539	102.04%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2014

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Sundt Gas Unit 1							
341.00 Structures and Improvements	$ 5,545	$ 5,964	107.55%	$ 3,808	68.67%	$ 5,722	103.19%
342.00 Fuel Holders, Products and Accessories	394,168	291,435	73.94%	147,155	37.33%	221,118	56.10%
343.00 Prime Movers	70,809	70,514	99.58%	37,259	52.62%	55,986	79.07%
344.00 Generators and Devices	4,315,668	4,541,928	105.24%	3,075,415	71.26%	4,621,184	107.08%
345.00 Accessory Electric Equipment	516,231	514,444	99.65%	345,496	66.93%	519,149	100.57%
346.00 Miscellaneous Power Plant Equipment	19,906	22,217	111.61%	15,534	78.03%	23,341	117.26%
Total Sundt Gas Unit 1	$ 5,322,327	$ 5,446,501	102.33%	$ 3,624,667	68.10%	$ 5,446,501	102.33%
Sundt Gas Unit 2							
341.00 Structures and Improvements	$ 5,545	$ 5,927	106.89%	$ 3,812	68.74%	$ 5,799	104.58%
342.00 Fuel Holders, Products and Accessories	394,168	290,725	73.76%	147,299	37.37%	224,102	56.85%
343.00 Prime Movers	70,809	69,056	97.52%	37,295	52.67%	56,742	80.13%
344.00 Generators and Devices	4,066,376	4,262,976	104.83%	2,849,724	70.08%	4,335,590	106.62%
345.00 Accessory Electric Equipment	562,580	556,440	98.91%	368,424	65.49%	560,522	99.63%
346.00 Miscellaneous Power Plant Equipment	29,844	32,913	110.28%	23,191	77.71%	35,283	118.22%
Total Sundt Gas Unit 2	$ 5,129,322	$ 5,218,038	101.73%	$ 3,429,745	66.87%	$ 5,218,038	101.73%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
STEAM PRODUCTION								
310.00	Rights-of-Way	$ 5,106,662	$ 2,446,505	47.91%	$ 648	0.01%	$ 2,447,153	47.92%
311.00	Structures and Improvements	205,277,689	79,186,489	38.58%	18,061,746	8.80%	97,248,235	47.37%
312.00	Boiler Plant Equipment	1,091,953,161	380,425,888	34.84%	65,856,752	6.03%	446,282,641	40.87%
314.00	Turbogenerator Units	303,041,923	92,264,412	30.45%	15,887,547	5.24%	108,151,958	35.69%
315.00	Accessory Electric Equipment	144,581,471	52,957,876	36.63%	9,150,049	6.33%	62,107,925	42.96%
316.00	Miscellaneous Power Plant Equipment	25,222,863	10,104,962	40.06%	1,178,742	4.67%	11,283,704	44.74%
	Total Steam Production Plant	$ 1,775,183,769	$ 617,386,132	34.78%	$ 110,135,484	6.20%	$ 727,521,616	40.98%
OTHER PRODUCTION								
Non-Solar								
341.00	Structures and Improvements	$ 23,403,461	$ 3,243,160	13.86%	$ 383,805	1.64%	$ 3,626,965	15.50%
342.00	Fuel Holders, Products and Accessories	19,977,187	2,718,793	13.61%	239,548	1.20%	2,958,341	14.81%
343.00	Prime Movers	202,005,134	42,290,760	20.94%	3,679,551	1.82%	45,970,311	22.76%
344.00	Generators and Devices	105,487,225	40,814,739	38.69%	3,777,323	3.58%	44,592,063	42.27%
345.00	Accessory Electric Equipment	13,809,819	5,200,835	37.66%	518,151	3.75%	5,718,985	41.41%
346.00	Miscellaneous Power Plant Equipment	15,307,160	2,504,902	16.36%	270,446	1.77%	2,775,348	18.13%
	Total Non-Solar	$ 379,989,986	$ 96,773,189	25.47%	$ 8,868,825	2.33%	$ 105,642,014	27.80%
Solar								
344.00	Generators and Devices	$ 170,320,932	$ 25,611,745	15.04%	$ 1,280,587	0.75%	$ 26,892,332	15.79%
	Total Solar	$ 170,320,932	$ 25,611,745	15.04%	$ 1,280,587	0.75%	$ 26,892,332	15.79%
	Total Other Production Plant	$ 550,310,918	$ 122,384,934	22.24%	$ 10,149,412	1.84%	$ 132,534,346	24.08%
DISTRIBUTION PLANT								
360.RW	Rights-of-Way	$ 7,865,073	$ 3,720,941	47.31%	$ -		$ 3,720,941	47.31%
361.00	Structures and Improvements	11,402,474	2,417,039	21.20%			2,417,039	21.20%
362.00	Station Equipment	157,067,530	48,009,871	30.57%			48,009,871	30.57%
364.00	Poles, Towers and Fixtures	222,006,967	67,521,575	30.41%			67,521,575	30.41%
365.00	Overhead Conductors and Devices	175,675,966	63,847,797	36.34%			63,847,797	36.34%
366.00	Underground Conduit	58,725,355	23,421,293	39.88%			23,421,293	39.88%
367.00	Underground Conductors and Devices	297,183,135	115,677,372	38.92%			115,677,372	38.92%
368.OH	Line Transformers - Overhead	103,657,922	39,735,096	38.33%			39,735,096	38.33%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
368.UG Line Transformers - Underground	172,890,932	65,875,110	38.10%			65,875,110	38.10%
369.OH Services - Overhead	17,542,236	7,990,202	45.55%			7,990,202	45.55%
369.UG Services - Underground	112,947,714	35,939,682	31.82%			35,939,682	31.82%
370.00 Meters	44,869,823	10,843,126	24.17%			10,843,126	24.17%
373.00 Street Lighting and Signal Systems	11,778,362	5,006,268	42.50%			5,006,268	42.50%
Total Distribution Plant	$ 1,393,613,489	$ 490,005,372	35.16%	$ -		$ 490,005,372	35.16%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 135,680,348	$ 21,570,039	15.90%	$ 126,776	0.09%	$ 21,696,815	15.99%
392.C0 Transportation - Class 0	1,238,946	458,248	36.99%	(53,946)	-4.35%	404,302	32.63%
392.C1 Transportation - Class 1	7,718,183	3,304,203	42.81%	(408,989)	-5.30%	2,895,214	37.51%
392.C2 Transportation - Class 2	3,839,907	1,609,294	41.91%	(189,552)	-4.94%	1,419,742	36.97%
392.C3 Transportation - Class 3	2,076,936	1,052,793	50.69%	(131,035)	-6.31%	921,757	44.38%
392.C4 Transportation - Class 4	2,935,027	1,180,337	40.22%	(129,837)	-4.42%	1,050,500	35.79%
392.C5 Transportation - Class 5	7,982,715	3,474,021	43.52%	(448,803)	-5.62%	3,025,218	37.90%
392.C6 Transportation - Class 6	365,200	80,311	21.99%	(12,047)	-3.30%	68,264	18.69%
392.C7 Transportation - Class 7	1,047,216	410,010	39.15%	(61,501)	-5.87%	348,508	33.28%
392.C8 Transportation - Class 8	9,957,500	3,613,292	36.29%	(530,533)	-5.33%	3,082,759	30.96%
392.C9 Transportation - Class 9	4,252,286	1,247,812	29.34%	(178,945)	-4.21%	1,068,867	25.14%
396.00 Power Operatied Equipment	11,860,940	2,412,819	20.34%	87,170	0.73%	2,499,990	21.08%
397.EM EMS and SCADA Equipment	11,304,371	3,110,221	27.51%			3,110,221	27.51%
Total Depreciable	$ 200,259,575	$ 43,523,399	21.73%	$ (1,931,242)	-0.96%	$ 41,592,158	20.77%
Amortizable							
391.00 Furniture and Office Equipment	$ 23,964,411	$ 7,698,753	32.13%	$ -		$ 7,698,753	32.13%
391.20 Network and Data Equipment	29,359,636	14,913,970	50.80%			14,913,970	50.80%
393.00 Stores Equipment	1,852,479	840,197	45.36%			840,197	45.36%
394.00 Tools, Shop and Garage Equipment	6,934,368	2,858,589	41.22%			2,858,589	41.22%
395.00 Laboratory Equipment	5,091,270	2,395,826	47.06%			2,395,826	47.06%
397.20 Telecommunications Equipment	57,456,141	19,662,636	34.22%			19,662,636	34.22%
398.00 Miscellaneous Equipment	4,348,209	1,815,347	41.75%			1,815,347	41.75%
Total Amortizable	$ 129,006,514	$ 50,185,318	38.90%	$ -		$ 50,185,318	38.90%
Total General Plant	$ 329,266,089	$ 93,708,717	28.46%	$ (1,931,242)	-0.59%	$ 91,777,476	27.87%
SUBTOTAL	$ 4,048,374,265	$ 1,323,485,155	32.69%	$ 118,353,655	2.92%	$ 1,441,838,810	35.62%

TUCSON ELECTRIC POWER COMPANY

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
NET SALVAGE							
108.02 Distribution	$ 1,393,613,489	$ -		$ 84,815,412	6.09%	$ 84,815,412	6.09%
Total Net Salvage	$ 1,393,613,489	$ -		$ 84,815,412	6.09%	$ 84,815,412	6.09%
TOTAL UTILITY	$ 4,048,374,265	$ 1,323,485,155	32.69%	$ 203,169,066	5.02%	$ 1,526,654,221	37.71%
STEAM PRODUCTION (by Unit)							
Four Corners							
310.00 Rights-of-Way	$ -	$ -	#DIV/0!	$ -		$ -	
311.00 Structures and Improvements	2,982,777	1,790,395	60.02%	117,850	3.95%	1,908,245	63.98%
312.00 Boiler Plant Equipment	76,402,061	56,979,152	74.58%	3,365,936	4.41%	60,345,088	78.98%
314.00 Turbogenerator Units	12,359,480	8,247,191	66.73%	583,323	4.72%	8,830,514	71.45%
315.00 Accessory Electric Equipment	4,390,980	1,526,418	34.76%	137,054	3.12%	1,663,472	37.88%
316.00 Miscellaneous Power Plant Equipment	3,832,234	2,401,796	62.67%	153,288	4.00%	2,555,084	66.67%
Total Four Corners	$ 99,967,532	$ 70,944,953	70.97%	$ 4,357,451	4.36%	$ 75,302,403	75.33%
Four Corners Unit 4							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	1,524,414	945,048	61.99%	59,082	3.88%	1,004,130	65.87%
312.00 Boiler Plant Equipment	39,609,538	30,452,510	76.88%	1,501,983	3.79%	31,954,492	80.67%
314.00 Turbogenerator Units	7,179,362	4,764,500	66.36%	333,469	4.64%	5,097,969	71.01%
315.00 Accessory Electric Equipment	2,274,836	839,579	36.91%	78,525	3.45%	918,105	40.36%
316.00 Miscellaneous Power Plant Equipment	1,929,161	1,244,724	64.52%	76,564	3.97%	1,321,288	68.49%
Total Four Corners Unit 4	$ 52,517,311	$ 38,246,361	72.83%	$ 2,049,623	3.90%	$ 40,295,985	76.73%
Four Corners Unit 5							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	1,458,363	845,348	57.97%	58,768	4.03%	904,116	62.00%
312.00 Boiler Plant Equipment	36,792,523	26,526,643	72.10%	1,863,953	5.07%	28,390,596	77.16%
314.00 Turbogenerator Units	5,180,118	3,482,691	67.23%	249,853	4.82%	3,732,544	72.06%
315.00 Accessory Electric Equipment	2,116,144	686,839	32.46%	58,529	2.77%	745,368	35.22%
316.00 Miscellaneous Power Plant Equipment	1,903,073	1,157,071	60.80%	76,724	4.03%	1,233,795	64.83%
Total Four Corners Unit 5	$ 47,450,221	$ 32,698,592	68.91%	$ 2,307,827	4.86%	$ 35,006,419	73.78%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Navajo								
310.00	Rights-of-Way	$ 12,229	$ 10,803	88.34%	$ 648	5.30%	$ 11,451	93.64%
311.00	Structures and Improvements	18,655,156	12,786,208	68.54%	778,935	4.18%	13,565,143	72.72%
312.00	Boiler Plant Equipment	88,544,201	63,639,561	71.87%	3,934,265	4.44%	67,573,826	76.32%
314.00	Turbogenerator Units	20,255,526	14,947,385	73.79%	904,267	4.46%	15,851,652	78.26%
315.00	Accessory Electric Equipment	14,829,858	9,298,812	62.70%	555,168	3.74%	9,853,980	66.45%
316.00	Miscellaneous Power Plant Equipment	4,518,597	2,766,505	61.22%	162,125	3.59%	2,928,630	64.81%
	Total Navajo	$ 146,815,567	$ 103,449,273	70.46%	$ 6,335,409	4.32%	$ 109,784,682	74.78%
Navajo Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	3,190,563	2,602,211	81.56%	130,111	4.08%	2,732,322	85.64%
312.00	Boiler Plant Equipment	27,198,582	19,904,578	73.18%	995,229	3.66%	20,899,807	76.84%
314.00	Turbogenerator Units	6,860,989	5,010,040	73.02%	255,954	3.73%	5,265,994	76.75%
315.00	Accessory Electric Equipment	3,544,300	2,201,346	62.11%	113,340	3.20%	2,314,686	65.31%
316.00	Miscellaneous Power Plant Equipment	471,227	386,830	82.09%	18,955	4.02%	405,785	86.11%
	Total Navajo Unit 1	$ 41,265,661	$ 30,105,004	72.95%	$ 1,513,588	3.67%	$ 31,618,592	76.62%
Navajo Unit 2								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	1,802,685	1,413,416	78.41%	95,946	5.32%	1,509,362	83.73%
312.00	Boiler Plant Equipment	26,882,286	19,927,056	74.13%	1,401,448	5.21%	21,328,503	79.34%
314.00	Turbogenerator Units	6,926,050	5,011,523	72.36%	334,587	4.83%	5,346,110	77.19%
315.00	Accessory Electric Equipment	3,172,330	2,183,748	68.84%	149,721	4.72%	2,333,469	73.56%
316.00	Miscellaneous Power Plant Equipment	515,874	440,017	85.30%	28,379	5.50%	468,397	90.80%
	Total Navajo Unit 2	$ 39,299,225	$ 28,975,760	73.73%	$ 2,010,081	5.11%	$ 30,985,841	78.85%
Navajo Unit 3								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	3,681,511	3,055,737	83.00%	184,940	5.02%	3,240,677	88.03%
312.00	Boiler Plant Equipment	27,718,514	20,005,857	72.18%	1,320,505	4.76%	21,326,362	76.94%
314.00	Turbogenerator Units	6,178,944	4,851,335	78.51%	308,818	5.00%	5,160,153	83.51%
315.00	Accessory Electric Equipment	5,139,872	3,913,169	76.13%	221,882	4.32%	4,135,051	80.45%
316.00	Miscellaneous Power Plant Equipment	549,362	469,492	85.46%	24,310	4.43%	493,802	89.89%
	Total Navajo Unit 3	$ 43,268,203	$ 32,295,589	74.64%	$ 2,060,456	4.76%	$ 34,356,045	79.40%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Navajo Common								
310.00	Rights-of-Way	$ 12,229	$ 10,803	88.34%	$ 648	5.30%	$ 11,451	93.64%
311.00	Structures and Improvements	9,980,397	5,714,845	57.26%	367,937	3.69%	6,082,782	60.95%
312.00	Boiler Plant Equipment	6,744,819	3,802,071	56.37%	217,083	3.22%	4,019,154	59.59%
314.00	Turbogenerator Units	289,543	74,488	25.73%	4,907	1.69%	79,395	27.42%
315.00	Accessory Electric Equipment	2,973,356	1,000,549	33.65%	70,225	2.36%	1,070,774	36.01%
316.00	Miscellaneous Power Plant Equipment	2,982,134	1,470,165	49.30%	90,482	3.03%	1,560,647	52.33%
	Total Navajo Common	$ 22,982,478	$ 12,072,920	52.53%	$ 751,283	3.27%	$ 12,824,203	55.80%
San Juan								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	14,437,744	987,235	6.84%	99,976	0.69%	1,087,211	7.53%
312.00	Boiler Plant Equipment	154,506,908	9,395,805	6.08%	1,067,582	0.69%	10,463,387	6.77%
314.00	Turbogenerator Units	44,295,673	3,010,479	6.80%	307,909	0.70%	3,318,387	7.49%
315.00	Accessory Electric Equipment	10,063,526	622,176	6.18%	63,816	0.63%	685,993	6.82%
316.00	Miscellaneous Power Plant Equipment	2,009,555	127,336	6.34%	13,354	0.66%	140,690	7.00%
	Total San Juan	$ 225,313,406	$ 14,143,031	6.28%	$ 1,552,637	0.69%	$ 15,695,668	6.97%
San Juan Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	14,268,404	986,462	6.91%	99,974	0.70%	1,086,436	7.61%
312.00	Boiler Plant Equipment	146,453,029	9,004,800	6.15%	848,101	0.58%	9,852,901	6.73%
314.00	Turbogenerator Units	44,295,673	3,010,479	6.80%	307,909	0.70%	3,318,387	7.49%
315.00	Accessory Electric Equipment	10,063,526	622,176	6.18%	63,816	0.63%	685,993	6.82%
316.00	Miscellaneous Power Plant Equipment	1,960,172	127,111	6.48%	13,354	0.68%	140,465	7.17%
	Total San Juan Unit 1	$ 217,040,804	$ 13,751,027	6.34%	$ 1,333,155	0.61%	$ 15,084,182	6.95%
San Juan Common								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	169,340	773	0.46%	2	0.00%	775	0.46%
312.00	Boiler Plant Equipment	8,053,879	391,005	4.85%	219,481	2.73%	610,485	7.58%
314.00	Turbogenerator Units							
315.00	Accessory Electric Equipment							
316.00	Miscellaneous Power Plant Equipment	49,383	226	0.46%			226	0.46%
	Total San Juan Common	$ 8,272,602	$ 392,004	4.74%	$ 219,482	2.65%	$ 611,486	7.39%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Springerville								
310.00	Rights-of-Way	$ 5,094,433	$ 2,435,702	47.81%	$ -		$ 2,435,702	47.81%
311.00	Structures and Improvements	141,726,641	55,092,231	38.87%	13,000,534	9.17%	68,092,765	48.05%
312.00	Boiler Plant Equipment	641,687,365	208,836,791	32.54%	37,062,864	5.78%	245,899,655	38.32%
314.00	Turbogenerator Units	173,649,915	51,074,703	29.41%	3,807,122	2.19%	54,881,825	31.60%
315.00	Accessory Electric Equipment	75,864,618	32,139,515	42.36%	3,120,179	4.11%	35,259,694	46.48%
316.00	Miscellaneous Power Plant Equipment	12,528,984	4,299,916	34.32%	523,009	4.17%	4,822,925	38.49%
Total Springerville		$ 1,050,551,956	$ 353,878,858	33.69%	$ 57,513,707	5.47%	$ 411,392,565	39.16%
Springerville Unit 1								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	20,076,015	7,957,893	39.64%	613,897	3.06%	8,571,789	42.70%
312.00	Boiler Plant Equipment	185,682,490	78,118,253	42.07%	5,867,581	3.16%	83,985,834	45.23%
314.00	Turbogenerator Units	49,547,312	21,018,043	42.42%	1,572,967	3.17%	22,591,011	45.59%
315.00	Accessory Electric Equipment	21,214,167	10,493,761	49.47%	626,111	2.95%	11,119,872	52.42%
316.00	Miscellaneous Power Plant Equipment	3,277,742	1,220,854	37.25%	98,927	3.02%	1,319,781	40.26%
Total Springerville Unit 1		$ 279,797,726	$ 118,808,805	42.46%	$ 8,779,482	3.14%	$ 127,588,287	45.60%
Springerville Unit 1 Common								
310.00	Rights-of-Way	$ 1,143,496	$ 463,859	40.57%	$ -		$ 463,859	40.57%
311.00	Structures and Improvements	52,492,826	21,135,153	40.26%	5,071,418	9.66%	26,206,572	49.92%
312.00	Boiler Plant Equipment	14,854,799	6,175,972	41.58%	1,365,625	9.19%	7,541,597	50.77%
314.00	Turbogenerator Units	1,264,322	550,930	43.58%	113,967	9.01%	664,897	52.59%
315.00	Accessory Electric Equipment	9,627,097	4,523,933	46.99%	774,811	8.05%	5,298,744	55.04%
316.00	Miscellaneous Power Plant Equipment	1,959,012	908,077	46.35%	163,145	8.33%	1,071,222	54.68%
Total Springerville Unit 1 Common		$ 81,341,552	$ 33,757,925	41.50%	$ 7,488,967	9.21%	$ 41,246,892	50.71%
Springerville Unit 2								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	36,540,030	9,853,583	26.97%	582,599	1.59%	10,436,182	28.56%
312.00	Boiler Plant Equipment	295,922,545	83,669,199	28.27%	4,577,883	1.55%	88,247,082	29.82%
314.00	Turbogenerator Units	122,055,348	29,067,492	23.82%	1,947,522	1.60%	31,015,014	25.41%
315.00	Accessory Electric Equipment	42,346,939	15,451,630	36.49%	1,061,201	2.51%	16,512,831	38.99%
316.00	Miscellaneous Power Plant Equipment	6,624,669	1,828,187	27.60%	124,470	1.88%	1,952,657	29.48%
Total Springerville Unit 2		$ 503,489,531	$ 139,870,091	27.78%	$ 8,293,675	1.65%	$ 148,163,767	29.43%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Springerville Unit 2 Common (Leasehold Imp.)							
310.00 Rights-of-Way	$ 2,280,838	$ 1,454,181	63.76%	$ -		$ 1,454,181	63.76%
311.00 Structures and Improvements	32,617,770	16,145,601	49.50%	6,732,620	20.64%	22,878,221	70.14%
312.00 Boiler Plant Equipment	6,282,729	2,479,582	39.47%	1,196,784	19.05%	3,676,366	58.52%
314.00 Turbogenerator Units	782,933	438,237	55.97%	172,665	22.05%	610,903	78.03%
315.00 Accessory Electric Equipment	2,676,415	1,670,192	62.40%	658,056	24.59%	2,328,247	86.99%
316.00 Miscellaneous Power Plant Equipment	667,561	342,797	51.35%	136,467	20.44%	479,264	71.79%
Total Springerville Unit 2 Common	$ 45,308,246	$ 22,530,590	49.73%	$ 8,896,592	19.64%	$ 31,427,182	69.36%
Springerville Coal Handling							
310.00 Rights-of-Way	$ 1,670,099	$ 517,662	31.00%	$ -		$ 517,662	31.00%
311.00 Structures and Improvements							
312.00 Boiler Plant Equipment	138,944,802	38,393,785	27.63%	24,054,991	17.31%	62,448,776	44.95%
314.00 Turbogenerator Units							
315.00 Accessory Electric Equipment							
316.00 Miscellaneous Power Plant Equipment							
Total Springerville Coal Handling	$ 140,614,901	$ 38,911,447	27.67%	$ 24,054,991	17.11%	$ 62,966,438	44.78%
Sundt							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	27,475,371	8,530,420	31.05%	4,064,451	14.79%	12,594,871	45.84%
312.00 Boiler Plant Equipment	130,812,626	41,574,579	31.78%	20,426,105	15.61%	62,000,685	47.40%
314.00 Turbogenerator Units	52,481,329	14,984,654	28.55%	10,284,927	19.60%	25,269,581	48.15%
315.00 Accessory Electric Equipment	39,432,489	9,370,955	23.76%	5,273,832	13.37%	14,644,787	37.14%
316.00 Miscellaneous Power Plant Equipment	2,333,493	509,409	21.83%	326,965	14.01%	836,375	35.84%
Total Sundt	$ 252,535,308	$ 74,970,017	29.69%	$ 40,376,281	15.99%	$ 115,346,298	45.68%
Sundt Unit 1							
310.00 Rights-of-Way	$ -	$ -		$ -		$ -	
311.00 Structures and Improvements	3,926,062	1,323,828	33.72%	861,859	21.95%	2,185,686	55.67%
312.00 Boiler Plant Equipment	13,782,181	5,488,270	39.82%	3,747,021	27.19%	9,235,291	67.01%
314.00 Turbogenerator Units	10,237,507	3,468,639	33.88%	2,335,969	22.82%	5,804,608	56.70%
315.00 Accessory Electric Equipment	6,536,315	1,200,408	18.37%	895,144	13.69%	2,095,552	32.06%
316.00 Miscellaneous Power Plant Equipment	490,578	111,778	22.79%	73,978	15.08%	185,757	37.86%
Total Sundt Unit 1	$ 34,972,643	$ 11,592,923	33.15%	$ 7,913,971	22.63%	$ 19,506,895	55.78%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
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Statement D

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Sundt Unit 2								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	2,812,689	677,497	24.09%	561,592	19.97%	1,239,089	44.05%
312.00	Boiler Plant Equipment	14,371,609	5,471,538	38.07%	3,810,028	26.51%	9,281,566	64.58%
314.00	Turbogenerator Units	8,451,923	3,432,107	40.61%	2,460,287	29.11%	5,892,395	69.72%
315.00	Accessory Electric Equipment	6,205,700	916,155	14.76%	742,697	11.97%	1,658,852	26.73%
316.00	Miscellaneous Power Plant Equipment	383,824	71,194	18.55%	57,572	15.00%	128,766	33.55%
	Total Sundt Unit 2	$ 32,225,745	$ 10,568,492	32.80%	$ 7,632,176	23.68%	$ 18,200,667	56.48%
Sundt Unit 3								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	2,762,012	809,005	29.29%	723,887	26.21%	1,532,893	55.50%
312.00	Boiler Plant Equipment	11,980,831	4,038,318	33.71%	3,330,991	27.80%	7,369,308	61.51%
314.00	Turbogenerator Units	14,830,615	4,546,648	30.66%	3,972,723	26.79%	8,519,371	57.44%
315.00	Accessory Electric Equipment	6,140,139	1,965,769	32.02%	1,743,463	28.39%	3,709,232	60.41%
316.00	Miscellaneous Power Plant Equipment	404,717	84,977	21.00%	85,546	21.14%	170,523	42.13%
	Total Sundt Unit 3	$ 36,118,314	$ 11,444,716	31.69%	$ 9,856,611	27.29%	$ 21,301,327	58.98%
Sundt Unit 4								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements	17,974,608	5,720,090	31.82%	1,917,114	10.67%	7,637,204	42.49%
312.00	Boiler Plant Equipment	80,576,055	26,562,451	32.97%	9,538,009	11.84%	36,100,460	44.80%
314.00	Turbogenerator Units	18,961,284	3,537,259	18.66%	1,515,947	7.99%	5,053,207	26.65%
315.00	Accessory Electric Equipment	20,550,335	5,288,623	25.73%	1,892,528	9.21%	7,181,150	34.94%
316.00	Miscellaneous Power Plant Equipment	1,054,374	241,460	22.90%	109,869	10.42%	351,329	33.32%
	Total Sundt Unit 4	$ 139,116,656	$ 41,349,883	29.72%	$ 14,973,467	10.76%	$ 56,323,350	40.49%
Sundt Solar Booster (Areva)								
310.00	Rights-of-Way	$ -	$ -		$ -		$ -	
311.00	Structures and Improvements							
312.00	Boiler Plant Equipment	10,101,950	14,003	0.14%	56	0.00%	14,059	0.14%
314.00	Turbogenerator Units							
315.00	Accessory Electric Equipment							
316.00	Miscellaneous Power Plant Equipment							
	Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 14,003	0.14%	$ 56	0.00%	$ 14,059	0.14%

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Statement D

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00	Structures and Improvements	$ 761,988	$ 154,739	20.31%	$ 25,746	3.38%	$ 180,486	23.69%
342.00	Fuel Holders, Products and Accessories	750,386	244,657	32.60%	22,612	3.01%	267,269	35.62%
343.00	Prime Movers	76,766	10,353	13.49%	6,729	8.77%	17,081	22.25%
344.00	Generators and Devices	30,772,866	9,953,323	32.34%	968,925	3.15%	10,922,248	35.49%
345.00	Accessory Electric Equipment	861,492	266,238	30.90%	62,870	7.30%	329,108	38.20%
346.00	Miscellaneous Power Plant Equipment	376,605	108,408	28.79%	10,068	2.67%	118,476	31.46%
	Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 10,737,719	31.96%	$ 1,096,949	3.26%	$ 11,834,668	35.22%
Gila River								
341.00	Structures and Improvements	$ 8,508,950	$ 1,923,845	22.61%	$ 161,377	1.90%	$ 2,085,222	24.51%
342.00	Fuel Holders, Products and Accessories	6,783,045	1,564,479	23.06%	131,378	1.94%	1,695,857	25.00%
343.00	Prime Movers	188,744,730	41,476,345	21.97%	3,443,741	1.82%	44,920,085	23.80%
344.00	Generators and Devices	32,783,434	7,880,799	24.04%	654,106	2.00%	8,534,905	26.03%
345.00	Accessory Electric Equipment	9,030,698	2,116,389	23.44%	176,157	1.95%	2,292,546	25.39%
346.00	Miscellaneous Power Plant Equipment	6,799,960	1,544,958	22.72%	129,746	1.91%	1,674,704	24.63%
	Total Gila River	$ 252,650,817	$ 56,506,815	22.37%	$ 4,696,504	1.86%	$ 61,203,319	24.22%
Gila River Unit 3								
341.00	Structures and Improvements	$ 957,417	$ 226,035	23.61%	$ 18,761	1.96%	$ 244,796	25.57%
342.00	Fuel Holders, Products and Accessories	178,424	38,506	21.58%	3,196	1.79%	41,702	23.37%
343.00	Prime Movers	181,571,712	40,272,150	22.18%	3,342,588	1.84%	43,614,738	24.02%
344.00	Generators and Devices	32,783,434	7,880,799	24.04%	654,106	2.00%	8,534,905	26.03%
345.00	Accessory Electric Equipment	6,860,554	1,619,698	23.61%	134,435	1.96%	1,754,133	25.57%
346.00	Miscellaneous Power Plant Equipment	135,558	30,841	22.75%	2,560	1.89%	33,400	24.64%
	Total Gila River Unit 3	$ 222,487,099	$ 50,068,029	22.50%	$ 4,155,646	1.87%	$ 54,223,675	24.37%
Gila River Common								
341.00	Structures and Improvements	$ 7,551,533	$ 1,697,810	22.48%	$ 142,616	1.89%	$ 1,840,426	24.37%
342.00	Fuel Holders, Products and Accessories	6,604,621	1,525,973	23.10%	128,182	1.94%	1,654,154	25.05%
343.00	Prime Movers	7,173,018	1,204,195	16.79%	101,152	1.41%	1,305,347	18.20%
344.00	Generators and Devices							
345.00	Accessory Electric Equipment	2,170,144	496,691	22.89%	41,722	1.92%	538,413	24.81%
346.00	Miscellaneous Power Plant Equipment	6,664,402	1,514,118	22.72%	127,186	1.91%	1,641,303	24.63%
	Total Gila River Common	$ 30,163,718	$ 6,438,786	21.35%	$ 540,858	1.79%	$ 6,979,644	23.14%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
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Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Luna								
341.00	Structures and Improvements	$ 13,232,832	$ 429,269	3.24%	$ 82,673	0.62%	$ 511,943	3.87%
342.00	Fuel Holders, Products and Accessories	11,352,383	375,419	3.31%	70,579	0.62%	445,998	3.93%
343.00	Prime Movers	11,151,074	139,519	1.25%	88,368	0.79%	227,887	2.04%
344.00	Generators and Devices	9,486,694	250,509	2.64%	160,294	1.69%	410,803	4.33%
345.00	Accessory Electric Equipment	9,647	23	0.24%	4	0.04%	27	0.28%
346.00	Miscellaneous Power Plant Equipment	7,424,592	243,455	3.28%	46,873	0.63%	290,327	3.91%
	Total Luna	$ 52,657,222	$ 1,438,194	2.73%	$ 448,791	0.85%	$ 1,886,985	3.58%
North Loop Gas								
341.00	Structures and Improvements	$ 888,601	$ 724,043	81.48%	$ 113,750	12.80%	$ 837,793	94.28%
342.00	Fuel Holders, Products and Accessories	303,037	98,389	32.47%	5,608	1.85%	103,998	34.32%
343.00	Prime Movers	1,890,946	554,189	29.31%	138,341	7.32%	692,530	36.62%
344.00	Generators and Devices	24,062,187	13,969,357	58.06%	1,797,976	7.47%	15,767,332	65.53%
345.00	Accessory Electric Equipment	2,829,171	1,761,821	62.27%	255,813	9.04%	2,017,633	71.32%
346.00	Miscellaneous Power Plant Equipment	656,253	550,697	83.92%	82,520	12.57%	633,217	96.49%
	Total North Loop Gas	$ 30,630,195	$ 17,658,496	57.65%	$ 2,394,007	7.82%	$ 20,052,503	65.47%
North Loop Gas Unit 1								
341.00	Structures and Improvements	$ 411,070	$ 338,131	82.26%	$ 45,310	11.02%	$ 383,441	93.28%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	678,545	363,159	53.52%	49,267	7.26%	412,426	60.78%
344.00	Generators and Devices	3,582,271	3,487,302	97.35%	472,149	13.18%	3,959,451	110.53%
345.00	Accessory Electric Equipment	790,955	643,803	81.40%	87,719	11.09%	731,523	92.49%
346.00	Miscellaneous Power Plant Equipment	306,369	261,396	85.32%	35,027	11.43%	296,423	96.75%
	Total North Loop Gas Unit 1	$ 5,769,210	$ 5,093,792	88.29%	$ 689,471	11.95%	$ 5,783,263	100.24%
North Loop Gas Unit 2								
341.00	Structures and Improvements	$ 196,078	$ 176,079	89.80%	$ 31,518	16.07%	$ 207,598	105.88%
342.00	Fuel Holders, Products and Accessories							
343.00	Prime Movers	263,450	(167,022)	-63.40%	25,032	9.50%	(141,991)	-53.90%
344.00	Generators and Devices	3,239,719	2,960,031	91.37%	541,676	16.72%	3,501,707	108.09%
345.00	Accessory Electric Equipment	504,895	396,530	78.54%	72,474	14.35%	469,004	92.89%
346.00	Miscellaneous Power Plant Equipment	128,559	126,556	98.44%	22,527	17.52%	149,084	115.97%
	Total North Loop Gas Unit 2	$ 4,332,701	$ 3,492,175	80.60%	$ 693,227	16.00%	$ 4,185,401	96.60%

TUCSON ELECTRIC POWER COMPANY
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Statement D

Account Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
North Loop Gas Unit 3							
341.00 Structures and Improvements	$ 196,078	$ 184,523	94.11%	$ 29,708	15.15%	$ 214,232	109.26%
342.00 Fuel Holders, Products and Accessories							
343.00 Prime Movers	948,951	358,052	37.73%	64,042	6.75%	422,094	44.48%
344.00 Generators and Devices	3,030,531	2,918,939	96.32%	488,229	16.11%	3,407,168	112.43%
345.00 Accessory Electric Equipment	503,907	414,896	82.34%	68,100	13.51%	482,997	95.85%
346.00 Miscellaneous Power Plant Equipment	128,559	132,626	103.16%	21,353	16.61%	153,978	119.77%
Total North Loop Gas Unit 3	$ 4,808,026	$ 4,009,037	83.38%	$ 671,433	13.96%	$ 4,680,469	97.35%
North Loop Gas Unit 4							
341.00 Structures and Improvements	$ 85,375	$ 25,309	29.64%	$ 7,214	8.45%	$ 32,523	38.09%
342.00 Fuel Holders, Products and Accessories	303,037	98,389	32.47%	5,608	1.85%	103,998	34.32%
343.00 Prime Movers							
344.00 Generators and Devices	14,209,666	4,603,085	32.39%	295,922	2.08%	4,899,007	34.48%
345.00 Accessory Electric Equipment	1,029,414	306,590	29.78%	27,519	2.67%	334,109	32.46%
346.00 Miscellaneous Power Plant Equipment	92,766	30,119	32.47%	3,613	3.89%	33,732	36.36%
Total North Loop Gas Unit 4	$ 15,720,258	$ 5,063,493	32.21%	$ 339,876	2.16%	$ 5,403,369	34.37%
Solar Units (Generators and Devices)							
344.00 DeMoss Petrie	$ 1,146,081	$ 581,895	50.77%	$ 29,095	2.54%	$ 610,990	53.31%
344.00 Fort Huachuca	36,709,538	786,429	2.14%	39,321	0.11%	825,751	2.25%
344.00 HQ Rooftop	303,184	32,476	10.71%	1,624	0.54%	34,099	11.25%
344.00 OH Rooftop	2,594,590	389,088	15.00%	19,454	0.75%	408,542	15.75%
344.00 OH Test Yard	388,459	185,913	47.86%	9,296	2.39%	195,208	50.25%
344.00 Prairie Fire	19,036,520	2,039,099	10.71%	101,955	0.54%	2,141,054	11.25%
344.00 Springerville Sites 1-3 (Legacy)	28,766,605	14,654,846	50.94%	732,742	2.55%	15,387,588	53.49%
344.00 Springerville Site 4	7,873,874	1,518,140	19.28%	75,907	0.96%	1,594,047	20.24%
344.00 Tucson	87,198	60,450	69.32%	3,022	3.47%	63,472	72.79%
344.00 U of A Tech Park Site 1	7,723,832	1,489,211	19.28%	74,461	0.96%	1,563,671	20.24%
344.00 U of A Tech Park Site 2	19,191,952	2,878,048	15.00%	143,902	0.75%	3,021,950	15.75%
344.00 White Mountain	46,499,099	996,151	2.14%	49,808	0.11%	1,045,959	2.25%
Total Solar Units	$ 170,320,932	$ 25,611,745	15.04%	$ 1,280,587	0.75%	$ 26,892,332	15.79%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
Sundt Gas								
341.00	Structures and Improvements	$ 11,090	$ 11,262	101.55%	$ 259	2.33%	$ 11,521	103.89%
342.00	Fuel Holders, Products and Accessories	788,336	435,849	55.29%	9,372	1.19%	445,221	56.48%
343.00	Prime Movers	141,618	110,355	77.92%	2,373	1.68%	112,728	79.60%
344.00	Generators and Devices	8,382,044	8,760,751	104.52%	196,023	2.34%	8,956,775	106.86%
345.00	Accessory Electric Equipment	1,078,811	1,056,365	97.92%	23,307	2.16%	1,079,672	100.08%
346.00	Miscellaneous Power Plant Equipment	49,750	57,384	115.35%	1,240	2.49%	58,624	117.84%
	Total Sundt Gas	$ 10,451,649	$ 10,431,966	99.81%	$ 232,574	2.23%	$ 10,664,539	102.04%
Sundt Gas Unit 1								
341.00	Structures and Improvements	$ 5,545	$ 5,596	100.92%	$ 126	2.27%	$ 5,722	103.19%
342.00	Fuel Holders, Products and Accessories	394,168	216,571	54.94%	4,548	1.15%	221,118	56.10%
343.00	Prime Movers	70,809	54,835	77.44%	1,152	1.63%	55,986	79.07%
344.00	Generators and Devices	4,315,668	4,524,215	104.83%	96,969	2.25%	4,621,184	107.08%
345.00	Accessory Electric Equipment	516,231	508,210	98.45%	10,940	2.12%	519,149	100.57%
346.00	Miscellaneous Power Plant Equipment	19,906	22,861	114.85%	480	2.41%	23,341	117.26%
	Total Sundt Gas Unit 1	$ 5,322,327	$ 5,332,287	100.19%	$ 114,214	2.15%	$ 5,446,501	102.33%
Sundt Gas Unit 2								
341.00	Structures and Improvements	$ 5,545	$ 5,666	102.19%	$ 133	2.40%	$ 5,799	104.58%
342.00	Fuel Holders, Products and Accessories	394,168	219,278	55.63%	4,824	1.22%	224,102	56.85%
343.00	Prime Movers	70,809	55,520	78.41%	1,221	1.72%	56,742	80.13%
344.00	Generators and Devices	4,066,376	4,236,536	104.18%	99,054	2.44%	4,335,590	106.62%
345.00	Accessory Electric Equipment	562,580	548,155	97.44%	12,367	2.20%	560,522	99.63%
346.00	Miscellaneous Power Plant Equipment	29,844	34,523	115.68%	760	2.54%	35,283	118.22%
	Total Sundt Gas Unit 2	$ 5,129,322	$ 5,099,679	99.42%	$ 118,359	2.31%	$ 5,218,038	101.73%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION										
310.00	Rights-of-Way	$ 6,273,568	$ 1,166,906	$ 5,106,662		0.0%	$ -	$ (734)	$ (734)	
311.00	Structures and Improvements	241,715,429	36,437,740	205,277,689	-0.7%	-19.5%	(254,013)	(40,030,339)	(40,284,352)	-16.7%
312.00	Boiler Plant Equipment	1,269,797,647	177,844,486	1,091,953,161	-5.3%	-18.2%	(9,352,892)	(198,749,235)	(208,102,126)	-16.4%
314.00	Turbogenerator Units	364,977,004	61,935,081	303,041,923	-3.6%	-15.4%	(2,209,759)	(46,699,803)	(48,909,562)	-13.4%
315.00	Accessory Electric Equipment	151,813,441	7,231,970	144,581,471	-0.8%	-19.4%	(54,707)	(28,114,543)	(28,169,250)	-18.6%
316.00	Miscellaneous Power Plant Equipment	27,947,025	2,724,162	25,222,863	-0.1%	-12.1%	(1,619)	(3,041,590)	(3,043,208)	-10.9%
	Total Steam Production Plant	$ 2,062,524,114	$ 287,340,345	$ 1,775,183,769	-4.1%	-17.8%	$ (11,872,989)	$ (316,636,243)	$ (328,509,232)	-15.9%
OTHER PRODUCTION										
Non-Solar										
341.00	Structures and Improvements	$ 23,624,549	$ 221,088	$ 23,403,461	3.3%	-14.5%	$ 7,192	$ (3,397,000)	$ (3,389,808)	-14.3%
342.00	Fuel Holders, Products and Accessories	19,985,288	8,101	19,977,187		-14.0%		(2,805,602)	(2,805,602)	-14.0%
343.00	Prime Movers	205,281,935	3,276,801	202,005,134		-8.9%		(18,070,205)	(18,070,205)	-8.8%
344.00	Generators and Devices	115,467,853	9,980,628	105,487,225	-0.4%	-9.3%	(43,629)	(9,811,971)	(9,855,600)	-8.5%
345.00	Accessory Electric Equipment	15,595,403	1,785,584	13,809,819		-8.6%	(318)	(1,190,453)	(1,190,771)	-7.6%
346.00	Miscellaneous Power Plant Equipment	15,414,670	107,510	15,307,160		-13.7%		(2,091,776)	(2,091,776)	-13.6%
	Total Non-Solar	$ 395,369,698	$ 15,379,712	$ 379,989,986	-0.2%	-9.8%	$ (36,755)	$ (37,367,008)	$ (37,403,763)	-9.5%
Solar										
344.00	Generators and Devices	$ 170,320,932	$ -	$ 170,320,932		-5.0%	$ -	$ (8,516,047)	$ (8,516,047)	-5.0%
	Total Solar	$ 170,320,932	$ -	$ 170,320,932		-5.0%	$ -	$ (8,516,047)	$ (8,516,047)	-5.0%
	Total Other Production Plant	$ 565,690,630	$ 15,379,712	$ 550,310,918	-0.2%	-8.3%	$ (36,755)	$ (45,883,055)	$ (45,919,810)	-8.1%
DISTRIBUTION PLANT										
360.RW	Rights-of-Way	$ 7,882,488	$ 17,415	$ 7,865,073			$ -	$ -	$ -	
361.00	Structures and Improvements	12,185,407	782,933	11,402,474						
362.00	Station Equipment	170,550,706	13,483,176	157,067,530						
364.00	Poles, Towers and Fixtures	233,941,047	11,934,080	222,006,967						
365.00	Overhead Conductors and Devices	185,805,025	10,129,059	175,675,966						
366.00	Underground Conduit	60,132,553	1,407,198	58,725,355						
367.00	Underground Conductors and Devices	304,814,478	7,631,343	297,183,135						
368.OH	Line Transformers - Overhead	122,002,086	18,344,164	103,657,922						
368.UG	Line Transformers - Underground	183,763,798	10,872,866	172,890,932						
369.OH	Services - Overhead	20,027,424	2,485,188	17,542,236						
369.UG	Services - Underground	113,190,446	242,732	112,947,714						
370.00	Meters	83,815,254	38,945,431	44,869,823						
373.00	Street Lighting and Signal Systems	12,730,933	952,571	11,778,362						
	Total Distribution Plant	$ 1,510,841,645	$ 117,228,156	$ 1,393,613,489			$ -	$ -	$ -	

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account	Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT										
Depreciable										
390.00	Structures and Improvements	$ 142,216,884	$ 6,536,536	$ 135,680,348	-25.1%	-5.0%	$ (1,640,671)	$ (6,784,017)	$ (8,424,688)	-5.9%
392.C0	Transportation - Class 0	2,693,017	1,454,071	1,238,946	18.8%	15.0%	273,365	185,842	459,207	17.1%
392.C1	Transportation - Class 1	18,234,904	10,516,721	7,718,183	18.8%	15.0%	1,977,144	1,157,727	3,134,871	17.2%
392.C2	Transportation - Class 2	11,814,454	7,974,547	3,839,907	18.8%	15.0%	1,499,215	575,986	2,075,201	17.6%
392.C3	Transportation - Class 3	9,677,240	7,600,304	2,076,936	18.8%	15.0%	1,428,857	311,540	1,740,398	18.0%
392.C4	Transportation - Class 4	14,756,225	11,821,198	2,935,027	18.8%	15.0%	2,222,385	440,254	2,662,639	18.0%
392.C5	Transportation - Class 5	15,016,948	7,034,233	7,982,715	18.8%	15.0%	1,322,436	1,197,407	2,519,843	16.8%
392.C6	Transportation - Class 6	365,200		365,200	18.8%	15.0%		54,780	54,780	15.0%
392.C7	Transportation - Class 7	1,047,216		1,047,216	18.8%	15.0%		157,082	157,082	15.0%
392.C8	Transportation - Class 8	10,369,813	412,313	9,957,500	18.8%	15.0%	77,515	1,493,625	1,571,140	15.2%
392.C9	Transportation - Class 9	4,607,987	355,701	4,252,286	18.8%	15.0%	66,872	637,843	704,715	15.3%
396.00	Power Operatied Equipment	20,256,159	8,395,219	11,860,940	2.3%		193,090		193,090	1.0%
397.EM	EMS and SCADA Equipment	11,481,719	177,348	11,304,371						
	Total Depreciable	$ 262,537,766	$ 62,278,191	$ 200,259,575	11.9%	-0.3%	$ 7,420,208	$ (571,930)	$ 6,848,278	2.6%
Amortizable										
391.00	Furniture and Office Equipment	$ 29,004,709	$ 5,040,298	$ 23,964,411			$ -	$ -	$ -	
391.20	Network and Data Equipment	87,362,414	58,002,778	29,359,636						
393.00	Stores Equipment	4,720,343	2,867,864	1,852,479						
394.00	Tools, Shop and Garage Equipment	13,766,165	6,831,797	6,934,368						
395.00	Laboratory Equipment	8,948,263	3,856,993	5,091,270						
397.20	Telecommunications Equipment	84,671,141	27,215,000	57,456,141						
398.00	Miscellaneous Equipment	6,295,272	1,947,063	4,348,209						
	Total Amortizable	$ 234,768,307	$ 105,761,793	$ 129,006,514			$ -	$ -	$ -	
	Total General Plant	$ 497,306,073	$ 168,039,984	$ 329,266,089	4.4%	-0.2%	$ 7,420,208	$ (571,930)	$ 6,848,278	1.4%
	SUBTOTAL	$ 4,636,362,462	$ 587,988,197	$ 4,048,374,265	-0.8%	-9.0%	$ (4,489,536)	$ (363,091,228)	$ (367,580,764)	-7.9%
NET SALVAGE										
108.02	Distribution	$ 1,511,081,011	$ 117,467,522	$ 1,393,613,489	-2.9%	-15.0%	$ (3,406,558)	$ (209,042,023)	$ (212,448,581)	-14.1%
	Total Net Salvage	$ 1,511,081,011	$ 117,467,522	$ 1,393,613,489	-2.9%	-15.0%	$ (3,406,558)	$ (209,042,023)	$ (212,448,581)	-14.1%
	TOTAL UTILITY	$ 6,147,443,473	$ 705,455,719	$ 5,441,987,754	-1.1%	-10.5%	$ (7,896,094)	$ (572,133,252)	$ (580,029,346)	-9.4%
STEAM PRODUCTION (by Unit)										
Four Corners										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,073,950	91,173	2,982,777		-6.3%		(189,175)	(189,175)	-6.2%
312.00	Boiler Plant Equipment	83,264,815	6,862,754	76,402,061	-12.4%	-6.3%	(851,462)	(4,841,671)	(5,693,133)	-6.8%
314.00	Turbogenerator Units	13,995,637	1,636,157	12,359,480		-6.3%		(777,830)	(777,830)	-5.6%
315.00	Accessory Electric Equipment	5,176,981	786,001	4,390,980		-6.3%		(278,272)	(278,272)	-5.4%
316.00	Miscellaneous Power Plant Equipment	4,006,877	174,643	3,832,234		-6.1%		(233,688)	(233,688)	-5.8%
	Total Four Corners	$ 109,518,260	$ 9,550,728	$ 99,967,532	-8.9%	-6.3%	$ (851,462)	$ (6,320,636)	$ (7,172,098)	-6.5%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Four Corners Unit 4									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	1,568,186	43,772	1,524,414		-6.0%		(91,465)	(91,465)	-5.8%
312.00 Boiler Plant Equipment	43,976,009	4,366,471	39,609,538	-19.5%	-6.0%	(851,462)	(2,376,572)	(3,228,034)	-7.3%
314.00 Turbogenerator Units	8,391,807	1,212,445	7,179,362		-6.0%		(430,762)	(430,762)	-5.1%
315.00 Accessory Electric Equipment	2,867,113	592,277	2,274,836		-6.0%		(136,490)	(136,490)	-4.8%
316.00 Miscellaneous Power Plant Equipment	2,037,484	108,323	1,929,161		-5.8%		(111,891)	(111,891)	-5.5%
Total Four Corners Unit 4	$ 58,840,599	$ 6,323,288	$ 52,517,311	-13.5%	-6.0%	$ (851,462)	$ (3,147,180)	$ (3,998,642)	-6.8%
Four Corners Unit 5									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	1,505,764	47,401	1,458,363		-6.7%		(97,710)	(97,710)	-6.5%
312.00 Boiler Plant Equipment	39,288,806	2,496,283	36,792,523		-6.7%		(2,465,099)	(2,465,099)	-6.3%
314.00 Turbogenerator Units	5,603,830	423,712	5,180,118		-6.7%		(347,068)	(347,068)	-6.2%
315.00 Accessory Electric Equipment	2,309,868	193,724	2,116,144		-6.7%		(141,782)	(141,782)	-6.1%
316.00 Miscellaneous Power Plant Equipment	1,969,393	66,320	1,903,073		-6.4%		(121,797)	(121,797)	-6.2%
Total Four Corners Unit 5	$ 50,677,661	$ 3,227,440	$ 47,450,221		-6.7%	$ -	$ (3,173,456)	$ (3,173,456)	-6.3%
Navajo									
310.00 Rights-of-Way	$ 12,229	$ -	$ 12,229		-6.0%	$ -	$ (734)	$ (734)	-6.0%
311.00 Structures and Improvements	19,133,681	478,525	18,655,156	-0.6%	-6.0%	(2,794)	(1,118,181)	(1,120,975)	-5.9%
312.00 Boiler Plant Equipment	93,542,762	4,998,561	88,544,201	1.6%	-5.9%	78,293	(5,215,450)	(5,137,157)	-5.5%
314.00 Turbogenerator Units	21,695,188	1,439,662	20,255,526	-0.5%	-5.9%	(7,076)	(1,188,857)	(1,195,933)	-5.5%
315.00 Accessory Electric Equipment	14,944,456	114,598	14,829,858	2.9%	-5.9%	3,374	(879,329)	(875,955)	-5.9%
316.00 Miscellaneous Power Plant Equipment	4,527,877	9,280	4,518,597	-17.4%	-5.9%	(1,619)	(266,897)	(268,516)	-5.9%
Total Navajo	$ 153,856,193	$ 7,040,626	$ 146,815,567	1.0%	-5.9%	$ 70,179	$ (8,669,447)	$ (8,599,269)	-5.6%
Navajo Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,183,276	(7,287)	3,190,563		-5.0%		(159,528)	(159,528)	-5.0%
312.00 Boiler Plant Equipment	28,591,944	1,393,362	27,198,582	-4.9%	-5.0%	(68,275)	(1,359,929)	(1,428,204)	-5.0%
314.00 Turbogenerator Units	7,568,560	707,571	6,860,989	-1.0%	-5.0%	(7,076)	(343,049)	(350,125)	-4.6%
315.00 Accessory Electric Equipment	3,763,595	219,295	3,544,300	-0.6%	-5.0%	(1,316)	(177,215)	(178,531)	-4.7%
316.00 Miscellaneous Power Plant Equipment	492,993	21,766	471,227	-4.0%	-4.9%	(871)	(23,090)	(23,961)	-4.9%
Total Navajo Unit 1	$ 43,600,368	$ 2,334,707	$ 41,265,661	-3.3%	-5.0%	$ (77,537)	$ (2,062,812)	$ (2,140,349)	-4.9%
Navajo Unit 2									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	1,882,084	79,399	1,802,685		-6.6%		(118,977)	(118,977)	-6.3%
312.00 Boiler Plant Equipment	28,261,337	1,379,051	26,882,286	4.9%	-6.6%	67,573	(1,774,231)	(1,706,657)	-6.0%
314.00 Turbogenerator Units	7,024,429	98,379	6,926,050		-6.6%		(457,119)	(457,119)	-6.5%
315.00 Accessory Electric Equipment	3,352,457	180,127	3,172,330	-0.6%	-6.6%	(1,081)	(209,374)	(210,455)	-6.3%
316.00 Miscellaneous Power Plant Equipment	539,942	24,068	515,874	-3.6%	-6.4%	(866)	(33,016)	(33,882)	-6.3%
Total Navajo Unit 2	$ 41,060,249	$ 1,761,024	$ 39,299,225	3.7%	-6.6%	$ 65,626	$ (2,592,717)	$ (2,527,091)	-6.2%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Navajo Unit 3									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,738,690	57,179	3,681,511		-6.0%		(220,891)	(220,891)	-5.9%
312.00 Boiler Plant Equipment	29,815,550	2,097,036	27,718,514	5.3%	-6.0%	111,143	(1,663,111)	(1,551,968)	-5.2%
314.00 Turbogenerator Units	6,805,747	626,803	6,178,944		-6.0%		(370,737)	(370,737)	-5.4%
315.00 Accessory Electric Equipment	4,794,821	(345,051)	5,139,872	0.3%	-6.0%	(1,035)	(308,392)	(309,427)	-6.5%
316.00 Miscellaneous Power Plant Equipment	455,762	(93,600)	549,362	0.3%	-5.8%	(281)	(31,863)	(32,144)	-7.1%
Total Navajo Unit 3	$ 45,610,570	$ 2,342,367	$ 43,268,203	4.7%	-6.0%	$ 109,827	$ (2,594,993)	$ (2,485,167)	-5.4%
Navajo Common									
310.00 Rights-of-Way	$ 12,229	$ -	$ 12,229		-6.0%	$ -	$ (734)	$ (734)	-6.0%
311.00 Structures and Improvements	10,329,631	349,234	9,980,397	-0.8%	-6.2%	(2,794)	(618,785)	(621,578)	-6.0%
312.00 Boiler Plant Equipment	6,873,931	129,112	6,744,819	-24.9%	-6.2%	(32,149)	(418,179)	(450,328)	-6.6%
314.00 Turbogenerator Units	296,452	6,909	289,543		-6.2%		(17,952)	(17,952)	-6.1%
315.00 Accessory Electric Equipment	3,033,583	60,227	2,973,356	11.3%	-6.2%	6,806	(184,348)	(177,542)	-5.9%
316.00 Miscellaneous Power Plant Equipment	3,039,180	57,046	2,982,134	0.7%	-6.0%	399	(178,928)	(178,529)	-5.9%
Total Navajo Common	$ 23,585,006	$ 602,528	$ 22,982,478	-4.6%	-6.2%	$ (27,738)	$ (1,418,925)	$ (1,446,663)	-6.1%
San Juan									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	15,360,481	922,737	14,437,744		-9.6%		(1,384,374)	(1,384,374)	-9.0%
312.00 Boiler Plant Equipment	179,068,616	24,561,708	154,506,908	-10.9%	-11.7%	(2,682,943)	(18,152,345)	(20,835,287)	-11.6%
314.00 Turbogenerator Units	47,886,955	3,591,282	44,295,673		-9.7%		(4,296,680)	(4,296,680)	-9.0%
315.00 Accessory Electric Equipment	10,694,978	631,452	10,063,526		-9.7%		(976,162)	(976,162)	-9.1%
316.00 Miscellaneous Power Plant Equipment	2,285,721	276,166	2,009,555		-9.3%		(186,216)	(186,216)	-8.1%
Total San Juan	$ 255,296,751	$ 29,983,345	$ 225,313,406	-8.9%	-11.1%	$ (2,682,943)	$ (24,995,777)	$ (27,678,720)	-10.8%
San Juan Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	15,191,141	922,737	14,268,404		-9.7%		(1,384,035)	(1,384,035)	-9.1%
312.00 Boiler Plant Equipment	170,696,078	24,243,049	146,453,029	-12.1%	-9.7%	(2,933,409)	(14,205,944)	(17,139,353)	-10.0%
314.00 Turbogenerator Units	47,886,955	3,591,282	44,295,673		-9.7%		(4,296,680)	(4,296,680)	-9.0%
315.00 Accessory Electric Equipment	10,694,978	631,452	10,063,526		-9.7%		(976,162)	(976,162)	-9.1%
316.00 Miscellaneous Power Plant Equipment	2,236,338	276,166	1,960,172		-9.5%		(186,216)	(186,216)	-8.3%
Total San Juan Unit 1	$ 246,705,490	$ 29,664,686	$ 217,040,804	-9.9%	-9.7%	$ (2,933,409)	$ (21,049,038)	$ (23,982,447)	-9.7%
San Juan Common									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	169,340		169,340		-0.2%		(339)	(339)	-0.2%
312.00 Boiler Plant Equipment	8,372,538	318,659	8,053,879	78.6%	-49.0%	250,466	(3,946,401)	(3,695,935)	-44.1%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment	49,383		49,383						
Total San Juan Common	$ 8,591,261	$ 318,659	$ 8,272,602	78.6%	-47.7%	$ 250,466	$ (3,946,739)	$ (3,696,273)	-43.0%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Springerville									
310.00 Rights-of-Way	$ 6,261,339	$ 1,166,906	$ 5,094,433			$ -	$ -	$ -	
311.00 Structures and Improvements	175,350,915	33,624,274	141,726,641	-0.7%	-17.8%	(251,219)	(25,222,559)	(25,473,778)	-14.5%
312.00 Boiler Plant Equipment	772,876,714	131,189,349	641,687,365	-4.5%	-18.3%	(5,896,780)	(117,543,561)	(123,440,341)	-16.0%
314.00 Turbogenerator Units	223,365,420	49,715,505	173,649,915	-4.4%	-6.6%	(2,202,683)	(11,423,692)	(13,626,375)	-6.1%
315.00 Accessory Electric Equipment	78,903,325	3,038,707	75,864,618	-1.9%	-8.8%	(58,081)	(6,675,884)	(6,733,965)	-8.5%
316.00 Miscellaneous Power Plant Equipment	14,477,485	1,948,501	12,528,984		-9.3%		(1,168,148)	(1,168,148)	-8.1%
Total Springerville	$ 1,271,235,198	$ 220,683,242	$ 1,050,551,956	-3.8%	-15.4%	$ (8,408,763)	$ (162,033,845)	$ (170,442,608)	-13.4%
Springerville Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	26,483,850	6,407,835	20,076,015		-5.5%		(1,104,181)	(1,104,181)	-4.2%
312.00 Boiler Plant Equipment	243,028,846	57,346,356	185,682,490		-5.5%		(10,212,537)	(10,212,537)	-4.2%
314.00 Turbogenerator Units	65,088,338	15,541,027	49,547,312		-5.5%		(2,725,102)	(2,725,102)	-4.2%
315.00 Accessory Electric Equipment	22,841,460	1,627,293	21,214,167		-5.5%		(1,166,779)	(1,166,779)	-5.1%
316.00 Miscellaneous Power Plant Equipment	4,778,042	1,500,300	3,277,742		-5.1%		(167,165)	(167,165)	-3.5%
Total Springerville Unit 1	$ 362,220,537	$ 82,422,811	$ 279,797,726		-5.5%	$ -	$ (15,375,764)	$ (15,375,764)	-4.2%
Springerville Unit 1 Common									
310.00 Rights-of-Way	$ 2,310,402	$ 1,166,906	$ 1,143,496			$ -	$ -	$ -	
311.00 Structures and Improvements	74,990,847	22,498,021	52,492,826		-16.8%		(8,818,795)	(8,818,795)	-11.8%
312.00 Boiler Plant Equipment	19,321,712	4,466,913	14,854,799		-16.8%		(2,495,606)	(2,495,606)	-12.9%
314.00 Turbogenerator Units	1,551,370	287,048	1,264,322		-16.8%		(212,406)	(212,406)	-13.7%
315.00 Accessory Electric Equipment	9,774,817	147,720	9,627,097		-16.8%		(1,617,352)	(1,617,352)	-16.5%
316.00 Miscellaneous Power Plant Equipment	2,140,360	181,348	1,959,012		-16.4%		(321,278)	(321,278)	-15.0%
Total Springerville Unit 1 Common	$ 110,089,508	$ 28,747,956	$ 81,341,552		-16.6%	$ -	$ (13,465,437)	$ (13,465,437)	-12.2%
Springerville Unit 2									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	38,669,006	2,128,976	36,540,030	-11.8%	-6.7%	(251,219)	(2,448,182)	(2,699,401)	-7.0%
312.00 Boiler Plant Equipment	358,654,246	62,731,701	295,922,545	-9.4%	-6.7%	(5,896,780)	(19,826,811)	(25,723,590)	-7.2%
314.00 Turbogenerator Units	155,942,778	33,887,430	122,055,348	-6.5%	-6.7%	(2,202,683)	(8,177,708)	(10,380,391)	-6.7%
315.00 Accessory Electric Equipment	43,609,568	1,262,629	42,346,939	-4.6%	-6.7%	(58,081)	(2,837,245)	(2,895,326)	-6.6%
316.00 Miscellaneous Power Plant Equipment	6,879,594	254,925	6,624,669		-6.3%		(417,354)	(417,354)	-6.1%
Total Springerville Unit 2	$ 603,755,192	$ 100,265,661	$ 503,489,531	-8.4%	-6.7%	$ (8,408,763)	$ (33,707,300)	$ (42,116,063)	-7.0%
Springerville Unit 2 Common (Leasehold Imp.)									
310.00 Rights-of-Way	$ 2,280,838	$ -	$ 2,280,838			$ -	$ -	$ -	
311.00 Structures and Improvements	35,207,212	2,589,442	32,617,770		-39.4%		(12,851,401)	(12,851,401)	-36.5%
312.00 Boiler Plant Equipment	7,670,230	1,387,501	6,282,729		-39.4%		(2,475,395)	(2,475,395)	-32.3%
314.00 Turbogenerator Units	782,933		782,933		-39.4%		(308,476)	(308,476)	-39.4%
315.00 Accessory Electric Equipment	2,677,480	1,065	2,676,415		-39.4%		(1,054,508)	(1,054,508)	-39.4%
316.00 Miscellaneous Power Plant Equipment	679,489	11,928	667,561		-39.3%		(262,351)	(262,351)	-38.6%
Total Springerville Unit 2 Common	$ 49,298,182	$ 3,989,936	$ 45,308,246		-37.4%	$ -	$ (16,952,131)	$ (16,952,131)	-34.4%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Springerville Coal Handling									
310.00 Rights-of-Way	$ 1,670,099	$ -	$ 1,670,099			$ -	$ -	$ -	
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	144,201,680	5,256,878	138,944,802		-59.4%		(82,533,212)	(82,533,212)	-57.2%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment									
Total Springerville Coal Handling	$ 145,871,779	$ 5,256,878	$ 140,614,901		-58.7%	$ -	$ (82,533,212)	$ (82,533,212)	-56.6%
Sundt									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	28,796,402	1,321,031	27,475,371		-44.1%		(12,116,050)	(12,116,050)	-42.1%
312.00 Boiler Plant Equipment	141,044,740	10,232,114	130,812,626		-40.5%		(52,996,208)	(52,996,208)	-37.6%
314.00 Turbogenerator Units	58,033,804	5,552,475	52,481,329		-55.3%		(29,012,744)	(29,012,744)	-50.0%
315.00 Accessory Electric Equipment	42,093,701	2,661,212	39,432,489		-49.0%		(19,304,896)	(19,304,896)	-45.9%
316.00 Miscellaneous Power Plant Equipment	2,649,065	315,572	2,333,493		-50.9%		(1,186,640)	(1,186,640)	-44.8%
Total Sundt	$ 272,617,712	$ 20,082,404	$ 252,535,308		-45.4%	$ -	$ (114,616,538)	$ (114,616,538)	-42.0%
Sundt Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	4,268,893	342,831	3,926,062		-58.6%		(2,300,672)	(2,300,672)	-53.9%
312.00 Boiler Plant Equipment	16,399,259	2,617,078	13,782,181		-58.7%		(8,090,140)	(8,090,140)	-49.3%
314.00 Turbogenerator Units	11,467,321	1,229,814	10,237,507		-58.7%		(6,009,417)	(6,009,417)	-52.4%
315.00 Accessory Electric Equipment	7,107,197	570,882	6,536,315		-58.7%		(3,836,817)	(3,836,817)	-54.0%
316.00 Miscellaneous Power Plant Equipment	516,709	26,131	490,578		-58.6%		(287,479)	(287,479)	-55.6%
Total Sundt Unit 1	$ 39,759,379	$ 4,786,736	$ 34,972,643		-58.7%	$ -	$ (20,524,525)	$ (20,524,525)	-51.6%
Sundt Unit 2									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,151,250	338,561	2,812,689		-66.3%		(1,864,813)	(1,864,813)	-59.2%
312.00 Boiler Plant Equipment	15,058,926	687,317	14,371,609		-66.3%		(9,528,377)	(9,528,377)	-63.3%
314.00 Turbogenerator Units	9,232,349	780,426	8,451,923		-66.2%		(5,595,173)	(5,595,173)	-60.6%
315.00 Accessory Electric Equipment	6,531,575	325,875	6,205,700		-66.4%		(4,120,585)	(4,120,585)	-63.1%
316.00 Miscellaneous Power Plant Equipment	411,098	27,274	383,824		-66.2%		(254,091)	(254,091)	-61.8%
Total Sundt Unit 2	$ 34,385,198	$ 2,159,453	$ 32,225,745		-66.3%	$ -	$ (21,363,039)	$ (21,363,039)	-62.1%
Sundt Unit 3									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,083,662	321,650	2,762,012		-75.7%		(2,090,843)	(2,090,843)	-67.8%
312.00 Boiler Plant Equipment	12,808,330	827,499	11,980,831		-75.7%		(9,069,489)	(9,069,489)	-70.8%
314.00 Turbogenerator Units	16,380,197	1,549,582	14,830,615		-75.7%		(11,226,776)	(11,226,776)	-68.5%
315.00 Accessory Electric Equipment	6,922,100	781,961	6,140,139		-75.7%		(4,648,085)	(4,648,085)	-67.1%
316.00 Miscellaneous Power Plant Equipment	458,756	54,039	404,717		-75.5%		(305,561)	(305,561)	-66.6%
Total Sundt Unit 3	$ 39,653,045	$ 3,534,731	$ 36,118,314		-75.7%	$ -	$ (27,340,754)	$ (27,340,754)	-68.9%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Sundt Unit 4									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	18,292,597	317,989	17,974,608		-32.6%		(5,859,722)	(5,859,722)	-32.0%
312.00 Boiler Plant Equipment	86,676,275	6,100,220	80,576,055		-32.6%		(26,267,794)	(26,267,794)	-30.3%
314.00 Turbogenerator Units	20,953,937	1,992,653	18,961,284		-32.6%		(6,181,379)	(6,181,379)	-29.5%
315.00 Accessory Electric Equipment	21,532,829	982,494	20,550,335		-32.6%		(6,699,409)	(6,699,409)	-31.1%
316.00 Miscellaneous Power Plant Equipment	1,262,502	208,128	1,054,374		-32.2%		(339,508)	(339,508)	-26.9%
Total Sundt Unit 4	$ 148,718,140	$ 9,601,484	$ 139,116,656		-32.6%	$ -	$ (45,347,812)	$ (45,347,812)	-30.5%
Sundt Solar Booster (Areva)									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements									
312.00 Boiler Plant Equipment	10,101,950		10,101,950		-0.4%		(40,408)	(40,408)	-0.4%
314.00 Turbogenerator Units									
315.00 Accessory Electric Equipment									
316.00 Miscellaneous Power Plant Equipment									
Total Sundt Solar Booster (Areva)	$ 10,101,950	$ -	$ 10,101,950		-0.4%	$ -	$ (40,408)	$ (40,408)	-0.4%
OTHER PRODUCTION (by Unit)									
DeMoss Petrie Gas Unit 1									
341.00 Structures and Improvements	$ 941,331	$ 179,343	$ 761,988		-9.0%	$ -	$ (68,579)	$ (68,579)	-7.3%
342.00 Fuel Holders, Products and Accessories	758,487	8,101	750,386		-9.0%		(67,535)	(67,535)	-8.9%
343.00 Prime Movers	528,037	451,271	76,766		-9.0%		(6,909)	(6,909)	-1.3%
344.00 Generators and Devices	31,682,855	909,989	30,772,866		-9.0%		(2,769,558)	(2,769,558)	-8.7%
345.00 Accessory Electric Equipment	2,300,817	1,439,325	861,492		-9.0%		(77,534)	(77,534)	-3.4%
346.00 Miscellaneous Power Plant Equipment	379,346	2,741	376,605		-9.0%		(33,894)	(33,894)	-8.9%
Total DeMoss Petrie Gas Unit 1	$ 36,590,873	$ 2,990,770	$ 33,600,103		-9.0%	$ -	$ (3,024,009)	$ (3,024,009)	-8.3%
Gila River									
341.00 Structures and Improvements	$ 8,508,950	$ -	$ 8,508,950		-8.4%	$ -	$ (713,794)	$ (713,794)	-8.4%
342.00 Fuel Holders, Products and Accessories	6,783,045		6,783,045		-8.4%		(569,597)	(569,597)	-8.4%
343.00 Prime Movers	188,744,730		188,744,730		-8.3%		(15,672,986)	(15,672,986)	-8.3%
344.00 Generators and Devices	32,783,434		32,783,434		-8.3%		(2,721,025)	(2,721,025)	-8.3%
345.00 Accessory Electric Equipment	9,030,698		9,030,698		-8.3%		(751,718)	(751,718)	-8.3%
346.00 Miscellaneous Power Plant Equipment	6,799,960		6,799,960		-8.4%		(571,061)	(571,061)	-8.4%
Total Gila River	$ 252,650,817	$ -	$ 252,650,817		-8.3%	$ -	$ (21,000,182)	$ (21,000,182)	-8.3%
Gila River Unit 3									
341.00 Structures and Improvements	$ 957,417	$ -	$ 957,417		-8.3%	$ -	$ (79,466)	$ (79,466)	-8.3%
342.00 Fuel Holders, Products and Accessories	178,424		178,424		-8.3%		(14,809)	(14,809)	-8.3%
343.00 Prime Movers	181,571,712		181,571,712		-8.3%		(15,070,452)	(15,070,452)	-8.3%
344.00 Generators and Devices	32,783,434		32,783,434		-8.3%		(2,721,025)	(2,721,025)	-8.3%
345.00 Accessory Electric Equipment	6,860,554		6,860,554		-8.3%		(569,426)	(569,426)	-8.3%
346.00 Miscellaneous Power Plant Equipment	135,558		135,558		-8.3%		(11,251)	(11,251)	-8.3%
Total Gila River Unit 3	$ 222,487,099	$ -	$ 222,487,099		-8.3%	$ -	$ (18,466,429)	$ (18,466,429)	-8.3%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Gila River Common									
341.00 Structures and Improvements	$ 7,551,533	$ -	$ 7,551,533		-8.4%	$ -	$ (634,329)	$ (634,329)	-8.4%
342.00 Fuel Holders, Products and Accessories	6,604,621		6,604,621		-8.4%		(554,788)	(554,788)	-8.4%
343.00 Prime Movers	7,173,018		7,173,018		-8.4%		(602,534)	(602,534)	-8.4%
344.00 Generators and Devices									
345.00 Accessory Electric Equipment	2,170,144		2,170,144		-8.4%		(182,292)	(182,292)	-8.4%
346.00 Miscellaneous Power Plant Equipment	6,664,402		6,664,402		-8.4%		(559,810)	(559,810)	-8.4%
Total Gila River Common	$ 30,163,718	$ -	$ 30,163,718		-8.4%	$ -	$ (2,533,752)	$ (2,533,752)	-8.4%
Luna									
341.00 Structures and Improvements	$ 13,269,836	$ 37,004	$ 13,232,832		-18.8%	$ -	$ (2,487,772)	$ (2,487,772)	-18.7%
342.00 Fuel Holders, Products and Accessories	11,352,383		11,352,383		-18.8%		(2,134,248)	(2,134,248)	-18.8%
343.00 Prime Movers	13,516,063	2,364,989	11,151,074		-18.8%		(2,096,402)	(2,096,402)	-15.5%
344.00 Generators and Devices	16,114,883	6,628,189	9,486,694		-18.8%		(1,783,498)	(1,783,498)	-11.1%
345.00 Accessory Electric Equipment	9,647		9,647		-18.8%		(1,814)	(1,814)	-18.8%
346.00 Miscellaneous Power Plant Equipment	7,449,920	25,328	7,424,592		-18.8%		(1,395,823)	(1,395,823)	-18.7%
Total Luna	$ 61,712,732	$ 9,055,510	$ 52,657,222		-18.8%	$ -	$ (9,899,558)	$ (9,899,558)	-16.0%
North Loop Gas									
341.00 Structures and Improvements	$ 891,728	$ 3,127	$ 888,601	230.0%	-14.2%	$ 7,192	$ (126,616)	$ (119,424)	-13.4%
342.00 Fuel Holders, Products and Accessories	303,037		303,037		-5.7%		(17,273)	(17,273)	-5.7%
343.00 Prime Movers	2,351,487	460,541	1,890,946		-15.4%		(290,864)	(290,864)	-12.4%
344.00 Generators and Devices	25,738,500	1,676,313	24,062,187	-2.6%	-9.8%	(43,629)	(2,357,800)	(2,401,430)	-9.3%
345.00 Accessory Electric Equipment	3,144,306	315,135	2,829,171	-0.1%	-11.9%	(318)	(336,170)	(336,488)	-10.7%
346.00 Miscellaneous Power Plant Equipment	735,694	79,441	656,253		-13.7%		(89,923)	(89,923)	-12.2%
Total North Loop Gas	$ 33,164,752	$ 2,534,557	$ 30,630,195	-1.5%	-10.5%	$ (36,755)	$ (3,218,646)	$ (3,255,401)	-9.8%
North Loop Gas Unit 1									
341.00 Structures and Improvements	$ 411,070	$ -	$ 411,070		-13.4%	$ -	$ (55,083)	$ (55,083)	-13.4%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	685,193	6,648	678,545		-13.4%		(90,925)	(90,925)	-13.3%
344.00 Generators and Devices	3,956,176	373,905	3,582,271	-10.0%	-13.4%	(37,391)	(480,024)	(517,415)	-13.1%
345.00 Accessory Electric Equipment	808,620	17,665	790,955	-0.6%	-13.4%	(106)	(105,988)	(106,094)	-13.1%
346.00 Miscellaneous Power Plant Equipment	306,369		306,369		-13.4%		(41,053)	(41,053)	-13.4%
Total North Loop Gas Unit 1	$ 6,167,428	$ 398,218	$ 5,769,210	-9.4%	-13.4%	$ (37,496)	$ (773,074)	$ (810,571)	-13.1%
North Loop Gas Unit 2									
341.00 Structures and Improvements	$ 196,078	$ -	$ 196,078		-17.9%	$ -	$ (35,098)	$ (35,098)	-17.9%
342.00 Fuel Holders, Products and Accessories									
343.00 Prime Movers	676,560	413,110	263,450		-17.9%		(47,158)	(47,158)	-7.0%
344.00 Generators and Devices	3,441,312	201,593	3,239,719	-1.5%	-17.9%	(3,024)	(579,910)	(582,934)	-16.9%
345.00 Accessory Electric Equipment	522,560	17,665	504,895	-0.6%	-17.9%	(106)	(90,376)	(90,482)	-17.3%
346.00 Miscellaneous Power Plant Equipment	128,559		128,559		-17.8%		(22,884)	(22,884)	-17.8%
Total North Loop Gas Unit 2	$ 4,965,069	$ 632,368	$ 4,332,701	-0.5%	-17.9%	$ (3,130)	$ (775,425)	$ (778,555)	-15.7%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
North Loop Gas Unit 3										
341.00	Structures and Improvements	$ 196,078	$ -	$ 196,078		-16.1%	$ -	$ (31,569)	$ (31,569)	-16.1%
342.00	Fuel Holders, Products and Accessories									
343.00	Prime Movers	989,734	40,783	948,951		-16.1%		(152,781)	(152,781)	-15.4%
344.00	Generators and Devices	3,387,718	357,187	3,030,531	-0.9%	-16.1%	(3,215)	(487,915)	(491,130)	-14.5%
345.00	Accessory Electric Equipment	521,572	17,665	503,907	-0.6%	-16.1%	(106)	(81,129)	(81,235)	-15.6%
346.00	Miscellaneous Power Plant Equipment	128,559		128,559		-16.1%		(20,698)	(20,698)	-16.1%
	Total North Loop Gas Unit 3	$ 5,223,661	$ 415,635	$ 4,808,026	-0.8%	-16.1%	$ (3,321)	$ (774,092)	$ (777,413)	-14.9%
North Loop Gas Unit 4										
341.00	Structures and Improvements	$ 88,502	$ 3,127	$ 85,375	230.0%	-5.7%	$ 7,192	$ (4,866)	$ 2,326	2.6%
342.00	Fuel Holders, Products and Accessories	303,037		303,037		-5.7%		(17,273)	(17,273)	-5.7%
343.00	Prime Movers									
344.00	Generators and Devices	14,953,294	743,628	14,209,666		-5.7%		(809,951)	(809,951)	-5.4%
345.00	Accessory Electric Equipment	1,291,554	262,140	1,029,414		-5.7%		(58,677)	(58,677)	-4.5%
346.00	Miscellaneous Power Plant Equipment	172,207	79,441	92,766		-5.7%		(5,288)	(5,288)	-3.1%
	Total North Loop Gas Unit 4	$ 16,808,594	$ 1,088,336	$ 15,720,258	0.7%	-5.7%	$ 7,192	$ (896,055)	$ (888,863)	-5.3%
Solar Units (Generators and Devices)										
344.00	DeMoss Petrie	$ 1,146,081	$ -	$ 1,146,081		-5.0%	$ -	$ (57,304)	$ (57,304)	-5.0%
344.00	Fort Huachuca	36,709,538		36,709,538		-5.0%		(1,835,477)	(1,835,477)	-5.0%
344.00	HQ Rooftop	303,184		303,184		-5.0%		(15,159)	(15,159)	-5.0%
344.00	OH Rooftop	2,594,590		2,594,590		-5.0%		(129,730)	(129,730)	-5.0%
344.00	OH Test Yard	388,459		388,459		-5.0%		(19,423)	(19,423)	-5.0%
344.00	Prairie Fire	19,036,520		19,036,520		-5.0%		(951,826)	(951,826)	-5.0%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605		28,766,605		-5.0%		(1,438,330)	(1,438,330)	-5.0%
344.00	Springerville Site 4	7,873,874		7,873,874		-5.0%		(393,694)	(393,694)	-5.0%
344.00	Tucson	87,198		87,198		-5.0%		(4,360)	(4,360)	-5.0%
344.00	U of A Tech Park Site 1	7,723,832		7,723,832		-5.0%		(386,192)	(386,192)	-5.0%
344.00	U of A Tech Park Site 2	19,191,952		19,191,952		-5.0%		(959,598)	(959,598)	-5.0%
344.00	White Mountain	46,499,099		46,499,099		-5.0%		(2,324,955)	(2,324,955)	-5.0%
	Total Solar Units	$ 170,320,932	$ -	$ 170,320,932		-5.0%	$ -	$ (8,516,047)	$ (8,516,047)	-5.0%
Sundt Gas										
341.00	Structures and Improvements	$ 12,704	$ 1,614	$ 11,090		-2.2%	$ -	$ (238)	$ (238)	-1.9%
342.00	Fuel Holders, Products and Accessories	788,336		788,336		-2.2%		(16,949)	(16,949)	-2.2%
343.00	Prime Movers	141,618		141,618		-2.2%		(3,045)	(3,045)	-2.2%
344.00	Generators and Devices	9,148,181	766,137	8,382,044		-2.1%		(180,089)	(180,089)	-2.0%
345.00	Accessory Electric Equipment	1,109,935	31,124	1,078,811		-2.2%		(23,218)	(23,218)	-2.1%
346.00	Miscellaneous Power Plant Equipment	49,750		49,750		-2.2%		(1,075)	(1,075)	-2.2%
	Total Sundt Gas	$ 11,250,524	$ 798,875	$ 10,451,649		-2.1%	$ -	$ (224,614)	$ (224,614)	-2.0%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Statement E

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Sundt Gas Unit 1									
341.00 Structures and Improvements	$ 6,352	$ 807	$ 5,545		-2.1%	$ -	$ (116)	$ (116)	-1.8%
342.00 Fuel Holders, Products and Accessories	394,168		394,168		-2.1%		(8,278)	(8,278)	-2.1%
343.00 Prime Movers	70,809		70,809		-2.1%		(1,487)	(1,487)	-2.1%
344.00 Generators and Devices	4,531,439	215,771	4,315,668		-2.1%		(90,629)	(90,629)	-2.0%
345.00 Accessory Electric Equipment	531,793	15,562	516,231		-2.1%		(10,841)	(10,841)	-2.0%
346.00 Miscellaneous Power Plant Equipment	19,906		19,906		-2.1%		(418)	(418)	-2.1%
Total Sundt Gas Unit 1	$ 5,554,467	$ 232,140	$ 5,322,327		-2.1%	$ -	$ (111,769)	$ (111,769)	-2.0%
Sundt Gas Unit 2									
341.00 Structures and Improvements	$ 6,352	$ 807	$ 5,545		-2.2%	$ -	$ (122)	$ (122)	-1.9%
342.00 Fuel Holders, Products and Accessories	394,168		394,168		-2.2%		(8,672)	(8,672)	-2.2%
343.00 Prime Movers	70,809		70,809		-2.2%		(1,558)	(1,558)	-2.2%
344.00 Generators and Devices	4,616,742	550,366	4,066,376		-2.2%		(89,460)	(89,460)	-1.9%
345.00 Accessory Electric Equipment	578,142	15,562	562,580		-2.2%		(12,377)	(12,377)	-2.1%
346.00 Miscellaneous Power Plant Equipment	29,844		29,844		-2.2%		(657)	(657)	-2.2%
Total Sundt Gas Unit 2	$ 5,696,057	$ 566,735	$ 5,129,322		-2.2%	$ -	$ (112,845)	$ (112,845)	-2.0%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
STEAM PRODUCTION (by Unit)										
Four Corners										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	2,982,777	125,729	2,857,048	-5.0%	-6.4%	(6,286)	(182,685)	(188,971)	-6.3%
312.00	Boiler Plant Equipment	76,402,061	3,267,354	73,134,707	-5.0%	-6.4%	(163,368)	(4,672,872)	(4,836,239)	-6.3%
314.00	Turbogenerator Units	12,359,480	523,849	11,835,631	-5.0%	-6.3%	(26,192)	(751,424)	(777,617)	-6.3%
315.00	Accessory Electric Equipment	4,390,980	180,525	4,210,455	-5.0%	-6.4%	(9,026)	(269,033)	(278,059)	-6.3%
316.00	Miscellaneous Power Plant Equipment	3,832,234	160,207	3,672,027		-6.4%		(234,978)	(234,978)	-6.1%
	Total Four Corners	$ 99,967,532	$ 4,257,665	$ 95,709,867	-4.8%	-6.4%	$ (204,873)	$ (6,110,991)	$ (6,315,864)	-6.3%
Four Corners Unit 4										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,524,414	64,249	1,460,165	-5.0%	-6.1%	(3,212)	(88,733)	(91,945)	-6.0%
312.00	Boiler Plant Equipment	39,609,538	1,694,925	37,914,613	-5.0%	-6.1%	(84,746)	(2,304,036)	(2,388,782)	-6.0%
314.00	Turbogenerator Units	7,179,362	303,478	6,875,884	-5.0%	-6.1%	(15,174)	(417,841)	(433,015)	-6.0%
315.00	Accessory Electric Equipment	2,274,836	93,584	2,181,252	-5.0%	-6.1%	(4,679)	(132,553)	(137,232)	-6.0%
316.00	Miscellaneous Power Plant Equipment	1,929,161	80,629	1,848,532		-6.1%		(112,334)	(112,334)	-5.8%
	Total Four Corners Unit 4	$ 52,517,311	$ 2,236,864	$ 50,280,447	-4.8%	-6.1%	$ (107,812)	$ (3,055,496)	$ (3,163,307)	-6.0%
Four Corners Unit 5										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,458,363	61,481	1,396,882	-5.0%	-6.7%	(3,074)	(93,952)	(97,026)	-6.7%
312.00	Boiler Plant Equipment	36,792,523	1,572,430	35,220,093	-5.0%	-6.7%	(78,621)	(2,368,836)	(2,447,457)	-6.7%
314.00	Turbogenerator Units	5,180,118	220,371	4,959,747	-5.0%	-6.7%	(11,019)	(333,583)	(344,602)	-6.7%
315.00	Accessory Electric Equipment	2,116,144	86,942	2,029,202	-5.0%	-6.7%	(4,347)	(136,480)	(140,827)	-6.7%
316.00	Miscellaneous Power Plant Equipment	1,903,073	79,578	1,823,495		-6.7%		(122,645)	(122,645)	-6.4%
	Total Four Corners Unit 5	$ 47,450,221	$ 2,020,801	$ 45,429,420	-4.8%	-6.7%	$ (97,061)	$ (3,055,496)	$ (3,152,557)	-6.6%
Navajo										
310.00	Rights-of-Way	$ 12,229	$ 506	$ 11,723		-6.3%	$ -	$ (737)	$ (737)	-6.0%
311.00	Structures and Improvements	18,655,156	647,268	18,007,888	-5.0%	-6.0%	(32,363)	(1,089,199)	(1,121,562)	-6.0%
312.00	Boiler Plant Equipment	88,544,201	2,742,632	85,801,569	-5.0%	-5.9%	(137,132)	(5,076,897)	(5,214,029)	-5.9%
314.00	Turbogenerator Units	20,255,526	611,609	19,643,917	-5.0%	-5.9%	(30,580)	(1,157,213)	(1,187,794)	-5.9%
315.00	Accessory Electric Equipment	14,829,858	486,654	14,343,204	-5.0%	-6.0%	(24,333)	(855,914)	(880,246)	-5.9%
316.00	Miscellaneous Power Plant Equipment	4,518,597	164,224	4,354,373		-6.2%		(268,361)	(268,361)	-5.9%
	Total Navajo	$ 146,815,567	$ 4,652,894	$ 142,162,673	-4.8%	-5.9%	$ (224,408)	$ (8,448,321)	$ (8,672,729)	-5.9%
Navajo Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,190,563	35,076	3,155,487	-5.0%	-5.0%	(1,754)	(156,480)	(158,234)	-5.0%
312.00	Boiler Plant Equipment	27,198,582	289,406	26,909,176	-5.0%	-5.0%	(14,470)	(1,334,421)	(1,348,891)	-5.0%
314.00	Turbogenerator Units	6,860,989	73,135	6,787,854	-5.0%	-5.0%	(3,657)	(336,608)	(340,265)	-5.0%
315.00	Accessory Electric Equipment	3,544,300	37,858	3,506,442	-5.0%	-5.0%	(1,893)	(173,884)	(175,777)	-5.0%
316.00	Miscellaneous Power Plant Equipment	471,227	5,200	466,027		-5.0%		(23,110)	(23,110)	-4.9%
	Total Navajo Unit 1	$ 41,265,661	$ 440,676	$ 40,824,985	-4.9%	-5.0%	$ (21,774)	$ (2,024,503)	$ (2,046,277)	-5.0%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
			Interim	Final	Interim	Final	Interim	Final	Total	
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Navajo Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,802,685	73,142	1,729,543	-5.0%	-6.7%	(3,657)	(115,420)	(119,077)	-6.6%
312.00	Boiler Plant Equipment	26,882,286	1,080,667	25,801,619	-5.0%	-6.7%	(54,033)	(1,721,861)	(1,775,894)	-6.6%
314.00	Turbogenerator Units	6,926,050	277,187	6,648,863	-5.0%	-6.7%	(13,859)	(443,709)	(457,569)	-6.6%
315.00	Accessory Electric Equipment	3,172,330	127,256	3,045,074	-5.0%	-6.7%	(6,363)	(203,212)	(209,575)	-6.6%
316.00	Miscellaneous Power Plant Equipment	515,874	21,188	494,686		-6.7%		(33,013)	(33,013)	-6.4%
	Total Navajo Unit 2	$ 39,299,225	$ 1,579,440	$ 37,719,785	-4.9%	-6.7%	$ (77,913)	$ (2,517,215)	$ (2,595,128)	-6.6%
Navajo Unit 3										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,681,511	150,256	3,531,255	-5.0%	-6.1%	(7,513)	(214,054)	(221,567)	-6.0%
312.00	Boiler Plant Equipment	27,718,514	1,110,320	26,608,194	-5.0%	-6.1%	(55,516)	(1,612,907)	(1,668,423)	-6.0%
314.00	Turbogenerator Units	6,178,944	250,312	5,928,632	-5.0%	-6.1%	(12,516)	(359,375)	(371,891)	-6.0%
315.00	Accessory Electric Equipment	5,139,872	208,272	4,931,600	-5.0%	-6.1%	(10,414)	(298,938)	(309,352)	-6.0%
316.00	Miscellaneous Power Plant Equipment	549,362	22,448	526,914		-6.1%		(31,940)	(31,940)	-5.8%
	Total Navajo Unit 3	$ 43,268,203	$ 1,741,608	$ 41,526,595	-4.9%	-6.1%	$ (85,958)	$ (2,517,215)	$ (2,603,173)	-6.0%
Navajo Common										
310.00	Rights-of-Way	$ 12,229	$ 506	$ 11,723		-6.3%	$ -	$ (737)	$ (737)	-6.0%
311.00	Structures and Improvements	9,980,397	388,794	9,591,603	-5.0%	-6.3%	(19,440)	(603,244)	(622,684)	-6.2%
312.00	Boiler Plant Equipment	6,744,819	262,239	6,482,580	-5.0%	-6.3%	(13,112)	(407,709)	(420,821)	-6.2%
314.00	Turbogenerator Units	289,543	10,974	278,569	-5.0%	-6.3%	(549)	(17,520)	(18,069)	-6.2%
315.00	Accessory Electric Equipment	2,973,356	113,268	2,860,088	-5.0%	-6.3%	(5,663)	(179,879)	(185,543)	-6.2%
316.00	Miscellaneous Power Plant Equipment	2,982,134	115,388	2,866,746		-6.3%		(180,298)	(180,298)	-6.0%
	Total Navajo Common	$ 22,982,478	$ 891,170	$ 22,091,308	-4.3%	-6.3%	$ (38,764)	$ (1,389,388)	$ (1,428,152)	-6.2%
San Juan										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	14,437,744	463,504	13,974,240	-5.0%	-9.7%	(23,175)	(1,358,633)	(1,381,809)	-9.6%
312.00	Boiler Plant Equipment	154,506,908	4,871,333	149,635,575	-5.0%	-12.0%	(243,567)	(17,890,509)	(18,134,076)	-11.7%
314.00	Turbogenerator Units	44,295,673	1,411,705	42,883,968	-5.0%	-9.8%	(70,585)	(4,218,946)	(4,289,532)	-9.7%
315.00	Accessory Electric Equipment	10,063,526	319,494	9,744,032	-5.0%	-9.8%	(15,975)	(958,623)	(974,597)	-9.7%
316.00	Miscellaneous Power Plant Equipment	2,009,555	63,827	1,945,728		-9.6%		(186,709)	(186,709)	-9.3%
	Total San Juan	$ 225,313,406	$ 7,129,861	$ 218,183,545	-5.0%	-11.3%	$ (353,302)	$ (24,613,421)	$ (24,966,723)	-11.1%
San Juan Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	14,268,404	458,417	13,809,987	-5.0%	-9.8%	(22,921)	(1,358,633)	(1,381,554)	-9.7%
312.00	Boiler Plant Equipment	146,453,029	4,622,894	141,830,135	-5.0%	-9.8%	(231,145)	(13,953,320)	(14,184,465)	-9.7%
314.00	Turbogenerator Units	44,295,673	1,411,705	42,883,968	-5.0%	-9.8%	(70,585)	(4,218,946)	(4,289,532)	-9.7%
315.00	Accessory Electric Equipment	10,063,526	319,494	9,744,032	-5.0%	-9.8%	(15,975)	(958,623)	(974,597)	-9.7%
316.00	Miscellaneous Power Plant Equipment	1,960,172	62,343	1,897,829		-9.8%		(186,709)	(186,709)	-9.5%
	Total San Juan Unit 1	$ 217,040,804	$ 6,874,853	$ 210,165,951	-5.0%	-9.8%	$ (340,625)	$ (20,676,232)	$ (21,016,858)	-9.7%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
San Juan Common										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	169,340	5,087	164,253	-5.0%		(254)		(254)	-0.2%
312.00	Boiler Plant Equipment	8,053,879	248,439	7,805,440	-5.0%	-50.4%	(12,422)	(3,937,189)	(3,949,611)	-49.0%
314.00	Turbogenerator Units									
315.00	Accessory Electric Equipment									
316.00	Miscellaneous Power Plant Equipment	49,383	1,483	47,900						
	Total San Juan Common	$ 8,272,602	$ 255,009	$ 8,017,593	-5.0%	-50.4%	$ (12,676)	$ (4,044,202)	$ (3,949,865)	-47.7%
Springerville										
310.00	Rights-of-Way	$ 5,094,433	$ 303,737	$ 4,790,696			$ -	$ -	$ -	
311.00	Structures and Improvements	141,726,641	9,894,361	131,832,280	-5.0%	-18.8%	(494,718)	(24,737,530)	(25,232,248)	-17.8%
312.00	Boiler Plant Equipment	641,687,365	56,287,561	585,399,804	-5.0%	-19.6%	(2,814,378)	(114,733,067)	(117,547,445)	-18.3%
314.00	Turbogenerator Units	173,649,915	15,167,291	158,482,624	-5.0%	-6.7%	(758,365)	(10,669,694)	(11,428,059)	-6.6%
315.00	Accessory Electric Equipment	75,864,618	6,485,462	69,379,156	-5.0%	-9.2%	(324,273)	(6,349,839)	(6,674,112)	-8.8%
316.00	Miscellaneous Power Plant Equipment	12,528,984	1,039,506	11,489,478		-10.1%		(1,164,365)	(1,164,365)	-9.3%
	Total Springerville	$ 1,050,551,956	$ 89,177,919	$ 961,374,037	-4.9%	-16.4%	$ (4,391,734)	$ (157,654,494)	$ (162,046,228)	-15.4%
Springerville Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	20,076,015	1,594,824	18,481,191	-5.0%	-5.5%	(79,741)	(1,014,863)	(1,094,604)	-5.5%
312.00	Boiler Plant Equipment	185,682,490	14,793,478	170,889,012	-5.0%	-5.5%	(739,674)	(9,384,078)	(10,123,752)	-5.5%
314.00	Turbogenerator Units	49,547,312	3,948,245	45,599,067	-5.0%	-5.5%	(197,412)	(2,503,995)	(2,701,407)	-5.5%
315.00	Accessory Electric Equipment	21,214,167	1,711,130	19,503,037	-5.0%	-5.5%	(85,557)	(1,070,976)	(1,156,532)	-5.5%
316.00	Miscellaneous Power Plant Equipment	3,277,742	259,549	3,018,193		-5.5%		(165,739)	(165,739)	-5.1%
	Total Springerville Unit 1	$ 279,797,726	$ 22,307,227	$ 257,490,499	-4.9%	-5.5%	$ (1,102,384)	$ (14,139,651)	$ (15,242,035)	-5.4%
Springerville Unit 1 Common										
310.00	Rights-of-Way	$ 1,143,496	$ 90,874	$ 1,052,622			$ -	$ -	$ -	
311.00	Structures and Improvements	52,492,826	4,192,244	48,300,582	-5.0%	-17.8%	(209,612)	(8,619,543)	(8,829,155)	-16.8%
312.00	Boiler Plant Equipment	14,854,799	1,188,740	13,666,059	-5.0%	-17.8%	(59,437)	(2,438,794)	(2,498,231)	-16.8%
314.00	Turbogenerator Units	1,264,322	101,482	1,162,840	-5.0%	-17.8%	(5,074)	(207,516)	(212,590)	-16.8%
315.00	Accessory Electric Equipment	9,627,097	778,804	8,848,293	-5.0%	-17.8%	(38,940)	(1,579,034)	(1,617,974)	-16.8%
316.00	Miscellaneous Power Plant Equipment	1,959,012	158,119	1,800,893		-17.8%		(321,381)	(321,381)	-16.4%
	Total Springerville Unit 1 Common	$ 81,341,552	$ 6,510,263	$ 74,831,289	-4.8%	-17.8%	$ (313,063)	$ (13,354,115)	$ (13,479,331)	-16.6%
Springerville Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	36,540,030	3,339,714	33,200,316	-5.0%	-6.9%	(166,986)	(2,289,215)	(2,456,200)	-6.7%
312.00	Boiler Plant Equipment	295,922,545	27,119,399	268,803,146	-5.0%	-6.9%	(1,355,970)	(18,534,404)	(19,890,374)	-6.7%
314.00	Turbogenerator Units	122,055,348	11,099,142	110,956,206	-5.0%	-6.9%	(554,957)	(7,650,607)	(8,205,564)	-6.7%
315.00	Accessory Electric Equipment	42,346,939	3,931,538	38,415,401	-5.0%	-6.9%	(196,577)	(2,648,803)	(2,845,380)	-6.7%
316.00	Miscellaneous Power Plant Equipment	6,624,669	606,145	6,018,524		-6.9%		(414,987)	(414,987)	-6.3%
	Total Springerville Unit 2	$ 503,489,531	$ 46,095,938	$ 457,393,593	-4.9%	-6.9%	$ (2,274,490)	$ (31,538,015)	$ (33,812,505)	-6.7%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Springerville Unit 2 Common (Leasehold Imp.)										
310.00	Rights-of-Way	$ 2,280,838	$ 54,667	$ 2,226,171			$ -	$ -	$ -	
311.00	Structures and Improvements	32,617,770	767,579	31,850,191	-5.0%	-40.2%	(38,379)	(12,813,909)	(12,852,288)	-39.4%
312.00	Boiler Plant Equipment	6,282,729	145,696	6,137,033	-5.0%	-40.2%	(7,285)	(2,469,040)	(2,476,324)	-39.4%
314.00	Turbogenerator Units	782,933	18,422	764,511	-5.0%	-40.2%	(921)	(307,577)	(308,498)	-39.4%
315.00	Accessory Electric Equipment	2,676,415	63,990	2,612,425	-5.0%	-40.2%	(3,199)	(1,051,026)	(1,054,225)	-39.4%
316.00	Miscellaneous Power Plant Equipment	667,561	15,693	651,868		-40.2%		(262,258)	(262,258)	-39.3%
	Total Springerville Unit 2 Common	$ 45,308,246	$ 1,066,047	$ 44,242,199	-4.7%	-40.2%	$ (49,784)	$ (17,799,439)	$ (16,953,594)	-37.4%
Springerville Coal Handling										
310.00	Rights-of-Way	$ 1,670,099	$ 158,196	$ 1,511,903			$ -	$ -	$ -	
311.00	Structures and Improvements					-65.1%				
312.00	Boiler Plant Equipment	138,944,802	13,040,248	125,904,554	-5.0%	-65.1%	(652,012)	(81,906,750)	(82,558,763)	-59.4%
314.00	Turbogenerator Units					-65.1%				
315.00	Accessory Electric Equipment					-65.1%				
316.00	Miscellaneous Power Plant Equipment					-65.1%				
	Total Springerville Coal Handling	$ 140,614,901	$ 13,198,444	$ 127,416,457	-4.9%	-65.1%	$ (652,012)	$ (82,890,314)	$ (82,558,763)	-58.7%
Sundt										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	27,475,371	1,952,799	25,522,572	-5.0%	-47.1%	(97,640)	(12,015,852)	(12,113,492)	-44.1%
312.00	Boiler Plant Equipment	130,812,626	9,546,882	121,265,744	-5.0%	-43.3%	(477,344)	(52,478,127)	(52,955,471)	-40.5%
314.00	Turbogenerator Units	52,481,329	2,986,121	49,495,208	-5.0%	-58.3%	(149,306)	(28,870,189)	(29,019,495)	-55.3%
315.00	Accessory Electric Equipment	39,432,489	2,508,542	36,923,947	-5.0%	-52.0%	(125,427)	(19,184,918)	(19,310,345)	-49.0%
316.00	Miscellaneous Power Plant Equipment	2,333,493	139,906	2,193,587		-54.1%		(1,186,405)	(1,186,405)	-50.8%
	Total Sundt	$ 252,535,308	$ 17,134,249	$ 235,401,059	-5.0%	-48.3%	$ (849,717)	$ (113,735,492)	$ (114,585,209)	-45.4%
Sundt Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,926,062	136,193	3,789,869	-5.0%	-60.6%	(6,810)	(2,295,820)	(2,302,630)	-58.6%
312.00	Boiler Plant Equipment	13,782,181	471,482	13,310,699	-5.0%	-60.6%	(23,574)	(8,063,333)	(8,086,908)	-58.7%
314.00	Turbogenerator Units	10,237,507	350,214	9,887,293	-5.0%	-60.6%	(17,511)	(5,989,508)	(6,007,019)	-58.7%
315.00	Accessory Electric Equipment	6,536,315	216,751	6,319,564	-5.0%	-60.6%	(10,838)	(3,828,255)	(3,839,093)	-58.7%
316.00	Miscellaneous Power Plant Equipment	490,578	16,412	474,166		-60.6%		(287,239)	(287,239)	-58.6%
	Total Sundt Unit 1	$ 34,972,643	$ 1,191,052	$ 33,781,591	-4.9%	-60.6%	$ (58,732)	$ (20,464,157)	$ (20,522,889)	-58.7%
Sundt Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	2,812,689	110,169	2,702,520	-5.0%	-68.8%	(5,508)	(1,859,111)	(1,864,619)	-66.3%
312.00	Boiler Plant Equipment	14,371,609	571,825	13,799,784	-5.0%	-68.8%	(28,591)	(9,493,113)	(9,521,704)	-66.3%
314.00	Turbogenerator Units	8,451,923	342,504	8,109,419	-5.0%	-68.8%	(17,125)	(5,578,611)	(5,595,737)	-66.2%
315.00	Accessory Electric Equipment	6,205,700	236,730	5,968,970	-5.0%	-68.8%	(11,837)	(4,106,159)	(4,117,995)	-66.4%
316.00	Miscellaneous Power Plant Equipment	383,824	14,718	369,106		-68.8%		(253,915)	(253,915)	-66.2%
	Total Sundt Unit 2	$ 32,225,745	$ 1,275,947	$ 30,949,798	-4.9%	-68.8%	$ (63,061)	$ (21,290,908)	$ (21,353,970)	-66.3%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Sundt Unit 3										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	2,762,012	124,459	2,637,553	-5.0%	-79.0%	(6,223)	(2,084,065)	(2,090,288)	-75.7%
312.00	Boiler Plant Equipment	11,980,831	543,246	11,437,585	-5.0%	-79.0%	(27,162)	(9,037,421)	(9,064,583)	-75.7%
314.00	Turbogenerator Units	14,830,615	662,973	14,167,642	-5.0%	-79.0%	(33,149)	(11,194,579)	(11,227,728)	-75.7%
315.00	Accessory Electric Equipment	6,140,139	271,786	5,868,353	-5.0%	-79.0%	(13,589)	(4,636,886)	(4,650,475)	-75.7%
316.00	Miscellaneous Power Plant Equipment	404,717	17,752	386,965		-79.0%		(305,761)	(305,761)	-75.5%
	Total Sundt Unit 3	$ 36,118,314	$ 1,620,216	$ 34,498,098	-4.9%	-79.0%	$ (80,123)	$ (27,258,712)	$ (27,338,836)	-75.7%
Sundt Unit 4										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	17,974,608	1,581,977	16,392,631	-5.0%	-35.2%	(79,099)	(5,776,856)	(5,855,955)	-32.6%
312.00	Boiler Plant Equipment	80,576,055	7,125,872	73,450,183	-5.0%	-35.2%	(356,294)	(25,884,260)	(26,240,553)	-32.6%
314.00	Turbogenerator Units	18,961,284	1,630,429	17,330,855	-5.0%	-35.2%	(81,521)	(6,107,491)	(6,189,013)	-32.6%
315.00	Accessory Electric Equipment	20,550,335	1,783,275	18,767,060	-5.0%	-35.2%	(89,164)	(6,613,618)	(6,702,782)	-32.6%
316.00	Miscellaneous Power Plant Equipment	1,054,374	91,024	963,350		-35.2%		(339,490)	(339,490)	-32.2%
	Total Sundt Unit 4	$ 139,116,656	$ 12,212,578	$ 126,904,078	-5.0%	-35.2%	$ (606,078)	$ (44,721,715)	$ (45,327,792)	-32.6%
Sundt Solar Booster (Areva)										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements									
312.00	Boiler Plant Equipment	10,101,950	834,456	9,267,494	-5.0%		(41,723)		(41,723)	-0.4%
314.00	Turbogenerator Units									
315.00	Accessory Electric Equipment									
316.00	Miscellaneous Power Plant Equipment									
	Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 834,456	$ 9,267,494	-5.0%		$ (41,723)	$ -	$ (41,723)	-0.4%
OTHER PRODUCTION (by Unit)										
DeMoss Petrie Gas Unit 1										
341.00	Structures and Improvements	$ 761,988	$ 60,324	$ 701,664		-9.8%	$ -	$ (68,785)	$ (68,785)	-9.0%
342.00	Fuel Holders, Products and Accessories	750,386	60,186	690,200		-9.8%		(67,661)	(67,661)	-9.0%
343.00	Prime Movers	76,766	6,017	70,749		-9.8%		(6,936)	(6,936)	-9.0%
344.00	Generators and Devices	30,772,866	2,467,553	28,305,313		-9.8%		(2,774,788)	(2,774,788)	-9.0%
345.00	Accessory Electric Equipment	861,492	68,973	792,519		-9.8%		(77,691)	(77,691)	-9.0%
346.00	Miscellaneous Power Plant Equipment	376,605	30,058	346,547		-9.8%		(33,972)	(33,972)	-9.0%
	Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 2,693,110	$ 30,906,993		-9.8%	$ -	$ (3,029,833)	$ (3,029,833)	-9.0%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Gila River										
341.00	Structures and Improvements	$ 8,508,950	$ 722,006	$ 7,786,944		-9.1%	$ -	$ (710,156)	$ (710,156)	-8.3%
342.00	Fuel Holders, Products and Accessories	6,783,045	575,960	6,207,085		-9.1%		(566,355)	(566,355)	-8.3%
343.00	Prime Movers	188,744,730	15,990,013	172,754,717		-9.1%		(15,678,278)	(15,678,278)	-8.3%
344.00	Generators and Devices	32,783,434	2,784,699	29,998,735		-9.1%		(2,721,926)	(2,721,926)	-8.3%
345.00	Accessory Electric Equipment	9,030,698	766,677	8,264,021		-9.1%		(750,871)	(750,871)	-8.3%
346.00	Miscellaneous Power Plant Equipment	6,799,960	577,149	6,222,811		-9.1%		(567,811)	(567,811)	-8.4%
	Total Gila River	$ 252,650,817	$ 21,416,503	$ 231,234,314		-9.1%	$ -	$ (20,995,398)	$ (20,995,398)	-8.3%
Gila River Unit 3										
341.00	Structures and Improvements	$ 957,417	$ 81,280	$ 876,137		-9.1%	$ -	$ (79,496)	$ (79,496)	-8.3%
342.00	Fuel Holders, Products and Accessories	178,424	15,110	163,314		-9.1%		(14,818)	(14,818)	-8.3%
343.00	Prime Movers	181,571,712	15,386,002	166,185,710		-9.1%		(15,078,810)	(15,078,810)	-8.3%
344.00	Generators and Devices	32,783,434	2,784,699	29,998,735		-9.1%		(2,721,926)	(2,721,926)	-8.3%
345.00	Accessory Electric Equipment	6,860,554	582,436	6,278,118		-9.1%		(569,643)	(569,643)	-8.3%
346.00	Miscellaneous Power Plant Equipment	135,558	11,493	124,065		-9.1%		(11,257)	(11,257)	-8.3%
	Total Gila River Unit 3	$ 222,487,099	$ 18,861,018	$ 203,626,081		-9.1%	$ -	$ (18,475,950)	$ (18,475,950)	-8.3%
Gila River Common										
341.00	Structures and Improvements	$ 7,551,533	$ 640,726	$ 6,910,807		-9.1%	$ -	$ (630,660)	$ (630,660)	-8.4%
342.00	Fuel Holders, Products and Accessories	6,604,621	560,850	6,043,771		-9.1%		(551,537)	(551,537)	-8.4%
343.00	Prime Movers	7,173,018	604,011	6,569,007		-9.1%		(599,469)	(599,469)	-8.4%
344.00	Generators and Devices					-9.1%				
345.00	Accessory Electric Equipment	2,170,144	184,242	1,985,902		-9.1%		(181,228)	(181,228)	-8.4%
346.00	Miscellaneous Power Plant Equipment	6,664,402	565,656	6,098,746		-9.1%		(556,554)	(556,554)	-8.4%
	Total Gila River Common	$ 30,163,718	$ 2,555,485	$ 27,608,233		-9.1%	$ -	$ (2,519,448)	$ (2,519,448)	-8.4%
Luna										
341.00	Structures and Improvements	$ 13,232,832	$ 1,216,311	$ 12,016,521		-20.7%	$ -	$ (2,487,831)	$ (2,487,831)	-18.8%
342.00	Fuel Holders, Products and Accessories	11,352,383	1,043,899	10,308,484		-20.7%		(2,134,208)	(2,134,208)	-18.8%
343.00	Prime Movers	11,151,074	1,011,828	10,139,246		-20.7%		(2,099,170)	(2,099,170)	-18.8%
344.00	Generators and Devices	9,486,694	871,757	8,614,937		-20.7%		(1,783,587)	(1,783,587)	-18.8%
345.00	Accessory Electric Equipment	9,647	869	8,778		-20.7%		(1,817)	(1,817)	-18.8%
346.00	Miscellaneous Power Plant Equipment	7,424,592	682,593	6,741,999		-20.7%		(1,395,824)	(1,395,824)	-18.8%
	Total Luna	$ 52,657,222	$ 4,827,258	$ 47,829,964		-20.7%	$ -	$ (9,902,437)	$ (9,902,437)	-18.8%
North Loop Gas										
341.00	Structures and Improvements	$ 888,601	$ 32,853	$ 855,748		-14.8%	$ -	$ (126,609)	$ (126,609)	-14.2%
342.00	Fuel Holders, Products and Accessories	303,037	24,306	278,731		-6.2%		(17,384)	(17,384)	-5.7%
343.00	Prime Movers	1,890,946	57,217	1,833,729		-15.9%		(291,465)	(291,465)	-15.4%
344.00	Generators and Devices	24,062,187	1,464,066	22,598,121		-10.4%		(2,361,288)	(2,361,288)	-9.8%
345.00	Accessory Electric Equipment	2,829,171	140,177	2,688,994		-12.5%		(336,519)	(336,519)	-11.9%
346.00	Miscellaneous Power Plant Equipment	656,253	25,875	630,378		-14.3%		(90,033)	(90,033)	-13.7%
	Total North Loop Gas	$ 30,630,195	$ 1,744,493	$ 28,885,702		-11.2%	$ -	$ (3,223,298)	$ (3,223,298)	-10.5%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
North Loop Gas Unit 1										
341.00	Structures and Improvements	$ 411,070	$ 13,106	$ 397,964		-13.9%	$ -	$ (55,157)	$ (55,157)	-13.4%
342.00	Fuel Holders, Products and Accessories					-13.9%				
343.00	Prime Movers	678,545	20,776	657,769		-13.9%		(91,166)	(91,166)	-13.4%
344.00	Generators and Devices	3,582,271	117,192	3,465,079		-13.9%		(480,257)	(480,257)	-13.4%
345.00	Accessory Electric Equipment	790,955	25,195	765,760		-13.9%		(106,134)	(106,134)	-13.4%
346.00	Miscellaneous Power Plant Equipment	306,369	9,806	296,563		-13.9%		(41,103)	(41,103)	-13.4%
	Total North Loop Gas Unit 1	$ 5,769,210	$ 186,076	$ 5,583,134		-13.9%	$ -	$ (773,818)	$ (773,818)	-13.4%
North Loop Gas Unit 2										
341.00	Structures and Improvements	$ 196,078	$ 6,462	$ 189,616		-18.5%	$ -	$ (35,010)	$ (35,010)	-17.9%
342.00	Fuel Holders, Products and Accessories					-18.5%				
343.00	Prime Movers	263,450	7,568	255,882		-18.5%		(47,245)	(47,245)	-17.9%
344.00	Generators and Devices	3,239,719	106,945	3,132,774		-18.5%		(578,419)	(578,419)	-17.9%
345.00	Accessory Electric Equipment	504,895	16,336	488,559		-18.5%		(90,205)	(90,205)	-17.9%
346.00	Miscellaneous Power Plant Equipment	128,559	4,314	124,245		-18.5%		(22,940)	(22,940)	-17.8%
	Total North Loop Gas Unit 2	$ 4,332,701	$ 141,626	$ 4,191,075		-18.5%	$ -	$ (773,818)	$ (773,818)	-17.9%
North Loop Gas Unit 3										
341.00	Structures and Improvements	$ 196,078	$ 6,462	$ 189,616		-16.6%	$ -	$ (31,542)	$ (31,542)	-16.1%
342.00	Fuel Holders, Products and Accessories					-16.6%				
343.00	Prime Movers	948,951	28,872	920,079		-16.6%		(153,054)	(153,054)	-16.1%
344.00	Generators and Devices	3,030,531	100,299	2,930,232		-16.6%		(487,441)	(487,441)	-16.1%
345.00	Accessory Electric Equipment	503,907	16,306	487,601		-16.6%		(81,112)	(81,112)	-16.1%
346.00	Miscellaneous Power Plant Equipment	128,559	4,314	124,245		-16.6%		(20,668)	(20,668)	-16.1%
	Total North Loop Gas Unit 3	$ 4,808,026	$ 156,254	$ 4,651,772		-16.6%	$ -	$ (773,818)	$ (773,818)	-16.1%
North Loop Gas Unit 4										
341.00	Structures and Improvements	$ 85,375	$ 6,822	$ 78,553		-6.2%	$ -	$ (4,899)	$ (4,899)	-5.7%
342.00	Fuel Holders, Products and Accessories	303,037	24,306	278,731		-6.2%		(17,384)	(17,384)	-5.7%
343.00	Prime Movers					-6.2%				
344.00	Generators and Devices	14,209,666	1,139,629	13,070,037		-6.2%		(815,171)	(815,171)	-5.7%
345.00	Accessory Electric Equipment	1,029,414	82,340	947,074		-6.2%		(59,068)	(59,068)	-5.7%
346.00	Miscellaneous Power Plant Equipment	92,766	7,441	85,325		-6.2%		(5,322)	(5,322)	-5.7%
	Total North Loop Gas Unit 4	$ 15,720,258	$ 1,260,537	$ 14,459,721		-6.2%	$ -	$ (901,845)	$ (901,845)	-5.7%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Solar Units (Generators and Devices)										
344.00	DeMoss Petrie	$ 1,146,081	$ 1,146,081	$ -	-5.0%		$ (57,304)	$ -	$ (57,304)	-5.0%
344.00	Fort Huachuca	36,709,538	36,709,538		-5.0%		(1,835,477)		(1,835,477)	-5.0%
344.00	HQ Rooftop	303,184	303,184		-5.0%		(15,159)		(15,159)	-5.0%
344.00	OH Rooftop	2,594,590	2,594,590		-5.0%		(129,730)		(129,730)	-5.0%
344.00	OH Test Yard	388,459	388,459		-5.0%		(19,423)		(19,423)	-5.0%
344.00	Prairie Fire	19,036,520	19,036,520		-5.0%		(951,826)		(951,826)	-5.0%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	28,766,605		-5.0%		(1,438,330)		(1,438,330)	-5.0%
344.00	Springerville Site 4	7,873,874	7,873,874		-5.0%		(393,694)		(393,694)	-5.0%
344.00	Tucson	87,198	87,198		-5.0%		(4,360)		(4,360)	-5.0%
344.00	U of A Tech Park Site 1	7,723,832	7,723,832		-5.0%		(386,192)		(386,192)	-5.0%
344.00	U of A Tech Park Site 2	19,191,952	19,191,952		-5.0%		(959,598)		(959,598)	-5.0%
344.00	White Mountain	46,499,099	46,499,099		-5.0%		(2,324,955)		(2,324,955)	-5.0%
	Total Solar Units	$ 170,320,932	$ 170,320,932	$ -	-5.0%		$ (8,516,047)	$ -	$ (8,516,047)	-5.0%
Sundt Gas										
341.00	Structures and Improvements	$ 11,090	$ 360	$ 10,730		-2.2%	$ -	$ (237)	$ (237)	-2.1%
342.00	Fuel Holders, Products and Accessories	788,336	24,187	764,149		-2.2%		(16,851)	(16,851)	-2.1%
343.00	Prime Movers	141,618	4,397	137,221		-2.2%		(3,026)	(3,026)	-2.1%
344.00	Generators and Devices	8,382,044	274,685	8,107,359		-2.2%		(178,687)	(178,687)	-2.1%
345.00	Accessory Electric Equipment	1,078,811	35,096	1,043,715		-2.2%		(23,034)	(23,034)	-2.1%
346.00	Miscellaneous Power Plant Equipment	49,750	1,662	48,088		-2.2%		(1,064)	(1,064)	-2.1%
	Total Sundt Gas	$ 10,451,649	$ 340,387	$ 10,111,262		-2.2%	$ -	$ (222,899)	$ (222,899)	-2.1%
Sundt Gas Unit 1										
341.00	Structures and Improvements	$ 5,545	$ 180	$ 5,365		-2.2%	$ -	$ (116)	$ (116)	-2.1%
342.00	Fuel Holders, Products and Accessories	394,168	12,093	382,075		-2.2%		(8,270)	(8,270)	-2.1%
343.00	Prime Movers	70,809	2,198	68,611		-2.2%		(1,485)	(1,485)	-2.1%
344.00	Generators and Devices	4,315,668	141,569	4,174,099		-2.2%		(90,352)	(90,352)	-2.1%
345.00	Accessory Electric Equipment	516,231	16,832	499,399		-2.2%		(10,810)	(10,810)	-2.1%
346.00	Miscellaneous Power Plant Equipment	19,906	666	19,240		-2.2%		(416)	(416)	-2.1%
	Total Sundt Gas Unit 1	$ 5,322,327	$ 173,539	$ 5,148,788		-2.2%	$ -	$ (111,450)	$ (111,450)	-2.1%
Sundt Gas Unit 2										
341.00	Structures and Improvements	$ 5,545	$ 180	$ 5,365		-2.2%	$ -	$ (120)	$ (120)	-2.2%
342.00	Fuel Holders, Products and Accessories	394,168	12,093	382,075		-2.2%		(8,581)	(8,581)	-2.2%
343.00	Prime Movers	70,809	2,198	68,611		-2.2%		(1,541)	(1,541)	-2.2%
344.00	Generators and Devices	4,066,376	133,116	3,933,260		-2.2%		(88,335)	(88,335)	-2.2%
345.00	Accessory Electric Equipment	562,580	18,264	544,316		-2.2%		(12,225)	(12,225)	-2.2%
346.00	Miscellaneous Power Plant Equipment	29,844	996	28,848		-2.2%		(648)	(648)	-2.2%
	Total Sundt Gas Unit 2	$ 5,129,322	$ 166,848	$ 4,962,474		-2.2%	$ -	$ (111,450)	$ (111,450)	-2.2%

TUCSON ELECTRIC POWER COMPANY

Statement G

Dismantlement Costs

Steam and Other Production

Unit	Capacity (MW)	Ownership Share	Shared Cost	Final Retirement	Distributed Cost	Inflation Rate	Spend Year	Trended Cost	Accrual Rate
A	B	C	D	E	F	G	H	I	J=I/E
STEAM PRODUCTION (by Unit)									
Four Corners (2009 Cost)									
4	785	7.00%		$ 50,280,447	$ 2,225,763	2.00%	2031	$ 3,055,496	6.1%
5	785	7.00%		45,429,420	2,225,763	2.00%	2031	3,055,496	6.7%
C		5.07%							
	1570		$ 4,451,526	$ 95,709,867	$ 4,451,526			$ 6,110,991	6.4%
	Allocated to Common:								
	Allocated to Units:		$ 4,451,526						
Navajo (2011 Cost)									
1	750	7.50%		$ 40,824,985	$ 1,727,894	2.00%	2019	$ 2,024,503	5.0%
2	750	7.50%		37,719,785	1,727,894	2.00%	2030	2,517,215	6.7%
3	750	7.50%		41,526,595	1,727,894	2.00%	2030	2,517,215	6.1%
C				22,091,308	953,719	2.00%	2030	1,389,388	6.3%
	2250		$ 6,137,400	$ 142,162,673	$ 6,137,400			$ 8,448,321	5.9%
	Allocated to Common:		953,719						
	Allocated to Units:		$ 5,183,681						
San Juan (2011 Cost)									
1	340	50.00%		$ 210,165,951	$ 15,670,000	2.00%	2027	$ 20,676,232	9.8%
C		50.00%		8,017,593	3,065,000	2.00%	2027	4,044,202	50.4%
	340		$ 18,735,000	$ 218,183,545	$ 18,735,000			$ 24,720,435	11.3%
	Allocated to Common:		3,065,000						
	Allocated to Units:		$ 15,670,000						
Springerville (2011 Cost)									
1	387	49.50%	$ 7,211,620	$ 257,490,499	$ 7,211,620	2.00%	2045	$ 14,139,651	5.5%
1C		49.50%	6,810,975	74,831,289	6,810,975	2.00%	2045	13,354,115	17.8%
2	390	100.00%	14,568,930	457,393,593	14,568,930	2.00%	2050	31,538,015	6.9%
2C		100.00%	13,759,545	44,242,199	13,759,545	2.00%	2024	17,799,439	40.2%
CH		49.28%	38,291,033	127,416,457	38,291,033	2.00%	2050	82,890,314	65.1%
	777		$ 80,642,103	$ 961,374,037	$ 80,642,103			$ 159,721,533	16.6%
	Allocated to Common:								
	Allocated to Units:		$ 80,642,103						
Sundt (2011 Cost)									
1	81	100.00%	$ 5,501,274	$ 33,781,591	$ 14,614,734	2.00%	2028	$ 20,464,157	60.6%
2	81	100.00%	5,501,274	30,949,798	14,614,734	2.00%	2030	21,290,908	68.8%
3	104	100.00%	6,283,406	34,498,098	17,984,639	2.00%	2032	27,258,712	79.0%
4	120	100.00%	7,992,322	126,904,078	21,493,745	2.00%	2048	44,721,715	35.2%
C			43,429,577						
	386		$ 68,707,853	$ 226,133,565	$ 68,707,853			$ 113,735,492	50.3%
	Allocated to Common:								
	Allocated to Units:		$ 68,707,853						
OTHER PRODUCTION (by Unit)									
DeMoss Petrie (2011 Cost)									
1	75	100.00%	$ 1,515,000	$ 30,906,993	$ 1,515,000	2.00%	2046	$ 3,029,833	9.8%
C									
	75		$ 1,515,000	$ 30,906,993	$ 1,515,000			$ 3,029,833	9.8%
	Allocated to Common:								
	Allocated to Units:		$ 1,515,000						
Gila River (2011 Costs)									
3	550	75.00%		$ 203,626,081	$ 8,879,744	2.00%	2048	$ 18,475,950	9.1%
C		75.00%	1,614,499	27,608,233	1,210,874	2.00%	2048	2,519,448	9.1%
	550		$ 10,090,618	$ 231,234,314	$ 10,090,618			$ 20,995,398	9.1%
	Allocated to Common:		1,210,874						
	Allocated to Units:		$ 8,879,744						

TUCSON ELECTRIC POWER COMPANY

Statement G

Dismantlement Costs

Steam and Other Production

Unit	Capacity (MW)	Ownership Share	Shared Cost	Final Retirement	Distributed Cost	Inflation Rate	Spend Year	Trended Cost	Accrual Rate
A	B	C	D	E	F	G	H	I	J=I/E
Luna (2011 Costs)									
1	555	33.33%		$ 47,829,964	$ 4,484,719	2.00%	2051	$ 9,902,437	20.7%
C									
	555		$ 4,484,719	$ 47,829,964	$ 4,484,719			$ 9,902,437	20.7%
	Allocated to Common:								
	Allocated to Units:		$ 4,484,719						
North Loop (2011 Costs)									
1	25	100.00%		$ 5,583,134	$ 563,684	2.00%	2027	$ 773,818	13.9%
2	25	100.00%		4,191,075	563,684	2.00%	2027	773,818	18.5%
3	25	100.00%		4,651,772	563,684	2.00%	2027	773,818	16.6%
4	20	100.00%		14,459,721	450,947	2.00%	2046	901,845	6.2%
C									
	95		$ 2,142,000	$ 28,885,702	$ 2,142,000			$ 3,223,298	11.2%
	Allocated to Common:								
	Allocated to Units:		$ 2,142,000						
Solar Units									
1			$ -	$ -	$ -			$ -	
C									
			$ -	$ -	$ -			$ -	
	Allocated to Common:								
	Allocated to Units:		$ -						
Sundt Gas (2011 Costs)									
1	25	100.00%	$ 81,185	$ 5,148,788	$ 81,185	2.00%	2027	$ 111,450	2.2%
2	25	100.00%	81,185	4,962,474	81,185	2.00%	2027	111,450	2.2%
C									
	50		$ 162,370	$ 10,111,262	$ 162,370			$ 222,899	2.2%
	Allocated to Common:								
	Allocated to Units:		$ 162,370						

TUCSON ELECTRIC POWER COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION												
310.00 Rights-of-Way									43.02	18.80		0.0
311.00 Structures and Improvements									35.83	20.41	-16.7	-19.5
312.00 Boiler Plant Equipment									39.35	23.05	-16.4	-18.2
314.00 Turbogenerator Units									37.19	23.25	-13.4	-15.4
315.00 Accessory Electric Equipment									35.88	21.47	-18.6	-19.4
316.00 Miscellaneous Power Plant Equipment									34.83	20.88	-10.9	-12.1
Total Steam Production Plant									38.17	22.58	-15.9	-17.8
OTHER PRODUCTION												
Non-Solar												
341.00 Structures and Improvements									41.75	32.67	-14.3	
342.00 Fuel Holders, Products and Accessories									40.63	31.82	-14.0	
343.00 Prime Movers									40.57	31.72	-8.8	
344.00 Generators and Devices									42.10	28.01	-8.5	
345.00 Accessory Electric Equipment									39.56	26.72	-7.6	
346.00 Miscellaneous Power Plant Equipment									42.19	32.46	-13.6	
Total Non-Solar									41.08	30.62	-9.5	-9.8
Solar												
344.00 Generators and Devices									28.00	24.49	-5.0	
Total Solar									28.00	24.49	-5.0	-5.0
Total Other Production Plant									35.89	28.19	-8.1	-8.3
DISTRIBUTION PLANT												
360.RW Rights-of-Way							60.00	R5	60.00	37.36		
361.00 Structures and Improvements	55.00	R1	55.46	47.86			55.00	R1	55.54	46.15		
362.00 Station Equipment	60.00	R2.5	59.84	45.73			55.00	R2	55.17	41.72		
364.00 Poles, Towers and Fixtures	50.00	R2.5	50.44	35.24			55.00	R2.5	55.24	41.84		
365.00 Overhead Conductors and Devices	55.00	R3	54.84	39.69			55.00	R4	54.61	38.78		
366.00 Underground Conduit	65.00	R4	64.79	45.02			65.00	R4	64.76	44.16		
367.00 Underground Conductors and Devices	47.00	R4	46.86	32.68			50.00	R4	49.83	34.36		
368.OH Line Transformers - Overhead	45.00	R2.5	45.48	29.84			50.00	R1.5	50.73	35.22		
368.UG Line Transformers - Underground	42.00	S2	42.05	29.51			45.00	R2.5	45.18	31.45		

TUCSON ELECTRIC POWER COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
369.OH Services - Overhead	45.00	S3	44.69	27.66			47.00	S3	46.63	29.69		
369.UG Services - Underground	60.00	S3	60.04	45.69			60.00	S3	60.05	44.81		
370.00 Meters	27.00	L1	27.43	20.37			20.00	L0.5	20.39	16.46		
373.00 Street Lighting and Signal Systems	50.00	R3	49.40	34.26			50.00	R3	49.38	32.64		
Total Distribution Plant									50.03	36.00		
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	40.00	R4	39.94	34.92	-5.7	-5.0	40.00	R3	39.96	33.19	-5.9	-5.0
392.C0 Transportation - Class 0	18.00	O2	19.87	12.63	14.7	15.0	18.00	O2	20.22	12.25	17.1	15.0
392.C1 Transportation - Class 1	8.00	L2	7.92	4.99	14.6	15.0	8.00	L2	8.11	4.41	17.2	15.0
392.C2 Transportation - Class 2	8.00	L1.5	8.03	4.98	14.6	15.0	8.00	L1.5	8.15	4.51	17.6	15.0
392.C3 Transportation - Class 3	9.00	L3	9.07	4.33	14.6	15.0	9.00	L2	9.33	4.29	18.0	15.0
392.C4 Transportation - Class 4	14.00	L1.5	13.94	7.99	14.6	15.0	14.00	L1.5	13.79	7.88	18.0	15.0
392.C5 Transportation - Class 5	13.00	S2	13.38	7.21	14.7	15.0	13.00	S2	13.39	7.18	16.8	15.0
392.C6 Transportation - Class 6	15.00	L2	15.00	13.52	15.0	15.0	15.00	L2	15.02	11.50	15.0	15.0
392.C7 Transportation - Class 7	14.00	L1.5	14.15	9.74	15.0	15.0	14.00	L1.5	14.50	8.45	15.0	15.0
392.C8 Transportation - Class 8	13.00	S2	13.18	9.15	15.0	15.0	13.00	S2	13.24	8.12	15.2	15.0
392.C9 Transportation - Class 9	20.00	S2	21.00	11.54	15.0	15.0	25.00	L2	25.55	17.56	15.3	15.0
396.00 Power Operatied Equipment	15.00	L2	15.22	10.00	3.7	5.0	15.00	L2	15.13	11.85	1.0	
397.EM EMS and SCADA Equipment	20.00	S3	20.01	15.57			20.00	S3	20.02	14.15		
Total Depreciable									24.20	18.60	2.6	-0.3
Amortizable												
391.00 Furniture and Office Equipment	24.00	SQ	24.00	17.60			24.00	SQ	24.00	16.29		
391.20 Network and Data Equipment	5.00	SQ	5.00	2.76			5.00	SQ	5.00	2.46		
393.00 Stores Equipment	15.00	SQ	15.00	9.74			15.00	SQ	15.00	8.20		
394.00 Tools, Shop and Garage Equipment	17.00	SQ	17.00	9.39			17.00	SQ	17.00	9.99		
395.00 Laboratory Equipment	17.00	SQ	17.00	9.19			17.00	SQ	17.00	9.00		
397.20 Telecommunications Equipment	15.00	SQ	15.00	9.12			15.00	SQ	15.00	9.87		
398.00 Miscellaneous Equipment	20.00	SQ	20.00	10.60			20.00	SQ	20.00	11.65		
Total Amortizable									10.98	6.71		
Total General Plant									16.44	11.62	1.4	-0.2
SUBTOTAL									36.90	24.77	-7.9	-9.0

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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
NET SALVAGE												
108.02 Distribution			48.80	34.76	-14.8	-15.0			50.03	36.00	-14.1	-15.0
Total Net Salvage									50.03	36.00	-14.1	-9.8
TOTAL UTILITY									29.43	27.04	-9.4	-10.5
STEAM PRODUCTION (by Unit)												
Four Corners												
310.00 Rights-of-Way												
311.00 Structures and Improvements			31.54	17.56	-7.9	-8.0			28.98	16.15	-6.2	-6.3
312.00 Boiler Plant Equipment			36.50	17.55	-8.4	-8.0			35.84	16.14	-6.8	-6.3
314.00 Turbogenerator Units			30.52	17.47	-7.0	-7.9			31.67	16.14	-5.6	-6.3
315.00 Accessory Electric Equipment			24.13	17.46	-6.4	-7.9			21.71	16.15	-5.4	-6.3
316.00 Miscellaneous Power Plant Equipment			30.17	17.57	-7.5	-7.8			30.04	16.15	-5.8	-6.1
Total Four Corners									33.83	16.14	-6.5	-6.3
Four Corners Unit 4												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2029	200-SC	30.90	17.10	-7.5	-7.5	2031	200-SC	28.98	16.15	-5.8	-6.0
312.00 Boiler Plant Equipment	2029	200-SC	35.85	17.10	-8.8	-7.5	2031	200-SC	35.79	16.14	-7.3	-6.0
314.00 Turbogenerator Units	2029	200-SC	28.99	17.10	-6.4	-7.5	2031	200-SC	30.68	16.14	-5.1	-6.0
315.00 Accessory Electric Equipment	2029	200-SC	22.43	17.11	-5.6	-7.5	2031	200-SC	21.93	16.15	-4.8	-6.0
316.00 Miscellaneous Power Plant Equipment	2029	200-SC	29.57	17.10	-6.9	-7.3	2031	200-SC	29.95	16.15	-5.5	-5.8
Total Four Corners Unit 4									33.63	16.14	-6.8	-6.0
Four Corners Unit 5												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2030	200-SC	32.23	18.06	-8.5	-8.5	2031	200-SC	28.97	16.15	-6.5	-6.7
312.00 Boiler Plant Equipment	2030	200-SC	37.23	18.05	-8.0	-8.5	2031	200-SC	35.90	16.14	-6.3	-6.7
314.00 Turbogenerator Units	2030	200-SC	32.97	18.05	-7.9	-8.5	2031	200-SC	33.16	16.14	-6.2	-6.7
315.00 Accessory Electric Equipment	2030	200-SC	26.99	18.06	-7.7	-8.5	2031	200-SC	21.47	16.15	-6.1	-6.7
316.00 Miscellaneous Power Plant Equipment	2030	200-SC	30.81	18.06	-8.1	-8.3	2031	200-SC	30.14	16.15	-6.2	-6.4
Total Four Corners Unit 5									34.06	16.14	-6.3	-6.7

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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Navajo												
310.00 Rights-of-Way			56.14	23.68	-7.0	-7.0			51.25	15.17	-6.0	-6.0
311.00 Structures and Improvements			41.75	23.36	-7.2	-7.2			32.54	13.56	-5.9	-6.0
312.00 Boiler Plant Equipment			39.61	22.84	-6.7	-7.2			28.93	10.66	-5.5	-5.9
314.00 Turbogenerator Units			41.38	22.72	-6.8	-7.2			29.14	10.12	-5.5	-5.9
315.00 Accessory Electric Equipment			37.59	23.16	-7.1	-7.2			23.29	10.77	-5.9	-5.9
316.00 Miscellaneous Power Plant Equipment			40.69	23.43	-7.0	-6.9			29.26	14.34	-5.9	-5.9
Total Navajo									28.67	11.04	-5.6	-5.9
Navajo Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2034	200-SC	52.47	21.81	-7.2	-7.1	2019	200-SC	36.65	4.47	-5.0	-5.0
312.00 Boiler Plant Equipment	2034	200-SC	37.97	21.84	-7.0	-7.1	2019	200-SC	21.07	4.47	-5.0	-5.0
314.00 Turbogenerator Units	2034	200-SC	39.73	21.84	-6.5	-7.1	2019	200-SC	20.90	4.47	-4.6	-5.0
315.00 Accessory Electric Equipment	2034	200-SC	40.48	21.83	-6.7	-7.1	2019	200-SC	13.49	4.47	-4.7	-5.0
316.00 Miscellaneous Power Plant Equipment	2034	200-SC	52.74	21.81	-6.7	-6.8	2019	200-SC	38.45	4.47	-4.9	-4.9
Total Navajo Unit 1									20.83	4.47	-4.9	-5.0
Navajo Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2035	200-SC	48.57	22.76	-7.4	-7.5	2030	200-SC	39.37	15.18	-6.3	-6.6
312.00 Boiler Plant Equipment	2035	200-SC	41.28	22.77	-6.9	-7.5	2030	200-SC	36.22	15.18	-6.0	-6.6
314.00 Turbogenerator Units	2035	200-SC	40.38	22.78	-7.4	-7.5	2030	200-SC	35.06	15.18	-6.5	-6.6
315.00 Accessory Electric Equipment	2035	200-SC	40.14	22.78	-7.2	-7.5	2030	200-SC	32.96	15.18	-6.3	-6.6
316.00 Miscellaneous Power Plant Equipment	2035	200-SC	50.34	22.75	-7.0	-7.2	2030	200-SC	45.75	15.17	-6.3	-6.4
Total Navajo Unit 2									35.95	15.18	-6.2	-6.6
Navajo Unit 3												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2036	200-SC	49.65	23.69	-6.9	-7.0	2030	200-SC	44.24	15.18	-5.9	-6.0
312.00 Boiler Plant Equipment	2036	200-SC	41.42	23.71	-6.1	-7.0	2030	200-SC	35.40	15.18	-5.2	-6.0
314.00 Turbogenerator Units	2036	200-SC	46.13	23.70	-6.4	-7.0	2030	200-SC	40.09	15.18	-5.4	-6.0
315.00 Accessory Electric Equipment	2036	200-SC	44.62	23.70	-7.5	-7.0	2030	200-SC	38.19	15.18	-6.5	-6.0
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	54.62	23.69	-8.1	-6.6	2030	200-SC	46.90	15.18	-7.1	-5.8
Total Navajo Unit 3									37.09	15.18	-5.4	-6.0

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A	B	C	D	E	F	G	H	I	J	K	L	M
Navajo Common												
310.00 Rights-of-Way	2036	200-SC	56.14	23.68	-7.0	-7.0	2030	200-SC	51.25	15.17	-6.0	-6.0
311.00 Structures and Improvements	2036	200-SC	35.95	23.72	-7.3	-7.3	2030	200-SC	27.94	15.19	-6.0	-6.2
312.00 Boiler Plant Equipment	2036	200-SC	33.84	23.73	-7.6	-7.3	2030	200-SC	27.58	15.19	-6.6	-6.2
314.00 Turbogenerator Units	2036	200-SC	25.06	23.75	-7.3	-7.3	2030	200-SC	19.12	15.20	-6.1	-6.2
315.00 Accessory Electric Equipment	2036	200-SC	26.57	23.74	-7.0	-7.3	2030	200-SC	20.77	15.20	-5.9	-6.2
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	35.23	23.73	-6.9	-7.0	2030	200-SC	25.02	15.19	-5.9	-6.0
Total Navajo Common									26.13	15.19	-6.1	-6.2
San Juan												
310.00 Rights-of-Way												
311.00 Structures and Improvements			43.50	22.50	-9.7	-9.6			28.84	12.30	-9.0	-9.6
312.00 Boiler Plant Equipment			33.25	22.30	-14.3	-15.1			25.11	12.30	-11.6	-11.7
314.00 Turbogenerator Units			35.64	22.18	-8.9	-9.6			28.61	12.30	-9.0	-9.7
315.00 Accessory Electric Equipment			37.69	22.02	-9.3	-9.5			25.55	12.30	-9.1	-9.7
316.00 Miscellaneous Power Plant Equipment			47.93	21.62	-8.7	-9.1			26.25	12.30	-8.1	-9.3
Total San Juan									25.98	12.30	-10.8	-11.1
San Juan Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2036	200-SC	43.21	23.71	-9.4	-9.9	2027	200-SC	29.28	12.30	-9.1	-9.7
312.00 Boiler Plant Equipment	2036	200-SC	35.47	23.72	-10.2	-9.9	2027	200-SC	25.40	12.30	-10.0	-9.7
314.00 Turbogenerator Units	2036	200-SC	38.79	23.72	-9.2	-9.9	2027	200-SC	28.61	12.30	-9.0	-9.7
315.00 Accessory Electric Equipment	2036	200-SC	38.47	23.72	-9.4	-9.9	2027	200-SC	25.55	12.30	-9.1	-9.7
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	45.09	23.70	-8.5	-9.6	2027	200-SC	26.97	12.30	-8.3	-9.5
Total San Juan Unit 1									26.25	12.30	-9.7	-9.7
San Juan Common												
310.00 Rights-of-Way												
311.00 Structures and Improvements			43.50	22.50	-9.7	-9.6	2027	200-SC	12.79	12.30	-0.2	-0.2
312.00 Boiler Plant Equipment	2036	200-SC	33.17	23.73	-247.3	-263.1	2027	200-SC	20.75	12.30	-44.1	-49.0
314.00 Turbogenerator Units			35.64	22.18	-8.9	-9.6						
315.00 Accessory Electric Equipment			37.69	22.02	-9.3	-9.5						
316.00 Miscellaneous Power Plant Equipment			47.93	21.62	-8.7	-9.1	2027	200-SC	12.79	12.30		
Total San Juan Common									20.41	12.30	-43.0	-47.7

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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Springerville												
310.00 Rights-of-Way									43.00	18.81		
311.00 Structures and Improvements									37.20	22.18	-14.5	-17.8
312.00 Boiler Plant Equipment									48.69	31.72	-16.0	-18.3
314.00 Turbogenerator Units									45.66	32.41	-6.1	-6.6
315.00 Accessory Electric Equipment									53.00	30.58	-8.5	-8.8
316.00 Miscellaneous Power Plant Equipment									44.94	29.44	-8.1	-9.3
Total Springerville									46.44	30.06	-13.4	-15.4
Springerville Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2021	200-SC	11.16	9.39	-0.1	-0.1	2045	200-SC	46.47	29.28	-4.2	-5.5
312.00 Boiler Plant Equipment	2021	200-SC	12.80	9.39	-0.3	-0.1	2045	200-SC	48.19	29.27	-4.2	-5.5
314.00 Turbogenerator Units	2021	200-SC	13.20	9.39	0.4	-0.1	2045	200-SC	48.45	29.27	-4.2	-5.5
315.00 Accessory Electric Equipment	2021	200-SC	12.87	9.39	-0.1	-0.1	2045	200-SC	54.33	29.25	-5.1	-5.5
316.00 Miscellaneous Power Plant Equipment	2021	200-SC	10.62	9.39			2045	200-SC	44.88	29.28	-3.5	-5.1
Total Springerville Unit 1									48.48	29.27	-4.2	-5.5
Springerville Unit 1 Common												
310.00 Rights-of-Way	2021	200-SC	28.42	9.38			2045	200-SC	49.87	29.27		
311.00 Structures and Improvements	2021	200-SC	17.98	9.38	-0.1	-0.1	2045	200-SC	49.61	29.27	-11.8	-16.8
312.00 Boiler Plant Equipment	2021	200-SC	15.67	9.39	-0.1	-0.1	2045	200-SC	50.76	29.27	-12.9	-16.8
314.00 Turbogenerator Units	2021	200-SC	20.92	9.38	-0.1	-0.1	2045	200-SC	52.60	29.26	-13.7	-16.8
315.00 Accessory Electric Equipment	2021	200-SC	15.50	9.39	-0.1	-0.1	2045	200-SC	56.09	29.25	-16.5	-16.8
316.00 Miscellaneous Power Plant Equipment	2021	200-SC	16.57	9.39			2045	200-SC	55.40	29.25	-15.0	-16.4
Total Springerville Unit 1 Common									50.69	29.27	-12.2	-16.6
Springerville Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2050	200-SC	50.98	36.57	-8.1	-7.6	2050	200-SC	46.76	33.86	-7.0	-6.7
312.00 Boiler Plant Equipment	2050	200-SC	50.50	36.57	-7.3	-7.6	2050	200-SC	47.64	33.86	-7.2	-6.7
314.00 Turbogenerator Units	2050	200-SC	51.50	36.56	-8.0	-7.6	2050	200-SC	44.78	33.87	-6.7	-6.7
315.00 Accessory Electric Equipment	2050	200-SC	55.14	36.55	-7.5	-7.6	2050	200-SC	53.98	33.83	-6.6	-6.7
316.00 Miscellaneous Power Plant Equipment	2050	200-SC	54.63	36.55	-6.8	-7.1	2050	200-SC	47.18	33.86	-6.1	-6.3
Total Springerville Unit 2									47.30	33.86	-7.0	-6.7

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A	B	C	D	E	F	G	H	I	J	K	L	M
Springerville Unit 2 Common (Leasehold Imp.)												
310.00 Rights-of-Way	2020	200-SC	29.45	8.40			2024	200-SC	33.31	9.38		
311.00 Structures and Improvements	2020	200-SC	20.67	8.41	-0.1	-0.1	2024	200-SC	21.21	9.38	-36.5	-39.4
312.00 Boiler Plant Equipment	2020	200-SC	16.90	8.41	-0.1	-0.1	2024	200-SC	16.91	9.39	-32.3	-39.4
314.00 Turbogenerator Units	2020	200-SC	21.89	8.41	-0.1	-0.1	2024	200-SC	25.40	9.38	-39.4	-39.4
315.00 Accessory Electric Equipment	2020	200-SC	27.50	8.41	-0.1	-0.1	2024	200-SC	31.60	9.38	-39.4	-39.4
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	20.55	8.41			2024	200-SC	22.26	9.38	-38.6	-39.3
Total Springerville Unit 2 Common									21.34	9.38	-34.4	-37.4
Springerville Coal Handling												
310.00 Rights-of-Way							2050	200-SC	61.72	33.79		
311.00 Structures and Improvements												
312.00 Boiler Plant Equipment	2021	200-SC	11.82	9.39	-0.1	-0.1	2050	200-SC	56.69	33.82	-57.2	-59.4
314.00 Turbogenerator Units												
315.00 Accessory Electric Equipment												
316.00 Miscellaneous Power Plant Equipment												
Total Springerville Coal Handling									56.74	33.82	-56.6	-58.7
Sundt												
310.00 Rights-of-Way												
311.00 Structures and Improvements									36.97	22.69	-42.1	-44.1
312.00 Boiler Plant Equipment									40.57	24.49	-37.6	-40.5
314.00 Turbogenerator Units									30.66	19.77	-50.0	-55.3
315.00 Accessory Electric Equipment									28.88	20.34	-45.9	-49.0
316.00 Miscellaneous Power Plant Equipment									26.85	19.56	-44.8	-50.9
Total Sundt									35.41	22.31	-42.0	-45.4
Sundt Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2018	200-SC	20.01	6.45	-52.6	-54.4	2028	200-SC	22.86	13.27	-53.9	-58.6
312.00 Boiler Plant Equipment	2018	200-SC	17.10	6.45	-33.3	-54.5	2028	200-SC	26.28	13.26	-49.3	-58.7
314.00 Turbogenerator Units	2018	200-SC	12.09	6.45	-49.7	-54.5	2028	200-SC	22.94	13.27	-52.4	-58.7
315.00 Accessory Electric Equipment	2018	200-SC	9.06	6.45	-53.8	-54.5	2028	200-SC	17.20	13.27	-54.0	-58.7
316.00 Miscellaneous Power Plant Equipment	2018	200-SC	10.84	6.45	-51.8	-54.4	2028	200-SC	18.52	13.27	-55.6	-58.6
Total Sundt Unit 1									22.58	13.27	-51.6	-58.7

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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Sundt Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2020	200-SC	19.23	8.41	-62.0	-64.2	2030	200-SC	21.69	15.19	-59.2	-66.3
312.00 Boiler Plant Equipment	2020	200-SC	20.39	8.41	-67.2	-64.2	2030	200-SC	28.86	15.19	-63.3	-66.3
314.00 Turbogenerator Units	2020	200-SC	20.59	8.41	-60.5	-64.2	2030	200-SC	30.70	15.19	-60.6	-66.2
315.00 Accessory Electric Equipment	2020	200-SC	11.91	8.41	-61.5	-64.3	2030	200-SC	18.62	15.20	-63.1	-66.4
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	13.45	8.41	-59.4	-64.2	2030	200-SC	19.76	15.20	-61.8	-66.2
Total Sundt Unit 2									25.66	15.19	-62.1	-66.3
Sundt Unit 3												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2022	200-SC	24.07	10.36	-71.5	-75.2	2032	200-SC	26.92	17.11	-67.8	-75.7
312.00 Boiler Plant Equipment	2022	200-SC	30.31	10.35	-76.9	-75.2	2032	200-SC	29.45	17.10	-70.8	-75.7
314.00 Turbogenerator Units	2022	200-SC	22.27	10.36	-73.2	-75.3	2032	200-SC	27.66	17.11	-68.5	-75.7
315.00 Accessory Electric Equipment	2022	200-SC	19.68	10.36	-67.5	-75.3	2032	200-SC	28.42	17.10	-67.1	-75.7
316.00 Miscellaneous Power Plant Equipment	2022	200-SC	15.48	10.36	-64.1	-75.2	2032	200-SC	23.16	17.11	-66.6	-75.5
Total Sundt Unit 3									28.24	17.11	-68.9	-75.7
Sundt Unit 4												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2048	200-SC	54.34	34.74	-24.5	-24.6	2048	200-SC	52.99	32.01	-32.0	-32.6
312.00 Boiler Plant Equipment	2048	200-SC	54.34	34.74	-24.1	-24.6	2048	200-SC	54.25	32.00	-30.3	-32.6
314.00 Turbogenerator Units	2048	200-SC	49.18	34.76	-24.7	-24.6	2048	200-SC	41.75	32.06	-29.5	-32.6
315.00 Accessory Electric Equipment	2048	200-SC	53.12	34.75	-23.9	-24.6	2048	200-SC	47.13	32.04	-31.1	-32.6
316.00 Miscellaneous Power Plant Equipment	2048	200-SC	48.38	34.77	-20.0	-24.2	2048	200-SC	44.82	32.05	-26.9	-32.2
Total Sundt Unit 4									50.81	32.02	-30.5	-32.6
Sundt Solar Booster (Areva)												
310.00 Rights-of-Way												
311.00 Structures and Improvements	30.00	SQ	30.00									
312.00 Boiler Plant Equipment	30.00	SQ	30.00				2048	200-SC	32.56	32.10	-0.4	-0.4
314.00 Turbogenerator Units	30.00	SQ	30.00									
315.00 Accessory Electric Equipment	30.00	SQ	30.00									
316.00 Miscellaneous Power Plant Equipment	30.00	SQ	30.00									
Total Sundt Solar Booster (Areva)									32.56	32.10	-0.4	-0.4

TUCSON ELECTRIC POWER COMPANY
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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
OTHER PRODUCTION (by Unit)												
DeMoss Petrie Gas Unit 1												
341.00 Structures and Improvements	2046	200-SC	40.04	32.98	-7.9	-9.2	2046	200-SC	36.97	30.24	-7.3	-9.0
342.00 Fuel Holders, Products and Accessories	2046	200-SC	42.61	32.97	-9.2	-9.2	2046	200-SC	42.70	30.22	-8.9	-9.0
343.00 Prime Movers	2046	200-SC	34.38	33.01	-9.2	-9.2	2046	200-SC	34.41	30.25	-1.3	-9.0
344.00 Generators and Devices	2046	200-SC	42.59	32.97	-9.2	-9.2	2046	200-SC	42.56	30.22	-8.7	-9.0
345.00 Accessory Electric Equipment	2046	200-SC	42.54	32.97	-9.2	-9.2	2046	200-SC	41.80	30.22	-3.4	-9.0
346.00 Miscellaneous Power Plant Equipment	2046	200-SC	41.25	32.98	-9.2	-9.2	2046	200-SC	40.73	30.22	-8.9	-9.0
Total DeMoss Petrie Gas Unit 1									42.35	30.22	-8.3	-9.0
Gila River												
341.00 Structures and Improvements									42.18	32.06	-8.4	-8.4
342.00 Fuel Holders, Products and Accessories									42.49	32.06	-8.4	-8.4
343.00 Prime Movers									41.47	32.06	-8.3	-8.3
344.00 Generators and Devices									42.63	32.06	-8.3	-8.3
345.00 Accessory Electric Equipment									42.38	32.06	-8.3	-8.3
346.00 Miscellaneous Power Plant Equipment									42.28	32.06	-8.4	-8.4
Total Gila River									41.72	32.06	-8.3	-8.3
Gila River Unit 3												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-8.3	-8.3
342.00 Fuel Holders, Products and Accessories	45.00	SQ	45.00				2048	200-SC	41.24	32.06	-8.3	-8.3
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	41.57	32.06	-8.3	-8.3
344.00 Generators and Devices	45.00	SQ	45.00				2048	200-SC	42.63	32.06	-8.3	-8.3
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-8.3	-8.3
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	41.89	32.06	-8.3	-8.3
Total Gila River Unit 3									41.75	32.06	-8.3	-8.3
Gila River Common												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.15	32.06	-8.4	-8.4
342.00 Fuel Holders, Products and Accessories	45.00	SQ	45.00				2048	200-SC	42.52	32.06	-8.4	-8.4
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	39.05	32.07	-8.4	-8.4
344.00 Generators and Devices	45.00	SQ	45.00									
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.39	32.06	-8.4	-8.4
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	42.29	32.06	-8.4	-8.4
Total Gila River Common									41.49	32.06	-8.4	-8.4

TUCSON ELECTRIC POWER COMPANY
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Vintage Group Procedure

Statement H

Account Description	Current Parameters						Proposed Parameters (at December 31, 2014)					
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Luna												
341.00 Structures and Improvements	2051	200-SC	42.47	37.52	-19.5	-19.6	2051	200-SC	42.38	34.80	-18.7	-18.8
342.00 Fuel Holders, Products and Accessories	2051	200-SC	42.51	37.52	-19.6	-19.6	2051	200-SC	42.56	34.80	-18.8	-18.8
343.00 Prime Movers	2051	200-SC	39.20	37.54	-16.3	-19.7	2051	200-SC	37.40	34.82	-15.5	-18.8
344.00 Generators and Devices	2051	200-SC	41.74	37.52	-14.5	-19.6	2051	200-SC	40.73	34.80	-11.1	-18.8
345.00 Accessory Electric Equipment	40.00		40.00				2051	200-SC	35.29	34.83	-18.8	-18.8
346.00 Miscellaneous Power Plant Equipment	2051	200-SC	42.48	37.52	-19.6	-19.6	2051	200-SC	42.48	34.80	-18.7	-18.8
Total Luna									40.97	34.80	-16.0	-18.8
North Loop Gas												
341.00 Structures and Improvements			24.42	7.02	-11.2	-12.1			34.58	13.74	-13.4	-14.2
342.00 Fuel Holders, Products and Accessories			43.49	33.88	-5.9	-5.9			42.70	30.22	-5.7	-5.7
343.00 Prime Movers			8.36	5.46	-12.5	-12.5			15.51	12.30	-12.4	-15.4
344.00 Generators and Devices			36.87	19.70	-8.5	-8.9			42.21	22.77	-9.3	-9.8
345.00 Accessory Electric Equipment			27.62	12.41	-9.3	-10.3			33.62	17.60	-10.7	-11.9
346.00 Miscellaneous Power Plant Equipment			27.71	8.02	-10.4	-11.7			38.64	14.59	-12.2	-13.7
Total North Loop Gas									37.09	20.31	-9.8	-10.5
North Loop Gas Unit 1												
341.00 Structures and Improvements	2017	200-SC	19.02	5.46	-11.1	-11.1	2027	200-SC	29.10	12.30	-13.4	-13.4
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2017	200-SC	9.86	5.46	-11.1	-11.1	2027	200-SC	19.70	12.30	-13.3	-13.4
344.00 Generators and Devices	2017	200-SC	27.57	5.46	-11.0	-11.1	2027	200-SC	38.80	12.29	-13.1	-13.4
345.00 Accessory Electric Equipment	2017	200-SC	20.04	5.46	-10.9	-11.1	2027	200-SC	28.69	12.30	-13.1	-13.4
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	19.46	5.46	-11.1	-11.1	2027	200-SC	30.66	12.30	-13.4	-13.4
Total North Loop Gas Unit 1									32.33	12.29	-13.1	-13.4
North Loop Gas Unit 2												
341.00 Structures and Improvements	2017	200-SC	30.61	5.46	-15.5	-15.5	2027	200-SC	41.27	12.29	-17.9	-17.9
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2017	200-SC	15.82	5.46	-15.5	-15.5	2027	200-SC	8.23	12.31	-7.0	-17.9
344.00 Generators and Devices	2017	200-SC	31.80	5.46	-14.7	-15.5	2027	200-SC	43.04	12.29	-16.9	-17.9
345.00 Accessory Electric Equipment	2017	200-SC	25.59	5.46	-15.1	-15.5	2027	200-SC	31.85	12.29	-17.3	-17.9
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	44.27	5.46	-15.5	-15.5	2027	200-SC	53.34	12.28	-17.8	-17.8
Total North Loop Gas Unit 2									33.25	12.29	-15.7	-17.9

TUCSON ELECTRIC POWER COMPANY
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Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
North Loop Gas Unit 3												
341.00 Structures and Improvements	2017	200-SC	30.61	5.46	-13.3	-13.3	2027	200-SC	41.27	12.29	-16.1	-16.1
342.00 Fuel Holders, Products and Accessories												
343.00 Prime Movers	2017	200-SC	7.31	5.46	-13.3	-13.3	2027	200-SC	17.12	12.30	-15.4	-16.1
344.00 Generators and Devices	2017	200-SC	32.28	5.46	-12.0	-13.3	2027	200-SC	43.69	12.29	-14.5	-16.1
345.00 Accessory Electric Equipment	2017	200-SC	25.63	5.46	-13.0	-13.3	2027	200-SC	31.87	12.29	-15.6	-16.1
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	44.27	5.46	-13.3	-13.3	2027	200-SC	53.34	12.28	-16.1	-16.1
Total North Loop Gas Unit 3									32.54	12.29	-14.9	-16.1
North Loop Gas Unit 4												
341.00 Structures and Improvements	2047	200-SC	42.41	33.89	2.7	-5.9	2046	200-SC	41.22	30.22	2.6	-5.7
342.00 Fuel Holders, Products and Accessories	2047	200-SC	43.49	33.88	-5.9	-5.9	2046	200-SC	42.70	30.22	-5.7	-5.7
343.00 Prime Movers												
344.00 Generators and Devices	2047	200-SC	43.46	33.88	-5.6	-5.9	2046	200-SC	42.66	30.22	-5.4	-5.7
345.00 Accessory Electric Equipment	2047	200-SC	42.61	33.89	-4.7	-5.9	2046	200-SC	41.29	30.22	-4.5	-5.7
346.00 Miscellaneous Power Plant Equipment	2047	200-SC	43.49	33.88	-3.2	-5.9	2046	200-SC	42.70	30.22	-3.1	-5.7
Total North Loop Gas Unit 4									42.56	30.22	-5.3	-5.7
Solar Units (Generators and Devices)												
344.00 DeMoss Petrie	20.00	S4	20.00	17.06			28.00	S6	28.00	16.15	-5.0	-5.0
344.00 Fort Huachuca	20.00	S4	20.00	17.06			28.00	S6	28.00	27.50	-5.0	-5.0
344.00 HQ Rooftop	20.00	S4	20.00	17.06			28.00	S6	28.00	25.50	-5.0	-5.0
344.00 OH Rooftop	20.00	S4	20.00	17.06			28.00	S6	28.00	24.50	-5.0	-5.0
344.00 OH Test Yard	20.00	S4	20.00	17.06			28.00	S6	28.00	16.83	-5.0	-5.0
344.00 Prairie Fire	20.00	S4	20.00	17.06			28.00	S6	28.00	25.50	-5.0	-5.0
344.00 Springerville Sites 1-3 (Legacy)	20.00	S4	20.00	17.06			28.00	S6	28.00	16.11	-5.0	-5.0
344.00 Springerville Site 4	20.00	S4	20.00	17.06			28.00	S6	28.00	23.50	-5.0	-5.0
344.00 Tucson							28.00	S6	28.00	11.82	-5.0	-5.0
344.00 U of A Tech Park Site 1	20.00	S4	20.00	17.06			28.00	S6	28.00	23.50	-5.0	-5.0
344.00 U of A Tech Park Site 2							28.00	S6	28.00	24.50	-5.0	-5.0
344.00 White Mountain							28.00	S6	28.00	27.50	-5.0	-5.0
Total Solar Units									28.00	24.49	-5.0	-5.0

TUCSON ELECTRIC POWER COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement H

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Sundt Gas												
341.00 Structures and Improvements			28.10	5.46	-1.8	-1.8			37.43	12.29	-1.9	-2.2
342.00 Fuel Holders, Products and Accessories			9.71	5.46	-1.8	-1.8			19.39	12.30	-2.2	-2.2
343.00 Prime Movers			15.82	5.46	-1.8	-1.8			25.38	12.30	-2.2	-2.2
344.00 Generators and Devices			30.02	5.46	-1.7	-1.7			39.83	12.29	-2.0	-2.1
345.00 Accessory Electric Equipment			22.40	5.46	-1.7	-1.8			34.86	12.29	-2.1	-2.2
346.00 Miscellaneous Power Plant Equipment			42.42	5.46	-1.8	-1.8			51.58	12.28	-2.2	-2.2
Total Sundt Gas									36.18	12.29	-2.0	-2.1
Sundt Gas Unit 1												
341.00 Structures and Improvements	2017	200-SC	28.10	5.46	-1.7	-1.7	2027	200-SC	37.43	12.29	-1.8	-2.1
342.00 Fuel Holders, Products and Accessories	2017	200-SC	9.71	5.46	-1.7	-1.7	2027	200-SC	19.39	12.30	-2.1	-2.1
343.00 Prime Movers	2017	200-SC	15.82	5.46	-1.7	-1.7	2027	200-SC	25.38	12.30	-2.1	-2.1
344.00 Generators and Devices	2017	200-SC	31.37	5.46	-1.7	-1.7	2027	200-SC	40.65	12.29	-2.0	-2.1
345.00 Accessory Electric Equipment	2017	200-SC	23.05	5.46	-1.7	-1.7	2027	200-SC	35.64	12.29	-2.0	-2.1
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	42.93	5.46	-1.7	-1.7	2027	200-SC	52.10	12.28	-2.1	-2.1
Total Sundt Gas Unit 1									36.88	12.29	-2.0	-2.1
Sundt Gas Unit 2												
341.00 Structures and Improvements	2017	200-SC	28.10	5.46	-1.8	-1.8	2027	200-SC	37.43	12.29	-1.9	-2.2
342.00 Fuel Holders, Products and Accessories	2017	200-SC	9.71	5.46	-1.8	-1.8	2027	200-SC	19.39	12.30	-2.2	-2.2
343.00 Prime Movers	2017	200-SC	15.82	5.46	-1.8	-1.8	2027	200-SC	25.38	12.30	-2.2	-2.2
344.00 Generators and Devices	2017	200-SC	28.72	5.46	-1.7	-1.8	2027	200-SC	38.99	12.29	-1.9	-2.2
345.00 Accessory Electric Equipment	2017	200-SC	21.84	5.46	-1.8	-1.8	2027	200-SC	34.18	12.29	-2.1	-2.2
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	42.08	5.46	-1.8	-1.8	2027	200-SC	51.24	12.28	-2.2	-2.2
Total Sundt Gas Unit 2									35.47	12.29	-2.0	-2.2

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the TEP study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes examples of the supporting schedules developed for distribution Account 364.00 (Poles, Towers and Fixtures). Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the TEP study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Net Salvage History.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column H) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 3. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Aging of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting

Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived projection life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – NET SALVAGE HISTORY

An Unadjusted Net Salvage History contains recorded activity–year retirements, salvage, cost of removal and other depreciation reserve activity appropriately recognized in the computation of average net salvage rates. This schedule provides a moving–average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving–average analysis of the components of unadjusted net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

An Adjusted Net Salvage History contains recorded activity–year total retirements, salvage, cost of removal and other depreciation reserve activity appropriately adjusted in the estimation of future net salvage rates. The moving–average adjusted net salvage analysis and component analysis are displayed in columns corresponding to an unadjusted net salvage analysis.

TUCSON ELECTRIC POWER COMPANY

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 55 - R2.5
Procedure: Vintage Group

Generation Arrangement

	December 31, 2014				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2014	0.5	9,740,855	55.00	54.53	0.9914	1.0000	9,657,263	177,108
2013	1.5	23,800,754	55.00	53.59	0.9743	1.0000	23,188,590	432,743
2012	2.5	25,286,360	55.01	52.65	0.9570	1.0000	24,198,197	459,642
2011	3.5	24,869,733	55.04	51.71	0.9394	1.0000	23,363,675	451,820
2010	4.5	8,388,159	54.95	50.78	0.9240	1.0000	7,751,061	152,646
2009	5.5	5,029,314	54.93	49.85	0.9075	1.0000	4,564,241	91,560
2008	6.5	4,036,772	54.97	48.93	0.8901	1.0000	3,592,975	73,436
2007	7.5	3,851,451	54.95	48.01	0.8737	1.0000	3,364,824	70,090
2006	8.5	4,754,782	54.98	47.09	0.8565	1.0000	4,072,351	86,476
2005	9.5	4,141,632	55.02	46.18	0.8394	1.0000	3,476,613	75,281
2004	10.5	5,016,957	55.05	45.28	0.8224	1.0000	4,126,142	91,132
2003	11.5	3,345,173	55.05	44.38	0.8061	1.0000	2,696,401	60,762
2002	12.5	4,742,134	55.01	43.48	0.7904	1.0000	3,748,101	86,200
2001	13.5	5,835,346	55.07	42.59	0.7734	1.0000	4,513,114	105,962
2000	14.5	2,083,580	55.12	41.71	0.7567	1.0000	1,576,738	37,804
1999	15.5	2,023,220	54.99	40.83	0.7426	1.0000	1,502,352	36,795
1998	16.5	2,198,533	55.11	39.96	0.7251	1.0000	1,594,110	39,894
1997	17.5	3,643,997	55.15	39.09	0.7088	1.0000	2,582,919	66,069
1996	18.5	3,260,736	54.97	38.24	0.6956	1.0000	2,268,148	59,321
1995	19.5	3,086,950	55.12	37.38	0.6782	1.0000	2,093,635	56,004
1994	20.5	1,839,508	54.61	36.54	0.6690	1.0000	1,230,665	33,681
1993	21.5	2,348,495	54.81	35.70	0.6513	1.0000	1,529,557	42,845
1992	22.5	4,127,225	54.92	34.87	0.6349	1.0000	2,620,274	75,146
1991	23.5	3,423,020	54.71	34.05	0.6223	1.0000	2,130,090	62,564
1990	24.5	1,884,075	53.43	33.23	0.6219	1.0000	1,171,782	35,262
1989	25.5	3,573,822	54.22	32.42	0.5980	1.0000	2,137,090	65,913
1988	26.5	3,376,623	54.44	31.62	0.5809	1.0000	1,961,512	62,029
1987	27.5	2,546,832	54.42	30.83	0.5665	1.0000	1,442,739	46,796
1986	28.5	2,695,532	54.68	30.05	0.5495	1.0000	1,481,128	49,293
1985	29.5	3,610,030	54.66	29.27	0.5355	1.0000	1,933,162	66,041
1984	30.5	2,817,291	54.65	28.51	0.5216	1.0000	1,469,534	51,552
1983	31.5	3,023,267	55.06	27.75	0.5039	1.0000	1,523,550	54,906
1982	32.5	2,401,285	55.33	27.00	0.4879	1.0000	1,171,647	43,396
1981	33.5	3,035,127	55.55	26.26	0.4727	1.0000	1,434,832	54,640
1980	34.5	2,846,562	55.64	25.53	0.4588	1.0000	1,306,027	51,157
1979	35.5	2,662,839	55.79	24.81	0.4447	1.0000	1,184,081	47,727
1978	36.5	2,271,238	55.50	24.10	0.4342	1.0000	986,135	40,920

TUCSON ELECTRIC POWER COMPANY

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 55 - R2.5
Procedure: Vintage Group

Generation Arrangement

	December 31, 2014				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1977	37.5	1,569,572	55.61	23.40	0.4207	1.0000	660,383	28,223
1976	38.5	1,420,363	56.24	22.71	0.4038	1.0000	573,531	25,256
1975	39.5	964,764	48.74	22.03	0.4520	1.0000	436,095	19,796
1974	40.5	2,194,546	56.33	21.36	0.3792	1.0000	832,277	38,962
1973	41.5	1,722,297	55.83	20.70	0.3709	1.0000	638,749	30,850
1972	42.5	1,207,492	55.17	20.06	0.3636	1.0000	439,042	21,887
1971	43.5	1,284,527	55.25	19.43	0.3516	1.0000	451,632	23,248
1970	44.5	1,123,959	56.54	18.81	0.3326	1.0000	373,854	19,879
1969	45.5	1,423,206	57.47	18.20	0.3167	1.0000	450,717	24,766
1968	46.5	985,798	57.23	17.61	0.3076	1.0000	303,272	17,226
1967	47.5	523,158	57.76	17.02	0.2947	1.0000	154,190	9,057
1966	48.5	502,979	58.19	16.46	0.2828	1.0000	142,255	8,643
1965	49.5	489,645	58.34	15.91	0.2727	1.0000	133,508	8,393
1964	50.5	793,572	57.95	15.37	0.2652	1.0000	210,470	13,693
1963	51.5	1,348,515	59.38	14.85	0.2501	1.0000	337,215	22,710
1962	52.5	1,337,973	59.40	14.34	0.2415	1.0000	323,080	22,525
1961	53.5	1,090,810	60.06	13.85	0.2307	1.0000	251,599	18,163
1960	54.5	632,186	59.59	13.38	0.2245	1.0000	141,926	10,609
1959	55.5	485,215	60.12	12.92	0.2149	1.0000	104,261	8,071
1958	56.5	393,613	60.20	12.48	0.2072	1.0000	81,574	6,538
1957	57.5	364,744	60.59	12.05	0.1989	1.0000	72,531	6,020
1956	58.5	406,424	61.25	11.64	0.1900	1.0000	77,221	6,635
1955	59.5	367,941	62.36	11.24	0.1803	1.0000	66,335	5,901
1954	60.5	148,796	62.30	10.86	0.1743	1.0000	25,941	2,388
1953	61.5	203,866	62.19	10.50	0.1688	1.0000	34,408	3,278
1952	62.5	382,527	63.96	10.14	0.1586	1.0000	60,671	5,981
1951	63.5	161,020	63.90	9.81	0.1535	1.0000	24,711	2,520
1950	64.5	148,176	61.74	9.48	0.1536	1.0000	22,755	2,400
1949	65.5	102,268	64.91	9.17	0.1413	1.0000	14,447	1,576
1948	66.5	329,679	66.15	8.87	0.1341	1.0000	44,204	4,984
1947	67.5	131,893	66.37	8.58	0.1292	1.0000	17,046	1,987
1946	68.5	60,678	67.31	8.30	0.1233	1.0000	7,479	902
1945	69.5	23,689	67.30	8.02	0.1192	1.0000	2,824	352
1944	70.5	7,193	69.41	7.76	0.1118	1.0000	804	104
1943	71.5	1,630	69.74	7.50	0.1076	1.0000	175	23
1942	72.5	6,501	67.02	7.25	0.1082	1.0000	703	97
1941	73.5	4,478	60.10	7.00	0.1165	1.0000	522	74

TUCSON ELECTRIC POWER COMPANY

Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Dispersion: 55 - R2.5
Procedure: Vintage Group

Generation Arrangement

	December 31, 2014				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1940	74.5	11,938	71.69	6.76	0.0943	1.0000	1,126	167
1939	75.5	8,794	73.04	6.52	0.0893	1.0000	786	120
1938	76.5	4,112	74.16	6.29	0.0848	1.0000	349	55
1937	77.5	3,899	75.16	6.06	0.0806	1.0000	314	52
1936	78.5	1,648	75.91	5.83	0.0768	1.0000	127	22
1935	79.5	1,950	77.31	5.60	0.0725	1.0000	141	25
1934	80.5	818	77.54	5.38	0.0694	1.0000	57	11
1933	81.5	1,996	78.60	5.16	0.0657	1.0000	131	25
1932	82.5	2,505	80.28	4.95	0.0616	1.0000	154	31
1931	83.5	1,881	80.88	4.73	0.0585	1.0000	110	23
1930	84.5	2,533	81.56	4.51	0.0553	1.0000	140	31
Total	15.5	$222,006,967	55.24	41.84	0.7575	1.0000	$168,161,101	$4,018,893

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2014	Derived Additions	1989 Opening Balance	Experience to 12/31/2014 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2014	0.5	9,755,652		9,740,855	0.9985	0.4992
2013	1.5	23,861,351		23,800,754	0.9975	1.4986
2012	2.5	25,192,104		25,286,360	1.0037	2.5098
2011	3.5	24,607,921		24,869,733	1.0106	3.5368
2010	4.5	8,597,818		8,388,159	0.9756	4.4403
2009	5.5	5,205,189		5,029,314	0.9662	5.4119
2008	6.5	4,127,468		4,036,772	0.9780	6.4451
2007	7.5	3,965,761		3,851,451	0.9712	7.4161
2006	8.5	4,847,219		4,754,782	0.9809	8.4392
2005	9.5	4,226,395		4,141,632	0.9799	9.4585
2004	10.5	5,056,066		5,016,957	0.9923	10.4798
2003	11.5	3,404,275		3,345,173	0.9826	11.4653
2002	12.5	4,892,972		4,742,134	0.9692	12.4060
2001	13.5	5,995,916		5,835,346	0.9732	13.4418
2000	14.5	2,114,651		2,083,580	0.9853	14.4633
1999	15.5	2,129,196		2,023,220	0.9502	15.3076
1998	16.5	2,270,138		2,198,533	0.9685	16.4007
1997	17.5	3,713,015		3,643,997	0.9814	17.4121
1996	18.5	3,395,318		3,260,736	0.9604	18.1896
1995	19.5	3,214,275		3,086,950	0.9604	19.3016
1994	20.5	1,986,494		1,839,508	0.9260	19.7527
1993	21.5	2,486,545		2,348,495	0.9445	20.9038
1992	22.5	4,335,956		4,127,225	0.9519	21.9603
1991	23.5	3,656,718		3,423,020	0.9361	22.6923
1990	24.5	2,163,363		1,884,075	0.8709	22.3490
1989	25.5	3,944,684		3,573,822	0.9060	24.0707
1988	26.5		3,662,824	3,376,623	0.9219	25.2144
1987	27.5		2,787,446	2,546,832	0.9137	26.1231
1986	28.5		2,964,885	2,695,532	0.9092	27.2972
1985	29.5		4,028,830	3,610,030	0.8960	28.1853
1984	30.5		3,148,303	2,817,291	0.8949	29.0720
1983	31.5		3,305,135	3,023,267	0.9147	30.3782
1982	32.5		2,616,718	2,401,285	0.9177	31.5360
1981	33.5		3,261,800	3,035,127	0.9305	32.6262
1980	34.5		3,100,138	2,846,562	0.9182	33.5909
1979	35.5		2,898,845	2,662,839	0.9186	34.5996
1978	36.5		2,507,643	2,271,238	0.9057	35.1598
1977	37.5		1,770,817	1,569,572	0.8864	36.1069

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2014	Derived Additions	1989 Opening Balance	Experience to 12/31/2014 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1976	38.5		1,549,656	1,420,363	0.9166	37.5598
1975	39.5		1,570,716	964,764	0.6142	30.8739
1974	40.5		2,557,849	2,194,546	0.8580	39.2693
1973	41.5		1,981,827	1,722,297	0.8690	39.5628
1972	42.5		1,477,248	1,207,492	0.8174	39.6840
1971	43.5		1,581,742	1,284,527	0.8121	40.5317
1970	44.5		1,309,103	1,123,959	0.8586	42.5683
1969	45.5		1,594,429	1,423,206	0.8926	44.2310
1968	46.5		1,142,953	985,798	0.8625	44.7103
1967	47.5		612,332	523,158	0.8544	45.9509
1966	48.5		565,758	502,979	0.8890	47.0650
1965	49.5		560,063	489,645	0.8743	47.8761
1964	50.5		941,991	793,572	0.8424	48.1397
1963	51.5		1,510,686	1,348,515	0.8927	50.1957
1962	52.5		1,537,009	1,337,973	0.8705	50.8214
1961	53.5		1,234,636	1,090,810	0.8835	52.0679
1960	54.5		804,195	632,186	0.7861	52.1641
1959	55.5		762,437	485,215	0.6364	53.2414
1958	56.5		634,696	393,613	0.6202	53.8416
1957	57.5		592,246	364,744	0.6159	54.7326
1956	58.5		638,164	406,424	0.6369	55.8665
1955	59.5		550,015	367,941	0.6690	57.4221
1954	60.5		232,114	148,796	0.6410	57.7937
1953	61.5		341,656	203,866	0.5967	58.0834
1952	62.5		578,387	382,527	0.6614	60.2346
1951	63.5		256,324	161,020	0.6282	60.5300
1950	64.5		379,679	148,176	0.3903	58.7062
1949	65.5		173,146	102,268	0.5906	62.1809
1948	66.5		541,754	329,679	0.6085	63.7022
1947	67.5		225,802	131,893	0.5841	64.1924
1946	68.5		107,195	60,678	0.5661	65.3726
1945	69.5		45,510	23,689	0.5205	65.5924
1944	70.5		12,945	7,193	0.5556	67.9052
1943	71.5		3,161	1,630	0.5156	68.4155
1942	72.5		18,486	6,501	0.3517	65.8689
1941	73.5		29,283	4,478	0.1529	59.1007
1940	74.5		26,194	11,938	0.4558	70.8222
1939	75.5		15,720	8,794	0.5594	72.2895

TUCSON ELECTRIC POWER COMPANY
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Age Distribution

Vintage	Age as of 12/31/2014	Derived Additions	1989 Opening Balance	Experience to 12/31/2014 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1938	76.5		7,693	4,112	0.5345	73.5203
1937	77.5		7,052	3,899	0.5528	74.6208
1936	78.5		3,305	1,648	0.4988	75.4482
1935	79.5		4,396	1,950	0.4436	76.9297
1934	80.5		1,496	818	0.5467	77.2184
1933	81.5		3,844	1,996	0.5193	78.3300
1932	82.5		4,221	2,505	0.5934	80.0626
1931	83.5		3,637	1,881	0.5171	80.7019
1930	84.5		8,290	2,533	0.3055	81.4199
1929	85.5		62		0.0000	68.6874
1928	86.5		35		0.0000	77.0000
1927	87.5		55		0.0000	69.0000
1926	88.5		12		0.0000	79.0000
Total	15.5	$169,146,458	$64,794,589	$222,006,967	0.9490	

TUCSON ELECTRIC POWER COMPANY
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1989	44,344,776	3,123,602	643,857	(1,152)	46,823,370
1990	46,823,370	2,237,399	550,895	(93)	48,509,780
1991	48,509,780	3,045,228	544,557		51,010,451
1992	51,010,451	3,556,393	500,697	(6,694)	54,059,453
1993	54,059,453	2,798,989	474,345	310,829	56,694,926
1994	56,694,926	2,766,210	642,086	11,403	58,830,453
1995	58,830,453	2,626,121	463,782		60,992,792
1996	60,992,792	2,029,805	467,048		62,555,549
1997	62,555,549	2,214,412	554,778		64,215,183
1998	64,215,183	3,102,562	205,176	18,059	67,130,628
1999	67,130,628	656,993	30,068		67,757,553
2000	67,757,553	5,308,924			73,066,477
2001	73,066,477	8,193,570	12,071		81,247,976
2002	81,247,976	5,459,971	196,636		86,511,312
2003	86,511,312	5,270,466	90,497		91,691,280
2004	91,691,280	4,402,769			96,094,049
2005	96,094,049	6,658,267	226,291		102,526,025
2006	102,526,025	10,595,487	136,154		112,985,358
2007	112,985,358	5,138,401	130,731		117,993,028
2008	117,993,028	6,518,177	(674)		124,511,879
2009	124,511,879	9,930,500	113,834	(621,860)	133,706,685
2010	133,706,685	8,872,197	843,269		141,735,614
2011	141,735,614	23,935,498	6,277,251		159,393,861
2012	159,393,861	25,488,117	23,622,435		161,259,543
2013	161,259,543	22,881,403	21,040,307		163,100,639
2014	163,100,639	13,145,332	17,726,165	63,487,161	222,006,967

TUCSON ELECTRIC POWER COMPANY
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1989	44,250,482	3,087,400	643,857	(1,152)	46,692,873
1990	46,692,873	2,411,979	550,895	(93)	48,553,863
1991	48,553,863	3,056,776	544,557		51,066,082
1992	51,066,082	3,535,937	500,697	(6,694)	54,094,627
1993	54,094,627	2,841,892	579,155	415,639	56,773,003
1994	56,773,003	2,767,505	642,086	11,403	58,909,825
1995	58,909,825	2,616,839	463,782		61,062,882
1996	61,062,882	2,063,749	467,048		62,659,583
1997	62,659,583	2,438,239	554,778		64,543,044
1998	64,543,044	3,196,710	205,176	18,059	67,552,637
1999	67,552,637	8,866,659	30,068		76,389,228
2000	76,389,228	1,947,897			78,337,125
2001	78,337,125	4,917,616	12,071		83,242,670
2002	83,242,670	5,239,635	196,636		88,285,669
2003	88,285,669	5,057,777	90,497		93,252,949
2004	93,252,949	6,283,475			99,536,424
2005	99,536,424	7,279,834	226,291		106,589,968
2006	106,589,968	8,730,779	127,621		115,193,125
2007	115,193,125	5,393,737	135,272		120,451,590
2008	120,451,590	5,442,881	3,318		125,891,153
2009	125,891,153	10,683,102	113,834	(621,860)	135,838,562
2010	135,838,562	8,597,818	760,533		143,675,847
2011	143,675,847	24,742,540	1,762,639	(175,825)	166,479,923
2012	166,479,923	25,233,310	1,229,043		190,484,190
2013	190,484,190	23,861,351	1,029,097		213,316,444
2014	213,316,444	9,755,652	1,065,129		222,006,967

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1926-2014
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1989-1993	28.5	56.1	O2	3.73	91.2	O4 *	5.97	47.4	R0.5	2.44
1990-1994	26.0	57.4	O2	5.02	48.6	S-.5	1.80	93.0	O4 *	4.82
1991-1995	9.3	57.0	L0	13.86	48.3	R0.5	10.05	45.2	R1	7.53
1992-1996	2.2	59.0	L0	13.83	51.9	S-.5	11.25	47.1	R1	7.93
1993-1997	5.9	61.9	L0	15.10	53.4	S-.5	12.31	48.2	R1	8.84
1994-1998	8.8	69.2	L0	17.30	57.0	S0	13.69	52.2	R1	10.96
1995-1999	22.3	85.3	L0	18.39	67.2	S0	15.22	58.0	R2	11.53
1996-2000	67.9	110.9	SC	0.73	110.5	SC	0.75	83.8	R1.5	1.08
1997-2001	72.3	136.1	R0.5	2.35	126.0	S0	2.02	90.6	R2	0.82
1998-2002	67.1	113.6	L1.5 *	5.81	72.4	S2 *	7.27	62.1	R4 *	17.99
1999-2003	50.5	108.3	L1.5 *	11.22	70.2	S2 *	4.72	62.6	S4 *	12.33
2000-2004	60.6	113.8	L1.5 *	7.96	72.8	S2 *	6.09	65.1	R4 *	13.99
2001-2005	0.0	88.7	L1.5 *	32.91	60.8	S3 *	16.64	56.4	S4 *	8.90
2002-2006	0.0	83.6	L1.5 *	31.12	59.0	S3 *	15.05	55.5	S4 *	8.28
2003-2007	0.0	88.9	L1.5 *	33.39	60.8	S3 *	17.45	56.4	S4 *	10.29
2004-2008	0.0	97.4	L1.5 *	35.75	63.8	S3 *	20.18	58.1	S4 *	11.77
2005-2009	12.1	105.1	L1.5 *	23.49	70.1	S3 *	11.30	64.7	S4 *	4.84
2006-2010	11.7	102.6	L1.5 *	19.36	72.7	S2 *	10.12	66.6	R4 *	4.33
2007-2011	2.9	68.7	L1.5 *	15.37	57.6	R3 *	5.44	56.7	R4 *	2.73
2008-2012	2.9	64.7	L1.5 *	11.71	57.0	R2.5	4.12	55.2	R3	2.48
2009-2013	5.0	63.5	L1.5 *	9.65	56.8	R2.5	3.35	54.7	R2.5	2.40
2010-2014	4.2	60.4	L1.5 *	8.56	55.6	S1.5	3.19	53.7	R2	1.98

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

Placement Band: 1926-2014

Hazard Function: Proportion Retired

Weighting: Exposures

Shrinking Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1989-2014	5.8	72.0	L1	13.39	59.1	R2	4.45	56.4	R2.5	2.33
1991-2014	5.9	72.6	L1 *	13.54	59.6	R2.5	4.29	57.0	R2.5	2.34
1993-2014	6.0	73.1	L1.5 *	13.69	60.1	R2.5	4.27	57.4	R3	2.38
1995-2014	6.1	73.7	L1.5 *	13.84	60.7	S2	4.19	58.1	R3	2.42
1997-2014	6.2	74.1	L1.5 *	13.92	61.2	S2	4.11	58.6	R3	2.43
1999-2014	6.2	73.9	L1.5 *	13.78	61.4	S2 *	3.99	59.0	R3	2.45
2001-2014	6.1	72.3	L1.5 *	13.08	60.9	S2	3.76	58.5	R3	2.41
2003-2014	6.1	71.4	L1.5 *	12.62	60.7	S2	3.75	58.3	R3	2.34
2005-2014	5.8	69.2	L1.5 *	11.82	59.8	S2	3.62	57.5	R3	2.35
2007-2014	6.6	68.5	L1.5 *	10.65	59.8	S2	3.43	57.4	R2.5	2.21
2009-2014	6.3	64.9	L1.5 *	9.10	58.1	S1.5	3.09	55.8	R2.5	2.08
2011-2014	4.9	58.2	L1.5 *	7.69	54.5	S1.5	3.12	52.7	R2	2.49
2013-2014	22.3	73.7	L1	5.20	69.5	S0	4.04	66.9	S0.5	3.45

TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1926-2014
Hazard Function: Proportion Retired
Weighting: Exposures

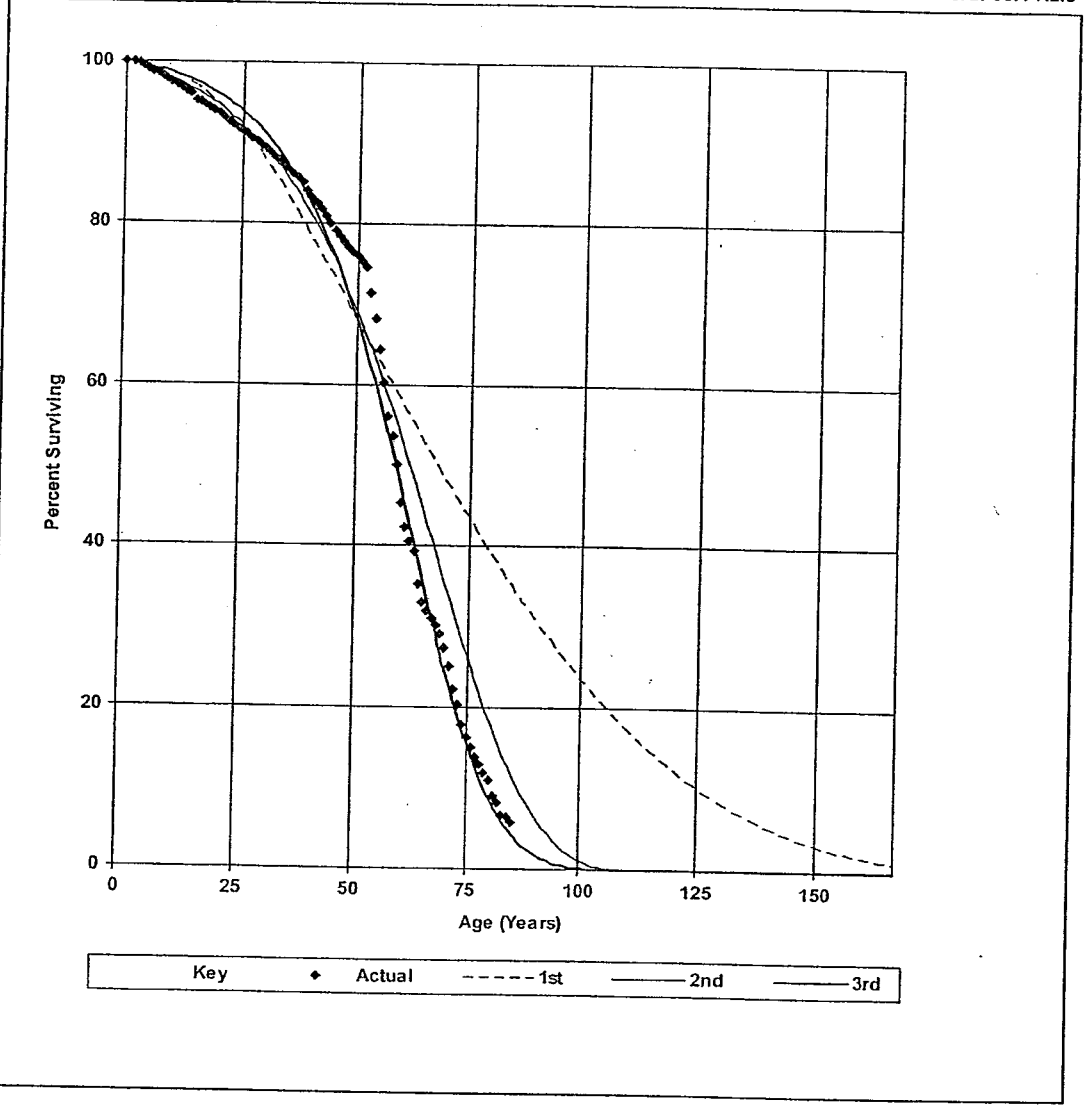
Progressing Band Life Analysis

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index	Average Life	Dispersion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1989-1990	30.5	52.3	O2	3.38	119.6	SC *	11.32	43.5	R0.5	3.62
1989-1992	22.4	54.4	O2	4.82	77.7	O4 *	6.41	46.7	R0.5	3.30
1989-1994	27.4	55.5	O2	3.37	67.3	O3 *	4.43	48.6	S-.5	2.30
1989-1996	2.4	57.8	L0	12.82	53.9	L0	11.81	45.9	R1	7.16
1989-1998	9.3	63.8	O2	14.22	58.5	L0	13.11	49.8	R1	9.26
1989-2000	32.4	76.7	O2	9.33	78.6	O2	9.54	58.0	R1	6.49
1989-2002	39.6	79.7	L0	6.83	64.1	S0	4.01	53.6	R2	8.19
1989-2004	44.9	87.6	L0	5.72	69.0	S0	2.91	57.4	R2	8.57
1989-2006	0.0	83.0	L0.5	27.73	60.0	R2	17.86	53.1	R3	8.24
1989-2008	0.0	88.2	L0.5	28.98	62.8	R2	19.31	55.1	R3	9.39
1989-2010	6.4	91.7	L0.5	19.65	66.3	R2	11.14	59.6	R3	3.74
1989-2012	2.4	71.5	L1 *	16.27	57.2	R2.5	5.85	54.7	R3	2.38
1989-2014	5.8	72.0	L1	13.39	59.1	R2	4.45	56.4	R2.5	2.33

TUCSON ELECTRIC POWER COMPANY
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1926-2014 Observation Band: 1989-2014
Hazard Function: Proportion Retired
Weighting: Exposures
1st: 72.0-L1 2nd: 59.1-R2 3rd: 56.4-R2.5

Graphics Analysis



TUCSON ELECTRIC POWER COMPANY

Distribution Plant

Account: 364.00 Poles, Towers and Fixtures

T-Cut: None

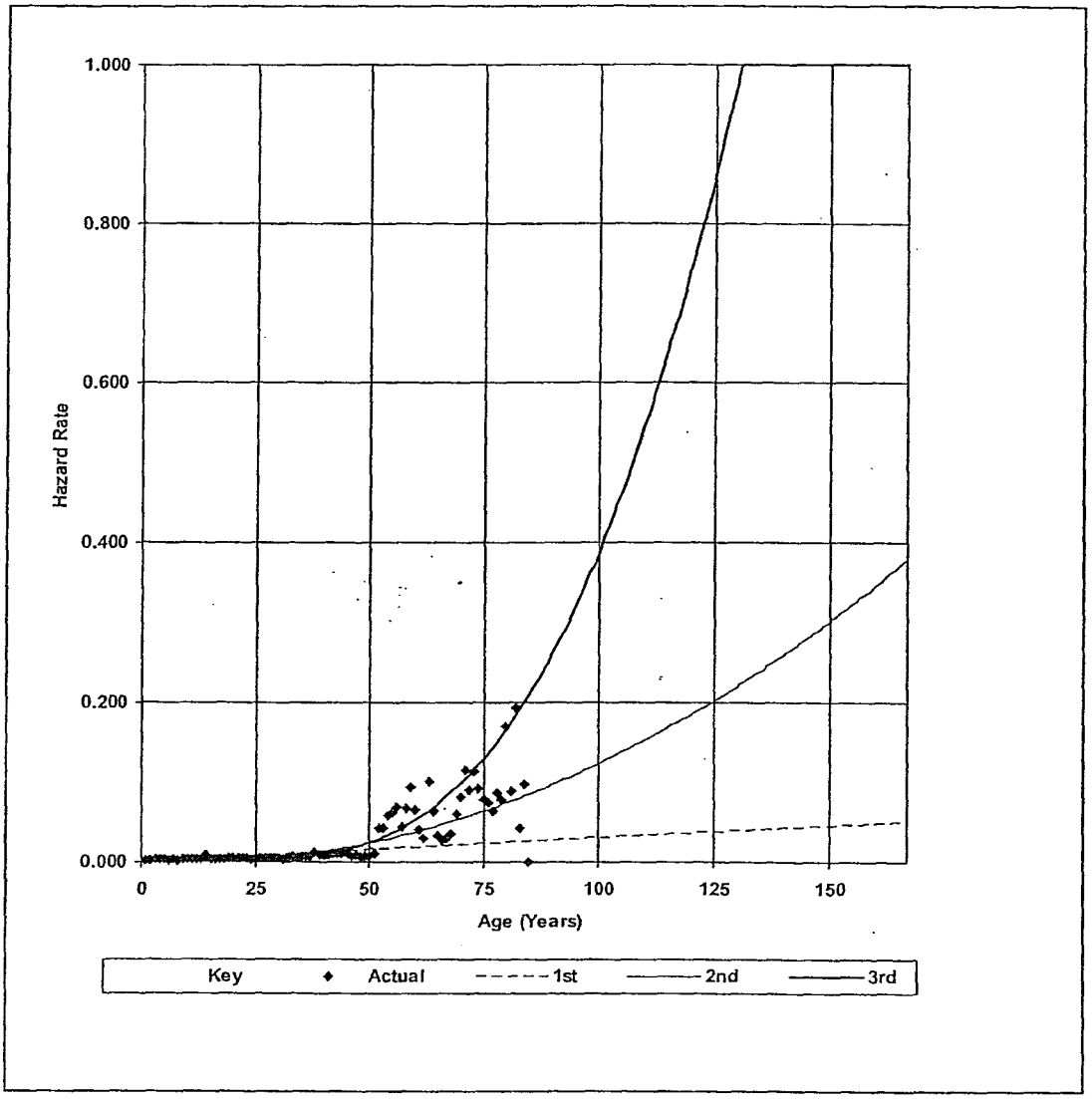
Placement Band: 1926-2014 Observation Band: 1989-2014

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

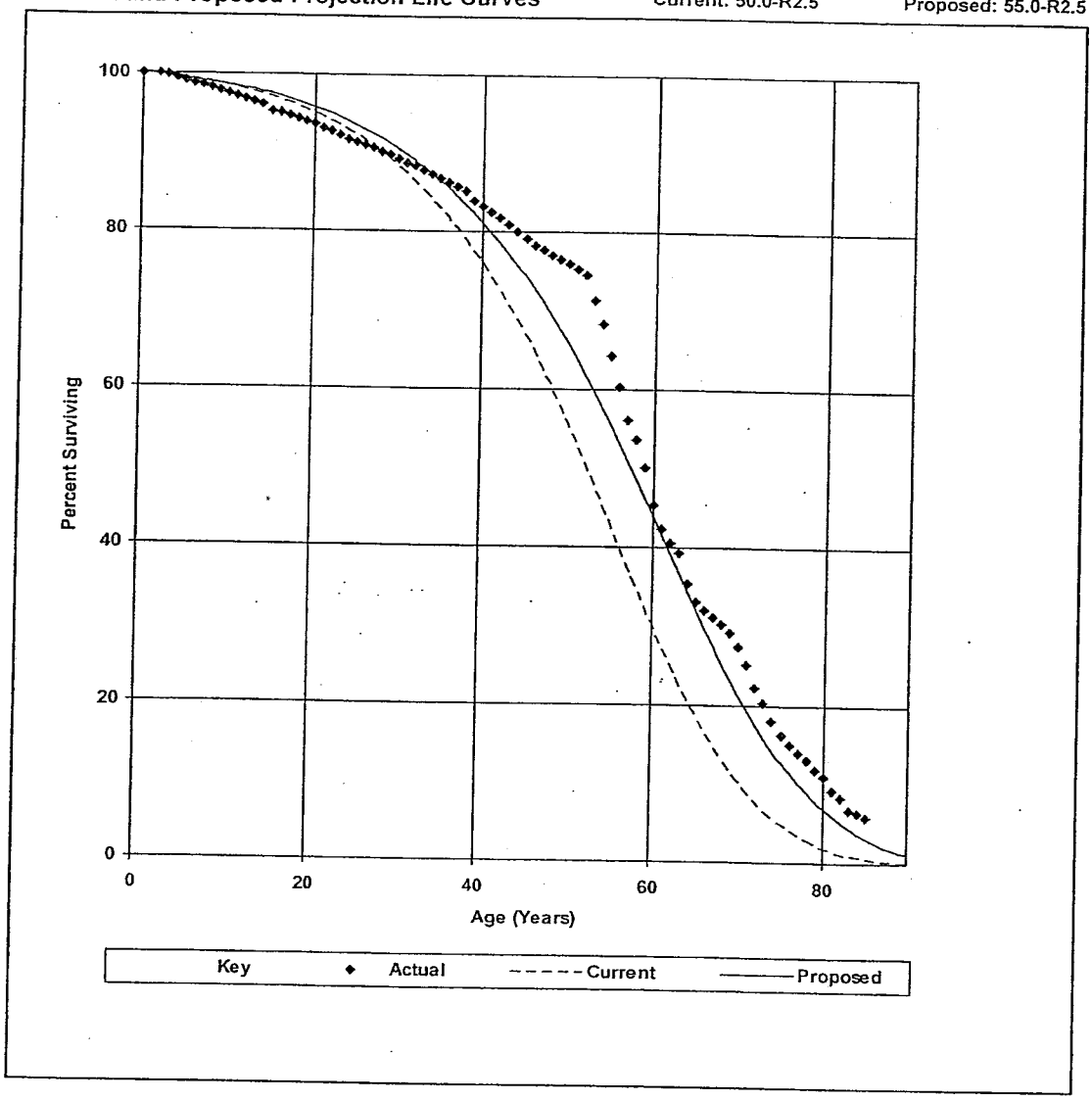
1st: 72.0-L1 2nd: 59.1-R2 3rd: 56.4-R2.5



TUCSON ELECTRIC POWER COMPANY
Distribution Plant
Account: 364.00 Poles, Towers and Fixtures

T-Cut: None
Placement Band: 1926-2014
Observation Band: 1989-2014

Current and Proposed Projection Life Curves Current: 50.0-R2.5 Proposed: 55.0-R2.5



TUCSON ELECTRIC POWER COMPANY

Net Salvage

Account: 108.02 Distribution

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1989	5,361,761	667,990	12.5		785,078	14.6		(117,088)	-2.2	
1990	3,337,683	1,316,905	39.5		1,433,463	42.9		(116,558)	-3.5	
1991	4,251,212	1,256,819	29.6		3,080,152	72.5		(1,823,333)	-42.9	
1992	2,355,616	783,444	33.3		2,189,522	92.9		(1,406,079)	-59.7	
1993	2,169,120	775,288	35.7	27.5	1,572,733	72.5	51.8	(797,445)	-36.8	-24.4
1994	3,641,728	975,582	26.8	32.4	2,389,843	65.6	67.7	(1,414,261)	-38.8	-35.3
1995	3,319,838	979,605	29.5	30.3	1,226,078	36.9	66.5	(246,472)	-7.4	-36.1
1996	2,301,967	997,479	43.3	32.7	1,291,111	56.1	62.9	(293,632)	-12.8	-30.2
1997	2,272,824	671,318	29.5	32.1	1,245,117	54.8	56.4	(573,799)	-25.2	-24.3
1998	1,411,419	545,596	38.7	32.2	944,014	66.9	54.8	(398,419)	-28.2	-22.6
1999	90,038	202,823	225.3	36.2	311,919	346.4	53.4	(109,096)	-121.2	-17.3
2000	3,427,554	819,167	23.9	34.1	(6,212)	-0.2	39.8	825,379	24.1	-5.8
2001	87,700	67,789	77.3	31.6	266,993	304.4	37.9	(199,203)	-227.1	-6.2
2002	1,780,979	549,785	30.9	32.1	401,616	22.6	28.2	148,168	8.3	3.9
2003	1,284,928	514,230	40.0	32.3	209,557	16.3	17.7	304,673	23.7	14.5
2004	10,734,023		0.0	11.3		0.0	5.0		0.0	6.2
2005	3,344,454	2,323,660	69.5	20.1	846,755	25.3	10.0	1,476,905	44.2	10.0
2006	2,636,547	479,963	18.2	19.6	4,691,270	177.9	31.1	(4,211,307)	-159.7	-11.5
2007	4,499,717	1,837,868	40.8	22.9	5,761,426	128.0	51.2	(3,923,559)	-87.2	-28.2
2008	2,105,375	1,465,293	69.6	26.2	1,335,375	63.4	54.2	129,918	6.2	-28.0
2009	(369,286)	1,490,991	-403.7	62.2	930,744	-252.0	111.0	560,247	-151.7	-48.8
2010	6,660,347	1,899,492	28.5	46.2	1,491,496	22.4	91.5	407,996	6.1	-45.3
2011	14,100,108	3,886,122	27.6	39.2	1,954,166	13.9	42.5	1,931,956	13.7	-3.3
2012	32,286,157	3,483,875	10.8	22.3	1,981,445	6.1	14.0	1,502,430	4.7	8.3
2013	30,399,599	3,167,575	10.4	16.8	1,645,569	5.4	9.6	1,522,006	5.0	7.1
2014	35,565,597	3,364,056	9.5	13.3	1,693,337	4.8	7.4	1,670,719	4.7	5.9
Total	179,057,006	34,522,713	19.3		39,672,565	22.2		(5,149,852)	-2.9	

TUCSON ELECTRIC POWER COMPANY

Net Salvage

Account: 108.02 Distribution

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1989	5,398,121	667,990	12.4		785,078	14.5		(117,088)	-2.2	
1990	3,306,759	1,316,905	39.8		1,433,463	43.3		(116,558)	-3.5	
1991	4,249,399	1,256,819	29.6		3,080,152	72.5		(1,823,333)	-42.9	
1992	2,328,078	783,444	33.7		2,189,522	94.0		(1,406,079)	-60.4	
1993	2,370,447	775,288	32.7	27.2	1,572,733	66.3	51.3	(797,445)	-33.6	-24.1
1994	3,669,298	975,582	26.6	32.1	2,389,843	65.1	67.0	(1,414,261)	-38.5	-34.9
1995	2,991,044	979,605	32.8	30.6	1,226,078	41.0	67.0	(246,472)	-8.2	-36.4
1996	2,628,926	997,479	37.9	32.3	1,291,111	49.1	62.0	(293,632)	-11.2	-29.7
1997	2,274,658	671,318	29.5	31.6	1,245,117	54.7	55.4	(573,799)	-25.2	-23.9
1998	2,156,667	545,596	25.3	30.4	944,014	43.8	51.7	(398,419)	-18.5	-21.3
1999	975,061	202,823	20.8	30.8	311,919	32.0	45.5	(109,096)	-11.2	-14.7
2000	4,408,607	819,167	18.6	26.0	(6,212)	-0.1	30.4	825,379	18.7	-4.4
2001	1,245,580	67,789	5.4	20.9	266,993	21.4	25.0	(199,203)	-16.0	-4.1
2002	3,459,416	549,785	15.9	17.8	401,616	11.6	15.7	148,168	4.3	2.2
2003	4,220,779	514,230	12.2	15.1	209,557	5.0	8.3	304,673	7.2	6.8
2004	1,343,658		0.0	13.3		0.0	5.9		0.0	7.4
2005	3,342,122	2,323,660	69.5	25.4	846,755	25.3	12.7	1,476,905	44.2	12.7
2006	2,536,197	479,963	18.9	26.0	4,691,270	185.0	41.3	(4,211,307)	-166.0	-15.3
2007	4,745,873	1,837,868	38.7	31.8	5,761,426	121.4	71.1	(3,923,559)	-82.7	-39.2
2008	2,869,248	1,465,293	51.1	41.2	1,335,375	46.5	85.2	129,918	4.5	-44.0
2009	1,245,916	1,490,991	119.7	51.5	930,744	74.7	92.0	560,247	45.0	-40.5
2010	6,741,625	1,899,492	28.2	39.5	1,491,496	22.1	78.3	407,996	6.1	-38.8
2011	9,584,974	3,886,122	40.5	42.0	1,954,166	20.4	45.6	1,931,956	20.2	-3.5
2012	9,894,066	3,483,875	35.2	40.3	1,981,445	20.0	25.4	1,502,430	15.2	14.9
2013	10,388,388	3,167,575	30.5	36.8	1,645,569	15.8	21.1	1,522,006	14.7	15.7
2014	18,904,562	3,364,056	17.8	28.5	1,693,337	9.0	15.8	1,670,719	8.8	12.7
Total	117,279,470	34,522,713	29.4		39,672,565	33.8		(5,149,852)	-4.4	

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

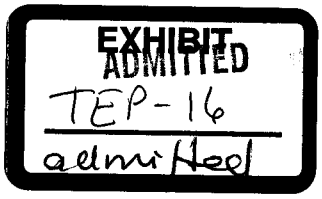
Rebuttal Testimony of

David J. Lewis

on Behalf of

Tucson Electric Power Company

July 25, 2016



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Exhibits

Exhibit DJL-R-1 Comparison of Adjustments to Revenue Requirement
Exhibit DJL-R-2 Correction of RUCO Adjustments
Exhibit DJL-R-3 Correction of Staff Adjustments
Exhibit DJL-R-4 Response to RUCO 11.02
Exhibit DJL-R-5 Post-Test Year Projects
Exhibit DJL-R-6 Staff Response to TEP 2.1

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David J. Lewis and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct Testimony in this proceeding?

A. No.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or "Company").

Q. What is your position with TEP?

A. I am the Manager of Revenue Requirements for UNS Energy Corporation ("UNS Energy"), an indirect, wholly owned subsidiary of Fortis Inc. ("Fortis"). I am responsible for monitoring and determining revenue requirements for all the regulated subsidiaries of UNS Energy, including TEP.

Q. Please describe your education and experience.

A. I hold a Bachelor of Science in Business Administration, a Master's of Business Administration and a Master's of Science in Accountancy. I have over 13 years' experience within the utility industry.

Prior to working for UNS Energy, I was employed by Green Valley Water Company as the principal accountant reporting directly to the Controller.

Before then, I was the business support analysis for Raytheon Missile Systems NAPI facility in Farmington, New Mexico.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. I address certain adjustments that Staff witnesses Donna Mullinax, Roxie McCullar and Michael McGarry recommend in their Direct Testimonies. I also address adjustments that Residential Utility Consumer Office ("RUCO") witnesses Jeffrey Michlik and Frank Radigan proposes in their Direct Testimonies. Any inadvertent omission of discussion of any adjustment should not be considered an acceptance of the position or recommendation.

Q. What else do you address in your Testimony?

A. I am providing an exhibit (**Exhibit DJL-R-1**) that summarizes adjustments that the Company is making in its Rebuttal Testimony.

II. COMPUTATION CORRECTIONS TO STAFF'S AND RUCO'S DIRECT FILINGS.

Q. Are there computation errors that you have identified within Staff's or RUCO's Adjustments?

A. Yes. I have provided an attachment, **Exhibit DJL-R-2 and Exhibit DJL-R-3,** which summarizes and explains the errors that I have identified and sets forth the corrected adjustments.

Q. What computation errors did you identify?

A. As explained in **Exhibit DJL-R-2 and Exhibit DJL-R-3**, the following errors were identified.

1. Correction of Staff's adjustment E-5 Cash Working Capital. Staff inadvertently used the ACC Jurisdictional factor twice in its calculation.

2. Staff did not adjust Accumulated Deferred Income Taxes to reflect proposed changes to Rate Base.

3. Correction of Staff's adjustment E-6 Depreciation Expense. Staff's methodology to adjust Accumulated Depreciation is incorrect. The Average Remaining Life depreciation technique used in the current depreciation study. It is a self-correcting approach in that its continued application constantly trues up the proposed depreciation rates over the average remaining life of the property to assure full recovery of the total asset cost. Therefore, Staff does not need to adjust accumulated reserve as proposed. Reducing the reserve balance overstates the asset value on which the Company is earning a return.

4. Correction to RUCO's adjustment JMM-22 Overhaul and Outage. During the discovery process, the Company identified a formula error that understated the amount of test year outage expense. RUCO's adjustment used the revised outage expense amounts; however, RUCO's intent was to adjust test year outage expense to a normalized amount of $8,127,571. The adjustment however reduced the filed outage amount proposed by the Company to $7,165,217. RUCO should have started with the Company's filed position, not the revised position since the revised amount was not reflected in the original revenue requirement they are adjusting from.

5. Correction to RUCO's adjustment JMM-24. The Accrual rates used in RUCO's post-test year adjustment do not reflect what TEP is currently requesting. The Company's post-test year pro-forma adjustment calculated ACC jurisdictional depreciation of $4,137,853. RUCO's pro-forma adjustment removes $7,870,808, which is roughly 60% more than the Company's filed position. This is because most of the accrual rates used by RUCO were twice that of what

the Company proposed. RUCO's pro-forma methodology removed twelve months of depreciation expense from test year expense for both post-test year plant and post-test year plant renewables. This is incorrect as explained in the Company's response to RUCO's data request RUCO 11.2 (attached as **Exhibit DJL-R-4**).

6. RUCO did not adjust Accumulated Deferred Income Taxes to reflect proposed changes to Rate Base.

7. Correction to RUCO's JMM-22 Overhaul and Outage. RUCO did not adjust the frequency percent to reflect a levelized average over the 2005 through 2015 period. RUCO intended to calculate a levelized average spread over 11 years instead of 17 years as reflected in their actual adjustment. This error occurred because RUCO did not correct the frequency formula, instead they used what was being calculated in the original pro-forma. Had RUCO corrected the formula, RUCO's revised Overhaul and Outage expense would have been approximately $13.1 million, not the $8.1 million presented in JMM-22.

III. REBUTTAL TO RATE BASE ADJUSTMENTS.

A. Post-Test Year Plant.

Q. Did Staff or RUCO make any adjustments to the Post-Test Year rate base amounts requested by the Company?

A. Yes, Staff witness Donna Mullinax removed 16 post-test year plant projects, 14 regular projects[1] and three renewable energy projects[2]. This adjustment reduces ACC

[1] Staff Adjustment E-1, Mullinax Direct Revenue Requirement Testimony, Table 2, page 9.
[2] Staff Adjustment E-2, Mullinax Direct Revenue Requirement Testimony, Table 4, page 13.

jurisdictional original cost rate base ("OCRB") by approximately $30.6 million.[3] RUCO witness Frank Radigan recommends the removal of all post-test year amounts proposed by the company. RUCO's adjustment reduces OCRB by approximately $80 million.

Q. Do you agree with Staff's recommendation to remove these 16 Post Test Year plant projects?

A. No, I do not. Ms. Mullinax recommends excluding post-test-year plant that was not in service within six months after the end of the test year. Her recommendation applies to regular Post Test Year Plant (Staff Adjustment E-1) and renewable Post Test Year Plant (Staff Adjustment E-2). Her reasoning is that the integrity of using a test year becomes increasingly blurred as more and more adjustments are made beyond the end of the test year period[4]. However, the Company is only requesting to include the costs incurred prior to the end of the test year, and invested in plant items that will be in service and benefiting customers by the time new rates are effective. We are not asking for inclusion of any costs incurred post-test year. These facilities will primarily be used to maintain service levels and system reliability and will serve existing test year customers.

Q. How much of the ACC Jurisdictional $30.6 million in Post Test Year plant removed from rate base by Staff is currently In Service?

A. The $30.6 million in Post Test Year plant is made up of $14.7 million in non-renewable projects and $15.9 million in renewable projects. For non-renewable projects, of the $14.7 million identified by Staff, approximately $13.3 million has been placed into service as of June 30, 2016. The Company expects the remaining $1.4 million to be in service by the time new rates become effective. For the renewable projects, of the $15.9 million identified by Staff, $7.2 million will be in service by August 31, 2016, and the

[3] Reduction to rate base of $15.9 million (Mullinax Direct Revenue Requirement Testimony, page 13, line 12) and $14.7 million for non-renewable plant (Mullinax Direct Revenue Requirement, page 9, line 8.
[4] Mullinax Direct Revenue Requirement Testimony, page 10, line 3 through 6.

remaining $8.7 million will be in service prior to new rates becoming effective. A list showing the current status of each of these 16 projects is attached as **Exhibit DJL-R-5**.

Q. Has the Commission allowed the use of Post-Test-Year Plant before?

A. Yes. The Commission approved including Post-Test-Year Plant for UNS Electric in the 2013 UNS Electric Rate Order. The Commission has also allowed Post-Test-Year Plant in numerous other cases, including: EPCOR Water Arizona, Inc., in Decision No. 75268 (December 31, 2015); Chaparral City Water Company, Decision No. 74568 (June 20, 2014); TEP in Decision No. 73912 (June 27, 2013); Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012), Rio Rico Utilities, Inc., in Decision No. 67279 (October 5, 2004); Arizona Water Co., in Decision No. 66849 (March 19, 2004); and Bella Vista Water Co., Inc., in Decision No. 65350 (November 1, 2002). Staff's response to TEP Data Request 2.1 shows that the Commission has not limited Post-Test Year Plant to 6 months and has approved longer periods in a number of cases. A copy of this response is attached as **Exhibit DJL-R-6**.

Q. Do you agree with RUCO's recommendation to remove all of Post-Test Year plant proposed by the Company?

A. No. As noted above, the Commission on several occasions has allowed companies to include Post-Test Year plant in rate base. Mr. Radigan believes the Company's request for post-test year plant recovery in rates requires a detailed presentation that the large and continuous build out of infrastructure reflects appropriate, efficient, effective, and timely decision-making.[5] As stated in Company witness Mr. Hutchens rebuttal testimony, as part of the Company's last rate case, TEP agreed to meet annually with Staff to review the Company's actual capital spending and future plans for the upcoming year. The point of these meeting is to create a free exchange of information of what the company needs in

[5] Radigan Direct Revenue Requirement Testimony, page 29, lines 9 through 13

order to maintain and improve system reliability and effective service. Mr. Radigan's argument is without merit and should not be considered.

B. Sundt Coal Handling Facilities.

Q. Did Staff or RUCO make and adjustment for Sundt Coal Handling Facilities?

A. Yes, Staff accepted the Company's ACC jurisdictional allocation correction to original filing. This adjustment increased jurisdictional rate base by $20,000.

C. Sundt and San Juan Unit 2 Materials and Supplies.

Q. Please explain the update to the Sundt Coal Handling Facility Materials and Supplies pro-forma adjustment.

A. Company witness Frank Marino is supporting this adjustment. The Revised adjustment increase rate base by $731,117 and reduces operating income by $243,706.

IV. REBUTTAL TO OPERATING INCOME ADJUSTMENTS.

A. TEP Proposed Depreciation Rates.

Q. Did Staff or RUCO adjust the proposed accrual rates as outlined in the 2015 Depreciation Study?

A. Yes. Staff witness Ms. McCullar recommends: a -5 percent future net salvage percent for Distribution plant; a final retirement year of 2032 for Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2; and the estimated dismantlement costs be set at current dollars instead of an estimated future dismantlement costs. I will address the recommended -5 percent future net salvage percent and the dismantlement

cost set at current dollars. Company witness Michael Sheehan will address the final year retirement dates proposed by Staff.

Q. Do you agree with Staff's proposal that dismantlement cost be set at current dollars?

A. No. Ms. McCullar believes it is inappropriate to charge ratepayers now for the estimated dismantlement cost in future dollars at the time of retirement, and instead proposes to estimate dismantlement costs in current dollars. This proposal is inappropriate and does not incorporate all the factors that should be considered in ratemaking, particularly the equitable treatment of different generation of customers. After accruing for terminal net salvage in current dollars, TEP will have to capitalize net cost of dismantlement in future years (when the facility is no longer providing service) to be recovered by future customers and not by the customers presently receiving service from these assets. Ms. McCullar proposal is designed to reduce rates for today's customers but to do so at the expense of tomorrow's customers. In addition, Ms. McCullar's approach ignores the reality of inflation; these future retirement costs will not be paid in current dollars, but rather in inflated future dollars at the time of retirement.

Q. Is it appropriate to ask current customers to pay for future costs of plant removal?

A. Yes, the future cost to remove plant is part of the service value that it renders to current customers, and a portion of those costs should be recovered from current customers. As future costs are recovered from current customers, they are deducted from rate base. Thus, current customers receive a benefit as they pay their fair, ratable portion of those costs.

Q. Do you agree with Staff's position to set net salvage for Distribution Plant at -5 percent?

A. Yes. The -5 percent future net salvage represents the 25 year historic average; therefore, using -5 percent for net salvage is appropriate.

Q. What do you recommend for Dismantlement costs and net salvage for Distribution Plant?

A. While TEP strongly believes that the requested Accrual rates provided in the 2015 Depreciation study should be approved, the Company will accept Mrs. McCullar recommendation of -5 percent future net salvage for distribution plant and dismantlement costs be set a current dollars in this proceeding. However, in the Company's opinion it is just pushing today's "cost to serve" to future customers.

B. Overhaul and Outage Adjustment.

Q. Did Staff or RUCO make an adjustment for Overhaul and Outage expense?

A. Yes, Staff witness McGarry, used a four-year period (2012 through 2015) to reflect the typical methodology to normalized expense between base rate cases. RUCO witness Michlik uses an historical average from 2005 to 2015 to reflect overhaul and outage expenses.

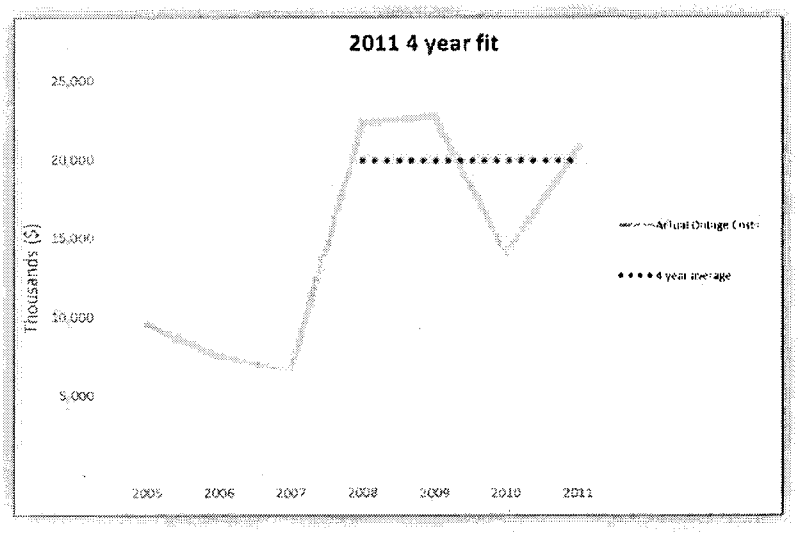
Q. Do you agree with either Staff or RUCO's adjustment?

A. No. First I will address my concerns with Mr. Michlik's adjustment. Ignoring the mathematical error explained earlier in my testimony, the Company strongly opposes Mr. Michlik's exclusion of outage expense related to Gila River Unit 3. As explained in greater detail by TEP witness Mr. Sheehan these outage costs are not represented in the calculation proposed by Mr. Michlik. In the most recent UNS Electric case, Mr. Michlik

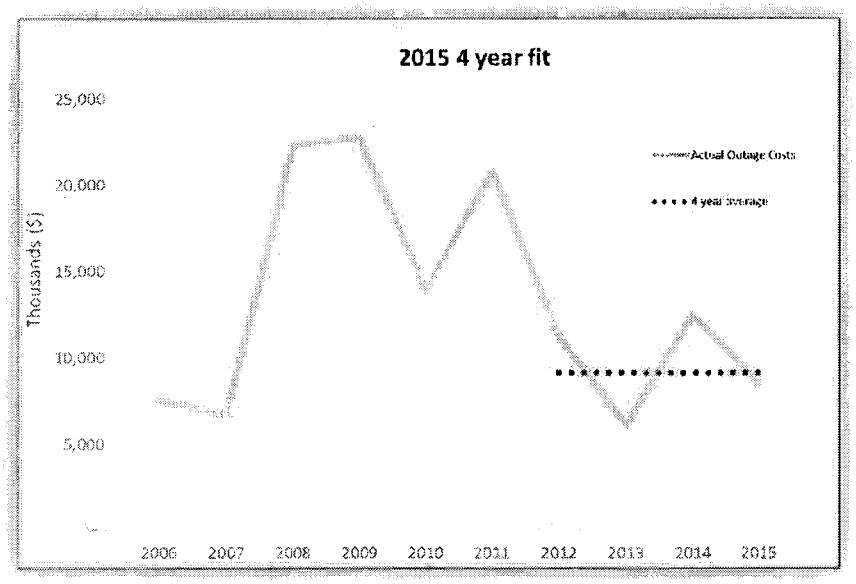
did not oppose recovery of the 25% ownership share of outage expense to be recovered in UNS Electric's base rates therefore, the Company does not understand his rationale to exclude TEP's share of these same outage costs from TEP's base rates.

By appropriately including Gila River Unit 3 and correcting for the calculation error; RUCO's levelized overhaul and outage expense would be $14.6 million. This is roughly the same as the company's revised position.

Staff witness McGarry methodology to "normalize expense" over a four year period significantly under recovers the actual levelized outage costs. As part of the 2013 TEP Settlement Agreement, the Company accepted Staff's ACC jurisdictional outage expense of $11.6 million to be recovered through base rates. This adjustment was based on actual historical costs for the period 2004 to 2011. Mr. McGarry's proposal to use just a four-year period will reduce outage costs to roughly $9.1 million. Had the Company used McGarry's four year average methodology in the last rate case, the outage expense would have been roughly $19 million. It seems that Staff's methodologies are changing significantly between rate cases with no recognition of the reality of the timing of outages. Generation overhauls are quite costly and do not occur at regular annual intervals. In general, minor overhauls are performed every 1 to 3 years and major overhauls are performed every 5 to 8 years. Thus, a 4 year normalization will completely miss the cost of major overhauls in some test years, while the normalized cost would shoot up if the major overhaul falls within the 4 year window. To use such a short normalization period will lead to extreme volatility in the normalized levels as depicted on the following tables:



*The chart above depicts higher averages cost in years where there are major outages.



*The chart above depicts lower average cost in years where there are no major outages.

As can be seen by these two graphs using a simple four year average creates huge swings in levelized outage expense. These swings are attributable to major outages that do not occur consistently in such short duration periods. Had McGarry used a 10 year historical

average, the result would have been similar to the requested amount proposed by the Company in its original filing.

C. **Rate Case Expense.**

Q. Did Staff or RUCO dispute the Company's pro forma rate case expense?

A. Yes, Staff recommends rate case expense of $900,000 normalized over four years. RUCO recommends a rate case expense of $950,000 normalized over three years.

Q. Do you agree with Staff and RUCO's recommendation?

A. No. Rate cases are complicated proceedings involving outside counsel and consultants. There are also costs for mailing and publishing notice. There is a significant amount of discovery that takes place. In addition to the application, there are three rounds of testimony prepared by the Company. There is a hearing and then post-hearing briefing, exceptions and open meeting. TEP believes that it is handling its rate cases in the most cost efficient manner possible as shown by its use of numerous internal personal for witnesses and rate case costs. TEP should be compensated for its actual costs.

Q. Do you have any other comments on this issue?

A. Yes. TEP's rate case involves 26 Interveners and 47 witnesses, and the Company has responded to over 3,000 data request. TEP incurred over $1 million in rate case expense in support of its 2012/2013 rate case even though that case ended in a settlement between the parties. UNS Electric is currently in a fully litigated rate case and has incurred over $1 million in rate case expense. Notably, the hearing in that case ran for a full 15 days, even though there revenue requirement issues were largely resolved prior to the hearing. Here, the hearing will likely be longer given the increased number of parties and witnesses, as well as the fact that there are numerous revenue requirement disputes in

addition to the rate design disputes addressed in the UNS Electric case. TEP's request to recover $1.2 million in this proceeding reflects the increasing complexity of rate cases in Arizona.

D Long Term Incentive Compensation.

Q. Please explain the update to the Long Term Incentive Compensation pro-forma adjustment.

A. Company witness Frank Marino is supporting this adjustment. The revised adjustment increase operating income by $880,967.

E Lime Costs.

Q. Please explain the Lime Cost pro-forma adjustment.

A. This adjustment removes all of the Lime Cost associated with our jointly owned coal-fired generating facilities from non-fuel operating cost presently recovered through base rates and moves them to be recovered in the base cost of fuel. This is the same methodology that was approved in 2013 TEP Settlement Agreement which allowed TEP to recover lime expense associated with the Springerville generating station as a variable cost tied to fuel consumption and reconciled through the PPFAC (See settlement agreement section 6.2). This section clearly states that, lime cost associated with fuel consumption are to be recovered as a fuel cost for all of TEP's generation facilities. During the Company's last rate case proceeding, only the cost of lime associated with Springerville was available and, as a result, was the only amount removed from non-fuel operating cost in the "cost of service" as part of the 2013 TEP Settlement Agreement. As such, the lime cost for the Companies other coal-fired generating facilities remained a part of non-fuel costs. We propose to treat the lime costs at all coal-fired generating

plants in a consistent manner to more accurately classifies and recover fuel-related costs through base cost of fuel rather than non-fuel rates.

Q. Why did TEP not make this adjustment in its direct filing?

A. It was an oversight not to include all lime costs incurred at all TEP's coal-fired generating facilities in the base fuel cost in the Company's initial filing. By moving the lime costs from the non-fuel component of base rates, this adjustment has a zero net impact to the cost of service.

F Transmission Expense.

Q. Please explain why the Transmission Expense increase operating income by $1.7 million in the Company's filed Rebuttal?

A. Sure, Transmission costs are recovered through base rates which reflect the transmission costs associated with serving retail customers. As a result of the Company reducing its annualized retail sales to reflect the curtailment of our largest customer's sight usage. This adjustment reduces the expected transmission costs in concurrence with the reduction in transmission revenues included in the adjusted test year revenues.

V. CONCLUSION.

Q. What is the Company's recommendation for revenue requirement?

A. TEP is requesting a revised increase in non-fuel base rates revenues of $100.6 million, or approximately 11 percent over adjusted retail electric revenues at current rates of $909.325 million.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit DJL – R – 1

TUCSON ELECTRIC POWER						
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT						
TEST YEAR ENDED JUNE 30, 2015						
ACC JURISDICTION						
EXHIBIT 1						
	TEP	ACC	RUCO	TEP	TEP	
	As Filed	As Filed	As Filed	Revised	Difference	Explanation of TEP Revisions
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	$2,108,583,243	-	
Rate Base Adjustments						
Jurisdictional Allocation (Demand and Energy)	-	-	(138,422,327)	(32,996,491)	(32,996,491)	Impact of change to jurisdictional allocations except for impacts to rate base adjustments listed below.
SGS CHF	(41,966,722)	(41,966,722)	(41,966,722)	(41,239,083)	727,640	Impact of change to jurisdictional allocations
Fortis Merger Rate Base Adjustment	(522,398)	(522,398)	(522,398)	(517,560)	4,838	Impact of change to jurisdictional allocations
Asset Retirement Obligation	-	-	-	-	-	
Post Test Year Plant	51,782,029	37,124,629	-	51,003,979	(778,051)	Impact of change to jurisdictional allocations
Post Test Year Plant - Renewables	20,794,266	4,872,919	-	20,433,724	(360,541)	Impact of change to jurisdictional allocations
Delayed Unitization	13,237,543	13,237,543	13,237,543	13,118,186	(119,357)	Impact of change to jurisdictional allocations
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(58,303,521)	(58,308,686)	(57,662,694)	645,992	Impact of change to jurisdictional allocations
ADIT - Extension of Bonus Depreciation	-	(12,814,172)	-	(12,672,205)	(12,672,205)	ADIT related to extension of bonus depreciation
San Juan Unit 2	-	-	-	(0)	(0)	
Sundt Coal Handling facilities	(19,120)	880	(19,120)	(18,789)	332	Impact of change to jurisdictional allocations
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,855,471	6,855,471	6,736,607	(118,864)	Impact of change to jurisdictional allocations
Sundt & San Juan M&S	1,225,594	1,225,594	1,225,594	1,956,711	731,117	Increase is do to the revision of obsolete inventory at Sundt
Head Quarters	-	-	(55,043,003)	-	-	
Working Capital	(27,325,154)	(19,387,724)	(25,313,900)	(20,740,139)	6,585,016	Impact of changes to pro forma adjustments including $160K in jurisdictional allocation
Accumulated Depreciation adj and LTI	-	9,020,000	-	-	-	
Total Adjustments	(3,905,553)	(30,315,876)	(267,935,924)	(42,256,127)	(38,350,574)	
Pro Forma OCRB	2,104,677,690	2,078,267,367	1,840,647,319	2,066,327,116	(38,350,574)	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Proposed Rate of Return	7.34%	6.68%	6.76%	7.16%		
Required Operating Income OCRB	$154,416,180	$138,763,150	$124,427,759	$147,984,232	(6,431,948)	
Fair Value Increment of Rate Base	$808,601,055	$808,600,679	$741,672,017	791,549,067	(17,051,988)	
Fair Value Rate Base (FVRB)	$2,913,278,745	$2,886,869,000	$2,582,319,188	$2,857,876,183	(55,402,562)	
Proposed FVROR	5.69%	5.00%	5.20%	5.57%		
Required Operating Income on FVRB	165,898,315	144,418,355	134,398,160	159,224,227	(6,674,088)	
Implied ROR on Fair Value Increment of Rate Base	1.42%	0.70%	1.34%	1.42%		
Original Operating Income - Unadjusted	$318,271,141	$318,271,141	$318,271,141	$318,271,141		
Operating Income Adjustments						
Operating Revenue Adjustments						
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	(10,719,946)	-	
Environmental Cost Adjustor	(1,260,631)	(1,260,631)	(1,260,631)	(1,260,631)	-	
REST and DSM	(48,370,058)	(48,370,058)	(48,370,058)	(48,370,058)	-	
Non-Retail & Non Recurring Revenue	(112,150)	(112,150)	(112,150)	(112,150)	-	
Springerville Units 3 & 4	(111,813,089)	(111,813,089)	(111,813,089)	(111,813,089)	-	
Power Supply Management	(1,099,586)	(1,099,586)	(1,099,586)	(1,099,586)	-	
Customer, Weather and Recalculation of Unbilled Revenue	(4,791,733)	(4,791,733)	(3,956,411)	(4,791,733)	-	
Base Cost of Fuel & Purchased Power	(17,815,595)	(17,815,595)	(17,815,595)	(32,594,041)	(14,778,446)	Variance is due to a decrease in kWh sales (from 9,021M to 8,881M) and a decrease in the proposed PPFAC rate (from 3.3692 to 3.2559).

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Miscellaneous Service Revenue	284,370	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	250,000	250,000	-	
Total Adjustments to Operating Revenues	(195,448,418)	(195,448,418)	(194,613,096)	(210,226,864)	(14,778,446)	
Operating Expense Adjustments						
Jurisdictional Allocation (Demand and Energy)	-	-	(19,532,187)	(2,619,840)	(2,619,840)	Impact of change to jurisdictional allocations except for impacts to operating expense adjustments listed below.
REST and DSM	(19,891,996)	(19,891,996)	(19,891,996)	(19,769,956)	122,040	Impact of change to jurisdictional allocations
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,696,421)	(1,696,421)	(1,663,540)	32,881	Impact of change to jurisdictional allocations
Springerville Units 3 & 4	(84,382,546)	(84,382,546)	(84,382,546)	(83,129,337)	1,253,210	Impact of change to jurisdictional allocations
Sales of SO2 Allowances	47	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(278,075)	(278,075)	(276,646)	1,429	Impact of change to jurisdictional allocations
Base Cost of Fuel & Purchased Power	226,811,827	226,811,827	226,811,827	212,033,380	(14,778,447)	See explanation in Operating Revenues section.
Gila River O&M	6,130,964	6,130,964	6,130,964	6,024,663	(106,301)	Impact of change to jurisdictional allocations
Springerville Unit 1	(11,558,130)	(11,558,130)	(11,558,130)	(11,384,664)	173,466	Impact of change to jurisdictional allocations
SGS Unit 1 Non Fuel O&M (50.5% Share)	-	-	-	15,243,913	15,243,913	Addition of non-fuel operating costs associated with the 50.5% share of SGS Unit 1.
Overhaul & Outage Normalization	5,176,492	1,043,941	(870,213)	5,644,715	468,223	Increase is due to a formula error that understated the proposed outage expected and includes an offsetting jurisdictional allocation impact of ($90K).
Payroll Expense	2,264,794	1,121,186	2,264,794	2,250,757	(14,037)	Impact of change to jurisdictional allocations
Payroll Tax Expense	151,051	76,051	151,051	151,051	-	
Pension & Benefits	2,004,436	2,050,431	1,056,440	1,576,055	(428,381)	Removed SERP expense as proposed by Staff and RUCO.
Post-Retirement Benefits	1,339,160	1,339,160	1,339,160	1,339,160	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Short-Term Incentive Compensation	702,960	(2,803,734)	(2,964,033)	1,578,745	875,785	During discovery, the company inadvertently included $1,056,578 of capital cost in determining the levelized costs to FERC 920. By doing so, the amount requested was understated. The $875,785 is the result of correcting this understatement and includes an offsetting $11K due to the change in jurisdictional allocations.
Rate Case Expense	107,834	(36,208)	27,834	107,834	-	
Injuries and Damages	1,419	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(212,696)	(416,963)	(212,690)	6	Impact of change to jurisdictional allocations
Bad Debt Expense	(149,199)	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,921,687)	(3,921,687)	(3,869,457)	52,230	Impact of change to jurisdictional allocations
Long Term Incentive Compensation	880,967	-	(639,979)	-	(880,967)	Remove long term incentive compensation as proposed by Staff.
Depr. & Amort. Expense	9,253,715	(1,665,318)	(9,202,556)	1,542,840	(7,710,875)	Decrease is due to removal of 2% inflation for dismantlement costs, and a 5% future net salvage value for distribution assets. Includes a jurisdictional allocation impact of ($201K)
Post Test Year Plant Depreciation and Amortization	-	-	-	4,568,108	4,568,108	Increase is due to $4.6M in post test year plant and renewables that was inadvertentaly excluded in the original filing.
Sundt & San Juan M&S	408,531	408,531	408,531	652,237	243,706	Increase is due to an increase in obsolete Sundt coal handling inventory.
Property Tax Expense	3,119,696	2,694,696	2,554,799	3,119,770	74	Impact of change to jurisdictional allocations
Asset Retirement Obligation	(393,590)	(393,590)	(393,590)	(386,765)	6,825	Impact of change to jurisdictional allocations
SGS Common Facilities Lease	(1,195,980)	(1,195,980)	(1,195,980)	(1,175,244)	20,736	Impact of change to jurisdictional allocations
San Juan Unit 1 SCNR O&M	955,223	955,223	955,223	938,661	(16,562)	Impact of change to jurisdictional allocations
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	(31,176,174)	-	
Lime Expense				(1,612,486)	(1,612,486)	Company removed lime expense included in test year related to our jointly owned facility. These costs are recovered in base cost of fuel
TEP Headquarters	-	-	(942,257)	-	-	
Credit Card Processing Fees	3,475,500	-	-	-	(3,475,500)	Removed credit card processing fees as proposed by Staff and RUCO.

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 1

	TEP As Filed	ACC As Filed	RUCO As Filed	TEP Revised	TEP Difference	Explanation of TEP Revisions
Income Tax Expense	(16,130,352)	(5,695,687)	15,747,439	(19,049,439)	(2,919,086)	Reflects conformity changes and includes offsetting jurisdictional allocation impact of ($855K)
Transmission Expense Adjustment	95,464,952	95,464,952	95,464,952	93,719,409	(1,745,544)	Decrease in transmission expense reflects the impact of a usage reduction related to one of the Company's largest customers.
D&O Insurance	-	(25,000)	(25,153)	(21,105)	(21,105)	Accepted 50/50 sharing as proposed by RUCO and Staff.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	-	(548,924)	-	-	
Severance Pay	-	-	(329,665)	(329,665)	(329,665)	Removed severance pay as proposed by RUCO.
SGS Legal Expenses Lessor Dispute	-	(1,340,000)	-	-	-	
Total Adjustments to Operating Expense	24,441,665	8,854,929	(22,305)	10,845,501	(13,596,164)	
Total Net Adjustments	(219,890,083)	(204,303,347)	(194,590,791)	(221,072,365)	(1,182,282)	
Adjusted Operating Income	$98,381,058	$113,967,794	$123,680,350	$97,198,776	($1,182,282)	
Operating Income Deficiency	$67,517,257	$30,450,561	$10,717,810	$62,025,451	($5,491,806)	
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223	1.6223	1.6223	
Increase in Gross Revenue Requirement	$109,534,118	$49,400,339	$17,387,642	$100,624,690	($8,909,428)	

Exhibit DJL – R – 2

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP	RUCO	RUCO		
	As Filed	**As Filed**	**As Corrected**	**Difference**	**Explanations of RUCO As Corrected**
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	-	
Rate Base Adjustments					
Jurisdictional Allocation		(138,422,327)	(138,422,327)	-	
SGS CHF	(41,966,722)	(41,966,722)	(41,966,722)	-	
Fortis Merger Rate Base Adjustment	(522,398)	(522,398)	(522,398)	-	
Asset Retirement Obligation	-	-	-	-	
Post Test Year Plant	51,782,029	-	-	-	
Post Test Year Plant - Renewables	20,794,266	-	-	-	
Delayed Unitization	13,237,543	13,237,543	13,237,543	-	
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(58,308,686)	(53,547,344)	4,761,342	RUCO's adjustments to Rate Base did not include corresponding adjustments to ADIT. Company adjusted ADIT to reflect rate case adjustments as proposed by RUCO.
San Juan Unit 2	-	(0)	(0)	-	
Sundt Coal Handling facilities	(19,120)	(19,120)	(19,120)	-	
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,855,471	6,855,471	-	
Sundt & San Juan M&S	1,225,594	1,225,594	1,225,594	-	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Head Quarters		(55,043,003)	(55,043,000)	3	
Working Capital	(27,325,154)	(25,313,900)	(27,351,091)	(2,037,191)	RUCO adjusted Company's Cash Working Capital worksheet to reflect RUCO"s adjustments using ACC jurisdictional values. However, the Company's Cash Working Capital worksheet uses pre-ACC jurisdictional values, then adjusts for the ACC jurisdictional ratio by the Revenue Requirements Model. Company corrected RUCO's Cash Working Capital worksheet to reflect pre-ACC jurisdictional values.
Total Adjustments	(3,905,553)	(267,935,924)	(265,211,769)	2,724,155	
Pro Forma OCRB	2,104,677,690	1,840,647,319	1,843,371,474	2,724,155	
Proposed Rate of Return	7.34%	6.76%	6.76%		
Required Operating Income OCRB	$154,416,180	$124,427,759	$124,611,912	184,153	
Fair Value Increment of Rate Base	$808,601,055	$741,672,017	$738,947,714	(2,724,303)	
Fair Value Rate Base (FVRB)	$2,913,278,745	$2,582,319,188	$2,582,319,188	-	
Proposed FVROR	5.69%	5.20%	5.21%		
Required Operating Income on FVRB	165,898,315	134,398,160	134,546,280	148,120	
Implied ROR on Fair Value Increment of Rate Base	1.42%	1.34%	1.34%		

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Original Operating Income - Unadjusted	$318,271,141	$318,271,141	$318,271,141		
Operating Income Adjustments					
Operating Revenue Adjustments					
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	-	
Environmental Cost Adjustor	(1,260,631)	(1,260,631)	(1,260,631)	-	
REST and DSM	(48,370,058)	(48,370,058)	(48,370,058)	-	
Non-Retail & Non Recurring Revenue	(112,150)	(112,150)	(112,150)	-	
Springerville Units 3 & 4	(111,813,089)	(111,813,089)	(111,813,089)	-	
Power Supply Management	(1,099,586)	(1,099,586)	(1,099,586)	-	
Customer, Weather and Recalculation of Unbilled Revenue	(4,791,733)	(3,956,411)	(3,956,411)	-	
Base Cost of Fuel & Purchased Power	(17,815,595)	(17,815,595)	(17,815,595)	-	
Miscellaneous Service Revenue	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	-	(250,000)	RUCO removed the entire value of the building including the value of the retail space. Since the retail space is no longer in rate base, Company eliminated the rent credit to avoid RUCO's double counting.
Total Adjustments to Operating Revenues	(195,448,418)	(194,613,096)	(194,863,096)	(250,000)	
Operating Expense Adjustments					

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
REST and DSM	(19,891,996)	(19,891,996)	(19,891,996)	-	
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,696,421)	(1,696,421)	-	
Springerville Units 3 & 4	(84,382,546)	(84,382,546)	(84,382,546.45)	-	
Sales of SO2 Allowances	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(278,075)	(278,075)	-	
Base Cost of Fuel & Purchased Power	226,811,827	226,811,827	226,811,827	-	
Gila River O&M	6,130,964	6,130,964	6,130,964	-	
Springerville Unit 1	(11,558,130)	(11,558,130)	(11,558,130)	-	
Overhaul & Outage Normalization	5,176,492	(870,213)	4,419,896	5,290,109	The correction has two parts. The first is to correct for RUCO's math error. RUCO's adjustment was intended to levelize expenses to $8,177,594. However, RUCO levelized expense to $9,165 ,217. The second adjustment is to correct the frequency percent. RUCO's intention was to use a levelized frequency percentage over 11 years, however, their formula was averaging over 17 years.
Payroll Expense	2,264,794	2,264,794	2,264,794	-	
Payroll Tax Expense	151,051	151,051	151,051	-	
Pension & Benefits	2,004,436	1,056,440	1,576,055	519,615	RUCO did not include additional benefits included in revised pro forma adjustment. Company corrected for revised pro forma.
Post-Retirement Benefits	1,339,160	1,339,160	1,339,160	-	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
Short-Term Incentive Compensation	702,960	(2,964,033)	(2,964,033)	-	
Rate Case Expense	107,834	27,834	40,708	12,874	RUCO did not use the ACC jurisdictional adjusted values in the adjustment. Company corrected RUCO's adjustment.
Injuries and Damages	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(416,963)	(406,087)	10,876	RUCO applied the same ACC jurisdictional ratio to all EEI adjustments. The ACC jurisdictional ratio varied on some EEI charges.
Bad Debt Expense	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,921,687)	(3,921,687)	-	
Long Term Incentive Compensation	880,967	(639,979)	(431,510)	208,469	RUCO removed LTI based on company's revised/corrected pro forma. Since the correction was not included in the model, RUCO should have used the originally filed pro forma adjustment to remove LTI. Also, RUCO applied payroll tax at a rate of 7.65%. The payroll tax rate on LTI should be 1.45%.
Depr. & Amort. Expense	9,253,715	(9,202,556)	(5,499,223)	3,703,333	RUCO removed 12 months of depreciation expense for both post test year and post test year renewables. By doing so RUCO doubled the expense related to non revewable to post year year.
Sundt & San Juan M&S	408,531	408,531	408,531	-	
Property Tax Expense	3,119,696	2,554,799	2,554,799	-	
Asset Retirement Obligation	(393,590)	(393,590)	(393,590)	-	
SGS Common Facilities Lease	(1,195,980)	(1,195,980)	(1,195,980)	-	
San Juan Unit 1 SCNR O&M	955,223	955,223	955,223	-	
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	-	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected
TEP Headquarters	-	(942,257)	2,948,646	3,890,903	RUCO removed deprecation expense related to new building. Treated HQ building as owned by UNS and calculated rent at "the going market rate." Company correction included the removal of HQ building from rate base and allow $5.3M of annual rent expense.
Credit Card Processing Fees	3,475,500	-	-	-	
Income Tax Expense	(16,130,352)	15,747,439	12,579,068	(3,168,371)	Reflects impact of corrected pro forma postions including a jurisdictional allocation change of $8,577,635.
Transmission Expense Adjustment	95,464,952	95,464,952	95,464,952	-	
Jurisdictional Allocation	-	(19,532,187)	(19,532,187)	-	
D&O Insurance	-	(25,153)	(21,105)	4,048	RUCO did not use the ACC jurisdictional adjusted value in the adjustment. Company corrected RUCO's adjustment.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	(548,924)	(521,442)	27,482	RUCO did not use the ACC jurisdictional adjusted value for wellness expenses in the adjustment. Company corrected RUCO's adjustment.
Severance Pay - New		(329,665)	(238,519)	91,146	RUCO incorrectly included portion of severance pay that was capitalized in the amount disallowed (O&M = $217K, Capitalized=$112, Sum $329).
Total Adjustments to Operating Expense	24,441,665	(22,305)	10,568,179	10,590,484	
Total Net Adjustments	(219,890,083)	(194,590,791)	(205,431,275)	(10,840,484)	
Adjusted Operating Income	$98,381,058	$123,680,350	$112,839,866	($10,840,484)	
Operating Income Deficiency	$67,517,257	$10,717,810	$21,706,414	$10,988,604	
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223	1.6223	
Increase in Gross Revenue Requirement	$109,534,118	$17,387,642	$35,214,596	$17,826,954	

TUCSON ELECTRIC POWER

COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT

TEST YEAR ENDED JUNE 30, 2015

ACC JURISDICTION

	TEP As Filed	RUCO As Filed	RUCO As Corrected	Difference	Explanations of RUCO As Corrected

Exhibit DJL – R – 3

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
Original Cost Rate Base - Unadjusted	$2,108,583,243	$2,108,583,243	$2,108,583,243	$0	
Rate Base Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	-	-	-	
SGS CHF	(41,966,722)	(41,966,722)	(41,966,722)	-	
Fortis Merger Rate Base Adjustment	(522,398)	(522,398)	(522,398)	-	
Asset Retirement Obligation	-	-	-	-	
Post Test Year Plant	51,782,029	37,124,629	37,124,629	-	
Post Test Year Plant - Renewables	20,794,266	4,872,919	4,872,919	-	
Delayed Unitization	13,237,543	13,237,543	13,237,543	-	
Accumulated Deferred Investment Tax Credit (ITC)	30,341,626	30,341,626	30,341,626	-	
Accumulated Deferred Income Taxes	(58,308,686)	(58,303,521)	(53,004,227)	5,299,294	Staff's adjustments to rate base did not include corresponding adjustments to ADIT. Company adjusted ADIT to reflect rate case adjustments as proposed by Staff.
ADIT - Extension of Bonus Depreciation	-	(12,814,172)	(12,814,172)	-	
San Juan Unit 2	-	-	-	-	
Sundt Coal Handling facilities	(19,120)	880	880	-	
SGS Unit 1 Lease Equity (related to 14.1% acquisition in 2006)	6,855,471	6,855,471	6,855,471	-	
Sundt & San Juan M&S	1,225,594	1,225,594	1,225,594	-	
Head Quarters	-	-	-	-	
Working Capital	(27,325,154)	(19,387,724)	(19,122,961)	264,763	Staff adjusted Company's Cash Working Capital worksheet to reflect Staff's adjustments using ACC jurisdictional values. However, the Company's Cash Working Capital worksheet uses pre-ACC jurisdictional values, then adjusts for the ACC jurisdictional ratio via the Revenue Requirements Model. Company corrected Staff's Cash Working Capital worksheet to reflect pre-ACC jurisdictional values.
Accumulated Depreciation adj and LTI	-	9,020,000	-	(9,020,000)	The average remaining life as used in the Company's depreciation study is self correcting. Thus, no adjustment is necessary. Reducing the reserve balance overstates the asset value on which the Company is earning a return.
Total Adjustments	(3,905,553)	(30,315,876)	(33,771,819)	(3,455,943)	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
Pro Forma OCRB	2,104,677,690	2,078,267,367	2,074,811,424	5,564,057	
Proposed Rate of Return	7.34%	6.68%	6.68%		
Required Operating Income OCRB	154,416,180	138,763,150	$138,532,390	(230,760)	
Fair Value Increment of Rate Base	808,601,055	808,600,679	$803,994,234	(4,606,445)	
Fair Value Rate Base (FVRB)	2,913,278,745	2,886,869,000	$2,878,806,457	(8,062,543)	
Proposed FVROR	5.69%	5.00%	5.00%		
Required Operating Income on FVRB	165,895,315	144,418,355	$144,155,350	(263,005)	
Implied ROR on Fair Value Increment of Rate Base	1.42%	0.70%	0.70%		
Original Operating Income - Unadjusted	318,271,141	318,271,141	$318,271,141	$0	
Operating Income Adjustments					
Operating Revenue Adjustments					
Lost Fixed Cost Revenue	(10,719,946)	(10,719,946)	(10,719,946)	-	
Environmental Cost Adjustor	(1,260,631)	(1,260,631)	(1,260,631)	-	
REST and DSM	(48,370,058)	(48,370,058)	(48,370,058)	-	
Non-Retail & Non Recurring Revenue	(112,150)	(112,150)	(112,150)	-	
Springerville Units 3 & 4	(111,813,089)	(111,813,089)	(111,813,089)	-	
Power Supply Management	(1,099,586)	(1,099,586)	(1,099,586)	-	
Customer, Weather and Recalculation of Unbilled Revenue	(4,791,733)	(4,791,733)	(4,791,733)	-	
Base Cost of Fuel & Purchased Power	(17,815,595)	(17,815,595)	(17,815,595)	-	
Miscellaneous Service Revenue	284,370	284,370	284,370	-	
TEP Headquarters - Retail Space	250,000	250,000	250,000	-	
Total Adjustments to Operating Revenues	(195,448,418)	(195,448,418)	(195,448,418)	-	
Operating Expense Adjustments					
Jurisdictional Allocation (Demand and Energy)	-	-	-	-	
REST and DSM	(19,891,996)	(19,891,996)	(19,891,996)	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
Non-Retail & Non Recurring Revenue	(1,696,421)	(1,696,421)	(1,696,421)	-	
Springerville Units 3 & 4	(84,382,546)	(84,382,546)	(84,382,546)	-	
Sales of SO2 Allowances	47	47	47	-	
Sales for Resale	(162,821,057)	(162,821,057)	(162,821,057)	-	
Power Supply Management	(278,075)	(278,075)	(278,075)	-	
Base Cost of Fuel & Purchased Power	226,811,827	226,811,827	226,811,827	-	
Gila River O&M	6,130,964	6,130,964	6,130,964	-	
Springerville Unit 1	(11,558,130)	(11,558,130)	(11,558,130)	-	
SGS Unit 1 Non Fuel O&M (50.5% Share)	-	-	-	-	
Overhaul & Outage Normalization	5,176,492	1,043,941	1,043,941	-	
Payroll Expense	2,264,794	1,121,186	1,121,186	-	
Payroll Tax Expense	151,051	76,051	76,051	-	
Pension & Benefits	2,004,436	2,050,431	1,576,433	(473,998)	The test year had $564,903 reflected in FERC 926 and $564,904 in FERC 426. The Company's pro forma moved the amounts reflected in FERC 426 (below the line) to FERC 926. Staff intended to remove 100% of SERP, but inadvertently only removed the amount reflected in FERC 426. Staff adjustment includes the revised pension and benefit amount as identified by the Company ($2,529,050)
Post-Retirement Benefits	1,339,160	1,339,160	1,339,160	-	
Short-Term Incentive Compensation	702,960	(2,803,734)	(2,803,734)	-	
Rate Case Expense	107,834	(36,208)	(36,208)	-	
Injuries and Damages	1,419	1,419	1,419	-	
Membership Dues	(212,696)	(212,696)	(212,696)	-	
Bad Debt Expense	(149,199)	(149,199)	(149,199)	-	
San Juan Unit 2 Direct Operating Cost	(3,921,687)	(3,921,687)	(3,921,687)	-	
Long Term Incentive Compensation	880,967	-	-	-	
Depr. & Amort. Expense	9,253,715	(1,665,318)	(1,588,163)	77,155	Staff assumes a 1 to 1 relationship on ACC jurisdictional ratios for post test year plant accumulated depreciation and depr. expense. ACC jurisdictional ratios are different.
Post Test Year Plant	-	-	-	-	
Sundt & San Juan M&S	408,531	408,531	408,531	-	
Property Tax Expense	3,119,696	2,694,696	2,694,696	-	
Asset Retirement Obligation	(393,590)	(393,590)	(393,590)	-	
SGS Common Facilities Lease	(1,195,980)	(1,195,980)	(1,195,980)	-	

TUCSON ELECTRIC POWER
COMPARISON OF ADJUSTMENTS TO REVENUE REQUIREMENT
TEST YEAR ENDED JUNE 30, 2015
ACC JURISDICTION
EXHIBIT 3

	TEP As Filed	ACC As Filed	ACC As Corrected	ACC Difference	Explanations of ACC As Corrected
San Juan Unit 1 SCNR O&M	955,223	955,223	955,223	-	
Fortis Merger Operating Income Adjustment	(31,176,174)	(31,176,174)	(31,176,174)	-	
Lime Expense	-	-	-	-	
Credit Card Processing Fees	3,475,500	-	-	-	
Income Tax Expense	(16,130,352)	(5,695,687)	(5,591,094)	104,594	Impact of Company corrections to Staff adjustments.
Transmission Expense Adjustment	95,464,952	95,464,952	95,464,952	-	
D&O Insurance	-	(25,000)	(21,105)	3,895	Staff did not use the pre-ACC jurisdictional ratio amount to adjust for the elimination of 50% of D&O insurance. Company corrected staff's adjustment by eliminating 50% of ACC jurisdictional D&O insurance amount.
Lobbying, Employee Recognition, Spot Award, Wellness - New	-	-	-	-	
Severance Pay	-	-	-	-	
SGS Legal Expenses Lessor Dispute	-	(1,340,000)	(1,124,730)	215,270	Staff's adjustment is a total Company position. The $215,270 is to reflect the portion not allocable to all jurisdictions.
Total Adjustments to Operating Expense	24,441,665	8,854,929	8,781,845	(73,084)	
Total Net Adjustments	(219,890,083)	(204,303,347)	(204,230,263)	73,084	
Adjusted Operating Income	$98,381,058	$113,967,794	$114,040,878	$73,084	
Operating Income Deficiency	$67,517,257	$30,450,561	$30,114,472	($336,089)	
Gross Revenue Conversion Factor	1.6223	1.6223	1.6223	1.6223	
Increase in Gross Revenue Requirement	$109,534,118	$49,400,339	$48,855,097	($545,242)	

Exhibit DJL – R – 4

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S ELEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
May 26, 2016

RUCO 11.02

Post Test Year Plant – Has the Company utilized the half-year convention when calculating accumulated depreciation on Post Test Year Plant?

RESPONSE:

The accumulated depreciation reflects a full year depreciation expense on the post-test year adjustment.

RESPONDENT:

Bernadette Porter

WITNESS:

Dallas Dukes

Exhibit DJL – R – 5

TUCSON ELECTRIC COMPANY
POST TEST YEAR
TEST YEAR ENDING JUNE 30, 2015

EXHIBIT DJL - R - 5

FERC	Project	Project Name	In Service Dates (A)	Post Test Year (B)	Total Depreciation (C)	ACC Juris. Ratio (D)	ACC Post Test Year Amount ('E)	ACC Depreciation (F)	NBV (G)
Projects Unitized									
	General								
303	D141OSP	Oracle Services Procurement	MAY-16	380,252	380,252	92.03%	349,945	349,945	-
303	D141AFR	2014 Acct Financial Reporting	MAY-16	2,365,016	450,479	92.03%	2,176,525	414,576	1,761,949
	Generation								
312	D14AD79	Selective Non-Catalytic Reduc	APR-16	9,774,013	257,057	89.78%	8,775,108	230,785	8,544,323
312	D13SK02	SGS U2 Mercury	MAY-16	1,075,679	21,729	89.78%	965,745	19,508	946,237
312	D13SE01	SGS U1 Mercury	MAR-16	498,459	8,673	89.78%	447,517	7,787	439,730
315	D02AB96	Irv #3 Step Transformer Replmt	JUN-16	1,660,946	204,462	89.78%	1,491,197	183,566	1,307,631
315	D08AB07	Sundt U3 MCC Replacement	JUN-16	258,865	31,938	89.78%	232,409	28,674	203,735
	Distribution								
362	D11DD93	NE T2A Swtchgr Replc	JAN-16	131,864	2,374	100.00%	131,864	2,374	129,491
		Sub-Total Projects Unitized		16,145,094	1,356,963		14,570,310	1,237,216	13,333,095
Projects Pending									
	Generation								
311	D13AC90	Sundt Cooling Tower Blowdown	DEC-16	158,920	16,758	89.78%	142,679	15,045	127,633
312	D12AC77	Sundt Condensate tank Piping	DEC-16	277,508	28,930	89.78%	249,147	25,974	223,173
312	D05AD32	San Juan Various Enviro Projs	DEC-16	220,886	7,786	89.78%	198,311	6,990	191,321
	Distribution								
362	D14NM15	Volt-Var Pilot Ph1 & 2	DEC-16	553,547	9,964	100.00%	553,547	9,964	543,583
362	D09EO02	Wilmot T2 Replacement	DEC-16	130,583	2,350	100.00%	130,583	2,350	128,232
367	D13LE28	RV- Tangerine West 3rd Fdr Tie	DEC-16	112,774	2,413	100.00%	112,774	2,413	110,360
		Sub-Total Projects Pending		1,454,218	68,202		1,387,041	62,737	1,324,303
		Grand Total		17,599,312	1,425,166		15,957,351	1,299,953	14,657,398
	Renewables								
344	D14PD43	Brt Buildout Plan Ft Huachuca Phase II	Aug-16	8,200,000	210,330	89.78%	7,361,960	188,834	7,173,126
344	NA	TEP Community Solar-Pima Cnty	SEP-16	10,000,000	256,500	89.78%	8,978,000	230,286	8,747,714
				18,200,000	466,830		16,339,960	419,120	15,920,840
			Grand Total	34,345,093.85	1,823,793.26		32,297,311.01	1,719,072.81	30,578,238.20

Exhibit DJL – R – 6

STAFF'S RESPONSE TO TUCSON ELECTRIC POWER COMPANY'S SECOND SET OF DATA REQUESTS TO ARIZONA CORPORATION COMMISSION UTILITIES DIVISION STAFF
DOCKET NO. E-01933A-15-0322
JUNE 24, 2016

Data Requests Regarding Direct Testimony of ACC Staff Witness Donna Mullinax

TEP 2.1: Regarding Ms. Mullinax's recommendation to limit Post Test Year Plant to plant that was in service by December 31, 2015. (Mullinax Direct at pages 8-9):

A. Does Staff agree that no ACC rule limits Post Test Year Plant to plant that was in service six months after the end of the test year. If not, please explain why not.

RESPONSE: **Staff agrees.**

RESPONDENT: Donna Mullinax

B. Does Staff agree that no written ACC policy limits Post Test Year Plant to plant that was in service six months after the end of the test year. If not, please explain why not.

RESPONSE: **Staff agrees.**

RESPONDENT: Donna Mullinax

C. Does Staff agree that in *EPCOR Water Arizona, Inc.*, Decision No. 75268 (Sep. 8, 2015), the Commission rejected RUCO's request to limit Post Test Year Plant to plant that was in service six months after then end of the test year. (See pages 16 to 17 of that Decision). If not, please explain why not.

RESPONSE: **Staff agrees that in the referenced *EPCOR Water Arizona, Inc.* case, Staff recommended the inclusion of Post Test Year plant additions that were completed by the end of the test year but were treated as CWIP, in addition to inclusion of projects that were still in CWIP but were completed by June 30, 2014 (Test Year - 12 months ended June 30, 2013). Staff stated that Commission rules contemplate the inclusion of Post Test Year plant in rate**

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

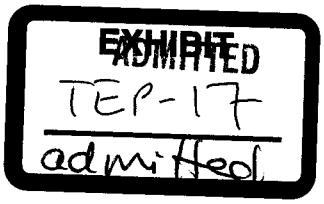
REBUTTAL TESTIMONY OF

MARK C. MANSFIELD

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016



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Exhibits

Exhibit MCM-R-1: Unit 1 Revised SIP Compliance Budget Approval

I. Introduction.

Q. Please state your name and business address.

A. My name is Mark C. Mansfield. My business address is 88 E Broadway, Tucson, Arizona 85702.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP" or the "Company") as Vice President Energy Resources.

Q. Please describe your background and work experience.

A. I have a Bachelor of Science degree in Mechanical Engineering from Brigham Young University, and a Master of Business Administration degree from the University of Utah. Before coming to TEP, I was employed in various capacities by PacifiCorp, an electric utility that serves parts of Utah, Wyoming, Idaho, Oregon, Washington and California. My primary focus during that tenure was in the operations and maintenance of large power plants. I served as an engineer and maintenance supervisor at the Carbon Plant; as Maintenance Superintendent at the Hunter Station; as Director of Technical Support for PacifiCorp's Generation Engineering Group in Salt Lake City, Utah; as the Plant Manager for the Naughton, Huntington, and Hunter Power Stations; and as Vice President of Thermal Operations, with responsibilities for PacifiCorp's coal-fired, gas-fueled, and geothermal generation assets and operations, including environmental and employee health and safety.

Q. What have been your responsibilities while employed by TEP?

A. Since joining the Company in June 2008, I have been responsible for the operations of the H. Wilson Sundt Generating Station and have overseen the Company's fleet of

combustion turbines, as well as the Company's interests in its power plants operated by other companies. In my current position, I am responsible for all the TEP generation assets.

Q. Did you file Direct Testimony in this proceeding?

A. No.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of TEP.

Q. Which Commission Staff or Intervenor Testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses the testimony filed on behalf of Western Resource Advocates ("WRA") Steven S. Michel. I also address Staff witnesses Michael McGarry's proposed adjustment to the period for averaging overhaul expenses.

II. Balanced Draft.

Q. What issues does Mr. Michel raise in his direct testimony?

A. Mr. Michel asserts that the Balanced Draft ("BD") technology installed on San Juan Unit 1 is not a prudent and used and useful investment[1].

Q. What is the basis for WRA challenging the installation of BD?

A. WRA believes that the BD installation was not required to comply with any applicable ambient air quality requirements or other regulations.[2]

[1] Direct Testimony of Steven S. Michel, page 3, lines 10-13.
[2] Direct Testimony of Steven S. Michel, page 3, lines 8-9.

Q. Can you provide an overview on the BD technology installed on San Juan Unit 1?

A. When fuel is combusted in a utility boiler, there is a large increase in gas volume. There are two types of furnaces used in the utility industry. The first type is called a positive pressure boiler. In this design the pressure inside the furnace is higher than atmospheric pressure. Because of this pressure difference if there are any leaks in the boiler casing or at any penetrations, flue gas and fly ash will escape to the outside atmosphere. The second type of boiler is called a balanced draft boiler. In a balanced draft design, the pressure inside the furnace is below atmospheric pressure. As a result if there are any cracks, holes or penetrations, outside air leaks into the boiler rather than flue gas or fly ash escaping.

Q. What are the advantages of a positive pressure boiler?

A. The only real advantage of a positive pressure boiler is that the induced draft fan can be sized smaller.

Q. What are the disadvantages of a positive pressure boiler?

A. The major disadvantage of a positive pressure boiler is that if there is any kind of opening or crack in the boiler casing, flue gas and fly ash escape to the atmosphere. A boiler like San Juan 1 will expand by one foot or more in length from cold to hot. Due to the high temperatures involved, metal must be used to seal the boiler. This sealing system is called the casing. Because of the thermal expansion the casing does crack resulting in leaks. Boilers also require soot blowers which must penetrate the casing. In a positive pressure boiler special seals must be used to contain the gas. These seals regularly fail due to the ash and temperatures to which they are exposed. For optimum operations, boiler heat transfer surfaces need to be visually inspected by operators. In this type boiler there are only a few viewing ports which use aspirated air to allow visual inspection.

Q. Are there other concerns with a positive pressure boiler?

A. The other concerns are employee health and safety, environmental protection and housekeeping. As the casing deteriorates, flue gas and fly ash leak out causing exposure to employees. At this point in the system the gas has not gone through any of the pollution control devices so it contains unabated amounts of SO_2, NOx, ash, etc.

Q. What are the advantages of a balanced draft boiler?

A. The advantage of a balanced draft boiler is that any breach in the casing causes air to leak into the boiler. This system eliminates both employee exposure to the boiler flue gas and secondary emissions to the atmosphere. This design also allows operators to open inspection doors and visually inspect the various heat transfer surfaces which allows for optimum soot blowing and the most efficient use of fuel.

Q. Did Public Service of New Mexico ("PNM") make any representations to TEP that BD was a necessary to comply with any applicable environmental requirements?

A. Yes. PNM made representations to TEP that BD was required to comply with the Title V air permit. As part of the October 24, 2013 Unit 1 BD capital budget approval,[3] PNM states the following work justification: "The project includes the installation of selective non-catalytic reduction (SNCR) technology to comply with the New Mexico Revised SIP, approved by the NM EIB on September 5, 2013. In addition, to comply with the Title V air permit, the unit will switch to a balanced draft configuration."

Q. Why was it ultimately decided to install balanced draft on San Juan Unit 1?

A. The decision to install balanced draft on San Juan Unit 1 was due to the fact that it was a requirement within the plant's air quality permit issued by the New Mexico Department

[3] See **Exhibit MCM-R-1** attached to my Rebuttal Testimony.

of Environmental Quality. The alternative would have been not to proceed with BD, which would have resulted in shutting down the unit given that it was required by the permit. Shutting the unit down would have triggered both "take or pay fuel" penalties and the need to remove the plant from service (which would increase the costs to decommission the unit). TEP would also be required to replace this baseload resource with a short lead time to acquire appropriate replacement resources, tramsmission capacity, etc.. These costs exceed the cost of installing balanced draft. Moreover, as described above the balanced draft system provides significant safety, health and environmental improvements.

III. Overhaul Averaging.

Q. Was it suggested that the time period that overhaul expenses are averaged over be changed?

A. Yes, Staff suggested the the overhaul averaging period be reduced from 8 years to 4 years, even though Staff had recommended an 8 year period in the last TEP rate case (which was subsequently incorporated as part of the settlement on revenue requirement).[4]

Q. Is four years an appropriate period a time to average overhaul expenses?

A. No, overhauls very from minor outages of a few weeks to major outages that can be six weeks or longer. The difference in outage scope and duration is usually driven by the turbine and generator requirements. Typically steam turbine valves are overhauled every 3 to 4 years, HP (high pressure) turbines every 6 to 8 years, LP (low pressure) turbines typically 9 to 12 years and generators typically 8 to 12 years. The combustion turbines have a nine year cycle for overhauls: the third year is a hot gas path overhaul, the sixth year is another hot gas path overhaul and the ninth year is a major overhaul of the hot gas

[4] See Direct Revenue Requirement Testimony of Staff Witness McGarry, page 7:1-6.

path and the compressor. These overhauls - and related outage frequencies - could vary by plus or minus a year due to the number of actual starts or hours of operation. The expense for each type of overhaul is very different. To actually obtain an average that accurately reflects the overhaul cycles and costs, an average of costs over ten years should be used.

Q. Does this conclude your testimony?

A. Yes it does.

Exhibit MCM – R – 1

ORIGINAL

SAN JUAN GENERATING STATION
CAPITAL BUDGET ITEM

Project Title:	Unit 1 Revised SIP Compliance			**Date:**	09/30/13
Project Manager:	Mitchell, David	CBI NO.:	13-60	Work Order No:	761-Y0060967
Project Start Date:	11/01/13	Budget Year:	2013	Retirement Order No:	761-Y0060986
Est Completion Date:	04/01/16	Outage Related:	Yes	Funding Project No:	761-21912
Est In-Service Date:	01/31/16	Outage Begins:	February	Original/Rev No:	Original

Description of Work/Justification:

The project includes the installation of selective non-catalytic reduction (SNCR) technology to comply with the New Mexico Revised SIP, approved by the NM EIB on September 5, 2013. In addition, to comply with the Title V air permit, the unit will switch to a balanced draft configuration. Component installation includes VFDs, ESP bypass duct, urea storage and distribution system and ash handling at the baghouse fabric filter system. Costs are estimated based on S&L submittal #31805D; issued Aug 7, 2013. Common costs for the project have been apportioned between Unit 1 and Unit 4 based on MWs.

Environmental Compliance Review?	No			
DCS Review Required?	No	Completed?	N/A	If no, explain To be completed at final design review
NERC Compliance Review Required?	No	Completed?	N/A	If no, explain To be completed at final design review

Cost Breakdown	Retirement Order Removal	Work Order Installation
PNM Labor		$1,100,500
Material	$43,242	$17,958,406
Contract	$277,470	$50,279,090
A&G Loads	$3,200	$700,000
AFUDC		$1,242,651
TOTAL	$323,912	$71,280,647
PROJECT TOTAL	$71,604,559	

Capital Budget Item Cash Flow

	Removal Cost (RO)		Installation Cost (WO)			
	2014	2015	2013	2014	2015	2016
Jan		$20,000		$226,891	$889,059	$1,101,006
Feb		$23,242		$355,584	$15,330,455	$1,103,022
Mar		$280,670		$156,595	$17,981,691	$874,279
Apr				$459,983	$17,394,918	
May				$157,343	$1,212,676	
Jun				$107,442	$1,215,186	
Jul				$208,352	$1,217,702	
Aug				$134,883	$1,220,228	
Sep				$187,319	$1,222,764	
Oct				$1,209,304	$1,225,309	
Nov			$458,666	$1,345,660	$1,227,864	
Dec			$708,553	$1,738,783	$1,230,429	
Total	$0	$323,912	$1,167,219	$6,286,839	$60,746,282	$3,078,307
	$323,912		$71,280,647			
AFUDC			$0	$99,507	$1,174,282	$8,862

Authorizations

	Per Cent	Amount	Signature	Date
PNM	50.00%	$36,423,605		10-24-2013
TEP	50.00%	$35,180,954		10-24-13
TOTAL	100.00%	$71,604,559		

Note: AFUDC applies to PNM share only

Recommended By: [signature] Date: 01/22/2014

Authorized By: (Signed above) Date:

Exec. Sign: (Signed above) Date:

In-Service date	
Signed off by:	
Proj Complete date:	
Signed off by:	

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-_____

Direct Testimony of

Susan M. Gray

on Behalf of

Tucson Electric Power Company

November 5, 2015

EXHIBIT
TEP-18
ADMITTED

TABLE OF CONTENTS

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Susan Gray. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?

A. I am the Vice President of Transmission and Distribution ("T&D") Operations and Engineering.

Q. Please describe your background and work experience.

A. I graduated from the University of Arizona with a B. S. in Electrical Engineering and a Masters in Business Administration.

I was hired in 1997 as an Energy Management System Engineer. Since that time I have served in several leadership roles in T&D Operations, including Director of Design and Construction Services from 2011 to 2013 and Senior Director of T&D Operations from 2013 to 2015.

Q. What is the purpose of your Direct Testimony?

A. The topics I cover include the Company's: (i) service territory; (ii) customer base; (iii) T&D safety and reliability performance; (iv) ongoing efforts to improve the T&D system; (v) workforce planning; (vi) actual and future T&D capital investments; and (vii) an overview of efforts to appropriately control the Company's T&D Operations and Maintenance ("O&M") expense.

II. TEP T&D OPERATIONS.

Q. Please describe TEP's service territory, customer base and sales mix.

A. TEP serves almost 415,000 customers in Pima County. Approximately 90% of TEP customers are residential, 9% are commercial and less than 1% are industrial/mining. The Company's service territory spans 1,155 square miles, extending north to the Pinal County line and south to the Santa Cruz County line. TEP serves customers in Tucson, South Tucson, Oro Valley, Sahuarita, Marana, and unincorporated areas of Pima County. TEP also provides power to Fort Huachuca, a U.S. Army base located in Cochise County.

As of June 30, 2015, TEP owned or participated in an overhead electrical T&D system consisting of:

- 615 circuit-miles of 500-kilovolt (kV) lines;
- 1,109 circuit-miles of 345-kV lines;
- 350 circuit-miles of 138-kV lines;
- 479 circuit-miles of 46-kV lines; and
- 2,615 circuit-miles of lower voltage primary lines.

TEP also operates 4,389 cable-miles of underground electric distribution lines. The Company operates 106 electric substations with a total installed transformer capacity of 13,132,404 kilovolt amperes.

Q. Please describe TEP's transmission system operations.

A. TEP's Extra-High Voltage ("EHV") transmission system (both 345-kV and 500-kV) links the Company's southern Arizona service territory to TEP's generation resources in New Mexico, northeastern and central Arizona as well as regional market hubs at Palo Verde and Four Corners. This EHV system connects to TEP's service territory at three EHV

substations on the periphery of Tucson. From these three EHV substations, a High Voltage ("HV") transmission system (138-kV) distributes the energy throughout TEP's service territory. TEP's HV transmission system includes looped 138-kV lines and radial 46-kV lines serving substations that provide 13.8-kV and 4-kV distribution service. In accordance with prudent utility practice and mandatory electric reliability standards established and enforced by the North American Electric Reliability Corporation ("NERC"), as approved by the Federal Energy Regulatory Commission ("FERC"), TEP employs operating procedures and controlled load shedding schemes to mitigate overloads of its 345-kV and 138-kV systems.

Q. Please describe the Company's commitment to providing safe and reliable service.

A. Providing safe, reliable and affordable electric service is the principal focus of TEP's business. We have earned a reputation for reliability that reflects our employees' commitment to effective, efficient operations. We are always faced with new challenges to manage O&M expenses and I am proud to say that our employees are responding by finding new, more efficient ways to operate while leveraging their expertise and experience to provide reliable service without compromising on safety.

Q. Would you provide an overview of TEP's T&D operations from a safety standpoint?

A. Safety is an essential part of TEP's operational philosophy. We strive to perform all of our work in a manner that prevents injury to ourselves, our co-workers, our customers and the communities we serve.

This philosophy is supported by our overall "Target Zero" safety strategy, which includes three elements:

1) Active safety leadership;

2) Increased employee involvement and engagement in safety activities; and

3) Hazard control and regulatory compliance.

The focused implementation of this strategy throughout the Company has resulted in an excellent and sustained total recordable incident rate ("TRIR"). The T&D TRIR has hovered around 1.0 from 2012 through June of 2015. The following formula was established by the Occupational Safety and Health Administration to calculate TRIR:

TRIR = (# of Recordable Injuries * 200,000) / # hours worked

	2012	2013	2014	YTD June 30, 2015
T&D Operations TRIR	0.80	0.96	1.67	0.79

Q. In Section 18.1 of the Settlement Agreement approved in TEP's last rate case, TEP agreed to initiate a study to examine potential loss of reductions and the costs required to convert 4.16 kV circuits to 13.8 kV. What is the status of that study?

A. The Company initiated the study on September 13, 2013. The Company determined that cost of conversion is not cost-effective compared to the minimal impact on loss reduction. Also, as contemplated by Section 18.1, TEP has continued to rely on distribution indices to evaluate TEP's reliability. This is discussed in more detail below.

Q. In Condition 28 of the Fortis/UNS Energy Merger settlement agreement, the Regulated Utilities, including TEP, agreed to use their best efforts to maintain or improve their quality of service based upon System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI"). Please discuss TEP's efforts in this area and the results.

A. Even before the Fortis/UNS Merger, TEP used its best efforts to maintain or improve its quality of service. TEP continues to use it best efforts to meet the standard set forth in the Settlement Agreement. Currently, TEP is performing better than the 3-year average on two of the measures and nearly the same on the third measure.

	2011 – 2013 3-year average	2013 – 2015 3-year average
	Value (minutes)	Value (minutes)
SAIDI	75.73	63.09
SAIFI	.91	.75
CAIDI	83.68	84.23

TEP is committed to effective and efficient operations and providing reliable service without compromising on safety. The Company's system reliability compares favorably on three common industry benchmarks: SAIDI, SAIFI and CAIDI. These comparisons can be made annually based on the Edison Electric Institute ("EEI") Distribution Reliability Survey, which aggregates data from utilities across the country. EEI survey data is formatted into first, second, third, and fourth quartiles to indicate how individual utilities compare to their peers. TEP's performance corresponded with EEI's first quartile in each year from 2012 to 2014, except SAIFI, which has improved from the third to the first quartile since 2012. Based on these figures, which are shown in the following table, TEP's distribution operations rank among the most reliable in the industry. The reliability of TEP's distribution operations provides customers with significant benefits, including safety, productivity, comfort and convenience.

	2012		2013		2014	
	Value (minutes)	EEI Quartile	Value (minutes)	EEI Quartile	Value (minutes)	EEI Quartile
SAIDI	69.79	1st	63.50	1st	57.12	1st
SAIFI	.93	3rd	.68	1st	.71	1st
CAIDI	74.66	1st	92.86	1st	80.05	1st

Q. Please describe TEP's ongoing efforts to upgrade its transmission system.

A. To improve our access to economic generating resources, TEP is constructing a new 500-kV transmission line that will link the Pinal Central Substation in central Arizona to TEP's Tortolita Substation northwest of Tucson. This line will increase the Company's cumulative import capacity by approximately 275 MW, providing new access to renewable and conventional energy resources. This project was originally planned to be in-service by the summer of 2011 but was delayed due to slow load growth. The project is expected to be complete by the end of 2015.

TEP is also completing a transmission system improvement program in 2015 to upgrade and strengthen the 138-kV transmission system that connects to the Company's Tortolita Substation on the north end of TEP's system. This program includes upgrades of six 138-kV lines in north Tucson that will accommodate the distribution of the increased capacity from the 500-kV line into our local distribution system.

In 2014, TEP completed construction of a new 138-kV line linking the DeMoss Petrie and Tucson Substations to improve reliability of its system in central Tucson. In particular, the new line provides support to stations "downstream" from the Tucson Substation.

I will discuss future transmission projects in the Growth and Planning section of my testimony.

Q. How does TEP assess the need for near-term reliability improvements to its distribution systems?

A. TEP uses a dual approach to assess the need for near-term reliability improvements to the distribution system:

(1) Annual Critical Circuit Analysis of Overhead and Underground 13.8-kV/46-kV – TEP engineers evaluate each circuit in the system annually based on reliability, demand, capacity, age and type of load. This data is used to create a critical circuit rating, which is used to prioritize patrols and subsequent work on these circuits. This analysis helps us identify and focus our resources on those circuits with the greatest need. It also provides insight, although it is not the sole determining factor, into which circuits need to be patrolled by journeyman linemen.

In 2014, we increased our focus on aging underground infrastructure, as cable began to reach the end of its useful life across the service territory. TEP engineers apply the same critical circuit methodology to underground circuits as they do overhead circuits, with an emphasis on substation getaways, which are the short sections of a power line, typically underground from a substation to the first structure outside of the substation. In late 2014, TEP engineers began to introduce new, more efficient technology and industry best practices to test suspect or high priority underground cable in order to better measure the current condition and remaining useful life of the cable, allowing TEP to prioritize maintenance or improvement work.

(2) Outage Response Circuit Patrols – TEP journeyman linemen perform detailed land-based patrols of circuits that have experienced recurring outages within a short timeframe. The purpose of these patrols is to identify issues associated with insulators, guy wires, poles, cross arms, ground wire attachments, static and neutral wires, conductors and other distribution equipment, as the potential source of the outages. These patrols are also used to evaluate the threat posed by nearby vegetation and evaluate the line for opportunities to implement circuit

improvements that would decrease outage length and severity. Any issues identified on these patrols or inspections are prioritized based on severity and addressed as needed.

TEP's application of this approach is designed to increase system reliability and safety.

Q. How does TEP identify necessary substation improvements?

A. To evaluate the performance of our substations, TEP's Asset Management department monitors the condition of equipment using Reliability Centered Maintenance (RCM) principles and Condition Based Maintenance (CBM) practices. Equipment is tested and monitored on-line; Asset Management Engineers review the results and consult manufacturers' representatives or other experts as appropriate, and then "flag" equipment when issues are detected. This flag may require further monitoring, maintenance, testing, or replacement needs. The data and analysis that the Asset Management department collects is a key input to TEP's five year maintenance plan.

Q. Please describe TEP's efforts to maintain substation transformers.

A. TEP takes significant steps to protect substation transformers that play a critical role in the reliability of service to our customers. Because new transformers can cost more than $1 million and can take nearly 18 months to build and install, TEP follows a well-defined and disciplined maintenance program. Annually, we update the substation transformer fleet assessment that weighs numerous factors to generate a health index number used in determining and ranking the condition of each transformer. Some of these factors include: oil condition, maintenance history, fault history, paper condition, bushings, lightning arrestors, age, maintenance bulletins, infrared scans and loading history. The resulting rankings are used to estimate equipment life cycles and are used in planning and budgeting for transformer replacements. We also seek to reduce risks to the operation of

our transformers through new engineering standards, including requirements for fire walls in new substations as well as substations that are upgraded for capacity improvements. As a mitigation measure for potential transformer failures, we maintain emergency spare units for line voltages as high as 138-kV to facilitate timely replacements. We also own two mobile transformers/substations and one portable transformer that can be used to stand in for failed units, for use during maintenance and outage conditions, as well as to supplement our capabilities during periods of high energy usage.

Q. Please describe TEP's efforts to maintain the reliability of other key substation components.

A. TEP maintains its largest, most critical substation circuit breakers by scheduling and performing maintenance based on the manufacturers' recommendations. For others, we employ a maintenance program based on the results of diagnostic tests, rather than a predetermined schedule. We also strategically make decisions regarding across-the-board upgrades of key components. An example of such a decision is related to breakers. TEP has decided to replace older EHV Gas Circuit Breakers (GCB) in 345-kV substations and 138- & 46-kV Oil Circuit Breakers (OCB) in all other substations as part of its long term reliability plan.

TEP diligently performs maintenance on components that protect the bulk electric system as defined by NERC. These include protective relays and their supporting subsystems, such as communications paths, voltage and current sensing devices, relays, power supplies (including batteries, battery chargers, and non-battery-based direct current ("DC") sources), and breaker trip-and-close circuitry. TEP's most recent NERC/WECC audit in 2014 resulted in no compliance violations.

Q. Please describe TEP's transmission line maintenance efforts.

A. TEP uses Transmission Line Asset Management Program software with a GIS data input interface to manage inspections and maintenance of its 138-kV and 345-kV structures. The program calls for inspections and upgrades based on a schedule that varies by voltage class.

TEP's transmission maintenance department performs aerial inspections of our 345-kV transmission lines on a semiannual basis. Inspectors look for imminent dangers to the system, such as sabotage or foreign objects caught in the lines or towers. They also observe the condition of anchors and guy wires and look for encroachment by trees or other vegetation. The same 345-kV lines and towers are subjected to a close inspection from the ground every five years. Repairs are then prioritized by severity of the defect and proximity to other maintenance items. The outcome of this prioritization is the repair of the highest number of items with the most efficient cost.

For TEP's 138-kV transmission system, ground patrols are performed annually. Crews inspect the condition of insulators, guy wires, wood poles, bracing, ground wire attachments, static wires, conductors and vegetation. In 2012, TEP began systematically replacing its older 138-kV wood structures with steel poles. The new steel structures will reduce the number of future service outages caused by pole failures, including those caused by accident damage, fires and storms.

Q. What role does vegetation management play in transmission line maintenance?

A. Maintaining adequate clearance around transmission lines is critical to TEP's efforts to provide safe and reliable service and comply with FERC's mandatory reliability standards as enforced by NERC. Our vegetation management efforts are intended to prevent plant material from encroachment into the NERC minimum vegetation clearance

distance, and to reduce the fuel available to any wildfire that may cross our transmission line corridors. Vegetation is cleared based on five-year growth cycles established through consultation with the U.S. Forest Service and other property owners. Our clearance efforts are designed to maintain adequate clearances for at least five years, though more frequent trimming is sometimes necessary if line inspections reveal faster-than-expected vegetation growth.

In 2010, TEP initiated a project to expand vegetation clear cutting efforts in its 345-kV transmission corridors[1]. When the lines were initially installed only minor trimming of trees was allowed where the bulk of the vegetation is trimmed to match the shape of the catenary curve of the conductors. This method is referred to as a "feathered right of way," where minimal trees are removed in the corridor. As a result of the FERC mandatory reliability standards and potential impacts from wild land fires, TEP initiated a project to clear cut the 345-kV right of way. The project was permitted and completed in sections over a five-year time period and was completed in 2014. The result of this project is a transmission system that has lower risks from vegetation-caused outages and higher resiliency to wild land fire impacts.

Q. What steps has TEP taken to protect the reliability of its service from cyber attacks?

A. TEP employs cyber and physical security systems and processes to protect its critical assets from cyberattacks. TEP's efforts are designed to comply with the Critical Infrastructure Protection ("CIP") standards established by NERC and adopted by FERC to preserve the reliability of the bulk electric system. These standards became fully

[1] TEP initiated clearing in high fuel areas and areas with tall trees in 2005 as reported to the Commission in TEP's 2005 Summer Preparedness presentation.

mandatory in 2009, creating compliance costs which have increased significantly and steadily since their inception.

The CIP standards require utilities to establish both physical and electronic security perimeters around key facilities and computer systems. A strict change control process enables these protections to be preserved as the underlying systems are expanded or modified. TEP commissions both internal and third-party vulnerability assessments of its critical cyber assets on a routine basis.

In addition to adhering to the NERC CIP regulations, TEP employs a comprehensive defense-in-depth cyber-security program to protect other critical information such as customer, employee, and financial data. The program is modeled after a number of recognized standards including NIST (National Institute of Standards and Technology), COBIT (Control Objectives for Information and Related Technology), and ISO (International Organization for Standardization). Each year, the cyber-security threat landscape has become increasingly more sophisticated and persistent. TEP takes these threats seriously and has dedicated cyber-security professionals, systems, and processes to protect the Company.

Q. How will future changes to cyber-security standards affect TEP?

A. Future versions of NERC's CIP standards are expected to apply to a broader range of assets as demonstrated in CIP v5, which must be implemented by April 2016 and in the draft edition of v6, which must be implemented by the end of 2016. Although a well-defined process is already in place to manage these assets, compliance with these new mandatory standards will continue to increase the Company's capital and O&M expenses and the amount of time and effort our employees must spend to document our compliance with NERC standards.

Q. In Condition 29 of the Fortis/UNS Energy Merger settlement agreement, the Regulated Utilities, including TEP, agreed to use their steady efforts to maintain or improve safe and reliable electric service. Please discuss TEP's efforts in this area.

A. I believe Section II of my testimony sets forth TEP's continuing efforts to maintain or improve safe and reliable service to its customers.

III. GROWTH AND PLANNING.

Q. Please describe the growth in TEP's customer base since the last test year and the forecast for future customer growth.

A. Since 2011, the test year used in TEP's last case, the Company has experienced annual customer growth of approximately 0.6%. We estimate that future customer growth will gradually increase to about 1% annually by 2018 and thereafter.

Q. Please describe TEP's retail sales since the last test year and what are your expectations for future retail energy sales?

A. The Company's test year retail sales are nearly 3% lower than sales levels from 2011, and residential use per customer in the test year is approximately 7.5% below 2011. Both of these reductions reflect the effects of energy efficiency, distributed generation and general economic conditions. We currently project that retail sales, on a weather normalized basis, will be relatively unchanged in 2016. In 2017 and beyond, we estimate annual sales growth to be in the 0.5% to 1% range. However, these estimates do not take into account changes in large industrial customer activity.

Q. How have recent reductions in TEP's retail sales affected the Company's plans to serve customers' future energy needs?

A. We have deferred planned transmission upgrades, substation expansions and other projects that would have been needed sooner if customer demand had continued to grow at its previous rate. Many of these projects remain part of our long-term plans, however, to address the prospect of future growth. As these projects were delayed, TEP was able to redirect the capital planned for these projects to expand on identified replacement and betterment projects and provide reliability benefits related to these projects sooner.

Q. How does TEP plan for transmission growth over the long term?

A. Our transmission planning addresses future growth and the integration of new generating resources and is set forth in TEP's ten-year Biennial Transmission Assessment ("BTA") filed with the Commission every other year. The most recent BTA was filed by TEP on January 29, 2015 (Docket No. E-00000D-15-0001).

TEP's BTA identifies future transmission needs for TEP's system. TEP's transmission system consists of EHV lines (both 500-kV and 345-kV) as well as 138kV HV lines.

Power flow analysis is conducted for TEP's transmission system to identify thermal overloads under normal and contingency conditions in compliance with the NERC Reliability Standards and Western Electricity Coordinating Council ("WECC") System Performance Criteria. Proposed projects are then determined such that the performance measures of the NERC Reliability Standards and WECC System Performance Criteria are met for Category A, B and C conditions.

Planning for the EHV system is conducted in conjunction with regional planning groups of which TEP is a member. These include both the Westconnect Region Planning function

and the Southwest Area Transmission ("SWAT") Sub-Regional Planning Group. TEP actively participates in various committees and subcommittees of these two groups to ensure that its EHV system is studied with an eye to the impacts of TEP EHV plans on the region or plans of others in the region on TEP.

TEP conducts an annual planning study for its HV Transmission System performance over a ten-year planning horizon. This results in identification of new facilities and upgrades to existing facilities, with associated in-service dates as needed to ensure adequate transmission capacity within TEP's service territory as the Tucson metropolitan area continues to develop. Capital improvements are proposed for the TEP 138kV system to accommodate new 138/13.8kV substations to address increased transmission facility loading, and to mitigate localized stability issues.

Q. What transmission improvements are planned to address future reliability and energy needs?

A. TEP has and will continue to develop multiple transmission projects over the next five years. These projects are intended to maintain service reliability and provide additional import capability to satisfy customers' energy needs. These projects include:

EHV System

- A 500-kV transmission line linking TEP's Tortolita Substation to the Pinal Central Substation which provides direct connectivity between Tucson and the Palo Verde market. (the Commission approved the CEC in Decision No. 73282 (July 30, 2012)) will be completed in 2015; and
- Replacement of Series Capacitors at both Vail and Phil Young / Greenlee 345-kV substations to support flows on TEP's system and maintain reliability of the transmission system will be completed in 2015;

HV System

- Five new 138-kV substations throughout the Tucson Metropolitan area; and
- Reconductoring of TEP's North Loop to Rancho Vistoso and Irvington to 22nd Street 138-kV lines, to improve TEP's ability to transmit power throughout Tucson.

Q. What substation improvements will be needed in coming years to maintain the reliability of TEP's service?

A. The distribution systems serving certain areas of TEP's service territory are reaching the capacity limits of existing substations. To continue to provide reliable service across its system and to serve future customer growth, TEP is planning several new substations and switchyards as well as upgrades to existing facilities. These projects include:

- New Orange Grove Substation – land has been acquired as well as approval from the local jurisdiction;
- New Craycroft Substation – existing site owned by TEP;
- New Harrison Substation – option for land acquisition is in-place and approval from local local jurisdiction is being sought;
- New Kino Substation – determination of location and connectivity is being assessed;
- Upgrades to the Rancho Vistoso, Tortolita, and North Loop Substations.

TEP's substation development efforts must overcome challenges associated with securing land and permits for such facilities. It typically takes about five years to permit, engineer, procure and build a standard distribution substation, with most of that time spent resolving land and permit-related issues. TEP has modified its planning process and substation standards in an effort to reduce delays and optimize the overall economics of our distribution infrastructure.

IV. WORKFORCE DEVELOPMENT.

Q. Please describe the Company's approach to workforce development in T&D Operations.

A. As a result of workforce planning efforts, TEP engineering determined that the Company needs to hire additional engineers over the next five years to build a stronger, in-house engineering team. This strategic decision is a key element of TEP's workforce planning strategy and will help manage overall engineering costs over time. TEP is working closely with a third party contractor, EASi LLC, to develop new engineers and engineering designers as part of an on the job training program. The program that has been developed provides this new group of future engineers/designers formal training and mentoring to prepare them for a potential career at TEP.

EASi LLC has implemented an industry proven engineering development program that combines coaching, mentoring, and hands-on experience by engaging the "trainees" in engineering new capital projects. EASi is providing subject matter experts in engineering to provide hands-on learning while completing capital projects. The approach is customized to TEP's needs and tightly integrated with our organizational goals and strategies.

After a period of three to five years, TEP will have a pool of competent candidates capable of performing engineering and design services for substation engineering from which TEP can select to fill core positions at TEP.

V. HISTORICAL T&D CAPITAL INVESTMENT.

Q. Please describe the Company's capital T&D spending since the last test year (2011).

A. Although slower growth has allowed the Company to defer some system expansion projects to future years, TEP has nonetheless invested significant capital over the past five years to maintain safe, reliable and responsible service, as well as gain efficiencies and operating cost savings through investment in new technology, such as automated meter reading. Some infrastructure costs were made necessary by robust growth over the many preceding years, including new residential demand on the previously undeveloped fringes of the Company's service territory. Other transmission line, substation and communication investments have been necessary in order to support the import of power from new sources, as a result of new generation projects.

Q. Please provide details regarding TEP's T&D and Communication capital investment since the last test year.

A. The following table outlines annual investment in Transmission, Distribution & Communication capital projects from 2012 through June 30, 2015.

($ Millions)	2012	2013	2014	YTD June 30, 2015	Total Capital Investments
Capital Expenditures	$130	$117	$127	$117	$491

TEP's total cumulative T&D and Communications capital investment for the three and a half years prior to and including the test year (January 1, 2012 – June 30, 2015) was approximately $491 million. This total includes $371 million for transmission and distribution system reinforcement and restoration, $26 million for communication technology improvements, $68 million to accommodate new business demands and

automated meter replacements and $26 million to accommodate public roadway improvements.

The Company also invested substantial capital in T&D system improvements, including, a major new 500-kV transmission line extending from the northwest region of our service territory, as well as related improvements to support this increased capacity at the Tortolita Substation and several 138-kV lines throughout the City of Tucson. Other significant projects included the installation of new 138-kV transmission lines to tie our DeMoss Petrie and Tucson Stations, as well as Canoa Ranch and DuVal Clear Stations, which have each provided improved reliability to our service territory to the south and within downtown Tucson. The Company has also invested capital to create new ties, upgrade capacity and replace critical distribution lines, as well as replace critical station transformers, breakers and switches. Finally, the Company completed the replacement of station capacitor banks in the southeast region of TEP's service area to support the voltage within TEP's system. The Company's substation build-out rate of expansion has slowed given the decreasing number of new customers.

We have also neared the completion in 2015 of significant operations and information technology projects to upgrade our systems and improve efficiency. One project is a multi-year project to automate meter reading with the installation of a fixed meter reading network, and the replacement of all 400,000+ meters across TEP's service territory. This will also further support improved information on customer usage patterns. TEP continues to keep its computer software systems up-to-date to leverage new capabilities, gain efficiencies, ensure accuracy and continue vendor support. For these reasons, our key T&D work and asset management systems were consolidated and replaced in phases during 2013, 2014, and 2015. This new system replaces dated technologies, provides for improvements in planning and scheduling, data visibility, resource planning, asset

management and lays the ground work for full integration with mobile technology. Leveraging new mobile technologies for field data collection, real-time scheduling and information access will drive further productivity gains.

VI. FUTURE CAPITAL INVESTMENT.

Q. Please describe TEP's plans for future T&D capital expenditures.

A. The following table outlines the estimated Transmission, Distribution & Communication capital expenditures for 2015-2019.

($ Millions)	2015	2016	2017	2018	2019	Total Capital Investments
Capital Expenditures	$217	$107	$94	$95	$111	$624

In order to continue to provide safe and reliable service to our customers, TEP expects to invest approximately $317 million in T&D system reinforcement and communication projects from 2015-2019, including $118 million for distribution projects and $199 million for transmission upgrades. Spending will decrease after 2015 primarily due to the completion of significant capital system reinforcement projects, including: approximately $86 million of improvements to our 500-kV and 138-kV transmission lines, and $12 million for the automated meter reading network. Also, TEP forecasts spending of approximately $15 million to interconnect the 500-kV transmission system from Gila River to the Jojoba Substation that will provide direct connectivity between TEP's Gila River resource and TEP's transmission rights on the Palo Verde to Pinal Central project. These investments will improve reliability by allowing TEP to bring additional power into its service territory. TEP plans to spend approximately $11 million to upgrade additional 345-kV capacitor banks in the southeast region of TEP's service area to

support TEP's system. In the later years, as previously mentioned, TEP plans to spend approximately $15 million for land and environmental preparation for new substations to support reliability and anticipated growth in central Tucson and the far reaches of the service territory to the northwest and east. Lastly, TEP expects to spend $84 million over the next five years to provide new infrastructure for upgrades and expansion that will support service to businesses and residences.

Q. How much does TEP expect to spend for capital improvements to its T&D operations automation?

A. With more distributed generation resources being deployed on the TEP distribution system, higher demands and lower energy consumption is expected. This puts demands on the T&D systems not previously contemplated. To meet these new demands, new methods and technology will be implemented. TEP intends to utilize technology to add more sensing and measurement devices and new methods for managing and operating the distribution system. TEP has approximately $38 million planned over the next five years to support the upgrade of essential and foundational communication infrastructure.

With increased demand and lower energy consumption, new techniques and strategies will be developed and implemented to effectively manage costs. By adding new measurement and sensing capabilities, the situational awareness of the distribution system will be increased. The situational awareness allows for real-time operations and planning opportunities for efficiency and productivity enhancements. To utilize the existing distribution system more efficiently, TEP is investigating the combined use of distributed energy resources ("DER"), storage, energy efficiency and demand response capabilities, in conjunction with optimization software to reduce the new infrastructure required due to the expected increased demand. New tools and capabilities will be required as a result of the new opportunities.

At the core of these changes is the need for a communications network that allows for intelligent electronic devices ("IED's") to be installed on the distribution system. The communications network allows for the backhaul of information from the IED's to centralized software and control applications. An integrated approach to the installation of field devices, software applications and historical data management will be needed. A distribution management system is the central software application that is needed to provide distribution supervisory control and data acquisition, outage management and geographical information into a single operations view. By combining the information from these systems into a single view, an electrical distribution system model can be created for both real-time applications and planning needs. The single view provides situational awareness of the distribution system that has not been possible in the past. It also creates a platform for additional applications to be implemented that will continue to provide value and new opportunities. The historical information also creates a new opportunity to drive value and decisions based on system performance and dynamic simulations.

VII. T&D OPERATING AND MAINTENANCE COSTS.

Q. Are the O&M costs incurred by TEP's T&D Operations in the test year appropriate?

A. Yes. T&D Operations managers actively monitor and manage all O&M expenses, working as a team to control expenses. Department managers are accountable for their department expenditures and are required to report on variances from the budget. Leadership collaborates with their staffs to identify and act on opportunities to be more efficient, while ensuring the continued safety of our employees and the community, and the continued reliability of electric service to our customers. For example, T&D Operations worked with FranklinCovey to initiate a process called 4 Disciplines of

Execution (4DX). 4DX is a simple, repeatable, and proven formula for executing on our most important strategic priorities. The process focuses on the physical execution of the priorities. In 2014, we improved our performance in meeting our capital project on-time and on-budget delivery. This positively impacts O&M by properly scheduling construction & maintenance resources, which reduce mobilization, overtime and rework expenses.

Our focus on cost control through continuous improvement has kept annual O&M cost increases under 2%, in spite of cost increases in materials, environmental and regulatory compliance and labor, by finding ways to be more efficient.

NERC and FERC regulations in the areas of reliability and CIP represent one scope change that has increased our costs of doing business. The most recent NERC standards for Protection System Maintenance now specify minimum maintenance activities. In some cases, new equipment and tasks have been added to the bulk electric system maintenance requirements. For example, there are significant (additional) testing requirements for protective relays, including verification of current and voltage quantities from instrument transformers. This has increased the amount of time that is required to perform relay maintenance. All of this testing also requires documentation and increased oversight to prevent errors. These additional monitoring and audit requirements add O&M costs in addition to the increase in the dues we are required to pay to these regulatory organizations so that they can manage the new programs.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-1933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

REBUTTAL TESTIMONY OF

SUSAN M. GRAY

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

EXHIBIT
TEP-19
ADMITTED

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Susan Gray. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct Testimony in this docket?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to describe TEP's distribution planning process and to respond to some of the statements made by RUCO witness Radigan and made by IBEW's witness Northrup.

II. DISTRIBUTION PLANNING PROCESS.

Q. Please describe how TEP's approach towards distribution planning and construction meets the needs of its customers in a cost-effective manner.

A. TEP's approach to distribution planning and construction is based on a 10-year forecast of peak demand, not total kWh sales. Customer growth leads to load growth and overall system growth. While customers may reduce their kWh usage, their peak demand may nonetheless grow. For example, if a customer installs roof-top solar on their home, their billed-energy usage will significantly decrease; however, when a cloud passes over on a hot, humid day, TEP must be able to instantly meet their full demand. This peak demand growth drives distribution planning and construction for TEP.

TEP is required to build a system able to meet the maximum peak demand for EVERY customer, EVERY hour of the day. This is accomplished through analysis of every one of

the Company's 410 circuits in the system, not by simply analyzing an aggregated sales forecast. Since 2011 (test year from last case), TEP has added about 10,000 new customers. So while overall sales volumes have declined, our system must account for the load requirements of these new customers. Load grows in pockets, not in an even distribution across the system. As such, TEP models each circuit with the current and anticipated load to evaluate the long-term needs in the area. As TEP becomes aware of plans for future growth, we incorporate those plans into the capital planning process.

Q. Please describe in more detail the length of the planning phase.

A. Building new substations and transmission lines is a lengthy process that includes often protracted land purchases, a siting process and an environmental permitting process. TEP begins the land acquisition and siting process at least five years in advance of planned construction. The lengthy timeline to build infrastructure to accommodate load growth doesn't allow for minor, short-term adjustments to customer building plans. Transmission and distribution assets have 30-50 year asset lives, so our plans can't be short-sighted, as Mr. Radigan suggests. If we install transformers sized for only the first 10 years of growth, we'll be replacing or adding transformers in a very costly and inefficient manner. We do incorporate potential growth as well as known growth in our forecasts, but known growth timelines can change and the external forces on our process aren't flexible enough to adjust accordingly. However, we do adjust our planning process for significant new/previously unknown changes in customer load.

Q. Please describe how this planning process is cost-effective.

A. TEP's approach to distribution planning incorporates the long-term needs of the system, which results in adding capacity to address current system needs while planning for future needs. This is a cost effective approach, because the Company can optimize the size of equipment to prevent the need for near-term replacements or additions. It is less expensive

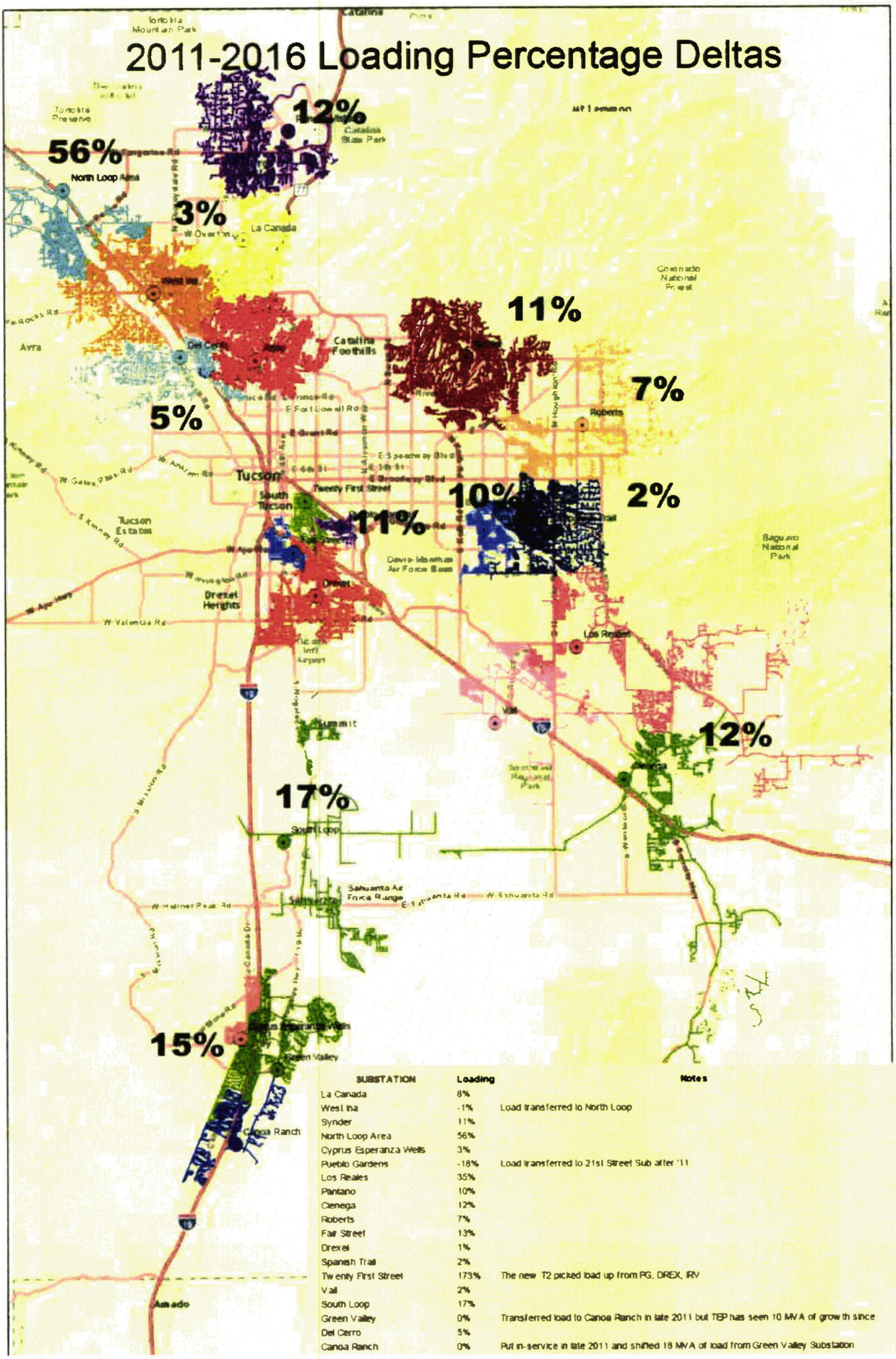
to size equipment with room for growth, than to size for the immediate need and constantly have to replace or add equipment as growth occurs. Moreover, the Company can take advantage of economies of scale through longer-term planning. For example, a 138/13.8 kV 15 MVA transformer costs $600,000 compared to $675,000 for a 25 MVA transformer. Similarly, a 30 MVA transformer costs $1.0 million, compared to $1.2 million for a 50 MVA transformer.

Q. If load growth forecasts change significantly, how does the Company adjust its planned system investments?

A. There are steps in the planning process where we can delay to adjust to changes in customer load. For example, once we purchase and permit a new substation site, we can postpone physical construction until the load growth is more certain. Land purchase plans can also shift, adjusting in-service dates to reflect to changes in the forecast. For example, the original in-service date for Orange Grove substation was 2013 in 2008, 2014 in 2009 and 2010, 2016 in 2011, 2017 in 2012, 2019 in 2013 and is currently forecast for 2018, which has been the planned in-service date since 2014.

Q. Please describe in more detail how growth in the number of customers affects the distribution system.

A. TEP builds new facilities to accommodate new customers (load growth), but also in response to gradual increases in demand that occur sporadically throughout TEP's service territory. Despite a reduction in total electricity consumption since the last rate case, we've seen load growth in certain pockets of our service territory which has reduced available capacity on existing infrastructure. The map below indicates the change in loads from 2011 to 2016, which greatly varies across the service territory.



SUBSTATION	Loading	Notes
La Canada	8%	
West Ina	-1%	Load transferred to North Loop
Synder	11%	
North Loop Area	56%	
Cyprus Esperanza Wells	3%	
Pueblo Gardens	-18%	Load transferred to 21st Street Sub after '11
Los Reales	35%	
Pantano	10%	
Cienega	12%	
Roberts	7%	
Fair Street	13%	
Drexel	1%	
Spanish Trail	2%	
Twenty First Street	173%	The new T2 picked load up from PG, DREX, IRV
Vail	2%	
South Loop	17%	
Green Valley	0%	Transferred load to Canoa Ranch in late 2011 but TEP has seen 10 MVA of growth since
Del Cerro	5%	
Canoa Ranch	0%	Put in-service in late 2011 and shifted 18 MVA of load from Green Valley Substation

Q. How does TEP plan for contingencies?

A. In order to plan for contingencies, TEP must evaluate the loading of individual components of the system and have excess capacity on surrounding equipment to absorb the load in the event of a failure. In substations, we use Automatic Throw-over Switches (ATOs) to shift load from one transformer to another when a breaker operates (an automatic closing of a normally open switch between two connected transformers). This alleviates outages associated with the breaker operation, but requires excess capacity on the adjacent equipment to carry the additional load. Without the ATO in service, in the event of a failure, TEP personnel must devise a switching plan to re-balance the load and manually switch to re-energize the affected customers. This can result in an outage lasting several hours, versus no outage at all when an ATO is in service. Our planning process identifies and addresses areas where ATO's must be taken out of service during seasonal peaks by increasing capacity in existing or new substations.

Q. Please comment on TEP's future distribution system requirements.

A. TEP's plan for the future is to migrate substations from 46kV to 138kV, where it is most cost effective, for improved reliability and system efficiency. The 46kV system is radial, while the 138kV system is looped. As such, an outage on a 46kV line leads to 4,000-6,000 customers out of power until the line can be manually switched to pick up the load. An outage on the 138kV system does not result in customer outages because the loop is immediately fed from the other direction. In addition to improved reliability, as the Company replaces 46kV substations with 138kV substations, it will eliminate older equipment that has higher operating and maintenance costs.

III. RESPONSE TO RUCO.

Q. In your opinion, does Mr. Radigan understand the basic requirements involved in distribution system planning necessary to provide reliable electric service?

A. No. His testimony relies on declining kWh sales to assess the Company's distribution planning process. As I previously mentioned, we're building and maintaining the system to reliably and safely meet the specific load requirements of our customers, which includes meeting their peak demand.

Q. Please respond to some of Mr. Radigan's specific examples.

A. Certainly. I will briefly rebut each of the examples used in Mr. Radigan's testimony where he questions the Company's distribution system investments.

Canoa Ranch

While Mr. Radigan agrees that the Canoa Ranch substation relieved loading issues on existing substations, he suggests that the 50 MVA transformer was oversized because it currently has excess capacity. As explained earlier in my testimony, we are not planning for the short term, but rather for the 30-50 year life of a substation transformer. If TEP followed Mr. Radigan's planning approach, the Company would already be at full capacity only 5 years after the substation was built. That's just poor planning and a short-sighted and inefficient approach to investing in our distribution system which would lead to costly additions and compromised reliability.

Since the Canoa Ranch substation was built in 2011, we have experienced an additional 10 MVA of load growth on the Green Valley substation. The Canoa Ranch substation was built to alleviate loading and voltage issues at the southern end of Green Valley. However, rapid development in the northern portion of Green Valley has created new loading issues

in the area. In fact, the Company is currently replacing a transformer at the Hartt substation (located north of the Green Valley substation) to move some of the load from Green Valley to Hartt.

As previously discussed, TEP's long term strategy is to build 138kV substations like Canoa Ranch. With the addition of the new substation, an older 46kV substation was retired, reducing O&M costs associated with the older equipment. Moving the load to Canoa Ranch moved approximately 2,000 customers to the looped 138kV system and has resulted in improved reliability for those customers.

In summary, the Canoa Ranch system is appropriate based on long term planning. It resolved voltage issues on this system, as well as helping with load issues on nearby systems. It also provides the benefits of a looped system. This project is well justified, in the public interest, and TEP fully stands by its decision.

Lateral 7.5

Mr. Radigan questions the decision to install a 25 MVA transformer and suggests that a 15 MVA would have been adequate. Again, this is a short-sighted approach to planning. If TEP installed a 15 MVA transformer, it would already be 87% loaded (13 MVA), less than nine years after it was installed. Our forecasted load growth for this area reaches almost 27 MVA by 2023. Again, TEP's actions are consistent with sound long term planning. While Mr. Radigan's approach would have saved a little money in the short term, it would be far more costly in the long term.

Kino

Mr. Radigan states that the "Kino area in southern Tucson is serviced by five substations, 21st St, 35th St, Pueblo Gardens, Drexel, and Fair St." While TEP has been able to serve the load growth at The Bridges with these substations thus far, the ultimate build out of the development is over 45 MVA and cannot be served without the new 75 MVA Kino substation. Multiple circuits at the Drexel and Irvington substations are 90-100% loaded and we are not able to keep the ATO's in service during the summer peak. Building the Kino substation will alleviate these loading issues. TEP will also retire Pueblo Gardens and 35th Street, both 46kV substations have older equipment and higher maintenance costs. Moving the 35th Street and Pueblo Gardens load to a 138kV substation like Kino will greatly improve the reliability for the 3,000 customers served by those substations.

Q. With reference to a residential and commercial development called "the Bridges," Mr. Radigan states, "...there has been little meaningful development at the Bridges in the last 10 years."[1] Is this a true statement?

A. No. The Bridges is a growing commercial development. There has been an influx of new business in this area, including a Costco, Wal-Mart and several other smaller businesses,

[1] Direct Revenue Testimony of Frank Radigan, page 27:2-3.

which were not shown in Mr. Radigan's misleading photos. In addition, there are plans for a movie theater (currently under construction), restaurants, and the construction of 160 residential homes. In addition, the Company is aware of plans to break ground in 2018 on a large development with significant load requirements. The total development plan for The Bridges area is 45-50 MVA, with over 4 MVA already in service.

Q. Mr. Radigan states that TEP should, "wait as existing equipment becomes unloaded due to declining sales"[2] to increase system reliability. Do you agree with this statement?

A. Absolutely not. Mr. Radigan's approach to increasing system reliability is completely unrealistic and shortsighted. We make decisions that are in the best long-term interests of our customers. As I explained earlier, TEP's distribution planning process is very thorough. In my 19 years with TEP, we have never relied on declining kWh sales to enhance system reliability. In fact, I can't imagine that any utility in the United States would employ this type of planning approach. I cannot stress enough that system load and kWh sales are two very different things. The distribution system must be capable of meeting the peak load of our entire system.

Declining sales are not reflective of system need. For example, even though TEP is seeing declining kWh sales, TEP experienced a city peak load on June 20, 2016 of 2,305 MW, which was an increase of 4% over the 2015 peak of 2,214 MW. This demonstrates that declining sales doesn't necessarily create capacity.

[2] Direct Revenue Testimony of Frank Radigan, page 23:1-2.

Q. Are you aware of a provision in the 2013 settlement agreement approved in TEP's last rate case[3] that requires the Company to meet with RUCO (and Commission Staff) annually to discuss capital expenditures, specifically for the distribution system?

A. Yes, I am. In the 2013 settlement agreement TEP agreed to meet annually with RUCO and Staff to discuss the Company's capital expenditures for distribution plant, planning horizons and related planning for the upcoming year.

Q. Is TEP holding these meetings with RUCO and Staff?

A. Yes. TEP met with RUCO and Staff on December 1, 2014 and December 2, 2015 to discuss plans for distribution system investments as required by the settlement agreement, and we also discussed TEP's plans for investments across our entire utility system, including generation and transmission assets. Copies of the presentation materials from those meetings are attached as exhibits to the Rebuttal Testimony of David G. Hutchens.

Q. What do you believe is the intent of these meetings?

A. The Company's goal in these meetings is to (i) keep RUCO and Staff apprised of TEP's capital investment plans, (ii) discuss any significant initiatives or projects, and (iii) solicit questions and feedback from RUCO and Staff regarding the Company's plans.

Q. Do you think these meetings have been helpful for RUCO and Staff?

A. While I cannot speak for RUCO, Staff witness McGarry specifically mentions these meetings in his Direct Testimony as follows:

> TEP agreed to meet annually with Staff to review the Company's actual capital spending and future plans for the upcoming year.

[3] Decision No. 73912 (June 27, 2013).

Meetings with Staff were held in December 2014 and then again in December 2015. Information presentation in these meetings is consistent with what the Company has overall included for recovery in current rate base. I would recommend that these meetings continue as Staff has conveyed that they were useful in gaining a clearer picture of what the Company was planning for the upcoming years.[4]

Q. Does TEP support Staff's recommendation that these meetings continue?

A. Absolutely. TEP appreciates the opportunity to meet with RUCO and Staff to discuss our capital expenditure needs and to discuss any major initiatives in our planning horizon.

IV. RESPONSE TO IBEW.

Q. Do you agree with Mr. Northrup's multiple assertions of "marked deterioration in the reliability and safety of TEP's operations"?

A. No, I absolutely disagree. TEP has maintained an exemplary safety and reliability record for the past several years.

I will begin with safety. As stated on page 4 of my Direct Testimony, T&D Operations has maintained an excellent and sustained total recordable incident rate ("TRIR"). The T&D TRIR has hovered around 1.0 from 2012 through June of 2016, as demonstrated in the table below. The following formula was established by the Occupational Safety and Health Administration to calculate TRIR:

[4] Direct Revenue Testimony of Michael McGarry, page 29:9-15.

TRIR = (# of Recordable Injuries * 200,000) / # hours worked

	2012	2013	2014	2015	YTD June 30, 2016
T&D Operations TRIR	0.80	0.96	1.67	0.40	1.59

Simply stated, a TRIR of 1.0 reflects on average one OSHA recordable incident per 100 workers per year. This excellent safety performance is a reflection of our commitment to safety and our overall "Target Zero" safety strategy, which includes three elements:

1. Active safety leadership;
2. Increased employee involvement and engagement in safety activities; and
3. Hazard control and regulatory compliance.

Q. Please comment on TEP's reliability performance.

A. TEP has maintained consistent focus on reliability. On page 5 of my Direct Testimony, I also demonstrate the Company's consistent reliability performance. The following table illustrates sustained performance for CAIDI and improved performance in SAIDI and SAIFI.

	2011 – 2013 3-year average Value (minutes)	**2013 – 2015 3-year average Value (minutes)**
SAIDI	75.73	63.09
SAIFI	.91	.75
CAIDI	83.68	84.23

Thus, TEP's electric customers on average experience less than one outage per year with an average duration of about one hour. For those customers experiencing an outage the average duration is less than 90 minutes.

Q. Do you agree with Mr. Northrup's concerns about Line Construction resources?

A. No, and I believe Mr. Northrup contradicts himself in his testimony on this matter. On the one hand, he asserts that we don't have as many linemen per customer as Central Hudson (page 6, lines 1-13), yet he later states that crews don't have enough work to stay busy (page 7, lines 10-11).

Many factors impact the timing of line construction work including: customer deadlines, regulatory requirements, outage coordination and permits. We often experience peaks and valleys in the volume of work due to these factors. The Company uses contractor resources to manage the fluctuations in work volume, which reduces the risk of laying off TEP employees when the workload is lighter. Comparing staffing between TEP and Central Hudson isn't valid because Central Hudson has very different business drivers including weather, vegetation, multiple district offices and availability of contractors in emergency situations.

We occasionally have large projects, like the 500kV line from Pinal Central to Tortolita or the 100 pole relocation public improvement project on Ajo Highway, that require many line construction resources for a short period of time. If we increased TEP resources to the level required to build these large projects, we would have to lay off those employees when the project was complete, which would be costly and inefficient.

Q. Is it true that TEP is not currently maintaining records for non-CIP (Critical Infrastructure Protection) breakers?

A. No, that is not true. We maintain records for all 1,349 of our substation breakers, whether they are designated as CIP or not. These records include the name plate information, test data, inspections, and history of maintenance that has been performed on the breakers since the installation date.

Q. Are you aware of "a disruption in the Company's workflow inasmuch as some crews do not actually have sufficient work to stay busy" as Mr. Northrup states on page 4, lines 9-11?

No, I am not aware of crews not having sufficient work to stay busy. The Company's Resource Management Team and Line Construction leadership coordinate closely to ensure that crews are assigned productive work every day. As demonstrated in the table below, TEP line crews have maintained a consistent level of work for the past 3 years. The minor differences are due to fluctuations in emergency work, including storm response.

	2013	2014	2015
Hours worked by TEP Line Crews	224,090	222,392	219,313

Q. Is Mr. Northrup's testimony describing Designers and Designer Apprentices as not qualified accurate?

A. I assume that Mr. Northrup is referring to the Distribution Designers in the T&D Operations department because this is the only current designer position. Based on that assumption, my answer is no, Mr. Northrup's testimony is not accurate. Mr. Northrup infers that the recently hired Distribution Design contractors are not qualified, which is not correct. Both of the contractors have over 10 years of experience as Distribution Designers

at other utilities and are qualified to perform this function at TEP. These contractors were identified through a nation-wide search and pre-qualification by a national recruitment firm. Multiple candidates were interviewed and TEP contracted with the top two candidates. In conjunction with hiring two Distribution Designer contractors, the Company is currently in the process of hiring a new class of at least four Distribution Designer Apprentices, which will be TEP's largest class ever of this type of apprentices.

Q. Do you understand the connection that Mr. Northrup is making between the Distribution Designers in T&D Operations and page 17 of your testimony?

A. No. Page 17 of my testimony is about the workforce planning efforts for T&D Engineering, not Operations. The designers mentioned in this section of my testimony are Engineering Designers, which is a position that does not yet exist at TEP.

Q. Does TEP hire out of state contractors?

A. Yes. TEP hires both in state and out of state contractors in order to ensure costs are reasonable. All construction contractors hired by TEP are required to hold licenses in the state of Arizona.

Q. Mr. Northrup's testimony states "TEP also just bid two transmission jobs out that could have been performed by TEP employees." Is this accurate?

A. No. TEP had an unusually high volume of transmission work in 2015 and 2016. While our employees are capable of doing this type of work, the employee and equipment resources required to complete all of the concurrent line work in 2015 and 2016 exceeded our internal capabilities. The Company takes into account many factors when determining to use internal or external resources for construction, including: length of the project, equipment requirements, other projects due at the same time, outage requirements,

proximity to the Irvington office and due dates. Work is assigned to internal and external crews in a manner to optimize efficiency and productivity.

Q. Please comment on Mr. Northrup's statement expressing concerns related to TEP's workforce planning initiatives and the 'aging workforce' problem.

A. We actively monitor and manage our Workforce Planning initiatives as they relate to not only retirements, but the changing business environment in which we are operating. Workforce planning is addressed on an on-going basis within the functional areas of the company and formally on an annual basis through efforts specific to organizational planning. Additionally, these workforce plans are incorporated and discussed during the annual business planning cycle and subsequent succession reviews.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

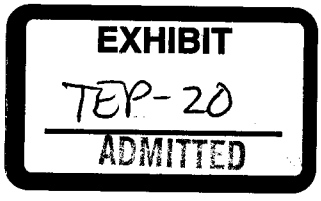
REJOINDER TESTIMONY OF

SUSAN M. GRAY

ON BEHALF OF

TUCSON ELECTRIC POWER COMPANY

SEPTEMBER 1, 2016



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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Susan Gray. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct Testimony and Rebuttal Testimony in this docket?

A. Yes.

Q. What is the purpose of your Rejoinder Testimony?

A. The purpose of my Rejoinder Testimony is to respond to some of the more significant statements made by IBEW's witness Northrup in his Surrebuttal Testimony. Mr. Northrup's Rebuttal Testimony provides examples of what he considers "marked deterioration in the reliability and safety of TEP's operations" and includes pictures of situations that Mr. Northrup believes are unsafe. We have examined each and every one of these alleged unsafe conditions and found his assertions to be false. Moreover, it is unconscionable that Mr. Northrup points to these as examples of unsafe conditions, yet did not show concern for the public and employees to bring these conditions to the attention of the Company with any specificity, at the time the alleged conditions were discovered. As previously stated, the Company has several joint safety programs, an annual assessment of its safety processes, and many well-established channels to report safety concerns to the Company to have those concerns immediately addressed.

Q. Do you have any general comments regarding the Company's commitment to safety and reliability?

A. Despite Mr. Northrup's mischaracterizations to the contrary, as I have stated in my Direct and Rebuttal, TEP has maintained an exemplary safety and reliability record and has

demonstrated consistent improvement year after year. Mr. Northrup's completely unfounded claims that there has been "marked deterioration in the reliability and safety of TEP's operation" will be discussed in further detail in this Rejoinder Testimony.

II. RELIABILITY AND SAFETY.

Q. On page 1 lines 21-24 and page 2 lines 1-4 of Mr. Northrup's Surrebuttal Testimony, he states that there has been a "marked deterioration in the reliability and safety of TEP's operation." To justify his statement, he later refers to the 4kV distribution system as "antiquated and obsolete." Do you agree?

A. No. While the vast majority (over 85%) of our customers are on 13.8kV distribution systems, our 4kV distribution systems are reliable and meet all requirements to remain in service. In fact, 2015 reliability data demonstrates that the Company's 4kV and 13.8kV distribution systems are equally as reliable. The ratio of outages per customer on the 4kV system was 0.64% versus 0.63% on the 13.8kV system. While the 4kV systems are older, the Company has maintained the performance as demonstrated by the reliability statistics. The Company is converting from 4kV to 13.8kV in a strategic, controlled and cost effective manner to improve operational flexibility by increasing the number of 14kV ties. This will allow TEP to serve larger customers than the 4kV system can support and to reduce distribution system losses.

Q. Please respond to Mr. Northrup's accusation about transformers lacking fuses.

A. Mr. Northrup also incorrectly states that there is not a fuse on transformers in the 4kV system. In recent discussions that I personally had with Mr. Northrup, he showed me a picture of a transformer without a fuse, so I believe this is the same transformer he is referencing in his testimony. The transformer in Mr. Northrup's picture was a Completely Self Protected (CSP) transformer, which are attached directly to the line without an

external cutout or fuse because they have internally mounted circuit breakers and fuselinks that provide the same fusing capability. Thus, an external fuse is unnecessary for this type of transformer. However, since 1975, the Company adopted a conventional type of transformer that does not have internal breakers or fuselinks, so external cutouts or fuses are installed in conjunction with the transformer. TEP's Distribution Technical Manual references the fusing size for 4kV banks on Section 7.6 – Overhead Equipment Protection and section 7.7 – Underground Equipment Protection also references the fusing size for protecting the underground equipment for the 13.8kV and 4kV system. It is the current TEP standard to install an external fuse with a transformer. Contrary to Mr. Northrup's assertions, the 4kV system is reliable and the transformers are in fact safely connected.

Q. On page 2 lines 5-9 of Mr. Northrup's Surrebuttal Testimony, he references an example of an old, rotted electrical pole that hasn't been "pulled". Please respond to his testimony.

A. Third parties such as telecommunications companies commonly have joint use or joint attachment agreements with TEP, to use a portion of the pole for their equipment such as cable or fiber. A joint use agreement is an arrangement where both parties are owners of a percentage of the pole that is jointly used. A third party attachment agreement indicates that the third party company is not a pole owner and lease the communication section of the pole from TEP, per Federal Communication Commission rules. When TEP replaces a pole with either arrangement, TEP is required to notify parties and request that their equipment be transferred to the new pole. Each company is allowed 30 days to transfer their equipment and assignments are sequential, and not scheduled at the same time. After the final transfer notification has been received, TEP performs a post check and schedules the pole for removal. Exhibit A of Mr. Northrup's testimony does show a picture of a pole that needs to be removed. The manual process described above was not working very effectively, which is likely why this pole hasn't been removed. Again, I find it

disappointing that Mr. Northrup prefers to use reports of such conditions through a rate case proceeding instead of notifying the Company immediately to be able to rectify the situation.

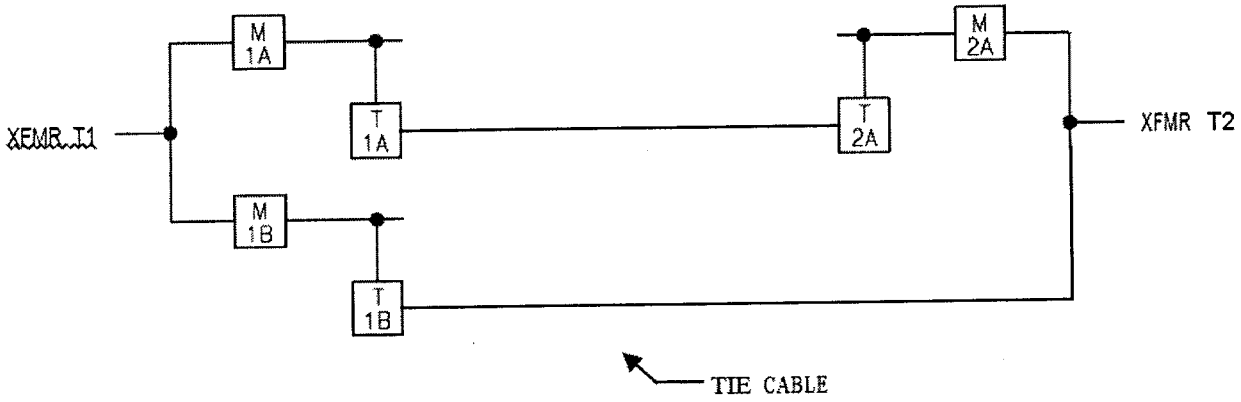
To address this notification issue, in 2015, TEP implemented the use of Notify™, a joint use process and asset management software. Notify™ has become the centralized area of sharing and communicating joint use activity by streamlining conversations between TEP and telecommunication companies. In addition to improving the transfer notification status, TEP is currently meeting regularly with telecommunication companies to strengthen relationships and improve communication efforts to address the backlog of pending transfers and pole removals.

Lastly, TEP is actively performing field checks for poles that are ready for removal without receiving completion of transfer notification. Field checks are performed routinely to identify poles that are ready for removal. TEP Telecommunication Specialists are also regularly field checking and submitting for pole removals. These practices are consistent with standard utility practice.

Q. On page 2 lines 16-19 of Mr. Northrup's Surrebuttal Testimony, he references Exhibit C and says that it is a picture of a 13.8kV feeder riser connected to a substation bus and claims that this is against industry standard. Do you agree with this claim?

A. No. The component in Exhibit C has been misidentified by Mr. Northrup as a feeder riser, but is actually a picture of tie cables at the Spanish Trail substation. It is TEP's standard to protect feeder risers with a 600A breaker, but tie cables in this configuration are protected by the transformer differential rather than a breaker. Mr. Northrup's assertion that this configuration is not industry standard and not properly protected is incorrect. The

configuration at Spanish Trail is depicted in the figure below. Spanish Trail has two transformers, T1 and T2, which are configured to automatically throw over (or pick up the other transformer's load) when a transformer trips offline. Since T1 has two switchgears (1A and 1B) and T2 has one switchgear (2A), tie cables are necessary to tie switchgear 1B to transformer T2. This configuration is appropriate and meets all applicable utility industry standards.



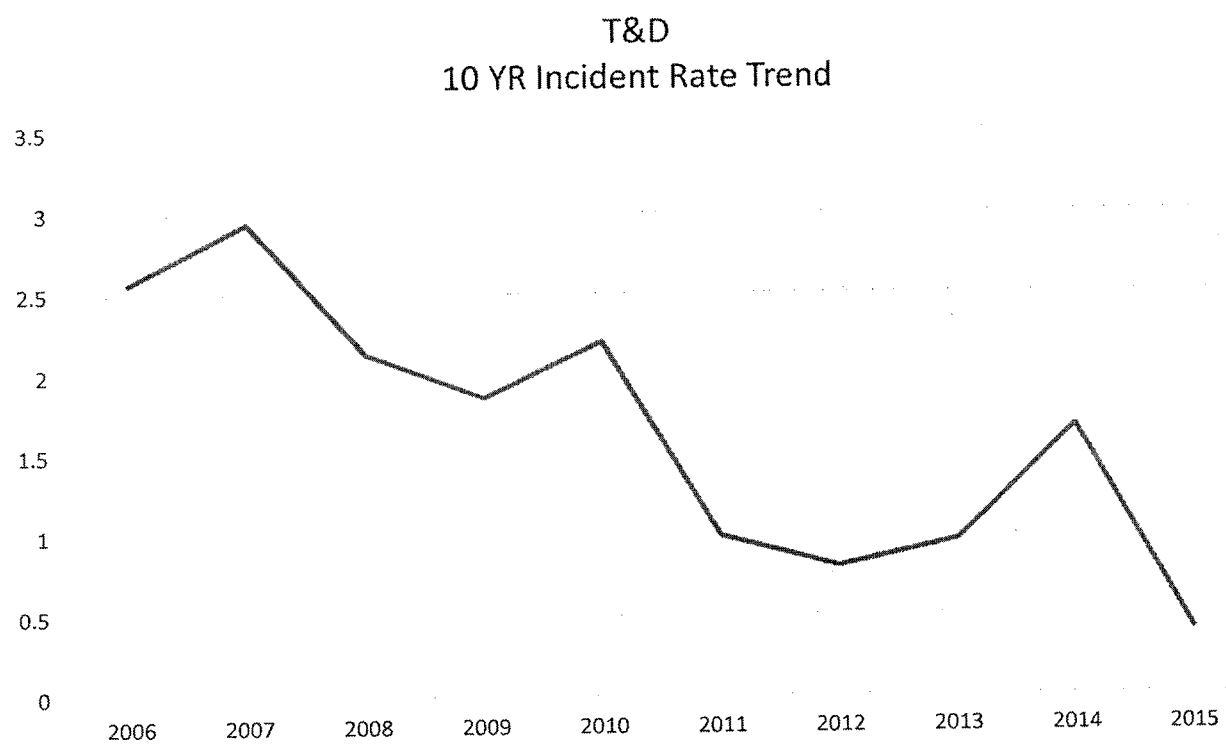
Q. On page 3 lines 6-10 of Mr. Northrup's Surrebuttal Testimony, he references the Hartt Substation in Green Valley as having a massive outage due to outdated and overloaded equipment. Please respond to this assertion.

A. If Mr. Northrup is referring to the outage that occurred on June 19, 2016, which affected one feeder at the Green Valley substation for only 10 minutes, then I disagree with his characterization of this as a "massive outage" and that it was due to "outdated equipment." The record-setting heat on that date led to an overloaded circuit and a need to transfer load from the Green Valley substation to the Hartt substation. Green Valley substation experienced over 2.5MVA of load growth in a single year; with the vast majority of load being in the Quail Creek area. In order to be able to have greater operational flexibility and to avoid future overloads, the 4.7MVA transformer at Hartt was replaced with a 12.5/15MVA transformer. Hartt substation also now has the capacity to accommodate anticipated load growth in the Green Valley area for 6 – 10 years.

Q. On page 3 lines 10-14 of Mr. Northrup's Surrebuttal Testimony, he compares the Total Recordable Incident Rate (TRIR) in 2012 to 2016 and states "This is nearly double the amount of injuries in half the amount of time." Please respond to his claim.

A. Safety is a top priority for TEP Leadership and any injury is a cause for concern. We continue to identify opportunities for improvement regarding safety and won't be satisfied until we meet our Target Zero goal of having no injuries. In my Rebuttal Testimony, I stated that the T&D TRIR has hovered around 1.0 from 2012 to June of 2016, which reflects on average one OSHA recordable incident per 100 workers per year. Safety performance has been consistently improving, as demonstrated in the 10 Year Incident Rate Trend chart below (Graph 1). The trend chart demonstrates that while there are year-to-year fluctuations, our recordable injury rate has trended downward and we continue to outperform the industry average.

Graph 1



Mr. Northrup's statement that the 2016 TRIR of 1.59 "is nearly double the amount of injuries in half the amount of time" is inaccurate. The 2016 TRIR of 1.59 reflects January through June 30th, so it is half the amount of time. In both 2012 and 2016 (through June), the TRIR reflects only 4 incidents for the timeframe, so it would be more accurate to say that the same number of incidents has occurred in half the time. A brief description of the injuries in both years is in the table below for comparison. In 2012, the four incidents occurred within the first eight months and ten days. This year's incidents have occurred in almost the same time period, so the rates are nearly identical.

Date of Incident	Brief Description of Incident
3/28/2012	Employee was driving on campus and was bitten/stung by insect. Insect bite.
5/14/2012	Employee lifted gate from 8032. Gate shifted upon lifting and heard pop in left shoulder. Shoulder strain.
7/24/2012	While reaching to the ground to get the drill check key, the ½ electric drill slipped off flat face of steel pole. It fell bit first through safety shoe, punctured left little toe. Foot laceration.
9/10/2012	Employee experienced pain in right wrist. Was transported to US Healthworks for examination. Employee was diagnosed with Carpal Tunnel. Carpal tunnel.
1/18/2016	An employee strained his wrist while operating a trailer jackstand. This is an OSHA recordable due to the rigid splint. Wrist strain.
3/29/2016	An employee wrenched their knee when they tripped over a cactus. Sprained knee.
5/12/2016	An employee strained his knee while holding a strand of wire on a fence for a co-worker. Sprained knee.

6/26/2016	An employee slipped and fell on a wet floor. Bruised back and shoulder.

Q. In his Surrebuttal Testimony on page 4, lines 3-7, Mr. Northrup references a request for substation breaker records. Do you agree with his testimony?

A. No. The union requested breaker records for a specific timeframe for the North Loop substation. The breakers were not serviced during that timeframe, so there were no maintenance records to report. However, the Union's assertion that the Company does not maintain records on breakers is just not accurate. TEP maintains records for all 1,349 of our substation breakers, whether they are designated as CIP or not. These records include the name plate information, test data, inspections and history of maintenance that has been performed on the breakers since the installation date.

Q. Please respond to Mr. Northrup's example of a safety incident in Kingman with a Sturgeon crew on page 4, lines 19-21.

A. TEP is not aware of the incident referred to in Mr. Northrup's testimony. Our standard practice when a contractor incident occurs is that the Company conducts an incident investigation to determine the root cause of the incident and identify mitigation actions that will prevent reoccurrence of safety incidents. We share the results of these investigations with our employees.

III. WORKFORCE PLANNING.

Q. Please respond to Mr. Northrup's testimony regarding TEP's workforce planning initiatives on page 5, lines 4-17 of his Surrebuttal Testimony.

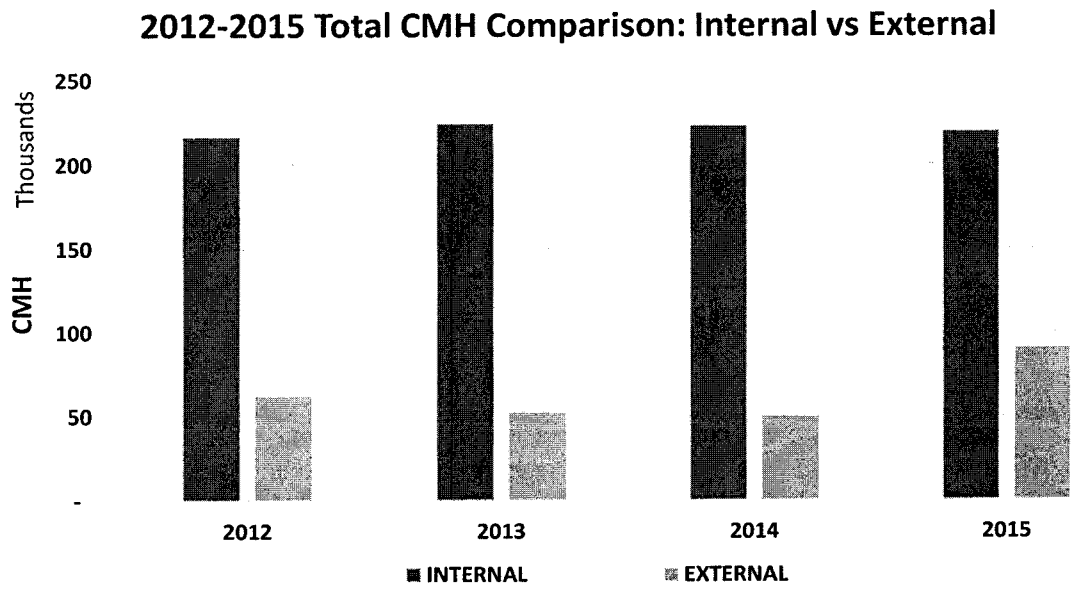
A. After I filed my Rebuttal Testimony, we met with Mr. Northrup to explain our workforce planning approach. He has incorrectly interpreted the workforce planning process as limited to just a three year view. As I explained in my Rebuttal Testimony, the Company

engages in a comprehensive business and workforce planning process annually – which looks out over a five year period of time. As outlined in our response to IBEW data request 1.07, we have an established development track for journeymen, with 8 steps of apprenticeship training prior to reaching journeyman status. Once journeymen status is reached, journeymen linemen work on a crew that has a crew leader who continues to provide guidance over the journeyman's work. While not part of an apprentice program, this requirement is outlined in the Crew Leader's job description. Both journeymen and crew leaders are responsible to train and guide the work of apprentices and pre-apprentices. This is also a requirement outlined in their job descriptions. Furthermore, this continuous progression ensures that 30-year plus employees do not depart from TEP 'without passing any knowledge along' as asserted by Mr. Northrup.

Q. On page 3 lines 19-22 of Mr. Northrup's Surrebuttal Testimony, he states that the crews do not have enough work to stay busy because TEP is assigning work to subcontractors. Do you agree with this statement?

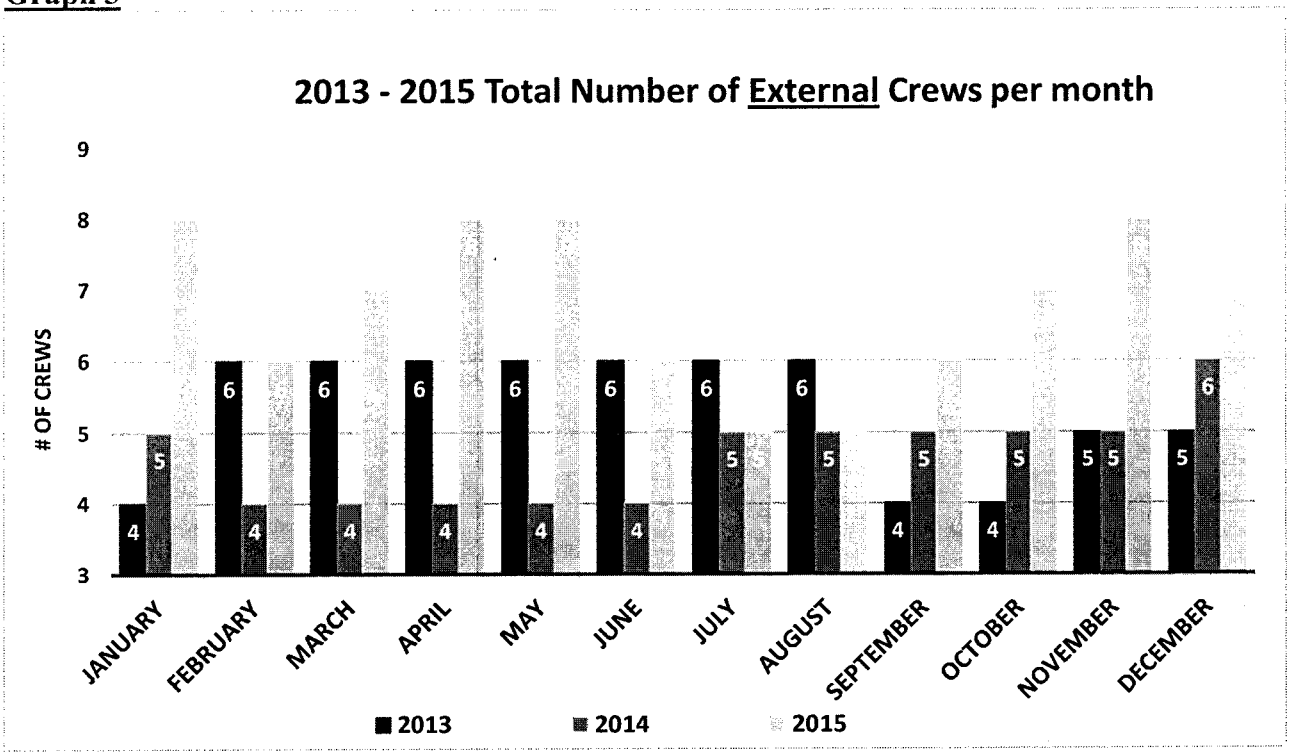
A. No. As stated in my Rebuttal Testimony, I am not aware of crews not having sufficient work to stay busy. When TEP's Resource Management Team is planning and prepping for Line Construction work, its first consideration is to account for the allocation of internal crew resources. Total work (Construction Man Hours ("CMH") completion) for internal crews has been steady for the past four years, see Graph 2 below.

Graph 2



Additionally, it should be noted that many factors impact the timing of line construction work including: customer deadlines, regulatory requirements, outage coordination and permits. Graph 3 illustrate the fluctuating use of external line construction resources used to accommodate the varying volumes of workload throughout the year.

Graph 3



Note: 2015 External crew count excludes the crews required to complete the Pinal Central-Tortolita 500kV Line.

The increase of external resources in the Fall of 2015 was due to the support needed to complete several 138kV line re-conductoring projects in order to comply with regulatory requirements. These large transmission projects were completed in December 2015. If we increased TEP resources to the level required to build these large projects, we would potentially have to lay off those employees when the project(s) are completed, which would be costly and inefficient.

Q. In his Surrebuttal Testimony on page 4, lines 11-15, Mr. Northrup asserts that the Distribution Design contractors "have no training on TEP's system, tools or standards" and that "they have produced no work." Please respond to this assertion.

A. I strongly disagree with Mr. Northrup's statements concerning training and work production. Both Distribution Design contractors came to TEP with 10+ years of

experience in utility distribution design industry. They were provided over 450 hours of training which included advanced software training, observing and participating in the design process with senior design staff, additional instruction on safety standards and standard procedures specific to TEP. On the job training continues under the supervision of senior design personnel and they continue to work on projects of varying degrees of complexity, including capacitor removals and installations, Critical Circuit Patrol maintenance and subdivision layouts. In the 3 to 6 months that they have been contracted by TEP, they have completed designs for 27 work orders and have an additional 21 in progress. Contrary to Mr. Northrup's assertions, these contractors have been trained on TEP's system, tools and standards and they have produced a reasonable amount of work for the timeframe they have been with the Company.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-_____

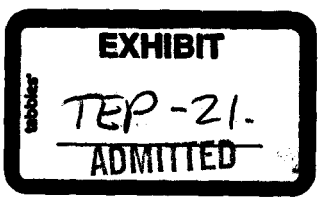
Direct Testimony of

Dallas J. Dukes

on Behalf of

Tucson Electric Power Company

November 5, 2015



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Exhibits

Exhibit DJD-1 Summary of Utilities with Three-Part Rate Designs

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am the Senior Director of Pricing and Economic Forecasting for Tucson Electric Power Company ("TEP" or the "Company"). I am responsible for monitoring and determining revenue requirements, customer pricing and rates structures for all the regulated subsidiaries of UNS Energy Corporation ("UNS Energy").

Q. Please describe your background and work experience.

A. I hold a Bachelor's of Science degree with a concentration in Accounting from Indiana University and a Master's in Business Administration from Anderson University. I am also a Certified Public Accountant. I have 25 years of experience within the utility industry. Before assuming my current position, I was employed as the Director of Accounting for TEP.

Prior to working for TEP, I was employed by Citizens Gas & Coke Utility ("Citizens Gas"), for approximately five years. Citizens Gas serves approximately 265,000 customers in the Indianapolis, Indiana area. The majority of my time at Citizens Gas was spent as the Controller.

Before then, I was the Controller and Director of Regulatory Affairs for Fountaintown Natural Gas Company, and Southeastern Indiana Natural Gas Company. Prior to that, I was employed by the Indiana Office of Utility Consumer Counselor ("OUCC") for

approximately seven years. The majority of my time at the OUCC was spent as a Principal Accountant. My primary duties at the OUCC were to perform professional investigative audits and to represent the public's interest as an expert witness in proceedings before the Indiana Utility Regulatory Commission.

Q. Could you please summarize your testimony regarding Rate Design?

A. In the first half of my testimony ("Rate Design") I discuss a portion of the Company's proposals to change both residential and small commercial customer classes' rate structures. These changes include: (1) raising the basic service charges for residential and small general service customers; (2) eliminating two of the volumetric rate tiers from the standard residential customer rate; (3) creating a new net-metering rider that allows customers with distributed generation ("DG customer") to offset energy consumption with energy production at the retail rate and to sell excess energy production to TEP and receive bill credits at the Renewable Credit Rate; (4) requiring partial requirements customers (including new net-metering DG customers) to choose from one of the two proposed three-part rate tariffs applicable for their service requirement. TEP is making these proposals to better align rate design with cost-causation and to reduce inter-class inequities. While the Company understands that there are several foundational rate-design principles, the primary principle remains that rates should reflect cost-based recovery. With that in mind, the Company's proposals address the many changes to the utility industry in recent years – including energy efficiency, distributed generation, slowing economic growth and demand response technology – that have contributed to flat or declining energy sales.

Right now, TEP's current rate design for residential and small commercial customers does not reflect the way costs are incurred to serve the customers within these classes. The two-part rate structure of a basic service charge and energy charges is antiquated and does not reflect the modern and burgeoning market for new distributed energy and demand-

management options. The energy (kWh) consumption from seasonal customers and DG customers (for example) is not reflective of the fixed costs imposed on the utility. Put simply, TEP's ability to recover these fixed costs and earn a fair return is limited.

Consequently, the fixed costs inadequately recovered from customers benefiting from the system, but not paying their fair share are shifted to other customers under the present rate design. In particular, higher energy use customers pay a higher percentage share of fixed costs despite the fact that the fixed costs to serve similar lower-use customers is the same. This phenomenon has created the mistaken belief that a customer using less energy reduces the utility's fixed cost to serve that customer – instead of simply a lower utilization of fixed assets that must remain ready to serve that customer.

I further detail how TEP is proposing a three-part rate design that adds a demand charge to the basic service charge and the energy charge. Specifically, the demand charges would recover fixed costs allocated to the customer's class based on the amount of the system they use and when they use it. This rate structure would more accurately reflect the cost of providing service while maintaining consistency with the Company's rate design objectives. I list the precedent for three-part rate designs to residential customers. I also explain that such a design (all of its three components) will provide proper price signals so that customers can make better informed choices about energy usage. In my testimony, I detail the specifics of the Company's proposed three-part rate proposals for Residential Demand and Demand TOU and Small General Service Demand and Demand TOU customers. I also provide the rate impacts to typical residential customers using several average energy (kWh) usages. Ultimately, I explain how the three-part rate rewards customers who improve their load factor consistent with more efficient use of the electric utility system – and how it is not the case that residential customers with very low usage will necessarily benefit less from such a structure.

The Company is not proposing to move all residential and small-commercial customers to a three-part rate structure in this case; however, the Company believes that a transition to a three part rate design is necessary to provide fair and accurate price signals that will lead to expanded technological advancement and more efficient use of the system. TEP is presently requesting to make such a change only mandatory for partial requirements customers, whose measured energy usage, as part of a two-part rate design, doesn't provide for recovery of the fixed cost to serve them and a reasonable opportunity to earn a return on its investment. This is consistent with the treatment of partial requirement customers in all other rate classes. However, TEP is fully supportive, if the Commission were to find it in the public interest, to order a more rapid transition to three-part rate design for all customers.

With regards to the two-part rate structure, TEP proposes to increase the basic service charge to a level closer to the appropriate minimum system-cost level. The Company also seeks to remove two of the rate tiers from the standard residential rate. Specifically, TEP seeks to increase the Basic Service Charge to $20.00 per month for tariff R-01, Residential Service – while having only two tiers in the volumetric Delivery Services-Energy charges (0-500 kWh and usage over 500 kWh). These proposals will begin the transition toward a more balanced rate structure that addresses the issues I have highlighted above.

The Company's proposal for the adoption of a new net-metering rider in this proceeding will only apply to net metering DG customers that submitted a completed application for interconnection to TEP's grid facilities after June 1, 2015. As proposed, existing net-metering DG customers and those with interconnection applications submitted before June 1, 2015 (and ultimately approved) will stay on the current rider until it expires in 20 years. New net metering DG customers will be compensated for any excess energy with a bill credit at the Renewable Credit Rate. Further, the Company will purchase this excess

energy from the DG customer during the billing cycle (that is, eliminating the banking option). This is a further step to send more accurate price signals to net metered customers about their true energy costs. Still, DG customers will see a significant savings on their electric bill, as I show through an example I detail later in my testimony. The new net-metering rider reduces, but does not eliminate, the subsidy provided to applicable DG customers.

I also explain that, since DG customers with net metering are partial requirements customers, the current two-part rate design options are ill-equipped in accounting for how these customers use TEP's system and for fair recovery of fixed cost. This is because two-part rates are designed to recover costs based on average consumption levels for full-requirements customers. So, it is appropriate to require all partial requirement customers, such as net-metered DG customers, to be on a three-part rate schedule. While further mitigating the cost shift I describe in preceding paragraphs, I show how DG customers still save on their total electric bill. These customers can also reduce bills through decreasing billing demand or energy usage.

Q. Please summarize the proposed Economic Development Rider.

A. I discuss the Company's proposal for an Economic Development Rider ("EDR"). This rider will help put TEP's service territory in a better competitive position to attract and expand commercial activity. The EDR will be available to customers with projected peak demand of 3,000 kW or more and a load factor of 75% or higher and for five years from the effective date – providing discounts on monthly electric bills according to a declining schedule. Potential participants must meet several criteria to qualify and the discounts will only apply to the qualifying additional loads from new business or existing business expansion – with total program participation limited to 200 MW. I detail the criteria and further describe the discounts to qualifying customers in the last section of my testimony.

Q. Please provide a summary of your testimony regarding Revenue Requirement.

A. In the second half of my testimony ("Revenue Requirement") I am sponsoring the historical information for the twelve month period ending June 30, 2015, (the "Test Year"), presented on the following schedules:

- A-1, A-2 and A-5
- B-1 through B-5
- C-1 and C-2

I will also be supporting in my direct testimony the pro forma adjustments made to the Test-Year on Schedules B-2 and C-2. Specifically, I will be sponsoring the rate base pro forma adjustments on Schedule B-2 listed below:

- Springerville Unit 1 Leasehold Improvements
- Springerville Unit 1 Lease Equity
- Asset Retirement Obligation
- Post Test Year Plant
- Post Test Year Plant - Renewables
- Delayed Unitization
- Working Capital

Additionally, I will be sponsoring Schedules C-1, C-2 and C-3, and the pro forma accounting adjustments reflected on Schedules C listed below:

- Lost Fixed Cost Revenue
- Environmental Cost Adjustor
- Renewable Energy Standard & Tariff ("REST") and Demand-Side Management ("DSM")
- Non-Retail & Non Recurring Revenue
- Springerville Units 3 & 4

- Sales of SO2 Allowances
- Sales for Resale
- Power Supply Management
- Base Cost of Fuel & Purchased Power
- Springerville Unit 1
- Overhaul & Outage Normalization
- Rate Case Expense
- Injuries & Damages
- Membership Dues
- Bad Debt Expense
- Asset Retirement Obligation
- Springerville Common Facilities Lease
- TEP Headquarters - Retail Space
- Credit Card Processing Fees

II. RATE DESIGN.

A. Overview.

Q. Is TEP proposing changes to its residential, commercial, and industrial rates?

A. Yes. I will be discussing some of the significant rate changes that TEP is proposing for the residential and small commercial customer classes. TEP witness Craig Jones will be discussing other proposed rate design changes.

Q. What are the rate design changes TEP is proposing?

A. To better align rate design with cost-causation and to reduce inter-class inequities, TEP is proposing the following changes for the residential and small commercial (small general

service) rate classes:

- Increase the basic service charge to $20 for standard residential customer rates.
- Increase the basic service charge to $30 for small general service customer rates.
- Eliminate two of the volumetric rate tiers from standard residential customer rates.
- Offer two three-part rate structure options to all customers meeting the applicability requirements for the residential and small general service rate classes.
- Freeze and grandfather the current Rider R-4 (Net Metering for Certain Partial Requirements Service (NM-PRS)), Pre June 1, 2015. Rider R-4 will have a proposed expiration date of May 31, 2035.
- Create a new Rider R-15 (NM-PRS), Post June 1, 2015, that discontinues the banking of kilowatt-hours ("kWh") but allows a net metered customer to: (i) continue to offset energy consumption with energy production at the retail rate and (ii) sell excess energy production to TEP at the Renewable Credit Rate as described in the testimony of Carmine Tilghman.
- Require partial requirement customers qualifying for the new Rider R-15 to choose from one of the two proposed three-part rate tariffs applicable for their service requirement.

Q. What are the guidelines or criteria adhered to in evaluating the Company's proposed rate design modifications?

A. TEP is generally following the principles outlined over five decades ago by Professor James C. Bonbright in his work, "Principles of Public Utility Rates," which was reissued in its second edition in 1988. While Professor Bonbright's "Principles" go back five decades, they continue to serve as the foundation for reasonable rate design objectives.

Q. What are those foundational principles?

A. They are as follows:

- The related "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
- Freedom from controversies as to proper interpretation.
- Effectiveness in yielding total revenue requirement under the fair-return standard.
- Revenue stability from year to year.
- Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
- Avoidance of "undue discrimination" in rate relationships.
- Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use.

Q. Is there one principle in rate design that is foundational or primary?

A. Yes. The principle of cost-causation, i.e. rates should reflect cost based recovery. The further away you get from this fundamental foundation, the closer you get to unduly burdensome and discriminatory rate structures that allow for both intra- & inter- class subsidization.

Q. Have fundamental changes occurred in the utility industry since Bonbright's principles were formulated?

A. Yes. At the time Bonbright's principles were formulated the utility industry was typically experiencing steady year-over-year growth in kWh sales and expanding its generation, transmission and distribution systems. In addition, customers had little to no options for alternative power supplies or the ability to control their demand on the expanding utility systems.

However, today there is a growing market of energy efficiency, distributed generation and demand response options available to our customers. New digital metering technology and communication applications also allow today's electrical customers to monitor how and when they use power and the grid.

These factors have contributed to flat or declining kWh sales. Rooftop solar and net metering have become significant factors, especially in Arizona, including TEP's service territory. So the discussion of appropriate pricing and incentive structures has become more complex and necessary as it is a much more important issue.

Q. What do you mean by appropriate pricing structures?

A. To address that, I first need to discuss the cost structure of TEP. The majority of utility costs are fixed – that is, they do not change with electricity usage. In the case of TEP, its fixed costs stem from investment in and maintenance of equipment and infrastructure, and the salaries of employees that are needed to provide safe, reliable power regardless of the kWh consumption of each individual customer.

Like any electric utility, TEP has an obligation to invest in and maintain a system to meet the potential maximum demand of every customer. For that reason, TEP incurs essentially the same costs to serve a residential customer who uses 10 kilowatts ("kW") for 10 hours per month (100 kWh) as it does to serve a neighbor who uses 10 kW for 100 hours per month (1,000 kWh). The only completely avoidable cost is the variable cost related to the energy production, primarily fuel, purchased power and any operating and maintenance ("O&M") costs directly related to energy production or procurement. It would be cost prohibitive and economically unsound to invest in an electrical system scaled differently to meet the unique and constantly changing demands of each individual customer.

Q. Are TEP's residential & small commercial pricing structures presently designed appropriately based on the principal of cost causation?

A. No. The Company's current rate design for residential and small commercial customers does not reflect the way costs are incurred to serve these customers. For decades, rate designs for these classes have incorporated a very simplistic two part rate structure; a basic service charge (customer charge) and energy charges. This was defensible because these customers typically had relatively similar usage levels and patterns. It also allowed utilities to avoid the higher cost of meters capable of measuring demand.

Historically, basic service charges have been limited to bare minimum levels while inclining price rate tiers have been added, forcing customers who use more power to pay an increasingly disproportional share of the fixed costs incurred on behalf of all customers. Today, though, customers have access to a burgeoning market of distributed energy resources ("DER") and demand management opportunities. The growing inequities that result from these new options are exacerbated by utility rates that have become even more inequitable. Thus, TEP is proposing rate design changes that are designed to address those inequities.

As I described above, a customer's individual kWh consumption is not indicative of the fixed costs they impose on their utility. A few examples to illustrate this point are summarized below.

- Seasonal Customers. TEP's service territory has many customers who only live in their homes for part of the year. Under the Company's current rates, these customers only pay a portion of the fixed costs associated with providing safe, reliable service to their homes.

- Vacant homes or businesses. Vacant homes and unoccupied apartments with little to no consumption generate far less revenue for TEP than is needed to cover the fixed costs necessary to assure service when re-inhabited.
- DG Customers. Customers with DG power systems still rely on TEP to supply the full potential kW requirements of their home whenever they need it. These customers also need the local distribution grid to support the reliable operation of their systems and to accept any excess power they generate. While TEP must provide the infrastructure to address these needs, it cannot recover the cost of these services from DG customers under current rates, which rely heavily on energy charges to recover fixed costs. This inequity is exacerbated by net metering, which allows customers to "bank" their systems' excess energy for free and exchange it for on-demand service from their utility.

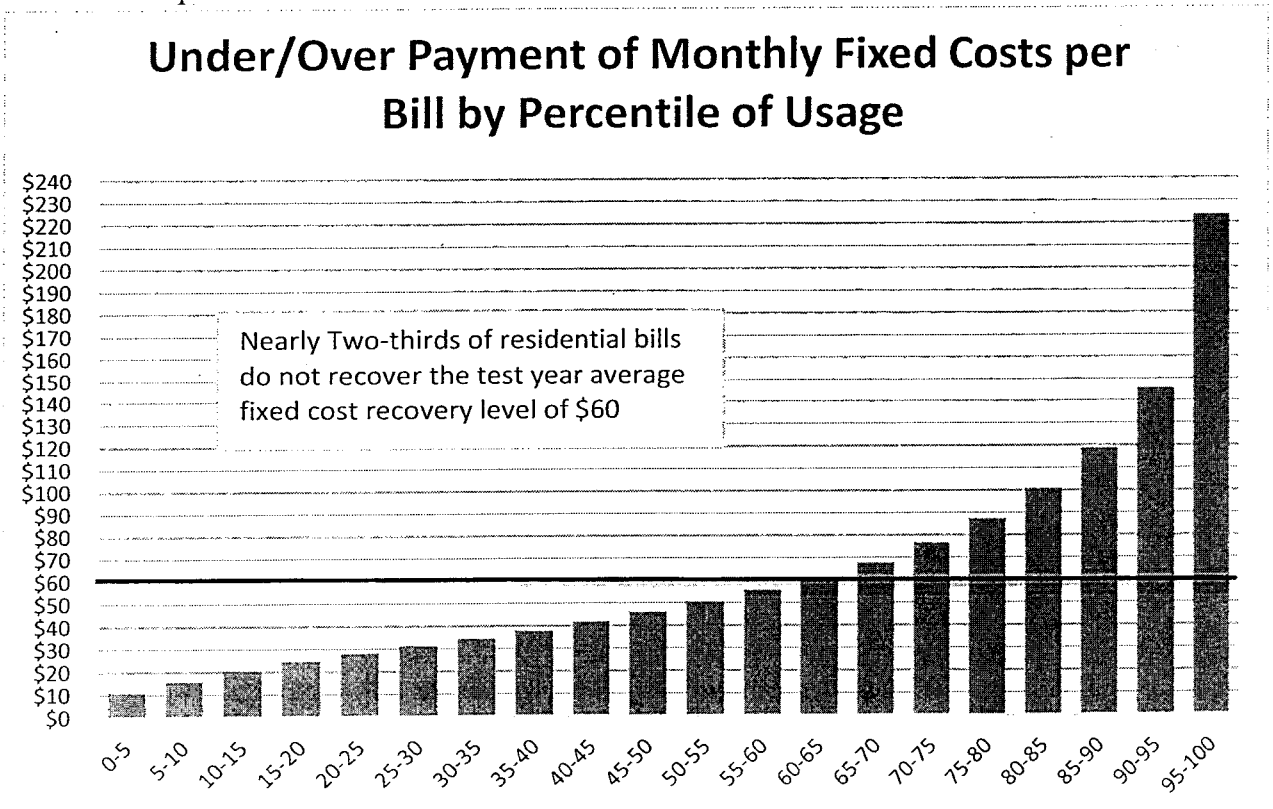
The situations described above limit TEP's ability to recover its fixed service costs. Nearly one out of every three residential (Residential R-01) bills issued by TEP during the test year – 1,308,714 to be precise – reflected usage of 400kWh or less. Because even a studio apartment with basic appliances and moderate usage would likely consume almost 400 kWh per month, these bills probably were generated by vacant homes, seasonal customers and DG customers. TEP recovered only $10 to $33 in fixed costs per month from these issued bills – a fraction of their equitable share of the fixed costs the Company incurs to provide service on their behalf. Those fixed costs are described in more detail in the testimony of TEP witness Craig Jones.

In rate proceedings, those unrecovered costs are shifted to other customers through the present volumetric rate design. Another way to look at it is: if each of the residential bills referenced above recovered just the test year's average monthly fixed cost recovered for

the class of $60, a minimum of $35 million would have been recovered and not have been shifted to other customers.

Q. Does the inclining block rate structure also contribute to these intra-class inequities?

A. Yes. As discussed above, kWh consumption doesn't directly correlate with how much of the system a customer may require at any point in time. TEP recovered, on average, $60 in fixed costs per bill from residential customers during the test year. As shown in the chart below, though, approximately two-thirds of the bills issued in the last 4 years to residential customers (applying the current R-01 rate) did not provide fixed cost recovery equivalent to the class average established in TEP's last rate case. This means that just over one-third of residential customers' bills recovered above average amounts of fixed costs, while two-thirds recovered below average amounts. There is no cost basis for such a disparity and as such this structure is unduly burdensome and unequitable to the higher consumption users.



particular billing period, their utility's fixed costs are reduced by a comparable amount. But such reductions simply result in lower utilization of utility assets that must remain at the ready to power every light, appliance, fan, air conditioner, computer, television and other equipment their customers might choose to use.

Q. Has TEP experienced a reduction in energy sales and use-per-customer ("UPC") for the residential and small commercial rate classes?

A. Yes, since 2011 TEP has seen a decline of approximately 7.5% in its UPC in just the residential customer class alone.

Q. What do you believe is driving these reductions?

A. There are several factors contributing to lower consumption, including: adoption of energy efficiency measures; more energy efficient construction codes and appliance standards; increased use of distributed generation; challenging economic conditions; and other conservation efforts by TEP's customers.

Q. Have these sales and UPC reductions resulted in lower costs for customers?

A. On the whole, they have not. While individual customers have enjoyed lower bills due to energy efficiency and DG systems, their bill savings have not resulted in equivalent system demand reductions. The level of investment and maintenance required to meet customer demand has not been reduced; rather, the burden of paying for it has been shifted from customers who use less energy to those who use more.

Q. Why is it important to distinguish between system savings and individual savings?

A. TEP witnesses Craig Jones and Carmine Tilghman will provide more detail about the cost drivers associated with the electric distribution system and the relationship with peak demand. Broadly speaking, though, the distribution system is a network designed

primarily to meet the non-coincidental peak demands of customers. The transmission and generation systems, by contrast, are designed to meet the coincidental peaks of the distribution system, with reserves and margins for growth and planning purposes.

When customers reduce their energy consumption through temporary vacancies or intermittent solar DG systems, their peak demand typically does not change. In the case of DG customers, it could even grow as a result of oversized generating facilities being added to maximize energy production; that is further discussed in the testimony of Carmine Tilghman.

So while customers enjoy bill savings from their reduced usage, the Company's fixed system costs for distribution service are not reduced. System savings can be realized in future years through reductions in the system's coincidental peak demand. So customers need to be given the proper price signals and incentives through rates to promote those beneficial changes.

Q. How could residential and small commercial rates be structured to most accurately reflect the costs of providing electric service?

A. The closest rate structure from a cost recovery only basis is a straight fixed-variable ("SFV") design. Under this method, the monthly basic service charge recovers all fixed service costs, while variable charges reflect those costs directly tied to energy usage.

Q. Is TEP proposing SFV rates in this proceeding?

A. No. Adoption of strict SFV rates would result in dramatic rate increases for customers at lower kWh consumption levels and not provide adequate price signals to customers to reduce their impacts on the electrical system. Such a structure is just too blunt an

instrument and would dissuade additional technological advancements and behavioral changes resulting in more efficient use of the utility system. This is not consistent with the Company's rate design objectives of providing more accurate price signals to more fairly recover fixed cost and promote more efficient use of the system and thus reduce cost for all customers.

Q. What type of rate structure would more accurately reflect the cost of providing service and also be consistent with the Company's rate design objectives?

A. A three-part rate design consistent with those presently employed for larger customers would be more appropriate and provide a balance between fixed cost recovery, cost causation and price signals incenting more efficient use of the utility system.

Q. How would costs be recovered through the three-part rate design proposed by the Company in this proceeding?

A. Three-part rates, incorporate the following components:

- **Basic Service Charge** – To recover fixed costs directly attributable to the customer, including the meter, service line, on-site equipment, meter reading and equipment, customer support and billing and a portion of the minimum distribution system cost.
- **Demand Charges** – To recover fixed costs allocated to the customer's class based on the amount of the system they use and when they use it.
- **Energy Charges** – To recover variable costs directly attributable to the customers' energy use.

Q. Do any utilities use three-part rates for residential and small commercial customers?

A. Yes. The Company had a review done by Black & Veatch Corporation and they identified 39 utilities offering three-part rates to residential customers. Please see attached **Exhibit DJD-1** listing the utilities and basic tariff information for 43 different

three-part rate designs presently in effect throughout the United States, including Arizona.

Q. Would TEP support three-part rates for all customers, not just partial requirements customers?

A. Yes. But it is critical that each component of the three-part rate closely reflects the actual cost of service. If properly designed, three-part rates more fairly allocate costs to the customers within a class that "cause" them and provide proper price signals that help customers make informed decisions regarding their energy and electrical system usage. Three-part rates also reward customers for better load factors and reductions in peak usage – attributes that lead to lower system costs, which benefits all customers.

The Basic Service Charge should be designed to recover the average unavoidable fixed costs that utilities incur each month. It should provide customers with a more accurate price signal that reflects the costs incurred to assure minimum service from the electrical grid to provide safe and reliable service.

Similarly, the Demand Charge should provide customers with a price signal that accurately reflects the cost of system resources that must be available to serve their individual peak load. They then can make proper usage and equipment purchase decisions that would reduce that portion of their bill while producing system benefits.

Finally, Energy Charges should reflect costs that are entirely avoidable when energy consumption is reduced.

B. Proposed Changes to the Standard Two-Part Rates.

Q. Is TEP requesting that all residential and small commercial customers be migrated to a three-part rate structure?

A. Although TEP is proposing a three-part rate structure as an option, it is not proposing to require all residential and small commercial customers to migrate to a three-part rate structure in this proceeding. TEP is requesting to begin moving toward a more balanced rate structure that would make such a move possible in its next rate filing.

Q. What are reasonable steps that can be taken in this proceeding to begin this transition?

A. For the standard residential and small general service rates (two-part rate structure classes), we can start by moving the basic service charge closer to the appropriate minimum system cost recovery level. In addition, we can remove two of the rate tiers from the standard residential rate. These changes will provide for more equitable recovery of fixed cost and reduce intra-class subsidization. The Company is proposing these changes at a level that it believes will provide for significant improvement of the rate structures without undue rate shock.

Q. What changes specifically are you requesting for residential customers in this proceeding?

A. For tariff R-01, Residential Service, we are requesting an increase in the Basic Service Charge to $20.00 per month. The Company is also requesting the elimination of the third and fourth tiers in the volumetric Delivery Services-Energy charges. In other words, the R-01 will have one tier from 0 – 500 kWh and another for all usage over 500 kWh.

C. Net Metering Rider Modifications.

Q. Is TEP requesting changes to its net-metering tariffs? What changes are you proposing for customers qualifying for Net Metering?

A. Yes. We are proposing the adoption of Rider R-15, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015. The Company's proposed net metering tariff is described in the testimony of Carmine Tilghman. The applicable three-part standard offer tariffs will be mandatory for partial requirement Net Metering customers taking service under this Rider.

Q. Will Rider R-15 apply to all Net Metering customers?

A. No. Most Net Metering customers will be grandfathered under the existing Net Metering tariff. Rider R-15 will only apply to Net Metering customers that submit completed application for interconnection to TEP's grid facilities after June 1, 2015. All existing Net Metering customers interconnected to TEP's system prior to June 1, 2015 and those with completed interconnection applications that were submitted prior to or on June 1, 2015 (and ultimately approved) will stay on the Net Metering Rider R-4 for a period not to exceed twenty years. TEP is proposing that the Rider R-4 expire no later than May 31, 2035.

Q. How will the Company purchase the excess energy produced by the Net Metering customer's facility?

A. Net Metering customers would be compensated for any excess energy their DG facility produces and delivers to TEP with a credit on their current monthly TEP bill using the Renewable Credit Rate. Net Metering customers could carry over unused bill credits to future months if they exceed the amount of their current bill.

Q. What is the Renewable Credit Rate and how is it developed?

A. The Renewable Credit Rate is the price at which TEP will compensate customers with DG for the excess energy produced by the customer's generation facility as discussed in Carmine Tilghman's testimony.

Q. If adopted, what issues will be remedied by TEP's Net Metering tariff proposal?

A. First, eliminating the banking option for excess energy production will no longer give DG customers the impression that their excess energy can be stored on TEP's system for future use at no cost. By simply purchasing the excess energy from the customer during their billing cycle, as opposed to allowing customers to use the kWh credits at a later time, TEP will send more accurate price signals to Net Metered customers about their true energy costs.

Second, eliminating the banking option helps to partially alleviate the bypass of fixed cost recovery that occurs when customers self-generate a portion of their energy requirements. The bypass of fixed cost recovery by DG customers can be illustrated with an example.

The table below presents the average monthly fixed cost recovery and average pre-tax monthly bills using TEP's proposed rates for three types of residential customers at monthly electric usage levels of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh. The three customer types all take service under standard offer tariff R-01 and the bills in this table are calculated with the R-01 rates proposed in this application. The first case is a full-requirements customer with no DG, the second a DG customer with Net Metering and banking of excess kWh, and the third a DG customer with Net Metering and utility purchase of excess kWh as proposed in this application. The DG customers have solar photovoltaic ("PV") systems sized to produce a kWh output that would yield zero excess

kWh on an annual basis and the load profiles for each customer size are from actual TEP customer data.

Monthly Usage	R-01 Full Requirements Service	R-01 with Net Metering: Banking Excess kWh	R-01 with Net Metering: TEP Purchases Excess kWh
500 kWh per Month			
Monthly Fixed Cost Recovery	$50.74	$20.00	$41.13
Average Monthly Bill (pre-tax)	$74.16	$23.42	$37.70
Unrecovered Fixed Costs	NA	$30.74	$9.61
Monthly Bill Savings	NA	$50.74	$36.46
900 kWh per Month			
Monthly Fixed Cost Recovery	$81.20	$20.16	$51.02
Average Monthly Bill (pre-tax)	$120.86	$23.61	$44.69
Unrecovered Fixed Costs	NA	$61.04	$30.18
Monthly Bill Savings	NA	$97.25	$76.17
1,200 kWh per Month			
Monthly Fixed Cost Recovery	$104.92	$20.00	$60.36
Average Monthly Bill (pre-tax)	$156.54	$23.42	$51.66
Unrecovered Fixed Costs	NA	$84.92	$44.56
Monthly Bill Savings	NA	$133.12	$104.88
1,500 kWh per Month			
Monthly Fixed Cost Recovery	$128.65	$20.11	$62.52
Average Monthly Bill (pre-tax)	$192.10	$23.54	$53.30
Unrecovered Fixed Costs	NA	$108.54	$66.13
Monthly Bill Savings	NA	$168.56	$138.80

In this example, a residential customer on R-01 using 900 kWh per month and no DG system would pay an average of $81.20 per month in fixed costs. The fixed cost recovery in this case consists of the fixed Basic Service Charge and the variable Delivery Services-Energy charges at that level of consumption. By contrast, the same customer with a DG system that produces the same annual kWh as consumed pays an average of $20.16 per month if allowed to bank kWh produced in excess of usage at any time in order to offset consumption at a later time. This results in a fixed cost recovery shortfall of $61.04. With a $20.00 per month Basic Service Charge, this customer is paying only $0.16 per month

above the Basic Service Charge for the fixed costs associated with the generation capacity, transmission, and distribution infrastructure to serve the customer.

The same DG customer under the regime where TEP purchases the excess kWh generated as proposed in this filing pays $51.02 in fixed costs. Under TEP's proposal, the Company would recover $30.86 more of its fixed costs than under the banking scheme, but is still $30.18 short of the fixed costs recovered from the non-DG customer. Keep in mind that the $61.04 in fixed costs that is bypassed using the banking scheme, like the utility infrastructure it is paying for, does not go away. It will ultimately have to be recovered from the other customers on the system who are not Net Metering customers. Because TEP purchases the excess kWh production, there are now $30.86 less in fixed costs that must be recovered from customers without Net Metering.

Q. Customers with DG systems undertake a significant capital investment to reduce their electric bills. How would this proposal impact their savings?

A. Under this proposal, DG customers would still see significant savings on their electric bills. In the example above, the monthly pre-tax bill savings for a Net Metering customer using 900 kWh per month are reduced by $21.08, from $97.25 to $76.17. This $76.17 is still a 63% reduction in that DG customer's monthly electric bill.

Q. Will this change to TEP's treatment of Net Metering completely eliminate the shifting of fixed costs due to DG?

A. No. The adoption of the new net-metering rider, which no longer allows for energy banking, will reduce but not eliminate the subsidy. However, when combined with the proposed standard offer three-part tariff, the magnitude of cost shifts to non-DG customers will be greatly reduced.

Q. Why is TEP proposing that new Net Metering customers be required to take standard offer service on a three-part tariff?

A. As I mentioned earlier, the proposed Net Metering changes will not fully mitigate the DG cost shift. The DG customers' usage patterns and load profiles are no longer those of a full requirements customer and their rate design should be consistent with other partial requirements customers. The three-part rate design is presently approved by the Arizona Corporation Commission ("ACC" or "Commission") for TEP's partial requirement customers in the larger rate classes.

The cost shift is also increased by the fact that a majority of the fixed costs to serve residential and small commercial customers are recovered through variable energy usage charges. These usage-based charges have built-in rate tiers that charge more for usage when a customer's consumption reaches each subsequent threshold. Assuming that fixed costs can fairly and equitably be recovered primarily through volumetric rates ignores the ever increasing magnitude of the cost shift created by DG customers, as well as energy efficiency and conservation.

DG customers avoid paying a substantial portion of their fixed costs of the system by avoiding these higher consumption levels. When the energy produced by a DG system is used by the customer and netted against the energy that would be delivered by the utility, the fixed costs embedded in the variable utility charges go unrecovered. Furthermore, the recovery of these fixed costs is being avoided primarily at the higher tier rates in the inverted block rate structure.

D. Three-Part Rate Proposals.

Q. Please summarize TEP's new three-part rate proposals for residential customers.

A. For the residential class, TEP is proposing RES-D and RES-D-TOU. For RES-D, we are proposing the same $20.00 per month Basic Service Charge that we are proposing for R-01. Also, we are proposing a two-tier monthly Demand Charge with the break point at 7 kW. Billing demand will be based on the 1-hour maximum measured demand during the billing month. The Delivery Service-Energy charges have a single tier and are reduced significantly from those in R-01 to reflect the fixed cost recovery being more properly recovered through the demand charges. All other charges are identical to those in R-01. For RES-D-TOU, the Basic Service, Demand, Delivery Services-Energy, and all other charges except Base Power are the same as those for RES-D. The Base Power Charges vary by time of use.

Q. How would the proposed three-part rates impact residential customer bills?

A. The table below shows average monthly bills (pre-tax) for residential customers using an average of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh. The customers in this example are full-requirements customers taking service under R-01 and RES-D at proposed rates. The following customer examples were developed from TEP's residential customer usage data. It is evident from the comparisons presented in this table that customers at the lower end of the usage spectrum pay higher monthly bills on the three-part rate than on the two-part rate.

Bills calculated using the three-part rate will exceed bills using the two-part rate at lower levels of consumption. As usage increases, customers on the three-part tariff will have lower monthly bills.

Average Monthly Usage	Average Monthly Load Factor	Average Monthly Bill		
		R-01	RES-D	Difference
500 kWh	18.4%	$74.16	$83.51	$9.35
900 kWh	23.3%	$120.86	$121.33	$0.47
1,200 kWh	26.7%	$156.54	$147.29	($9.25)
1,500 kWh	31.5%	$192.10	$169.45	($22.65)

Q. From this information, can one conclude that residential customers with very low usage will benefit less from a three-part rate than higher usage customers?

A. No. One other piece of information in this table is the average monthly load factor for each customer profile. Load factor is a concept that indicates how a customer is using energy relative to the peak demand that the customer incurs. One commonly used definition of the load factor is the average demand over a period divided by peak demand. By this definition as average demand increases relative to peak demand, the load factor increases. It also follows that as a customer uses more energy, i.e., more kWh, for any given peak demand, the load factor increases. It is generally accepted that a higher load factor implies a more efficient use of the utility system.

The load profiles used for these bill comparisons were developed from test-year TEP residential customer load data. One trend that is evident is that higher usage customers generally have higher load factors. As shown in the table above, the lower usage customers with lower load factors see bill increases on the three-part rate. However, these bill increases are reduced and customers actually realize a positive benefit at higher usage levels and higher load factors. This occurs because the load factor is increasing not peak usage. The higher usage customers are using more kWh per kW than lower usage customers. Because the Delivery Services-Energy charges in the three-part rate are approximately 60% lower than those in the two-part rate, the benefits of the lower per kWh charges begin to take over as the load factor increases.

Q. What can one conclude from these results?

A. The three-part rate with a demand charge rewards customers with higher load factors, all else equal. More important, a three-part rate will reward customers who improve their load factor. If residential customers choose to take service on a three-part rate they will reduce their electric bills by improving their load factor or maintaining a higher load factor. As I mentioned earlier, higher load factors are consistent with more efficient use of the electric utility system. Under a three-part rate, customers receive a price signal encouraging them to improve their load factor, which benefits the customer by reducing their electric bills and benefits all TEP customers as the system is used more efficiently.

Q. Are there other ways customers can benefit from a three-part rate design?

A. Absolutely. Customers continue to have more options to save in the future when technology can help them manage and reduce demand. As a simple example, consider someone with two air conditioning units, a pool pump and an electric water heater. That person (or TEP through energy efficiency programs) could invest in systems that prevent all four appliances from coming on at one time. The units are cycled and thus the impact on the system and their demand charge is reduced as it relates to those pieces of equipment. These types of control systems are currently available and properly designed rate structures and customer education programs could lead to more installations and system benefits, by providing the proper economic incentive.

Q. Could a three-part rate structure for residential and small commercial customers encourage development of business models and customer applications aimed at reducing customers' individual demand?

A. Yes. A three-part rate structure will provide customers pricing options that could lead to earlier adoption of new energy technologies. For example, TEP and other companies will

be incentivized to combine technologies like solar panels, energy storage and demand control systems to maximize customer savings and profitability of their programs.

Q. Please summarize TEP's new three-part rate proposal for small commercial customers.

A. The small commercial three-part rate tariffs TEP is proposing are SGS-D and SGS-D TOU. We are proposing a Basic Service Charge of $30.00 per month and a two-tiered Demand Charge with a break point at 7 kW. The second tier in the GS-10 Delivery Services-Energy charges has been removed for the three-part rate and the energy charges are reduced significantly to reflect the fixed cost recovery being more appropriately recovered through demand charges. For SGS-D TOU the Basic Service, Demand, Delivery Service-Energy, and all other charges except Base Power are the same as those for SGS-D. The Base Power Charges vary by time of use.

Q. Is TEP proposing that all residential and small commercial customers take service on three-part rate tariffs?

A. No. At this time TEP is proposing three-part rate tariffs as optional for residential and small commercial customers who are not taking service under the Net Metering Rider R-15. All residential and commercial Net Metering Rider R-15 customers will be required to take service under the applicable three-part standard offer tariff.

E. Partial Requirements Customers.

Q. In your summary you state that TEP is proposing that partial requirement customers qualifying for the new Net Metering Rider R-15 must choose from one of the two proposed three-part rate tariffs applicable for their service requirement. Why is TEP proposing to require these customers to use a three-part rate tariff?

A. Simply stated, the Company's current two-part rate design options do not account for how these customers use the system and will never properly recover a fair level of fixed costs. **The two-part rates are designed to recover costs based on the average consumption levels of full-requirements customers** - and as presently designed and proposed rely on energy charges to recover fixed cost. Also as discussed above, even with the changes we are proposing to our present full requirement tariffs (higher Basic Service Charges and elimination of two residential tiers) – these new rates will continue to recover the majority of fixed cost through volumetric energy rates.

Q. Do TEP's proposed three-part rates for partial-requirements residential and small commercial customers further mitigate the DG cost shifting covered earlier?

A. Yes. The table below presents monthly fixed cost recovery and average monthly electric bills for the same four residential customer profiles that I presented earlier. The examples in this case are for a full-requirements residential customer on R-01 at proposed rates and two partial-requirements Net Metering customers, one on the proposed R-01 two-part rate and the other on the proposed RES-D three-part rate. In both of the Net Metering cases, TEP is purchasing the excess output of the DG system at the Renewable Credit Rate.

As is evident from the results in this table, the three-part rate goes a long way toward further mitigating the DG cost shift. For the 900 kWh per month customer I discussed earlier, only $10.11 per month in fixed costs is now bypassed. Furthermore, the customer is still saving $55.87 per month on their total electric bill, which is a savings of 46% from R-01 full requirements service.

Monthly Usage	R-01 Full Requirements Service	R-01 2-part Rate with Net Metering	RES-D 3-part Demand Rate with Net Metering
500 kWh per Month			
Monthly Fixed Cost Recovery	$50.74	$41.13	$55.92
Average Monthly Bill (pre-tax)	$74.16	$37.70	$52.65
Unrecovered Fixed Costs	NA	$9.61	-$5.18
Monthly Bill Savings	NA	$36.46	$21.51
900 kWh per Month			
Monthly Fixed Cost Recovery	$81.20	$51.02	$71.09
Average Monthly Bill (pre-tax)	$120.86	$44.69	$64.99
Unrecovered Fixed Costs	NA	$30.18	$10.11
Monthly Bill Savings	NA	$76.17	$55.87
1,200 kWh per Month			
Monthly Fixed Cost Recovery	$104.92	$60.36	$80.40
Average Monthly Bill (pre-tax)	$156.54	$51.66	$71.94
Unrecovered Fixed Costs	NA	$44.56	$24.52
Monthly Bill Savings	NA	$104.88	$84.60
1,500 kWh per Month			
Monthly Fixed Cost Recovery	$128.65	$62.52	$83.91
Average Monthly Bill (pre-tax)	$192.10	$53.30	$74.93
Unrecovered Fixed Costs	NA	$66.13	$44.74
Monthly Bill Savings	NA	$138.80	$117.17

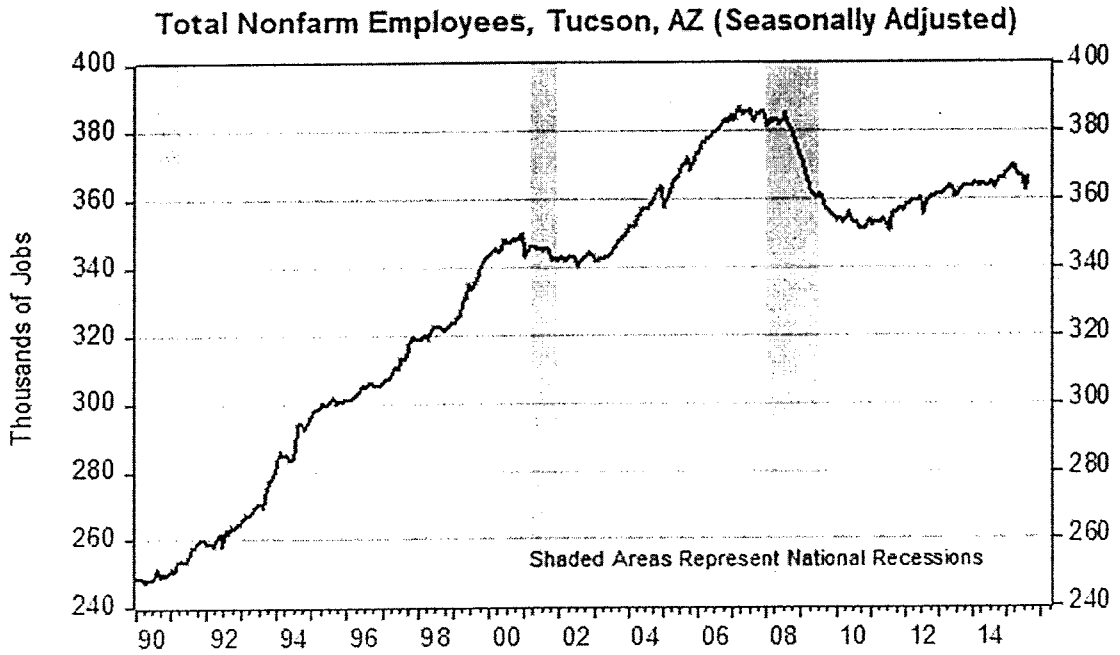
Q. You showed how residential DG customers with Net Metering will continue to see significant bill savings on the proposed three-part tariff. Are there any other opportunities for these customers to lower their monthly bills and realize added savings?

A. Yes. The incentive still exists for DG customers to reduce bills by decreasing billing demand or energy usage. However, because volumetric energy charges embodied in the three-part rate are much lower than those in the two-part rate, the potential savings from reduced energy use are not as high as those from reducing peak demand. Regardless, peak demand reductions that are greater than energy use reductions on a percentage basis will yield a higher load factor and provide benefits to the customer and the electric system.

F. Economic Development Rider.

Q. Why is TEP proposing an Economic Development Rider in this proceeding?

A. The TEP service territory has been very slow to recover from the economic downturn post 2007, which has resulted in lower kWh sales and thus fewer sales units to spread the fixed cost of the system and more cost being allocated to the remaining customers. I've already discussed the declining sales in the TEP service territory and those impacts on customers' bills. The Tucson area has also been very slow to recover from an employment perspective as well. As shown in the chart below the Tucson area has yet to get back to employment levels that existed in 2006.



Souce: U.S. Department of Labor

Q. Do you believe an Economic Development Rider could assist business growth in TEP's service territory?

A. Yes. The inclusion of this additional incentive along with the rate design changes discussed in TEP witness Craig Jones' testimony, reducing rates for the business classes, should put the TEP service territory in a better competitive position to attract and expand business load. This would be beneficial to the entire customer base and the State of Arizona.

Q. Please describe TEP's proposed Economic Development Rider.

A. TEP is proposing to offer Rider 13, Economic Development Rider ("EDR") to current or potential commercial and industrial customers that meet certain economic development criteria within the TEP service areas. The EDR will be available to customers with a projected peak demand of 3000 kW or more and a load factor of 75% or higher. The EDR will be available for five years from the effective date and provides qualifying customers with discounts on monthly electric bills according to a declining schedule over a five-year period at which point the discount is terminated. The discounts will apply only to the qualifying additional loads from new or expanding business operations and total program participation will be limited to 200 MW of applicable load.

Q. What are the qualifying criteria for the proposed EDR?

A. In addition to demand and load factor, customers must meet several criteria to qualify for the proposed EDR. First, potential EDR customers must qualify for at least one of two Arizona state tax credit programs designed to promote business recruitment, retention, and expansion. Arizona's Quality Jobs Tax Credit (A.R.S. § 41-1525) program provides a tax credit for net increases of at least 25 full-time employees residing in the state and hired in qualified employment positions. The Qualified Facility Tax Credit (A.R.S. § 41-1512) program provides for a refundable tax credit for qualifying capital investment in a

manufacturing facility that creates new jobs, of which at least 51 percent pay a wage that equals or exceeds 125 percent of the median state wage. Also, the applicant must provide health insurance coverage for all net new full-time positions and cover at least 80 percent of new employees' health care premiums.

Q. Please describe the discounts available to customers qualifying for the proposed EDR.

A. All provisions, charges, and adjustments in the participants' applicable standard offer retail rate schedule will continue to apply. The proposed EDR will apply discounts on electric bills specific only to the qualifying additional load of participating customers. Economic Development is defined as new or expanding business operations that build new facilities. The discounts for Economic Development will be 20% in Year 1, declining to 2.5% in Year 5, and terminating after Year 5. Economic Redevelopment is defined as new or expanding business operations that occupy existing vacant facilities. The discounts for business expansion that qualifies as Economic Redevelopment will be 30% in Year 1, declining to 5% in Year 5, and zero after Year 5.

III. REVENUE REQUIREMENT.

A. Requested Revenue Increase.

Q. What is the overall revenue increase being requested by TEP?

A. TEP is requesting a $109.5 million increase to test year adjusted non-fuel revenues, which when compared to test year adjusted retail revenue is a 12.0% increase. However, that is not a complete description of the proposed increase when compared with rates presently being paid by customers; that include a PPFAC rate of $0.00682 per kWH that went into effect in April 2015. If the test year adjusted revenues reflected a full year with the present

PPFAC rate in effect the increase would be offset by a proposed $42.2 million reduction in fuel. When comparing the proposed revenues to test year adjusted revenues with the present PPFAC applied for the entire period, TEP's request would increase revenue by approximately $67.3 million, or 7.1%.

Summary of Requested Retail Rate Impact		
	Sch. A	
(in Millions)	Adjusted Test Yr. W/ Proposed Fuel ($303.9M)	Adjusted Test Yr. Sales W/ Current Fuel Rates ($346.1M)
Retail Revenue	$ 909.3	$ 951.5
Non-Fuel Increase	$ 109.5	$ 109.5
Less:		
Fuel Reduction (to get to $303.9M)	$ -	$ (42.2)
Net Increase in Retail Revenue	$ 109.5	$ 67.3
Percentage Increase	12.0%	7.1%
Presented another way:		
Proposed Retail Revenue	$ 1,018.8	$ 1,018.8
Less:		
TY Retail Revenue w/alt. PPFAC rates	$ (909.3)	$ (951.5)
Net Increase	$ 109.5	$ 67.3
Percentage Increase	12.0%	7.1%

B. **Summary of Schedules.**

1. **"A" Schedules.**

Q. Please describe the information contained on summary Schedule A-1.

A. Schedule A-1 provides a summary of the increase in revenue requirement that the Company is requesting. Lines 1 through 8 of Schedule A-1 present the data used in determining the Company's revenue requirement. The data presented pursuant to three valuation methodologies: (1) original cost rate base ("OCRB"); (2) reconstruction cost new less depreciation ("RCND"); and (3) fair value rate base ("FVRB"). FVRB is determined by adding together OCRB and RCND rate base amounts and dividing that total by two. This gives equal weight to both methods when determining the fair value amount. This method of determining the fair value is consistent with prior Commission practice.

Q. Please describe the information contained on Schedule A-2.

A. Schedule A-2 presents a summary of the results of operations for the Test Year and the two prior calendar years, compared with the projected year. Lines 1-16 of Schedule A-2 set forth the summary of operations for the Test Year. Schedule A-2 also presents projected results of operation for the year ending December 31, 2015 under the headings "present rates" and "proposed rates".

Q. Please describe the information contained on Schedule A-5.

A. Schedule A-5 presents a summary of changes in financial position for the Test-Year and the prior two calendar years. This schedule also includes the projected financial position as of June 30, 2016.

2. "B" Schedules.

Q. Please describe the information on Schedule B-1.

A. Schedule B-1 provides a summary of the company's OCRB and RCND rate base as of the end of the Test-Year, including the related pro forma adjustments to rate base. Rate base is comprised of net utility plant, certain regulatory assets and working capital, with deductions from rate base for accumulated deferred income taxes ("ADIT"), customer advances for construction, and customer deposits. The schedule also reflects the adjusted OCRB and RCND rate bases for the Total Company and what is jurisdictional to the Commission.

Q. Please explain briefly the information contained on Schedule B-2, B-3 and B-4.

A. Schedule B-2 shows the pro forma adjustments to the OCRB. The information presented includes the actual per-book balances (as prepared under Generally Accepted Accounting Principles or "GAAP") and the end of the Test-Year, pro forma adjustments, and the adjusted balances on a Total Company and Commission jurisdictional basis. Schedule B-3 provides the same detail by functional account classification as shown on Schedule B-2, except that it is shown on an RCND basis. Schedule B-4 shows the plant in service accounts on a RCN and RCND basis.

Q. Please explain briefly the terms RCN and RCND.

A. The ACC has defined RCND in Title 14 as:

> An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the Test-Year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the

accounts of the public service corporation, shall be increased to a reconstruction new basis. (A.A.C. R14-2-103(A) (3) (n)).

The RCN is the estimated cost of constructing the company's property in today's cost levels; this is done through a trending study. RCND refers to the net amount after deducting accumulated depreciation and amortization.

Q. Please explain briefly the basis for the determination of the RCND rate base.

A. Plant in service and customer advances for construction reported at RCN are summarized from the results of a detailed plant cost trending study. The accumulated depreciation and ADIT reported on a RCN basis have been computed by multiplying the corresponding original cost balance by a ratio, the numerator of which is gross RCN of depreciable plant, and the denominator of which is gross original cost of depreciable plant. All other rate base elements are reflected at original cost.

Q. Please describe the plant cost trending study.

A. The trending study was prepared to establish an index number that represents a ratio between the cost of an item at its in-service date ("or "Vintage"), and its cost at a base period. The indices are applied to the Company's original cost to estimate the reconstruction or reproduction cost at current cost levels. For example, the RCN value for 2009 Vintage assets in Account no. 362, Distribution plant – Station Equipment was computed as follows:

2014 Index Value Acct 362 / 2009 Index Value

=2014 Cost Index for Acct 362

Original Cost of 2009 vintage assets in Acct. 362 X 2014 Cost index for Acct 362

=RCN for Acct 362 (current costs)

For most accounts, the Handy – Whitman Index of Public utility Construction Costs for the Plateau Region was employed (based on the most recently available index numbers). For plant accounts 303, 391, 393, 394 and 398 the "Marshall Valuation Service cost Index" was used. For plant accounts 392, 395, 396 and 397, the Bureau of Labor Statistics producer price index was used.

Once the RCN value has been established it is then multiplied by a net book value percentage. The net book value percent is simply the original cost less accumulated depreciation divided by the original cost.

For example, assume the Company has distribution station equipment with an original cost of $100,000, and accumulated depreciation of $50,000. The original cost less accumulated depreciation would be $50,000 ($100,000 - $50,000). Also, assume the Vintage year is 2009 and has a RCN value of $117,500. Multiplying the RCN by the net book value percent yields RCND of $58,750 ($117,500 x 50%=$58,750).

Q. What is the Handy – Whitman Index?

A. It is an index of public utility construction costs that has been published continuously since 1924 by Whitman, Requardt and Associates of Baltimore, Maryland. The Handy – Whitman Index is a well-recognized, widely used and generally accepted method for measuring differences in property values for insurance and other purpose, including the valuation of public utility property for rate case purposes.

The Handy – Whitman Index is comprised of index values for various accounts prescribed by the FERC Uniform System of Accounts and for six geographical divisions

of the country, including the Plateau Division, in which Arizona and New Mexico are located. These index numbers result from a comparison of the current prices of materials, labor, and equipment to prices in a base year. Index values are determined for each year as of January 1 and July 1.

The index values are used to determine cost trend factors, which are then applied to know original costs of similar plant and property to determine the fluctuation in cost between the date of installation and the date of valuation.

Q. What is the Marshall Index?

A. The Marshall Index, prepared by the firm of Marshall & Swift, is an index of construction cost trend valuations. It was used in the development of costs reported in the RCND Study for those plant accounts not reported by Handy – Whitman. The Company used the Bureau of Labor producer price index when neither the Handy – Whitman nor the Marshall indices were available.

Q. Please explain Schedule B-5.

A. This Schedule summarizes the computation of the allowance for working capital that the Company is requesting for inclusion in rate base in this rate case. I explain these computations later in my testimony.

Q. Why are the original costs and RCND costs of working capital the same in Schedule B-5?

A. They are the same because the original costs are at current prices or have been adjusted to current prices, meaning they have not been significantly affected by inflationary factors.

3. "C" Schedules.

Q. Please explain Schedule C-1.

A. Schedule C-1 shows the Income Statement as prepared in accordance with GAAP for the twelve months ending June 30, 2015, the Test-Year in the case. It also summarizes the effect of proposed pro forma adjustments made to operating revenues and expenses, and the resulting adjusted net operating income.

Q. What is the purpose of Schedule C-2?

A. Schedule C-2 presents the detailed pro forma adjustments that reflect the full annual impact of operation changes, annualizations, normalizations, and other adjustments made to revenues and expenses. I will discuss these adjustments in detail later in my testimony.

Q. What is the purpose of Schedule C-3?

A. Schedule C-3 calculates the revenue conversion factor. This recognizes that the Company will need to "gross up" the net income deficiency to account for income taxes and additional bad debt.

C. Pro Forma Adjustments.

Q. Please explain what a Pro Forma Adjustment is?

A. Public utility rates are based on the prudently incurred costs of providing safe, reliable service. The Company's revenue requirement is based on an historical Test-Year that reflects a level of operating revenues, expenses and net plant investment that occurred during that period. Because a historical Test-Year is being used, it creates a critical need to adjust the recorded Test-Year for actual occurrences not expected to recur or for events

that are expected to occur but did not exist during the Test-Year. Such adjustments may be in the form of eliminations, annualizations or normalizations.

Q. What is an Elimination Adjustment?

A. Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service; thus, not eligible for reflection in revenue requirements.

Q. What is an Annualization Adjustment?

A. Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. Annualization adjustments recognize that certain events that happen in a Test-Year are ongoing and must be spread over the entire Test-Year period. Examples are annualizations of revenues to reflect end-of-Test-Year customer levels and annualization of depreciation expense to reflect end-of-Test-Year plant investments and any proposed new deprecation rates. The Annualization adjustment synchronizes the Test-Years investments, revenue and cost relationships.

Q. What is a Normalization Adjustment?

A. Normalization adjustments reflect that the recorded Test-Year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequently than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the Test-Year may not be viewed as "normal," thus requiring a restatement for ratemaking purposes. Normalization adjustments are made in such instances when a Test-Year level of revenues or expenses is not representative of what would be expected on an on-going

basis. Examples in this case include the adjustment for bad debt expense, the overtime factor implicit in the payroll adjustment, and the adjustment to normalize the level of outside legal expense.

D. Rate Base Pro Forma Adjustments.

1. Springerville Leasehold Improvements.

Q. Please explain the Springerville ("SGS") Leasehold Improvements Adjustment.

A. Over the years, TEP has made numerous capital improvements to SGS Unit 1; these improvements have been made in order to keep the facilities in good operating condition and to improve operating efficiencies at SGS as it provided service to our customers. This adjustment is necessary to continue the recovery of the remaining book value of those improvements that have been reclassified to a regulatory asset at the termination of the lease. The details of this request are in the direct testimony of TEP witness Kentton Grant.

Q. How were SGS leasehold improvements treated in TEP's last rate case?

A. The improvements were included in rate base at their original cost, net of accumulated amortization. Amortization of the leasehold improvements was also included in the Company's non-fuel revenue requirement using a 10-year amortization period.

Q. Is TEP requesting a change to the amortization period approved in the previous rate case?

A. No. TEP is requesting to continue the amortization period established and approved in the last case.

2. Springerville Unit 1 Lease Equity.

Q. Please explain the SGS Unit Lease Equity adjustment.

A. TEP is requesting the recovery of its investment in the SGS Unit lease equity originally made in 2006. The adjustment is necessary to bring the book value as of the end of the test year up to the unrecovered net investment of $42.7 million. The details of this request are in the direct testimony of TEP witness Kentton Grant.

3. Asset Retirement Obligation.

Q. Please explain the Asset Retirement Obligation ("ARO") Adjustment.

A. This adjustment is necessary to remove the balances of ARO assets reported in Plant in Service. ARO assets exist only for those assets where there is a *legal* obligation to physically remove the assets at the end of their useful lives. In this rate case, the expected costs to remove the related assets from Plant in Service are implicit in the Negative Net Salvage component of our depreciation rates, and used in the preparation of the depreciation annualization adjustment.

Q. Is this adjustment consistent with the treatment of ARO in TEP's last rate proceeding?

A. Yes.

4. Post-Test-Year Plant.

Q. Please describe your proposal for including Post Test-Year Plant.

A. TEP has adjusted its ACC jurisdictional rate base to include approximately $51.8 million of used and useful plant additions that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2015. The post test-year amount being requested only reflects the portion of those facilities invested in prior to the end of the test year. These projects will be benefiting customers by the time new rates are effective.

Q. Has the Commission allowed the use of Post Test-Year Plant before?

A. Yes. The Commission approved including Post-Test-Year Plant for UNS Electric in the 2013 UNS Electric Rate Order. The Commission has also allowed Post-Test-Year Plant in numerous other cases, including: TEP in Decision No. 73912 (June 27, 2013); Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012), Rio Rico Utilities, Inc., in Decision No. 67279 (October 5, 2004); Arizona Water Co., in Decision No. 66849 (March 19, 2004); and Bella Vista Water Co., Inc., in Decision No. 65350 (November 1, 2002).

Q. What are the benefits of including Post Test-Year Plant in rate base?

A. It more closely aligns the recovery of costs with the benefits that are currently being provided to existing customers. It also lowers the cost to customers by limiting the amount of Allowance For Funds Used During Construction ("AFUDC") charged to the assets, thereby reducing the future depreciation and carrying costs associated with this plant. Additionally, the timely recovery of costs necessary to maintain a safe, reliable electric system is necessary to mitigate larger rate impacts that result from the use of historic test years combined with little to no increase in sales.

Q. Is this adjustment consistent with the treatment of Post Test-Year investments in TEP's last rate proceeding?

A. Yes.

5. Post-Test-Year Plant Renewables.

Q. Please describe your proposal for including Post Test-Year Plant Renewables.

A. TEP has adjusted its ACC jurisdictional rate base to include approximately $20.8 million of used and useful plant additions that have been, or are expected to be, placed in service between July 1, 2015 and December 31, 2016. The post test-year amount being requested reflects the portion of the facilities expected to be in service prior to the rate being established in this proceeding going into effect. This adjustment extends out an additional 12 months beyond the non-renewable post-test-year cut-off. This allows for the reflection of these renewable asset investments approved through the REST application process to be recovered through base rates as opposed to being recovered through the REST tracker. These projects will be benefiting customers by the time new rates are effective.

Q. Is this adjustment consistent with the treatment of Post Test-Year Renewable investments in TEP's last rate proceeding?

A. Yes.

6. Delayed Unitization.

Q. Please explain the Delayed Unitization Adjustment.

A. The adjustment for Delayed Unitization represents plant additions that were used and useful as of the end of the test year, but not part of the Balance in FERC Account 106,

Completed Construction not Classified, as of June 30, 2015. The Delayed Unitization adjustment represents additional costs incurred on previously unitized projects and projects that were completed as of June 30, 2015 that became known subsequent to test-year-end. Because these projects are used and useful, they should be included as part of test year rate base.

Q. Is this adjustment consistent with the treatment of Delayed Unitizations in TEP's last rate proceeding?

A. Yes.

7. Working Capital.

Q. What is working capital?

A. Working capital is generally viewed as investor funding of day-to-day operating costs, in excess of the balance of net utility plant reflected in rate base that is required for the provision of utility service.

Q. What are the items of working capital for which the Company requests a return?

A. The components of working capital that the Company is requesting be included in rate base are:

(i) Fuel Inventory;

(ii) Materials and Supplies;

(iii) Prepayments; and

(iv) Cash Working Capital.

As more fully explained later in my testimony, the amounts requested for rate base inclusion for fuel inventory, materials and supplies, and prepayments are based on test-

year recorded balances, adjusted to reflect normal levels. The cash working capital component was determined by the use of a lead-lag study.

Q. Please explain the Working Capital adjustment.

A. The Working Capital adjustment was computed in two parts. As indicated on page 2 of Schedule B-5, the first piece adjusts the recorded end-of-test-year balances for Fuel Inventory to reflect the targeted inventory day level as recommend by Staff in a prior rate case. Materials and Supplies, and Prepayments are adjusted to reflect the 13-month average balance, in recognition of the variability in the monthly balances of the accounts. These treatments are consistent with the treatment of such accounts in prior rate cases.

The second part of the Working Capital adjustment is the reflection in rate base of a measure of Cash Working Capital, developed through the preparation of a comprehensive lead-lag study.

Q. What is Cash Working Capital?

A. The receipt of customer revenues for the provision of service, and the disbursement of cash for the payment of the various costs of providing service, rarely occur simultaneously. This is the fundamental consideration underlying the concept of Cash Working Capital. Cash Working Capital is generally viewed as the component of working capital that represents the amount of invested cash required to pay day-to-day operating expenses incurred in rendering service to customers. It may either increase or decrease rate base. If the computation of Cash Working Capital produces a positive result, then it indicates that there is an additional investment for which a return is warranted. Thus, that amount is added to rate base. If the computation produces a negative result, then it implies non-investor funding of Cash Working Capital, requiring a

rate base deduction. In developing this adjustment, a comprehensive lead-lag study was prepared.

Q. What is a lead-lag study?

A. A lead-lag study is a detailed analysis of the dynamic movement of funds throughout the organization, between the receivable and payable balance sheet accounts and related revenues and expenses that are reflected in the operating income component of revenue requirements. The method is generally viewed as the most accurate measure of Cash Working Capital. The Commission has stated a clear preference for the use of lead-lag studies in support of requested cash working capital amounts reflected in rate base.

The focal point of all lead-lag studies is the "point of service". This is the instant in time at which customers receive service and, coincident therewith, the utility incurs the cost of providing that service. A lead-lag study measures the average length of time between the provision of service and the ultimate receipt of payment from the customer ("revenue lag"). The result is compared with the average length of time between the point at which the utility incurs a cost of providing that service and the date upon which it makes the related cash disbursement ("payment lead" if payment precedes the cost benefit, or "payment lag" if the payment occurs after the cost benefit). Cash Working Capital reflects the effect on costs of service of the difference between the revenue lag and payment leads or lags.

As may be seen on page 3 of Schedule B-5, a lead-lag study computes the Cash Working Capital associated with each component of cost of service. The revenue lag is constant for all cost categories. The various major expenses are analyzed separately for purposes of developing a specific payment lead or lag. Once the applicable expense lead or lag is known, it is compared with the revenue lag to determine the net lead or lag for that study

category. After dividing the net lead or lag by 365 days to arrive at an annual percentage factor, the result is multiplied by the corresponding adjusted test-year expense amount to quantify the Cash Working Capital requirement associated with that cost of service item. Consistent with past Commission policy, the effect of non-cash expenses such as depreciation and deferred income taxes are reflected in the study at a zero requirement.

Q. How was the average revenue lag computed?

A. The revenue lag is comprised of three distinct parts: the service lag, the billing lag, and the customer payment lag.

The service lag is measured from the midpoint of the period of service to the end of the period, the date upon which meters are read. A key underlying assumption is that service is taken uniformly throughout the period. With each customer being billed under 12 monthly billing cycles during the year, the average service lag is computed as 15.21 days [365 days / (12 X 2)].

The billing lag is typically measured from the meter read date to the date customer bills are prepared and balances entered into accounts receivable. The billing lag was computed based on actual meter read dates and bill mailing schedules used by TEP during the test-year.

The customer payment lag is measured from the point at which the customer bill enters accounts receivable to the date that either a payment is received or the account is written off as uncollectible. The lag was determined by computing the average accounts receivable turnover for the 12 months during the test-year. The accounts receivable turnover factor is calculated by the average daily balance of accounts receivable over the average daily revenues billed

Q. How were the payment leads and lags computed?

A. The payment leads and lags were developed based on analyses of actual payment history, contractual and statutory payment dates, and samples of expenditures.

Q. What was the overall result of the lead-lag study?

A. The study showed that there was negative Cash Working Capital and a corresponding decrease was made as a pro forma adjustment to rate base.

Q. Are these adjustments consistent with the treatment of Working Capital in TEP's last rate proceeding and approved by the Commission?

A. Yes.

E. Revenue and Expense Pro Forma Adjustments.

1. Lost Fixed Cost Revenue.

Q. Please explain the Lost Fixed Cost Revenue Adjustment.

A. This adjustment removes all revenues collected under the Lost Fixed Cost Recovery mechanism. These revenues are not collected as part of base rates, so they must be excluded from Test-Year revenues in order to calculate new base rates.

2. Environmental Cost Adjustor.

Q. Please explain the Environmental Cost Adjustor Adjustment.

A. This adjustment removes all revenues collected under the Environmental Cost Adjustor mechanism. These revenues are not collected as part of base rates, so they must be excluded from Test-Year revenues in order to calculate new base rates.

3. Renewable Energy Standard & Tariff ("REST") and Demand-Side Management ("DSM").

Q. Please explain the REST and DSM Adjustment.

A. This adjustment excludes from Test-Year revenue and expense activity directly related to the Renewable Energy Standard & Tariff ("REST") and Demand-Side management ("DSM") adjustor programs. These programs have separate funding mechanisms and should thus be excluded from Test-Year revenue and expenses in the process of establishing retail base rates.

4. Non-Retail & Non-Recurring Revenue.

Q. Please explain the Non-Retail Revenue and Non-Recurring Revenue adjustments.

A. This adjustment is necessary to exclude revenues collected during the test year that will not reoccur in the years when new rates will be in effect.

5. Springerville Units 3 & 4.

Q Please explain the Springerville Units 3 & 4 adjustment

A. TEP operates units 3 & 4 of the Springerville Generating Station on behalf of the unit owners, Salt River Project and Tri-State Generation and Transmission Association. Therefore, it is necessary to remove all expenses and associated reimbursements related to operating those facilities on their behalf. The result of this adjustment is to assure that the customers of TEP are not incurring any cost related to those operations and receive the benefit of administrative, common and other cost allocated to those facilities.

Q. Is this adjustment consistent with the treatment of Springerville Units 3 & 4 revenue and expenses in TEP's last rate proceeding?

A. Yes.

6. Sales of SO2 Allowances.

Q. Please explain the Revenues on Sale of SO2 Allowances Adjustment.

A. The Company is allowed to retain 50% of the revenues from the sale of SO2 allowances. The balance is credited to the PPFAC for the benefit of retail customers. The adjustment is necessary to remove the 50% being retained by the Company from test-year results.

Q. Is this adjustment consistent with the treatment of Sales of SO2 Allowances in TEP's last rate proceeding?

A. Yes.

7. Sales for Resale.

Q. Please explain the Sales for Resale Adjustment.

A. These adjustments are necessary because the revenue associated with short-term wholesale sales is recorded and 100% of that is also booked as a PPFAC regulatory liability (ultimately to credit customers through the PPFAC). There are also expenses associated with producing those revenues and those are expensed as incurred. Without adjustment the profit on those sales would flow through the income statement. Therefore an adjustment is made to the Company's actual books to bring the expenses up to the revenue level.

By making that adjustment, there is no operating income from wholesale transactions.

That "profit" is maintained in the PPFAC regulatory liability, which is then credited to customers through the PPFAC process. So the PPFAC rate reflects any profit in wholesale transactions and reduces the ultimate cost to customers. Therefore, we take the cost and the revenue out of the test year (which zero themselves out) because the profit on short-term wholesale transactions is already reflected in the PPFAC rates, and the total average cost of PPFAC eligible expenses being passed along to customers.

In addition long-term wholesale sales must be excluded from jurisdictional revenue as they are not related to the recovery of cost within jurisdictional base rates.

Q. Is this adjustment consistent with the treatment of Sales for Resale in TEP's last rate proceeding?

A. Yes.

8. Power Supply Management Agreements.

Q. Please explain the Power Supply Management Agreement Adjustment.

A. The Company provides coordination of wholesale energy supplies, energy scheduling and management of ancillary services for non-retail load within the TEP control service area. The adjustment is necessary to remove the revenues associated with these agreements, as well as the proportional cost associated with providing these services. By providing these services, TEP is reducing the cost of power supply management to its retail customers.

Q. Is this adjustment consistent with the treatment of Power Supply Management Agreements in TEP's last rate proceeding?

A. Yes.

9. Base Cost of Fuel & Purchased Power.

Q. Please explain the Base Cost of Fuel & Purchased Power Adjustment.

A. The adjustment is necessary to insure that the fuel, purchased power and purchased transmission costs that are eligible to be reconciled through the PPFAC process ("PPFAC-eligible costs") are equivalent to the revenues reflected in TEP's filing – and thus have no incremental effect on adjusted operating income in this case.

The adjustment is establishing the average base cost of fuel, purchased power and purchased transmission being requested within retail rates. The projected rate is being supported by and explained in Company witness Michael Sheehan's Direct Testimony. This rate was applied to customer-annualized and weather-normalized sales to come up with the amount of PPFAC-eligible costs and revenue to be included within TEP's filing. This represents TEP's best present estimate of the average per-kWh cost of PPFAC-eligible costs to be charged to customers when the rates established in this proceeding go into effect.

Q. Is this adjustment consistent with the treatment of Base Cost of Fuel & Purchased Power in TEP's last rate proceeding?

A. Yes. The resulting outcome is consistent with prior treatment and approval. In past filings this was an incremental adjustment to test year levels after removing revenues and cost associated with non-jurisdictional activity. In this filing TEP has simplified the adjustment in its cost of service model, by simply removing all jurisdictional and non-jurisdictional revenue and expenses related to fuel, purchased power & purchased transmission incurred during the test year – and replacing it with the entire pro-forma jurisdictional level. The end result is the same, just a bit easier to follow in the work papers and supporting materials.

10. Springerville Unit 1.

Q. Please explain the Springerville ("SGS") Unit 1 Adjustment.

A. As explained in the direct testimony of Company witness Kentton Grant, TEP has become the owner of a 49.5% undivided interest in Springerville Unit 1. However, TEP has all the cost attributable with operating 100% of the unit included in its test-year unadjusted expenses. This adjustment is necessary to remove those cost attributable to the other 50.5% of SGS Unit 1.

The adjustment doesn't include the reduction of test year property tax expense or depreciation. These amounts are removed from TEP's retail cost of service in those individual adjustments, by excluding the 50.5% portion of SGS Unit 1 from the plant values being used to calculate those pro forma levels.

11. Overhaul & Outage Normalization.

Q. Please describe the Overhaul and Outage Normalization Adjustment.

A. Generating overhauls are quite costly and do not occur at regular annual intervals; thus, the maintenance expense recorded in any given year is not representative of an average annual cost. This adjustment is intended to reflect in test-year maintenance expense a normal annual level of plant overhaul and outage costs. The adjustment includes an estimated recurring level of outage expense for the newly acquired Gila River facility and that amount is discussed in the direct testimony of Company witness Michael Sheehan. In addition, the adjustment excludes cost related to the 50.5% share of SGS unit 1 not owned by TEP and San Juan Unit 2, scheduled to be non-operational by the end of 2017.

Q. How was the adjustment calculated?

A. As was done in a similar adjustment filed in the last TEP rate case, this adjustment reflects the actual frequency and incremental cost of major and minor plant overhauls at each generating unit during recent years and forecasted for future years. This adjustment also excludes outage expenses related to San Juan Unit 2, which will no longer be serving retail customers after the calendar year 2017. With that data, a normal annual cost level was computed, with the adjustment being the difference between that amount and such costs recorded during the test year.

Q. Is this adjustment consistent with the treatment of Overhaul and Outage Normalization in TEP's last rate proceeding?

A. Yes.

12. Rate Case Expense.

Q. Please explain the Rate Case Expense adjustment.

A. TEP is estimating that it will incur incremental outside services rate case expense in this proceeding. TEP is requesting over a period of three years, recovery of the excess of these costs over test-year recorded rate case amortization expense.

Q. Can this cost estimate be revised and updated prior to the Commission's final decision in this case?

A. Yes. A majority, if not all, of these costs will be known and measureable prior to the closure of the docket in this case and can be revised prior to the final decision being rendered.

13. Injuries and Damages Expense.

Q. Please explain the Injuries and Damages Expense Adjustment.

A. The Injuries and Damages Expense adjustment normalizes the test-year expense to reflect the average annual expense.

Q. Is this adjustment consistent with the treatment of Injury and Damage Expense in TEP's last rate proceeding?

A. Yes.

14. Membership Dues.

Q. Please explain the Membership Dues Expense adjustment.

A. This adjustment removes the portion of membership dues paid to Edison Electric Institute for legislative advocacy, and other dues paid to organizations that have been voluntarily excluded from pro forma operating expenses for purposes of this rate case.

15. Bad Debt Expense.

Q. Please explain the Bad Debt Expense Adjustment.

A. Bad Debt Expense is adjusted to a level reflective of final, pro forma weather-normalized, customer-annualized test-year operating revenues, and the average percentage of bad debt expense experienced during the past three years.

Q. Is this adjustment consistent with the treatment of Bad Debt Expense in TEP's last rate proceeding?

A. Yes.

16. Asset Retirement Obligation Expense.

Q. Please explain the Asset Retirement Obligation Expense Adjustment.

A. Consistent with the removal of ARO assets from rate base, as previously described, this adjustment removes from test-year operating expense the corresponding ARO depreciation and accretion expense. Estimated asset removal costs are now included as Negative Net Salvage in the new depreciation rates proposed by Dr. White and used in the depreciation annualization adjustment.

17. Springerville Common Facilities Lease.

Q. Please explain the Springerville Common Facilities Lease adjustment.

A. This adjustment is necessary to reflect the capital lease associated with the Common Facilities at Springerville still remaining as an operating expense – based on the levelized annual lease expense. This adjustment is consistent with the treatment of this lease in TEP's prior proceedings and required by Commission rule, which does not allow for rate base treatment of capital leases.

18. TEP Headquarters - Retail Space.

Q. Please explain the TEP Headquarters – Retail Space Adjustment.

A. With respect to the unoccupied retail space (approximately 12,000 square feet) at the Company's headquarters; TEP is including an equivalent rental amount of $250,000. This amount is being included as a dollar-for-dollar reduction to the jurisdictional cost of service. The proposed adjustment is in accordance with Section 20.1 of the Settlement Agreement approved in TEP's last general rate proceeding, Docket No. E-01933A-12-0291.

19. Credit Card Processing Fees.

Q. Please explain the Credit Card Processing Fees Adjustment.

A. The Company is proposing to include the majority of the cost associated with providing credit card payment service within its cost of service. Presently, 100% of third-party transactions fees associated with credit card payments are paid directly to the third-party vendor by the customer making the payment. TEP is requesting to reduce those costs presently charged to credit card paying customers to $1.00 per transaction, limited to one transaction per month for up to $700. Therefore a pro forma adjustment is necessary to include the remaining cost of providing this service in test year expense levels. The details of this proposal and why TEP is requesting such a policy change are explained in the Direct Testimony of TEP witness Denise A. Smith.

Q. Does this conclude your testimony?

A. Yes.

Exhibit DJD-1

Line	Utility	Service Characteristics	Demand Interval	Ratchet	Monthly Minimum	Customer Charge	Demand Charge (per kW, except where kVA indicated)							
								Seasonal		Seasonal Time of Use				
										On Peak		Off Peak		Max
							Year round	Summer	Winter	Summer	Winter	Summer	Winter	Demand
1	Alabama Power	Single Phase	15 min	None	Base+Demand Charge	$14.50	$ 1.50							
2	Alaska Electric Light and Power Company	Single Phase	Not specified	None	Customer Charge	$11.49		$ 11.11	$ 6.72					
		Single Phase				$27.00								
3	Albemarle Electric Member Corp	Three Phase	15 min	None	Facilities Charge	$54.00				$	13.50			$ 2.25
4	Arizona Public Service Co. - APS	Single Phase	60 min	None		$16.90				$ 13.50	$ 9.30			
5	Black Hills - South Dakota	Single Phase	15 Min	None	Customer Charge	$13.00								$ 8.10
6	Black Hills - Wyoming	Single Phase	15 Min	None	Customer Charge	$15.50	$ 8.25							
		Single Phase				$30.00								
7	Carteret-Craven Electric Member Corp	Three Phase	15 min	None	Customer Charge	$57.30				$	11.95	$ 9.95	$ -	
		Single Phase				$32.00								
8	Central Electric Membership Corporation	Three Phase	15 min	None	Facilities Charge	$58.00				$	8.25	$ 7.25	$ 3.15	
9	Central New Mexico Electric Coop., Inc			None	Customer Chage	$18.75	$ 10.00							
10	Consolidated Electric Coop		Not specified	None	Not specified	$25.00	$4.50/kW above 30kW							
		Premanant resident				$17.50								
11	Delaware County Elec Coop Inc	Second home	15 min	None	Service Charge	$22.50	$1.00/kVA above 10 kVA							
12	Duke Energy Carolinas, LLC	Single/Three phase	30 min		Facilities Charge	$13.38				$	7.77	$ 3.88	$ -	
13	Duke Energy Carolinas, LLC		30 min	None	Facilities Charge	$13.38	$ 1.78							
14	Duke Energy Carolinas, LLC		30 min	None	Facilities Charge	$13.38	$ 1.48							
		Single Phase				$14.13								
15	Duke Energy North Carolina	Three Phase	15 min	None	Customer Charge	$22.84		$ 4.97	$ 3.69					
16	Duke Energy Ohio	Single	15 min	Yes	Customer Charge	$6.00								
		Single Phase				$9.60								
17	Duke Energy South Carolina	Three Phase	15 min	None	Facilities Charge	$18.60		$ 5.20	$ 3.89					
18	Edgecombe-Martin County E M C			None		$31.00				$	8.75	$ 8.00	$ -	
19	Fort Collins	Single Phase	15 min	None	Customer Charge	$5.07	$ 2.26							
20	Georgia Power	Single/Three phase	30 min	None	Service Charge	$10.00	$ 6.53							
21	Greenville NC (as of Aug 2015)		15 min	None	Facilities Charge	$19.47	$ 7.94							
		Single Phase				$15.00	$1.00/kVA for transformer above 25 kVA (single phase)							
22	Jackson Electric Coop.	Three Phase		None	Customer Charge	$1.00/kVA								
23	Kentucky Utilities Company		15 min	None	Service charge	$10.75		$ 13.05	$ 3.70					
		Single Phase				$15.09								
24	Kinston, North Carolina (City of)	Three Phase	15 min	None	Service Charge	$27.09		$ 10.15	$ 7.89					
25	Lakeland Electric	Single phase	30 min	None	Customer charge, Demand charge, plus Adjustments	$9.50	$ 4.80							
26	Longmont, Colorado (City of)		15 min	None	Customer Charge	$15.40	$ 5.75							
27	Louisville Gas and Electric Company		15 min	None	Service Charge	$10.75		$ 12.38	$ 3.25					
28	Loveland, Colorado (City of)		15 min	None	Base Charge	$21.10		$ 9.00	$ 6.90					
29	Medina Electric Cooperative, Inc.	Single/Three phase	kVA rate	None	Customer Charge	$27.50	$1.50/kVA for billing kVA over 15 kVA							
30	Mohave Electric Cooperative, Inc.	Single Phase	15 min	None	Customer Charge	$21.50	$ 8.50							
31	Ohio Power Company	Singel Phase	on peak avg	None	Customer Charge	$10.02								
32	Pee Dee Electric Member Corp		Not specified	None	Facilities Charge	$25.00				$	8.25	$ 6.80	$ -	$ 2.45
		Single-Phase				$30.00								
33	Piedmont Electric Member Corp	Three-Phase	15 Min	None	Facilities Charge	$69.45				$	15.95	$ 14.95	$ 1.25	
34	Public Service Company of Colorado (Xcel)		15 min	None	Service and Facility Charge plus Demand Charge	$12.25		$ 8.57	$ 6.59					

Line	Utility	Service Characteristics	Demand Interval	Ratchet	Monthly Minimum	Customer Charge	Demand Charge (per kW, except where kVA indicated)							
							Year round	Seasonal		Seasonal Time of Use				Max Demand
								Summer	Winter	On Peak		Off Peak		
										Summer	Winter	Summer	Winter	
						<200 Amp Service Summer: $30.94 Winter: $32.44 >200 Amp Service Summer: $43.94 Winter: $45.44				0-3kW: $8.03 3-10kW: $14.63 >10kW: $27.77 July&August 0-3kW: $9.59 3-10kW: $17.82 >10kW: $34.19	0-3kW: $3.55 3-10kW: $5.68 >10kW: $9.74			
35	Salt River Project, Arizona	Single/Three phase	30 min	None	Service Chage									
36	Santee Cooper, South Carolina		Not specified	None	Customer Charge	$22.00	$ 17.19							
37	Smithfield, North Carolina (Town of)	Single Phase	15 Min	None	Customer Charge	$15.95				$	6.24	$	-	
38	Swanton Village, Vermont	Single Phase	15 min	12 month 85%	Customer charge plus 85% of highest demand charge	$25.05	$ 6.38							
39	Tri-County Electric Coop, Inc (Florida)	Single Phase	Not specified	None	$28.00	$23.00 $22.00	$ 7.00							
40	Vigilante Electric Coop, Inc	Single Phase	Not specified	None	Base Charge	$29.50	$0.50/kVA for billing kVA over 15 kVA							
41	Virginia Electric & Power Company		30 min	None	Customer Charge	$16.53		$ 8.32	$ 4.87					
42	Virginia Electric & Power Company		30 min	None	Customer Charge	$7.00	$ 2.059							
43	Virginia Electric & Power Company		30 min	None	Customer Charge	$12.00				$	5.682	$	3.946	

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-1933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

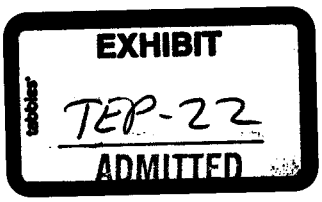
Rebuttal Testimony of

Dallas J Dukes

on Behalf of

TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016



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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. I am filing Rebuttal Testimony on behalf of Tucson Electric Power Company. ("TEP" or the "Company").

Q. How is your Rebuttal Testimony organized?

A. My testimony is organized as follows.

II. Proposed Reduction in Non-Fuel Revenue Requirement

III. Rate Design

IV. Net Metering Tariff

V. Economic Development Rider

II. PROPOSED REDUCTIONS IN NON-FUEL REVENUE REQUIREMENT.

A. Reduction in Non-Fuel Revenue Increase.

Q. Is TEP reducing its requested non-fuel revenue increase from the $109.5 million requested in its Application?

A. Yes, TEP is reducing its requested non-fuel revenue increase from $109.5 million to $100.6 million over test year adjusted non-fuel revenues. However, that $9.0 million non-fuel reduction does not provide a complete understanding of the reduced request and the net impact to customers being proposed by TEP in this Rebuttal filing. In our initial request we proposed a total retail revenue requirement of $1,050.6 million, in our Rebuttal filing we are requesting a total retail revenue requirement of $1,026.9 million—an overall *reduction* of $23.7 million. This is a 21.6% reduction in the originally requested increase to customers. The table below summarizes these changes in more detail.

Table 1: Requested Revenue Revenue Requirement (Thousands of Dollars)

As Filed Position	**$1,050,566**	
Rate Base Adjustments		**Rebuttal Testimony Sponsor**
Wholesale Jurisdiction (Demand and Energy)	(3,503)	Michael Sheehan
Sundt & SJ M&S	76	David J. Lewis
ADIT Bonus Depreciation	(1,471)	Frank P. Marino
Working Capital	483	David J. Lewis
Subtotal of Adjustments	(4,415)	
Rate of Return Adjustments		
Decrease Allowed ROE from 10.35% to 10%	(5,907)	Ann E. Bulkley
Revenue & Expense Adjustments		
Wholesale Jurisdiction (Demand and Energy)	(4,093)	Michael Sheehan
Transmission Expense	(1,748)	David J. Lewis
Credit Card Fees	(3,483)	Denise A. Smith
Depreciation and Amortization	(2,948)	David J. Lewis
Lime Expense	(1,616)	David J. Lewis
Overhaul & Outages	559	David J. Lewis
Compensation and Benefit Adjustments	(775)	Frank P. Marino
Sundt & SJ M&S	244	David J. Lewis
Reduction of Base Cost of Fuel	(14,778)	Michael Sheehan
Springerville Unit 1 Non-Fuel Expense	15,244	Kentton C. Grant
Other	47	
Subtotal of Adjustments	(13,347)	
Rebuttal Revenue Requirement	**$1,026,897**	
Proposed Reduction	**($23,669)**	

Q. Please explain why the non-fuel revenue increase is only decreasing by $9.0 million, but the retail revenue requirement is decreasing by $23.7 million?

A. The Company initially requested to recover through the PPFAC non-fuel operating costs associated with the 50.5% of Springerville Unit 1 not owned by the Company but that would be providing service to retail customers. The amount proposed to be recovered was approximately $16 million annually, which when jurisdictionally allocated is

approximately $15 million. As discussed in the Rebuttal Testimony of Kentton C. Grant, the Company is now requesting to recover those costs through non-fuel rates, not the PPFAC. The request to recover these costs as an operating cost and not as a component of the PPFAC, increases the Company's requested non-fuel revenue increase, but correspondingly decreases the fuel revenues requested.

III. RATE DESIGN.

Q. Is the Company making any significant changes to the rate design proposals in Direct Testimony?

A. No, however we are accepting Staff's proposals regarding the basic service charge as described below.

Q. Please briefly summarize the key changes the Company initially proposed for the Residential and Small General Service ("SGS") customer classes.

A. In its Application, the Company's proposed to: (i) to increase the basic service charge for residential customers from $10 to $20; for the SGS class from $15.50 to $30.00 for single phase service; (ii) eliminate the third and fourth rate tiers for volumetric Delivery Services-Energy charges; (iii) implement mandatory three-part rates for all partial requirement residential and SGS customers who installed distributed generation after June 1, 2015 (collectively, "New DG Customers"); and (iv) provide optional three-part rates for all other residential and SGS customers.

Q. What are the primary reasons for updating TEP's rate design?

A. In this proceeding, the Company is attempting to gradually and fairly modify its rates to (i) reduce intra-class subsidization, (ii) promote fairness and recover costs from cost causers, (iii) provide flexibility to accommodate changing customer usage patterns, (iv)

move toward rate structures that encourage the integration of new energy technologies on the electric system, thus promoting more efficient use of the electric system, and (iv) create a sustainable rate structure that ensures that the Company can continue delivering safe, reliable and affordable electric services for the benefit of all our customers.

A. Basic Service Charge.

Q. Has the Company made any changes in its proposals as described above?

A. Yes. The Company is reducing the requested basic customer charges from $20 to $17 for the Residential class and from $30 to $27 for the SGS class, based on Staff's recommendations.[1]

Q. Why has the Company reduced its requested basic service charges for these classes?

A. The Company strongly believes that modernizing rate design in a manner that allows for more appropriate recovery of costs is an essential component of this rate case and that its proposals of $20 and $30 appropriately implements a portion of this goal. However, the Company recognizes that rate design changes are subject to impact consideration and gradualism. We appreciate Staff's recognition of the necessity of moving toward more equitable and cost based rates.

Q. Were there other parties to the proceeding that oppose the increasing of the basic service charges for these classes?

A. Yes.

[1] Direct Rate Design Testimony of Staff Witness Howard Solganick ("Solganick"), page 30:1, 31:4.

Q. In general, what were the arguments against increasing the basic service charge?

A. These arguments range from using a customer cost estimate methodology that only reflects a portion of actual customer costs, to misapplied policy arguments. Such arguments include claims that higher customer charges will adversely impact low income customers, that our requested basic service charge is too high and is not "common utility practice," or that the higher basic service charge will reduce investment in energy efficiency, and that fixed cost shouldn't be recovered through fixed charges.

Q. Please comment on why the Company disagrees with these assertions.

A. I am not going to attempt to respond to all of the interveners' assertions, however, Company witnesses, Dr. Overcast and Mr. Jones go into detailed explanations in their Rebuttal Testimonies as to why each of the interveners' arguments should **not** dissuade the Commission from allowing TEP to move toward a fairer and more equitable cost based rate structure to the benefit of its customers. As concluded by Staff's witness Solganick, regarding the basic service charge increase (emphasis added), "All residential Basic Service Charges should be $17.00 to **approximate** the Company's **costs**."[2] Rates are inequitable if they are not based on cost.

> Just and reasonable rates must reflect cost causation. Since the customer component of cost is the same for all customers in a properly designed rate class, setting the rate below the properly determined customer costs (discussed above including the minimum system classification) means that low use customers are subsidized by high use customers creating an inequity that is not justified except for social policy related to customers and only customers who have incomes that allow them to qualify as recipients of low income related services. Maintaining low customer charges based on the impact on low use customers assumes incorrectly that there is a correlation between low use and low income customers who qualify as low income customers with poverty status.[3]

[2] Solganick, page 30:1

[3] Rebuttal Testimony of Company Witness Dr. H. Edward Overcast ("Overcast Rebuttal"), page 24:10.

Q. What about the assertion that TEP's requested higher basic service charge deviates from common utility practice?

A. That is simply not true and blatantly ignores the data that is readily available to the contrary.

> As a practical matter the common utility practice has been to increase customer charges. In fact, there are about 1,000 electric utilities with residential customer charges equal to or greater than $20 per month[4] as proposed by TEP. On that basis alone the common practice that includes IOUs, Cooperatives and Municipal Utilities is to increase customer charges and to reflect customer costs in rates.[5]

Q. What about the assertion that the requested higher basic service charge will reduce the incentive to invest in energy efficiency?

A. The argument just doesn't hold up if one looks at the basic facts. Even with our proposed elimination of the third and fourth rate tiers as proposed by the Company, and with the originally proposed $20 basic service charge, 99.5% of the billed consumption (based on test year bill frequency data) would be billed at a higher per kWh rate. Let me say that another way, the Company's proposal only reduces the volumetric rate for ½% of the expected sales to customers. For a typical customer, their billed consumption will increase in the range of 6-14%. Under the Company's proposal, each additional kWh in the 501-1,000 range of kWh consumption will cost the Customer an additional 11.6 cents (excluding taxes and assessments). With present rates it would cost them an additional 10.2 cents. It's just misleading for any party to state that an incentive to reduce consumption will be diminished with TEP's proposed rate structure.

In addition, for parties that champion increasing the inequity of our rate structure brings into question the motives of these parties, especially those who in the same sections of

[4] Utility Rate Database, http://en.openei.org/wiki/Utility_Rate_Database .
[5] Overcast Rebuttal, page 32:7.

their testimonies argue that the Company's proposals will harm low-income customers. The bill frequency data for our actual low-income customers (not a statewide or national survey) show that less than 44% of all low income bills are under 500 kWh – which is equivalent to our non-low income customer group. In general, the distribution of usage levels for our low income is about the same as other residential customers. So these groups are arguing to add further unjustified cost recovery burdens on these higher usage customers – which include a significant proportion of our low-income customers. Company witness Dr. Overcast sums it up very succinctly in his Rebuttal testimony.

> As this statement notes higher energy charges result in uneconomic bypass including DG, DER and energy efficiency. By charging rates that exceed marginal cost even including plausible values for externalities, the RUCO proposal and indeed the proposals of all the opponents of the TEP customer charge increase are supporting a significant loss in social welfare to support their own end-use opportunities.[6]

Q. What about the assertion that it is a faulty premise to recover fixed cost through fixed charges?

A. Again, these types of assertions appear to be based, not in cost basis or sound economic theory, but in a results driven quest to push ever greater amounts of fixed cost recovery onto the higher usage customers. Not one of the parties proposing to recover greater amounts of fixed cost through volumetric rates is proposing to eliminate the inclining rate tiers or place a larger portion of those fixed cost recoveries into the first volumetric rate tier. Instead, they are proposing to unjustifiably increase the cost to the higher usage customers as compared to today's rates, thus increasing the inequities that exist in our current rate structure. As I stated in my Direct Testimony, we presently have just over 33% of our residential customers paying substantially more than their fair share of fixed cost and 66% of our customers paying less than their fair share of fixed cost. To argue

[6] Overcast Rebuttal, page 35:14.

that this inequitable situation should be exacerbated and to not put forth any proposals to at least make progress in addressing this issue is not in the public interest.

B. Elimination of the Third and Fourth Rate Tiers.

Q. Is the Company changing its proposal to remove the third and fourth rate tiers for volumetric delivery services-energy charges?

A. No. The Company and Staff[7] both recommend elimination of the third and fourth tiers.

Q. In general, what were the arguments against eliminating the third and fourth rate tiers for volumetric Delivery Services-Energy charges?

A. These arguments generally fell into three categories; elimination of the tiers will result in: (i.) a disproportionate impact to lower usage customers; (ii.) regressive rates; and (iii.) a weakening of the price signal to save energy.

Q. Does the Company agree with any of these assertions?

A. No, not at all.

Q. What about the assertion that elimination of these tiers will have a disproportionate impact on lower usage customers or that it's a regressive policy?

A. For these arguments to have any merit, one would have to assume that today's low customer charge with inverted block volumetric rate structures is fair and equitable to all of our customers. Because, with the exception of Staff, other parties are essentially arguing to retain the current structure or to actually place a greater unjustified cost burden on the higher energy using customers. The Company, through my testimony as well as

[7] Solganick, page 29:21-23.

the testimony of Mr. Jones and Dr. Overcast, have provided substantial evidence to refute this false assertion.

> The unequal treatment of customers who have the same costs but provide very different levels of revenue to recover those costs is a perfect demonstration of undue discrimination and that the current rates are no longer just and reasonable as the result of a combination of the net metering provisions and the current inverted block two-part rate with a low monthly basic customer charge. Essentially, the recovery of almost all of the fixed cost of service in volumetric charges results in undue discrimination when the customers in a class are no longer homogeneous.[8]

As I explained above, the Company's proposal is to move gradually toward more equitable cost recovery within the entire residential rate class. It is counter intuitive to argue that moving toward a more balanced and fair rate structure is "regressive." Again, that requires the assumption that; (i) the present rate structure is fairly balanced and/or equitable – which it is not of (ii) we are proposing to move toward a structure that puts a greater amount of cost recovery onto the lower usage customers than is fair and equitable – which we are not.

Next I want to address the assertion that the impact to lower usage customers is disproportionate or will adversely impact that group. This claim is only true if one ignores the plain facts that this group of customers is not presently paying the cost to serve them AND that you have to give that group a larger portion of any increase (or smaller portion of any decrease) to move toward equity. The dollar impacts on low usage customers can be illustrated with a simple example. The revised basic service charge increase is $7 or about 23 cents per day. Then if you assume that a low usage customer uses, on average 500 kWhs or less per month, and take our proposal to increase the first tier by 0.5 cents – at worst that is about 8 cents per day. So in total the increase we are

[8] Overcast Rebuttal, page 76:3.

asking for to make progress toward a more equitable rate structure is at worst about 31 cents per day or about $9.50 per month for a low usage customer. Of course, $10 per month could be substantial to a significant portion of these low usage customers, and TEP is not discounting that. However, to make any progress toward more equitable cost based rates we have to increase these lower usage bills greater than that of an average customer proportionately **(although these customers are still seeing a dollar increase that is less than the typical residential customer, as discussed in Mr. Jones' Rebuttal Testimony)**. TEP is requesting a justifiable rate increase to recover the cost to serve, and as such, all rates by class are going to go up.

> The issue of low-use customer impacts has been discussed above, but essentially the current rates and low customer charge are inequitable because they do not recover costs caused by low-use customers.[9]

Q. What about the assertion that elimination of the third and fourth tiers will reduce incentives for customers to conserve?

A. I've already discussed this previously in my testimony – this is simply a false statement. TEP is proposing to increase the cost per kWh consumed by our customers thereby *increasing* the incentive to conserve – to assert anything else is just incorrect.

C. Three-Part Rates for all Partial Requirement Residential and Small General Service Customers.

Q. To make it clear, are all of TEP's proposed rate design changes simply to address partial requirement customers, such as solar DG customers?

A. No, regardless of the misguided accusations made by certain other parties, TEP is not designing rates with the sole purpose of eliminating solar DG installations in our service

[9] Overcast Rebuttal, page 34:5.

territory, or reducing the incentive for customers to conserve or limiting the ability of customers to reduce their bills through investment in new appliances, technology or simply through behavioral changes. TEP is attempting to gradually address the totality of inequitable and uneconomic issues caused by recovering the vast majority of our fixed system cost through two-part, inverted block volumetric pricing with a low basic service charge. In short, we are trying to gradually shift towards an overall rate design that more accurately reflects cost causation.

However, our proposal to implement three-part rates for new DG customers is meant to address the unique subsidization issues related to serving them with two-part rate design and net-metering. This is discussed extensively in the Rebuttal Testimony of Company witnesses Dr. Overcast, and Mr. Jones. In addition, the bill impacts of these proposed changes are discussed in the Rebuttal Testimony of Company Witness Mr. Bachmeier.

> All of this evidence suggests that with a two part rate and net metering with banking can never result in just and reasonable rates for partial requirement DG customers. The only possible alternative to treat partial requirements, DG customers equitably is a separate rate class with a three-part rate.[10]

Q. What are the general arguments made by parties in this proceeding against TEP requesting that partial requirements/DG customers being limited to three-part rate options?

A. These arguments fall into three general categories (i.) DG customers (partial requirement customers) are an insignificant portion of sales and revenue loss and that the Company recovers the lost revenue through the LFCR process, (ii.) DG customers are not different than full requirement customers, and (iii.) it's discriminatory to treat them differently than standard full requirement customers and the rules don't allow it.

[10] Overcast Rebuttal, page 75:2.

Q. Please address the assertions that DG customers (partial requirements customers) are an insignificant portion of sales and revenue loss and that the Company recovers the lost revenue through the LFCR process.

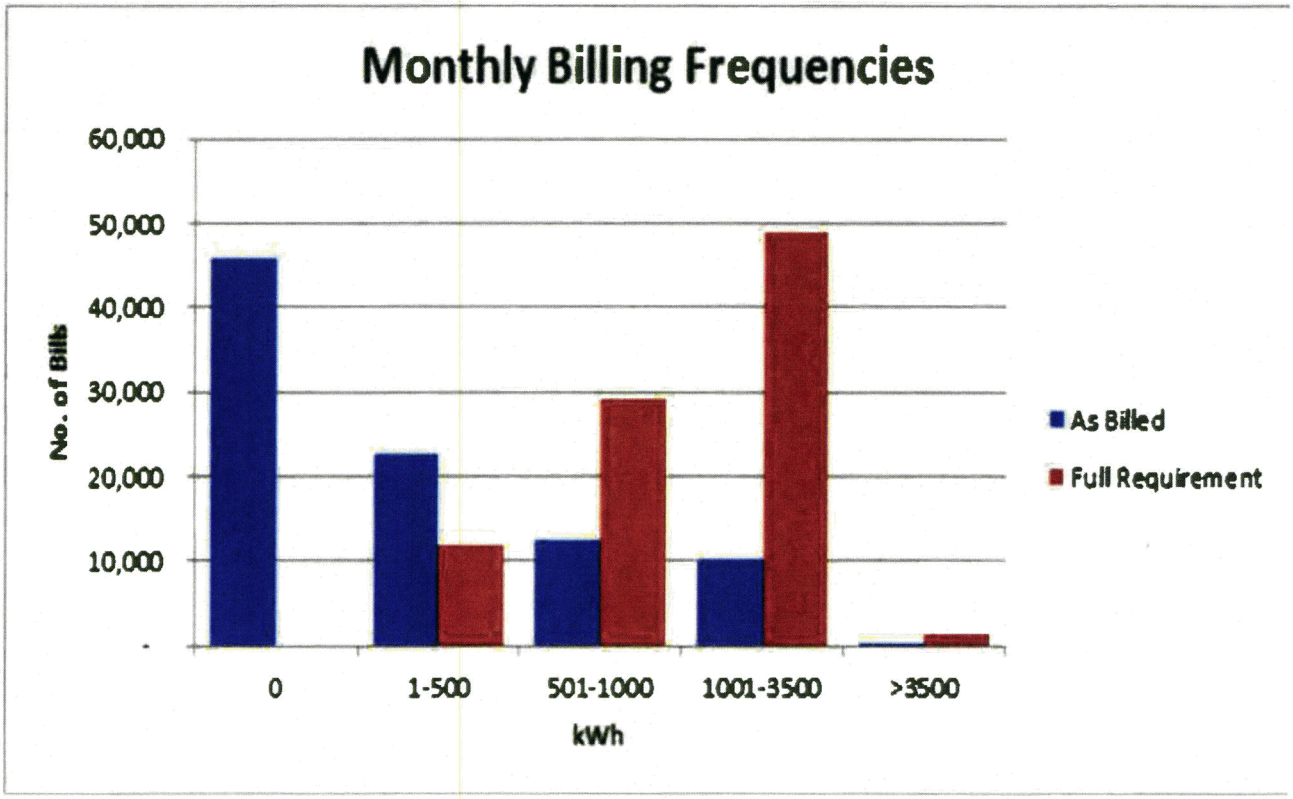
A. The major flaw in this argument is that it ignores key facts: (i) the number of DG applications and thus the magnitude of the transfer of cost to other customers is growing rapidly[11] – so to ignore the issue now, because it's deemed fairly small (by the intervening parties) at this time, is just poor rate making policy and just adds to the cost burden of other non-DG customers and to the difficulty of addressing it later and (ii) the cost burden is not small or insignificant; the transfer of cost recovery is substantial and growing, as pointed out in the Rebuttal Testimony of Mr. Jones. The transfer of cost for the 12,000 current NEM customers is approaching the $9 million range – that is not an insignificant amount and will continue to grow if rate design is not meaningfully updated in this proceeding.

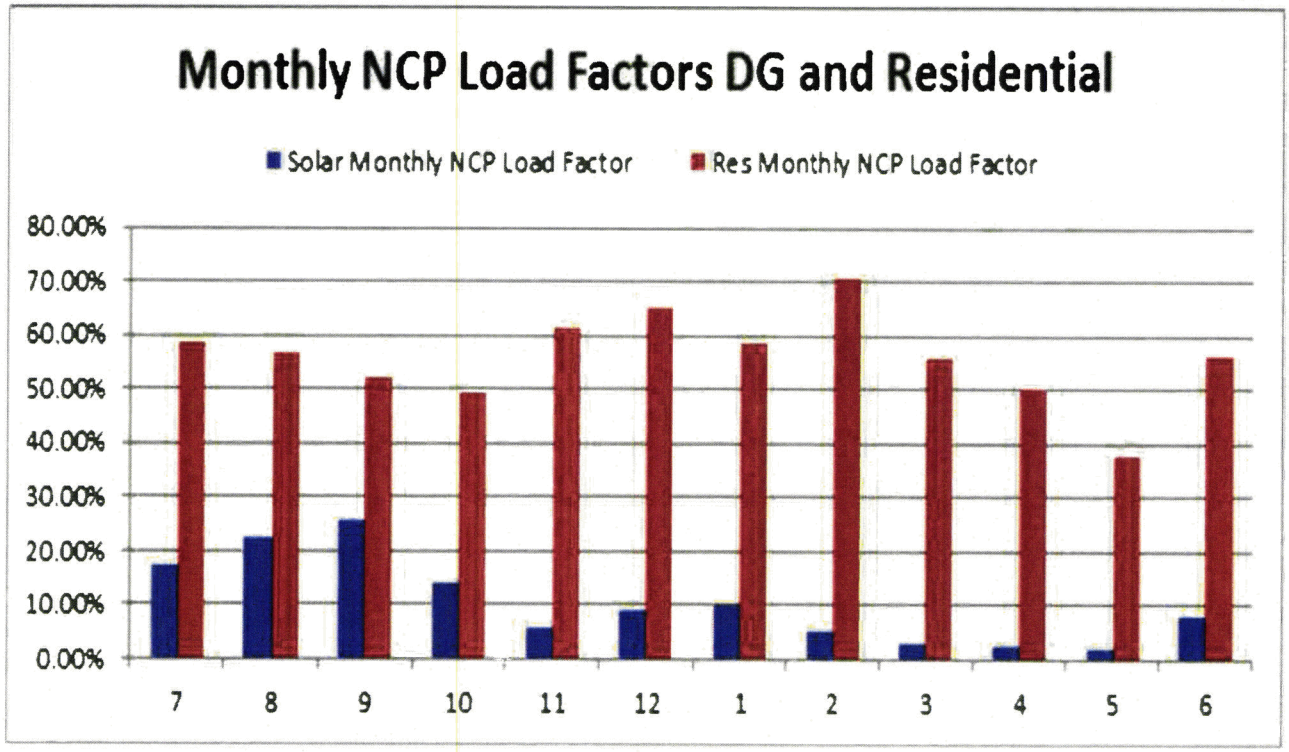
Q. Please address the assertions that DG customers (partial requirement customers) are no different than standard full requirement customers.

A. This is just a completely false assertion and blatantly ignores the clear facts and load profiles; to claim that a customer that self generates a portion of their own electricity is the same as a standard full requirements customer is baffling. This claim is refuted extensively in the Rebuttal Testimony of Dr. Overcast, but let me just share a couple of the major facts. Below are two charts provided by Dr. Overcast in his Rebuttal Testimony based on the actual data of TEP's customers. The first clearly shows the difference for billing purposes (thus cost recovery purposes) related to these customers billed energy profiles when they move from a full requirements customer to a partial

[11] As of June 30, 2016, TEP had added over 9,000 DG customers since December 31, 2011 (an approximate 300% increase when compared to count in the test year used in the last cast).

requirements customer. The second chart clearly shows the degraded load factor for these customers. They are billed for very little energy in comparison to the load they draw from the system. It is simply smoke and mirrors to assert that DG customers act like full requirements customers in their usage of the system when applying rates that recover cost to serve through volumetric energy charges.





Q. Please address the assertion that it's discriminatory to treat DG customers differently than standard full requirement customers.

A. This position, quite frankly, is wholly unfounded. There is more than ample justification to put DG customers on a separate rate structure. TEP witness Dr. Overcast, provides detailed Rebuttal Testimony as to (i) what the cost to serve DG customers is, (ii) why separate rate treatment is appropriate for DG customers, (iii) why the current rate structure is not capable of reflecting costs for DG customers (as partial requirements customers) and (iv) why a separate rate class for DG customers must include demand charges. In short, and especially given the fact that allocating costs on a two-part rate design for DG customers does not provide the right price signals or properly reflect cost recovery or causation, DG customers should be placed on a separate three-part rate with demand charges. TEP strongly disagrees with any assertion that it is discriminatory to

recover the cost of serving a partial requirements customer (DG customer) based on how they use the system.

> When the difference in the annual bill of a full requirements customer and a partial requirements customer with identical peak demands is 19 times a partial requirements customer's total bill the subsidy is no longer just and reasonable and constitutes undue discrimination. The only practical solution is to eliminate the net metering provision and recover costs under a separate rate schedule for partial requirements customers as proposed by TEP.[12]

Q. Have other public utility commissions found justification to place DG customers in a separate rate class?

A. Yes. The commission in Nevada and Utah, for example, placed DG customers (NEM customers) in a separate rate class. The Utah Public Service Commission, in Docket No. 14-035-114, found reason to order, on November 10, 2015, cost of service studies that segregates DG customers from the class they would otherwise participate in and as part of the Utah PSC's examination of the costs and benefits of net metering. Clearly, utility commissions in other states are finding that DG customers impact the grid differently than traditional full requirements customers.

IV. NET METERING TARIFF.

Q. Briefly summarize the Company's proposed net metering tariff

A. Under TEP's proposed Net Metering Tariff, new DG Customers, among other things, (i) would not be allowed to "bank" or carry-forward excess kilowatt-hours ("kWh") to offset future electricity consumption and (ii) would be compensated for excess energy at the Renewable Credit Rate.[13]

[12] Overcast Rebuttal, page 76:15.

[13] Equivalent to the most recent utility-scale renewable purchased power agreement connected to the distribution system of Tucson Electric Power.

Q. Is the Company willing to consider other net metering proposals or alternative methodologies of valuing excess generation produced by DG customers?

A. Certainly. However, with the exception of RUCO, none of the other parties in this proceeding provided any new net metering proposals or any real alternatives in their testimony.

Q. Is the current rate case proceeding the proper venue to approve a new net metering tariff?

A. Yes, without question. I would like to point out that TEP and its sister company, UNS Electric ("UNSE"), filed applications in March 2015 to update their net metering tariffs.[14] Although both TEP and UNSE believe that the Commission can approve a net metering tariff outside of a rate case, several parties who are Intervenors in this rate case, argued that a net metering tariff must be approved in a rate case. In light of the procedural posture in that docket, in June 2015, TEP withdrew its net metering application and accelerated the filing of its rate case. Yet these parties have yet to offer any new net metering proposals in this docket.

While we understand Staff's desire to wait for the outcome of the Commission's investigation of the value and cost of DG (Docket No. E-00000J-14-0023), this proceeding is the proper venue for approval of a new net metering tariff for TEP. It is unclear when that proceeding will conclude and what result it will ultimately produce. On the other hand, this rate proceeding will provide sufficient Company specific data and evidence to support the Commission's approval, modification or rejection of TEP's proposed net metering tariff.

[14] March 25, 2015, Docket No. E-04204A-15-0099 (TEP) and Docket No. E-01933A-15-0100 (TEP).

Q. Do you have any estimates of how the Company's proposed three-part rate structure and net metering tariff will impact new DG customers?

Yes. Company Rebuttal witness Mr. Bachmeier is addressing these impacts in his Rebuttal Testimony.

V. ECONOMIC DEVELOPMENT RATE.

Q. Briefly describe the Company's proposed Economic Development Rate ("EDR").

A. As a way to help promote economic development in the Company's service territories, TEP proposed to offer discounted rates to new or existing large business customers that meet certain requirements, including a minimum load factor.

Q. Would you like to make any clarifying remarks about the Company's proposed EDR?

A. Yes. The testimonies of several parties express concerns about costs being shifted from EDR customers to other customer classes. I would like to emphasize that the any lost non-fuel revenues resulting from discounts provided to customers through the EDR *will be borne by the Company*. TEP will not seek recovery of any lost non-fuel revenues associated with the EDR in future rate case proceedings. The long-term benefits of attracting or retaining large, high load factor customers greatly outweigh the short-term costs.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-01933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

Testimony of Dallas J. Dukes

In Support of Settlement Agreement on Revenue Requirement

on Behalf of

Tucson Electric Power Company

August 25, 2016

EXHIBIT
TEP-23
ADMITTED

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you provide Direct and Rebuttal testimonies in this proceeding?

A. Yes.

II. SUMMARY OF TESTIMONY.

Q. What is the purpose of your testimony?

A. I am testifying in support of the Settlement Agreement regarding Revenue Requirement ("Agreement") filed on August 15, 2016.

III. REVENUE REQUIREMENT.

A. Revenue Increase

Q. Please describe the settled-upon revenue increase.

A. Attachment "A" to the Settlement Agreement sets forth the adjustments to TEP's Direct and Rebuttal revenue requirement that resulted in the revenue requirement included within the Settlement Agreement. With respect to non-fuel revenues, the Settlement Agreement provides for a non-fuel revenue increase of $81.5 million, of which $15.2 million is contingent upon TEP completing the purchase of a 50.5% interest in Springerville Unit 1

("SGS Unit 1"). This amount is $44.3 million less than the $125.8 million that the Company originally requested.[1]

B. Cost of Capital

Q. Please describe the cost of capital changes agreed upon by the Signatories.

A. The Company's Rebuttal filing reduced the requested return on equity ("ROE") to 10.00% from 10.35% originally requested by the Company. That change reduced the Company's requested non-fuel revenue increases by approximately $5.9 million. As a result of the Settlement Agreement, there were additional cost of capital items agreed upon by the Signatories. Those items are: (i) the adoption of TEP's test year capital structure of 49.97% long-term debt and 50.03% common equity; (ii) an ROE reduction to 9.75% and an embedded cost of long-term debt of 4.32% (resulting in a weighted average cost of capital of 7.04%); and (iii) the return on the fair value increment of rate base reduced from the requested 1.42% to 1.00% (resulting in a fair value rate of return on fair value rate base of 5.34%). As a result of these capital structure changes the Company's requested non-fuel revenue increase was additionally reduced by approximately $9.6 million. Thus, reducing the Company's initial non-fuel revenue increase by approximately $15.5 million.

C. Rate Base Adjustments

Q. Please describe the rate base adjustments agreed to by the Signatories.

A. In the Company's Rebuttal filing it had already accepted several intervening parties' positions and reduced its OCRB by approximately $38.4 million. As a result of the Settlement Agreement, there are four additional adjustments resulting in a further reduction of OCRB of approximately $21.1 million. Bringing the total reduction in the Company's initial OCRB to $59.5 million less than originally proposed.

[1] This amount includes a $109.5 million non-fuel base rate increase and $16.3 million in non-fuel O&M related to SGS Unit 1 that was initially requested to be recovered through the PPFAC.

The additional reductions agreed upon by the Signatories for the purposes of the Settlement Agreement are comprised of: (i) an agreement to reduce the in-service cut-off date from December 31, 2016 to June 30, 2016, for investments made prior to the end of the test year, but not in service (these investments are referred to as Post Test Year adjustments); (ii) the rolling forward of accumulated amortization related to the leasehold improvements associated with the 50.5% share of SGS Unit 1 through December 31, 2016; (iii) the permanent reduction of the book value of the TEP Headquarters building; and (iv) the conforming changes related to the Settlement Agreement impacting cash working capital.

D. Operating Expense Adjustments

Q. Please describe the operating expense adjustments agreed to by the Signatories.

A. In the Company's Rebuttal filing, it had already accepted several intervening parties' positions and reduced its pro forma operating expenses by approximately $13.6 million. As a result of the Settlement Agreement there are additional adjustments resulting in a further reduction of operating expense by approximately $9.0 million. The total reduction in the Company's initially proposed pro-forma operating expenses is $22.6 million.

The additional reductions agreed upon by the Signatories for the purposes of the Settlement Agreement are comprised of: (i) the agreement to normalize generation overhaul and outage expenses based upon the most recent six years of actual data;.(ii) the exclusion of the wage and payroll tax increase associated with anticipated 2017 non-union wage increases; (iii) the recovery of only 50% of the normalized cost associated with the Company's Short Term Incentive compensation plan; (iv) a $1 million cap on the recovery of rate case expense amortized over four years; (v) the removal of expenses associated with the Company's Long Term Incentive compensation plan; (vi) a reduction of $1.1 million in

test year legal cost; and.(vii) conforming changes to depreciation and income tax expenses associated with agreed upon depreciation rate and rate base changes.

Q. Did the Signatories come to an agreement on depreciation rates?

A. Yes. The Settlement Agreement adopted the depreciation rates contained in TEP's Rebuttal Testimony, with modifications to the depreciation for San Juan Unit 1 and depreciation rates for distribution plant.

Q. Please describe the adjustments for early plant retirement included in TEP's Direct Testimony.

A. TEP Witness Dr. White sponsored a depreciation study in his Direct Testimony. The depreciation rates proposed by Dr. White included adjustments to reflect the early retirement of San Juan Unit 2 and the Sundt Coal Handling Facilities[2] as well as various adjustments to generation asset expected service lives[3], including a reduction to the expected service life for San Juan Unit 1 from 2036 to 2027. TEP proposed to reduce the expected service life for San Juan Unit 1 as a result of the uncertainty associated with Company's participation in that Unit beyond 2022.

Q. How were the early retirements of San Juan Unit 2 and the Sundt Coal Handling Facilities treated in the depreciation study?

A. They were treated consistent with the treatment specified in the Settlement Agreement approved in the 2012 TEP Rate Order, Decision No. 73912 (June 27, 2013) ("2012 TEP Rate Order"). The 2012 TEP Rate Order states at Section 20.3 that "if TEP makes any filing with the ACC related to the early retirement of any production asset, TEP will propose that any then-existing excess depreciation reserve for production plant be applied

[2] See TEP Witness Marino Direct Testimony pages 7 through 11.
[3] See TEP Witness Sheehan Direct Testimony pages 21 through 28.

to the unrecovered book value of the retiring asset." This provision allows unrecovered remaining asset costs to be absorbed by excess depreciation reserves that exist on other assets as identified in the depreciation study.

Q. Did Dr. White identify any differences between recorded and computed depreciation reserves?

A. Yes. After reflecting the early retirement of San Juan Unit 2 and the Sundt Coal Handling Facilities, Dr. White identified a reserve shortfall in total for all of TEP's assets which he proposed to amortize over the composite remaining life of each asset category.

Q. Did TEP propose any changes to depreciation rates in its Rebuttal Testimony?

A. Yes. TEP accepted certain changes to depreciation rates based on Staff Witness McCullar's proposed adjustments. These adjustments were accepted by TEP Witness Lewis in his Rebuttal Testimony at pages 7 through 9.

Q. Do these adjustments impact the difference between the recorded and computed depreciation reserves that was presented in TEP's Direct Testimony?

A. Yes. These adjustments result in an overall excess depreciation reserve for all of TEP's assets, compared with the reserve shortfall identified in TEP's Direct Testimony.

Q. Please summarize the adjustments to depreciation rates included in the Settlement Agreement.

A. The Settlement Agreement adopted the depreciation rates contained in TEP's Rebuttal Testimony, except that (i) the rates for San Juan Unit 1 and Common ("San Juan Unit 1") were adjusted to reflect a depreciable life of TEP's total investment of six (6) years or through the year 2022, (ii) $90 million of distribution excess reserves are to be transferred

to San Juan Unit 1, and (iii) depreciation rates on distribution plant were adjusted to offset changes (i) and (ii).

Q. Is it reasonable to shorten the life of San Juan Unit 1 to 6 years?

A. Yes. Given the uncertainty surrounding TEP's continued operation of San Juan Unit 1 after the expiration of the current fuel supply agreement and plant participation agreement in 2022, it is reasonable to shorten its expected useful life as it relates to TEP's participation to 2022.

Q. Is it reasonable to utilize excess distribution depreciation reserves to offset plant costs associated with San Juan Unit 1?

A. Yes. In the 2012 TEP Rate Order, the Commission acknowledged the reasonableness of applying excess depreciation reserves to offset the effects of early production plant retirements (that could otherwise cause a large rate impact). Utilizing excess distribution depreciation reserves will mitigate the rate impact of the San Juan Unit 1 accelerated depreciation resulting from shortening the life to 6 years.

Q. Is the impact of adjusting distribution depreciation rates for the San Juan Unit 1 issues you discuss above reasonable?

A. Yes. The composite distribution rate for distribution assets was reduced slightly from 1.78% to 1.56%. This is a reasonable result in order to mitigate the rate impact of the San Juan Unit 1 adjustments.

Q. Have you updated the depreciation study schedules sponsored by TEP Witness Dr. White in his Direct Testimony?

A. Yes. Attached as Exhibit DJD-S-1 are the depreciation study schedules that reflect the provisions of the Settlement Agreement.

Q. Does this conclude your testimony?

A. Yes

Exhibit DJD-S-1

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
STEAM PRODUCTION							
310.00	Rights-of-Way	3.03%	0.00%	3.03%	2.64%	0.00%	2.64%
311.00	Structures and Improvements	3.37%	0.33%	3.70%	3.16%	0.51%	3.67%
312.00	Boiler Plant Equipment	2.89%	0.38%	3.27%	3.15%	0.35%	3.50%
314.00	Turbogenerator Units	3.27%	0.72%	3.99%	3.41%	0.40%	3.82%
315.00	Accessory Electric Equipment	3.72%	0.94%	4.66%	3.08%	0.50%	3.59%
316.00	Miscellaneous Power Plant Equipment	3.34%	0.40%	3.74%	3.00%	0.31%	3.31%
	Total Steam Production Plant	3.09%	0.47%	3.56%	3.19%	0.39%	3.58%
OTHER PRODUCTION							
Non-Solar							
341.00	Structures and Improvements	2.51%	0.31%	2.82%	2.56%	0.19%	2.75%
342.00	Fuel Holders, Products and Accessories	2.71%	0.31%	3.02%	2.64%	0.19%	2.83%
343.00	Prime Movers	2.36%	0.04%	2.40%	2.46%	0.12%	2.58%
344.00	Generators and Devices	2.13%	0.15%	2.28%	1.90%	0.10%	2.00%
345.00	Accessory Electric Equipment	2.34%	0.08%	2.42%	2.05%	0.09%	2.14%
346.00	Miscellaneous Power Plant Equipment	2.45%	0.27%	2.72%	2.48%	0.18%	2.66%
	Total Non-Solar	2.33%	0.11%	2.44%	2.31%	0.12%	2.43%
Solar							
344.00	Generators and Devices	5.13%	0.00%	5.13%	3.44%	0.17%	3.61%
	Total Solar	5.13%	0.00%	5.13%	3.44%	0.17%	3.61%
	Total Other Production Plant	3.19%	0.08%	3.27%	2.66%	0.14%	2.80%
DISTRIBUTION PLANT							
360.RW	Rights-of-Way	1.43%	0.00%	1.43%	1.06%	0.00%	1.06%
361.00	Structures and Improvements	1.72%	0.00%	1.72%	1.45%	0.00%	1.45%
362.00	Station Equipment	1.53%	0.00%	1.53%	1.37%	0.00%	1.37%
364.00	Poles, Towers and Fixtures	1.74%	0.00%	1.74%	1.37%	0.00%	1.37%
365.00	Overhead Conductors and Devices	1.63%	0.00%	1.63%	1.33%	0.00%	1.33%
366.00	Underground Conduit	1.35%	0.00%	1.35%	1.05%	0.00%	1.05%
367.00	Underground Conductors and Devices	1.87%	0.00%	1.87%	1.44%	0.00%	1.44%
368.OH	Line Transformers - Overhead	1.87%	0.00%	1.87%	1.42%	0.00%	1.42%
368.UG	Line Transformers - Underground	2.09%	0.00%	2.09%	1.62%	0.00%	1.62%
369.OH	Services - Overhead	1.85%	0.00%	1.85%	1.45%	0.00%	1.45%
369.UG	Services - Underground	1.52%	0.00%	1.52%	1.23%	0.00%	1.23%
370.00	Meters	3.29%	0.00%	3.29%	4.23%	0.00%	4.23%
373.00	Street Lighting and Signal Systems	1.77%	0.00%	1.77%	1.41%	0.00%	1.41%
	Total Distribution Plant	1.80%	0.00%	1.80%	1.48%	0.00%	1.48%

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Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
GENERAL PLANT							
Depreciable							
390.00	Structures and Improvements	2.49%	0.15%	2.64%	2.53%	0.15%	2.68%
392.C0	Transportation - Class 0	4.96%	-0.73%	4.23%	5.14%	-0.86%	4.28%
392.C1	Transportation - Class 1	12.43%	-1.81%	10.62%	12.97%	-2.20%	10.77%
392.C2	Transportation - Class 2	12.25%	-1.78%	10.47%	12.88%	-2.23%	10.65%
392.C3	Transportation - Class 3	10.71%	-1.56%	9.15%	11.49%	-2.02%	9.47%
392.C4	Transportation - Class 4	7.03%	-1.02%	6.01%	7.59%	-1.35%	6.24%
392.C5	Transportation - Class 5	7.31%	-1.08%	6.23%	7.87%	-1.31%	6.56%
392.C6	Transportation - Class 6	6.65%	-1.00%	5.65%	6.78%	-1.01%	5.77%
392.C7	Transportation - Class 7	6.98%	-1.04%	5.94%	7.20%	-1.08%	6.12%
392.C8	Transportation - Class 8	7.50%	-1.13%	6.37%	7.85%	-1.19%	6.66%
392.C9	Transportation - Class 9	4.66%	-0.70%	3.96%	4.02%	-0.61%	3.41%
396.00	Power Operatied Equipment	6.48%	-0.24%	6.24%	6.72%	-0.06%	6.66%
397.EM	EMS and SCADA Equipment	4.96%	0.00%	4.96%	5.12%	0.00%	5.12%
Total Depreciable		4.12%	-0.17%	3.95%	4.25%	-0.21%	4.04%
Amortizable							
391.00	Furniture and Office Equipment	← 24 Year Amortization →		4.15%	← 24 Year Amortization →		4.15%
391.20	Network and Data Equipment	← 5 Year Amortization →		18.68%	← 5 Year Amortization →		18.68%
393.00	Stores Equipment	← 15 Year Amortization →		6.35%	← 15 Year Amortization →		6.35%
394.00	Tools, Shop and Garage Equipment	← 17 Year Amortization →		5.72%	← 17 Year Amortization →		5.72%
395.00	Laboratory Equipment	← 17 Year Amortization →		5.78%	← 17 Year Amortization →		5.78%
397.20	Telecommunications Equipment	← 15 Year Amortization →		6.59%	← 15 Year Amortization →		6.59%
398.00	Miscellaneous Equipment	← 20 Year Amortization →		5.00%	← 20 Year Amortization →		5.00%
Total Amortizable		8.75%	0.00%	8.75%	8.75%	0.00%	8.75%
Total General Plant		5.94%	-0.11%	5.83%	6.01%	-0.12%	5.89%
SUBTOTAL		2.89%	0.21%	3.10%	2.76%	0.17%	2.93%
NET SALVAGE							
108.02	Distribution	0.00%	0.27%	0.27%	0.00%	0.08%	0.08%
Total Net Salvage		0.00%	0.27%	0.27%	0.00%	0.08%	0.08%
TOTAL UTILITY		2.89%	0.30%	3.19%	2.76%	0.21%	2.97%
STEAM PRODUCTION (by Unit)							
Four Corners							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	2.19%	0.17%	2.36%	2.42%	0.11%	2.53%
312.00	Boiler Plant Equipment	1.60%	0.15%	1.75%	1.50%	0.10%	1.60%
314.00	Turbogenerator Units	2.33%	0.14%	2.47%	1.99%	0.08%	2.07%
315.00	Accessory Electric Equipment	3.48%	0.19%	3.67%	4.00%	0.16%	4.16%
316.00	Miscellaneous Power Plant Equipment	2.39%	0.17%	2.56%	2.25%	0.09%	2.34%
Total Four Corners		1.82%	0.15%	1.97%	1.73%	0.10%	1.83%
Four Corners Unit 4							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	2.13%	0.16%	2.29%	2.29%	0.11%	2.40%
312.00	Boiler Plant Equipment	1.50%	0.16%	1.66%	1.36%	0.12%	1.48%
314.00	Turbogenerator Units	2.44%	0.12%	2.56%	2.02%	0.06%	2.08%
315.00	Accessory Electric Equipment	3.87%	0.17%	4.04%	3.87%	0.12%	3.99%
316.00	Miscellaneous Power Plant Equipment	2.34%	0.15%	2.49%	2.14%	0.08%	2.22%
Total Four Corners Unit 4		1.78%	0.15%	1.93%	1.61%	0.11%	1.72%

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Component Accrual Rates

Current: VG Procedure / RL Technique

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Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
Four Corners Unit 5							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	2.26%	0.19%	2.45%	2.55%	0.12%	2.67%
312.00	Boiler Plant Equipment	1.70%	0.13%	1.83%	1.66%	0.07%	1.73%
314.00	Turbogenerator Units	2.17%	0.16%	2.33%	1.96%	0.09%	2.05%
315.00	Accessory Electric Equipment	3.07%	0.22%	3.29%	4.15%	0.19%	4.34%
316.00	Miscellaneous Power Plant Equipment	2.45%	0.20%	2.65%	2.37%	0.10%	2.47%
Total Four Corners Unit 5		1.86%	0.14%	2.00%	1.86%	0.08%	1.94%
Navajo							
310.00	Rights-of-Way	0.29%	0.02%	0.31%	0.69%	0.04%	0.73%
311.00	Structures and Improvements	1.43%	0.10%	1.53%	2.51%	0.13%	2.64%
312.00	Boiler Plant Equipment	1.66%	0.10%	1.76%	3.10%	0.14%	3.24%
314.00	Turbogenerator Units	1.51%	0.10%	1.61%	3.11%	0.14%	3.25%
315.00	Accessory Electric Equipment	1.87%	0.13%	2.00%	3.84%	0.18%	4.02%
316.00	Miscellaneous Power Plant Equipment	1.58%	0.11%	1.69%	2.80%	0.13%	2.93%
Total Navajo		1.63%	0.10%	1.73%	3.09%	0.14%	3.23%
Navajo Unit 1							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	0.69%	0.05%	0.74%	4.09%	0.20%	4.29%
312.00	Boiler Plant Equipment	1.75%	0.12%	1.87%	5.97%	0.29%	6.26%
314.00	Turbogenerator Units	1.58%	0.09%	1.67%	6.00%	0.27%	6.27%
315.00	Accessory Electric Equipment	1.51%	0.09%	1.60%	8.45%	0.39%	8.84%
316.00	Miscellaneous Power Plant Equipment	0.67%	0.05%	0.72%	3.97%	0.19%	4.16%
Total Navajo Unit 1		1.61%	0.11%	1.72%	6.02%	0.29%	6.31%
Navajo Unit 2							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	0.99%	0.07%	1.06%	1.35%	0.06%	1.41%
312.00	Boiler Plant Equipment	1.52%	0.09%	1.61%	1.64%	0.06%	1.70%
314.00	Turbogenerator Units	1.60%	0.12%	1.72%	1.75%	0.09%	1.84%
315.00	Accessory Electric Equipment	1.62%	0.11%	1.73%	1.99%	0.10%	2.09%
316.00	Miscellaneous Power Plant Equipment	0.88%	0.06%	0.94%	0.89%	0.04%	0.93%
Total Navajo Unit 2		1.51%	0.10%	1.61%	1.66%	0.07%	1.73%
Navajo Unit 3							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	0.99%	0.07%	1.06%	1.05%	0.05%	1.10%
312.00	Boiler Plant Equipment	1.58%	0.08%	1.66%	1.77%	0.06%	1.83%
314.00	Turbogenerator Units	1.22%	0.07%	1.29%	1.35%	0.05%	1.40%
315.00	Accessory Electric Equipment	1.33%	0.11%	1.44%	1.51%	0.08%	1.59%
316.00	Miscellaneous Power Plant Equipment	0.73%	0.08%	0.81%	0.89%	0.06%	0.95%
Total Navajo Unit 3		1.44%	0.08%	1.52%	1.61%	0.06%	1.67%
Navajo Common							
310.00	Rights-of-Way	0.29%	0.02%	0.31%	0.69%	0.04%	0.73%
311.00	Structures and Improvements	1.91%	0.14%	2.05%	2.76%	0.14%	2.90%
312.00	Boiler Plant Equipment	2.19%	0.17%	2.36%	2.82%	0.16%	2.98%
314.00	Turbogenerator Units	3.86%	0.28%	4.14%	4.86%	0.24%	5.10%
315.00	Accessory Electric Equipment	3.49%	0.24%	3.73%	4.34%	0.19%	4.53%
316.00	Miscellaneous Power Plant Equipment	2.00%	0.13%	2.13%	3.30%	0.15%	3.45%
Total Navajo Common		2.23%	0.16%	2.39%	3.08%	0.15%	3.23%

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Component Accrual Rates
Current: VG Procedure / RL Technique
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Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
San Juan							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	1.72%	0.15%	1.87%	7.57%	0.59%	8.16%
312.00	Boiler Plant Equipment	2.45%	0.74%	3.19%	7.63%	0.74%	8.37%
314.00	Turbogenerator Units	2.06%	0.18%	2.24%	7.57%	0.60%	8.17%
315.00	Accessory Electric Equipment	2.09%	0.19%	2.28%	7.62%	0.60%	8.22%
316.00	Miscellaneous Power Plant Equipment	1.58%	0.12%	1.70%	7.60%	0.58%	8.18%
	Total San Juan	2.30%	0.56%	2.86%	7.61%	0.70%	8.31%
San Juan Unit 1							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	1.72%	0.15%	1.87%	8.83%	0.70%	9.53%
312.00	Boiler Plant Equipment	2.38%	0.25%	2.63%	8.96%	0.72%	9.68%
314.00	Turbogenerator Units	2.06%	0.18%	2.24%	8.85%	0.70%	9.55%
315.00	Accessory Electric Equipment	2.09%	0.19%	2.28%	8.96%	0.71%	9.67%
316.00	Miscellaneous Power Plant Equipment	1.59%	0.12%	1.71%	8.91%	0.69%	9.60%
	Total San Juan Unit 1	2.25%	0.23%	2.48%	8.93%	0.71%	9.64%
San Juan Common							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	1.66%	0.16%	1.82%	9.93%	0.02%	9.95%
312.00	Boiler Plant Equipment	3.76%	9.71%	13.47%	9.18%	3.67%	12.85%
314.00	Turbogenerator Units	2.30%	0.20%	2.50%	0.00%	0.00%	0.00%
315.00	Accessory Electric Equipment	2.10%	0.20%	2.30%	0.00%	0.00%	0.00%
316.00	Miscellaneous Power Plant Equipment	1.36%	0.12%	1.48%	9.93%	0.00%	9.93%
	Total San Juan Common	3.70%	9.46%	13.16%	9.20%	3.57%	12.77%
Springerville							
310.00	Rights-of-Way	3.04%	0.00%	3.04%	2.65%	0.00%	2.65%
311.00	Structures and Improvements	3.72%	0.05%	3.77%	2.74%	0.46%	3.20%
312.00	Boiler Plant Equipment	3.16%	0.07%	3.23%	2.05%	0.21%	2.26%
314.00	Turbogenerator Units	2.97%	0.08%	3.05%	2.14%	0.09%	2.23%
315.00	Accessory Electric Equipment	3.30%	0.08%	3.38%	1.84%	0.12%	1.96%
316.00	Miscellaneous Power Plant Equipment	3.99%	0.06%	4.05%	2.19%	0.16%	2.35%
	Total Springerville	3.22%	0.07%	3.29%	2.15%	0.21%	2.36%
Springerville Unit 1							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	7.97%	0.01%	7.98%	2.02%	0.05%	2.07%
312.00	Boiler Plant Equipment	6.15%	0.03%	6.18%	1.94%	0.04%	1.98%
314.00	Turbogenerator Units	5.77%	-0.05%	5.72%	1.93%	0.04%	1.97%
315.00	Accessory Electric Equipment	6.08%	0.01%	6.09%	1.68%	0.05%	1.73%
316.00	Miscellaneous Power Plant Equipment	8.69%	0.00%	8.69%	2.11%	0.04%	2.15%
	Total Springerville Unit 1	6.24%	0.01%	6.25%	1.93%	0.04%	1.97%
Springerville Unit 1 Common							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	1.92%	0.00%	1.92%
311.00	Structures and Improvements	3.00%	0.01%	3.01%	1.93%	0.12%	2.05%
312.00	Boiler Plant Equipment	4.24%	0.00%	4.24%	1.88%	0.14%	2.02%
314.00	Turbogenerator Units	1.83%	0.00%	1.83%	1.81%	0.14%	1.95%
315.00	Accessory Electric Equipment	4.35%	0.00%	4.35%	1.68%	0.16%	1.84%
316.00	Miscellaneous Power Plant Equipment	3.72%	0.00%	3.72%	1.70%	0.15%	1.85%
	Total Springerville Unit 1 Common	3.34%	0.01%	3.35%	1.88%	0.13%	2.01%

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A		B	C	D=B+C	E	F	G=E+F
Springerville Unit 2							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	1.86%	0.15%	2.01%	2.12%	0.09%	2.21%
312.00	Boiler Plant Equipment	1.88%	0.14%	2.02%	2.08%	0.10%	2.18%
314.00	Turbogenerator Units	1.84%	0.14%	1.98%	2.22%	0.10%	2.32%
315.00	Accessory Electric Equipment	1.69%	0.13%	1.82%	1.83%	0.07%	1.90%
316.00	Miscellaneous Power Plant Equipment	1.71%	0.11%	1.82%	2.10%	0.07%	2.17%
Total Springerville Unit 2		1.85%	0.14%	1.99%	2.10%	0.09%	2.19%
Springerville Unit 2 Common (Leasehold Imp.)							
310.00	Rights-of-Way	2.80%	0.00%	2.80%	3.60%	0.00%	3.60%
311.00	Structures and Improvements	4.34%	0.01%	4.35%	5.18%	1.67%	6.85%
312.00	Boiler Plant Equipment	5.50%	0.00%	5.50%	6.29%	1.81%	8.10%
314.00	Turbogenerator Units	4.06%	0.00%	4.06%	4.47%	1.53%	6.00%
315.00	Accessory Electric Equipment	3.06%	0.00%	3.06%	3.75%	1.29%	5.04%
316.00	Miscellaneous Power Plant Equipment	4.37%	0.00%	4.37%	4.98%	1.68%	6.66%
Total Springerville Unit 2 Common		4.34%	0.01%	4.35%	5.15%	1.59%	6.74%
Springerville Coal Handling							
310.00	Rights-of-Way	5.44%	0.00%	5.44%	1.84%	0.00%	1.84%
311.00	Structures and Improvements	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
312.00	Boiler Plant Equipment	1.65%	0.00%	1.65%	1.96%	0.59%	2.55%
314.00	Turbogenerator Units	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
315.00	Accessory Electric Equipment	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
316.00	Miscellaneous Power Plant Equipment	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Total Springerville Coal Handling		1.70%	0.00%	1.70%	1.96%	0.58%	2.54%
Sundt							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	3.91%	2.04%	5.95%	2.87%	0.95%	3.82%
312.00	Boiler Plant Equipment	3.73%	1.76%	5.49%	2.64%	0.77%	3.41%
314.00	Turbogenerator Units	6.15%	3.63%	9.78%	3.46%	1.37%	4.83%
315.00	Accessory Electric Equipment	5.67%	3.17%	8.84%	3.60%	1.35%	4.95%
316.00	Miscellaneous Power Plant Equipment	6.31%	3.45%	9.76%	3.86%	1.49%	5.35%
Total Sundt		4.58%	2.42%	7.00%	3.00%	1.01%	4.01%
Sundt Unit 1							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	9.95%	5.37%	15.32%	4.68%	2.06%	6.74%
312.00	Boiler Plant Equipment	10.40%	5.02%	15.42%	4.17%	1.71%	5.88%
314.00	Turbogenerator Units	11.68%	6.16%	17.84%	4.67%	2.00%	6.67%
315.00	Accessory Electric Equipment	13.14%	7.13%	20.27%	5.98%	2.63%	8.61%
316.00	Miscellaneous Power Plant Equipment	12.19%	6.50%	18.69%	5.61%	2.52%	8.13%
Total Sundt Unit 1		11.26%	5.81%	17.07%	4.73%	2.02%	6.75%
Sundt Unit 2							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	8.40%	5.33%	13.73%	4.80%	2.24%	7.04%
312.00	Boiler Plant Equipment	8.25%	5.37%	13.62%	3.77%	1.86%	5.63%
314.00	Turbogenerator Units	8.22%	5.19%	13.41%	3.58%	1.71%	5.29%
315.00	Accessory Electric Equipment	10.07%	6.35%	16.42%	5.49%	2.69%	8.18%
316.00	Miscellaneous Power Plant Equipment	9.57%	5.95%	15.52%	5.21%	2.51%	7.72%
Total Sundt Unit 2		8.62%	5.51%	14.13%	4.16%	2.02%	6.18%

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
Sundt Unit 3							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	6.64%	4.90%	11.54%	3.92%	2.01%	5.93%
312.00	Boiler Plant Equipment	6.17%	4.67%	10.84%	3.64%	1.93%	5.57%
314.00	Turbogenerator Units	6.82%	5.09%	11.91%	3.83%	1.99%	5.82%
315.00	Accessory Electric Equipment	7.15%	5.16%	12.31%	3.75%	1.90%	5.65%
316.00	Miscellaneous Power Plant Equipment	7.90%	5.55%	13.45%	4.47%	2.25%	6.72%
	Total Sundt Unit 3	6.66%	4.95%	11.61%	3.77%	1.96%	5.73%
Sundt Unit 4							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	1.47%	0.36%	1.83%	2.01%	0.35%	2.36%
312.00	Boiler Plant Equipment	1.47%	0.35%	1.82%	1.97%	0.33%	2.30%
314.00	Turbogenerator Units	1.73%	0.43%	2.16%	2.47%	0.40%	2.87%
315.00	Accessory Electric Equipment	1.53%	0.36%	1.89%	2.22%	0.38%	2.60%
316.00	Miscellaneous Power Plant Equipment	1.78%	0.31%	2.09%	2.32%	0.34%	2.66%
	Total Sundt Unit 4	1.52%	0.36%	1.88%	2.08%	0.35%	2.43%
Sundt Solar Booster (Areva)							
310.00	Rights-of-Way	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
311.00	Structures and Improvements	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
312.00	Boiler Plant Equipment	3.34%	0.00%	3.34%	3.11%	0.01%	3.12%
314.00	Turbogenerator Units	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
315.00	Accessory Electric Equipment	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
316.00	Miscellaneous Power Plant Equipment	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Total Sundt Solar Booster (Areva)	3.34%	0.00%	3.34%	3.11%	0.01%	3.12%
OTHER PRODUCTION (by Unit)							
DeMoss Petrie Gas Unit 1							
341.00	Structures and Improvements	2.46%	0.19%	2.65%	2.61%	0.10%	2.71%
342.00	Fuel Holders, Products and Accessories	2.30%	0.21%	2.51%	2.18%	0.11%	2.29%
343.00	Prime Movers	2.90%	0.27%	3.17%	2.84%	0.00%	2.84%
344.00	Generators and Devices	2.30%	0.21%	2.51%	2.19%	0.11%	2.30%
345.00	Accessory Electric Equipment	2.30%	0.21%	2.51%	2.24%	0.03%	2.27%
346.00	Miscellaneous Power Plant Equipment	2.38%	0.22%	2.60%	2.32%	0.11%	2.43%
	Total DeMoss Petrie Gas Unit 1	2.31%	0.21%	2.52%	2.20%	0.11%	2.31%
Gila River							
341.00	Structures and Improvements	2.26%	0.00%	2.26%	2.39%	0.11%	2.50%
342.00	Fuel Holders, Products and Accessories	2.26%	0.00%	2.26%	2.37%	0.11%	2.48%
343.00	Prime Movers	2.26%	0.00%	2.26%	2.41%	0.11%	2.52%
344.00	Generators and Devices	2.26%	0.00%	2.26%	2.34%	0.11%	2.45%
345.00	Accessory Electric Equipment	2.26%	0.00%	2.26%	2.36%	0.11%	2.47%
346.00	Miscellaneous Power Plant Equipment	2.26%	0.00%	2.26%	2.38%	0.11%	2.49%
	Total Gila River	2.26%	0.00%	2.26%	2.39%	0.11%	2.50%
Gila River Unit 3							
341.00	Structures and Improvements	2.26%	0.00%	2.26%	2.36%	0.10%	2.46%
342.00	Fuel Holders, Products and Accessories	2.26%	0.00%	2.26%	2.42%	0.11%	2.53%
343.00	Prime Movers	2.26%	0.00%	2.26%	2.40%	0.11%	2.51%
344.00	Generators and Devices	2.26%	0.00%	2.26%	2.34%	0.11%	2.45%
345.00	Accessory Electric Equipment	2.26%	0.00%	2.26%	2.36%	0.10%	2.46%
346.00	Miscellaneous Power Plant Equipment	2.26%	0.00%	2.26%	2.38%	0.11%	2.49%
	Total Gila River Unit 3	2.26%	0.00%	2.26%	2.39%	0.11%	2.50%

TUCSON ELECTRIC POWER COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
Gila River Common							
341.00	Structures and Improvements	2.26%	0.00%	2.26%	2.39%	0.11%	2.50%
342.00	Fuel Holders, Products and Accessories	2.26%	0.00%	2.26%	2.37%	0.11%	2.48%
343.00	Prime Movers	2.26%	0.00%	2.26%	2.58%	0.11%	2.69%
344.00	Generators and Devices	2.26%	0.00%	2.26%	0.00%	0.00%	0.00%
345.00	Accessory Electric Equipment	2.26%	0.00%	2.26%	2.38%	0.11%	2.49%
346.00	Miscellaneous Power Plant Equipment	2.26%	0.00%	2.26%	2.38%	0.11%	2.49%
	Total Gila River Common	2.26%	0.00%	2.26%	2.43%	0.11%	2.54%
Luna							
341.00	Structures and Improvements	2.63%	0.51%	3.14%	2.77%	0.26%	3.03%
342.00	Fuel Holders, Products and Accessories	2.62%	0.52%	3.14%	2.77%	0.26%	3.03%
343.00	Prime Movers	2.65%	0.51%	3.16%	2.83%	0.26%	3.09%
344.00	Generators and Devices	2.63%	0.50%	3.13%	2.79%	0.25%	3.04%
345.00	Accessory Electric Equipment	2.57%	0.00%	2.57%	2.86%	0.28%	3.14%
346.00	Miscellaneous Power Plant Equipment	2.62%	0.52%	3.14%	2.77%	0.26%	3.03%
	Total Luna	2.63%	0.51%	3.14%	2.79%	0.25%	3.04%
North Loop Gas							
341.00	Structures and Improvements	3.17%	0.35%	3.52%	1.01%	0.08%	1.09%
342.00	Fuel Holders, Products and Accessories	2.22%	0.13%	2.35%	2.21%	0.07%	2.28%
343.00	Prime Movers	10.88%	1.39%	12.27%	5.69%	0.53%	6.22%
344.00	Generators and Devices	2.21%	0.18%	2.39%	1.39%	0.03%	1.42%
345.00	Accessory Electric Equipment	2.96%	0.30%	3.26%	1.72%	0.12%	1.84%
346.00	Miscellaneous Power Plant Equipment	2.69%	0.29%	2.98%	0.68%	0.04%	0.72%
	Total North Loop Gas	2.85%	0.27%	3.12%	1.66%	0.08%	1.74%
North Loop Gas Unit 1							
341.00	Structures and Improvements	4.39%	0.49%	4.88%	1.29%	0.15%	1.44%
342.00	Fuel Holders, Products and Accessories	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
343.00	Prime Movers	9.60%	1.06%	10.66%	3.68%	0.40%	4.08%
344.00	Generators and Devices	2.65%	0.29%	2.94%	0.04%	0.00%	0.04%
345.00	Accessory Electric Equipment	4.10%	0.45%	4.55%	1.37%	0.13%	1.50%
346.00	Miscellaneous Power Plant Equipment	4.26%	0.48%	4.74%	1.04%	0.11%	1.15%
	Total North Loop Gas Unit 1	3.88%	0.43%	4.31%	0.79%	0.08%	0.87%
North Loop Gas Unit 2							
341.00	Structures and Improvements	1.98%	0.31%	2.29%	0.60%	0.09%	0.69%
342.00	Fuel Holders, Products and Accessories	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
343.00	Prime Movers	5.30%	0.82%	6.12%	13.43%	0.54%	13.97%
344.00	Generators and Devices	1.85%	0.26%	2.11%	0.47%	0.04%	0.51%
345.00	Accessory Electric Equipment	2.68%	0.39%	3.07%	1.55%	0.20%	1.75%
346.00	Miscellaneous Power Plant Equipment	0.89%	0.13%	1.02%	-0.12%	-0.02%	-0.14%
	Total North Loop Gas Unit 2	2.13%	0.31%	2.44%	1.37%	0.09%	1.46%
North Loop Gas Unit 3							
341.00	Structures and Improvements	2.17%	0.29%	2.46%	0.27%	0.04%	0.31%
342.00	Fuel Holders, Products and Accessories	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
343.00	Prime Movers	13.34%	1.78%	15.12%	4.98%	0.62%	5.60%
344.00	Generators and Devices	1.99%	0.22%	2.21%	0.09%	-0.03%	0.06%
345.00	Accessory Electric Equipment	2.85%	0.37%	3.22%	1.26%	0.15%	1.41%
346.00	Miscellaneous Power Plant Equipment	1.09%	0.15%	1.24%	-0.48%	-0.07%	-0.55%
	Total North Loop Gas Unit 3	4.30%	0.54%	4.84%	1.17%	0.12%	1.29%

TUCSON ELECTRIC POWER COMPANY

Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	Current (at 12/31/2014) Investment	Net Salvage	Total	Proposed (at 12/31/2014) Investment	Net Salvage	Total
A		B	C	D=B+C	E	F	G=E+F
North Loop Gas Unit 4							
341.00	Structures and Improvements	2.29%	-0.10%	2.19%	2.30%	-0.15%	2.15%
342.00	Fuel Holders, Products and Accessories	2.22%	0.13%	2.35%	2.21%	0.07%	2.28%
343.00	Prime Movers	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
344.00	Generators and Devices	2.22%	0.13%	2.35%	2.21%	0.06%	2.27%
345.00	Accessory Electric Equipment	2.27%	0.11%	2.38%	2.30%	0.05%	2.35%
346.00	Miscellaneous Power Plant Equipment	2.22%	0.06%	2.28%	2.21%	0.03%	2.24%
	Total North Loop Gas Unit 4	2.22%	0.13%	2.35%	2.22%	0.05%	2.27%
Solar Units (Generators and Devices)							
344.00	DeMoss Petrie	5.13%	0.00%	5.13%	3.05%	0.15%	3.20%
344.00	Fort Huachuca	5.13%	0.00%	5.13%	3.56%	0.18%	3.74%
344.00	HQ Rooftop	5.13%	0.00%	5.13%	3.50%	0.18%	3.68%
344.00	OH Rooftop	5.13%	0.00%	5.13%	3.47%	0.17%	3.64%
344.00	OH Test Yard	5.13%	0.00%	5.13%	3.10%	0.15%	3.25%
344.00	Prairie Fire	5.13%	0.00%	5.13%	3.50%	0.18%	3.68%
344.00	Springerville Sites 1-3 (Legacy)	5.13%	0.00%	5.13%	3.05%	0.15%	3.20%
344.00	Springerville Site 4	5.13%	0.00%	5.13%	3.43%	0.18%	3.61%
343.00	Tucson	5.13%	0.00%	5.13%	2.60%	0.13%	2.73%
344.00	U of A Tech Park Site 1	5.13%	0.00%	5.13%	3.43%	0.18%	3.61%
345.00	U of A Tech Park Site 2	5.13%	0.00%	5.13%	3.47%	0.17%	3.64%
346.00	White Mountain	5.13%	0.00%	5.13%	3.56%	0.18%	3.74%
	Total Solar Units	5.13%	0.00%	5.13%	3.44%	0.17%	3.61%
Sundt Gas							
341.00	Structures and Improvements	0.26%	0.01%	0.27%	-0.16%	-0.02%	-0.18%
342.00	Fuel Holders, Products and Accessories	8.51%	0.15%	8.66%	3.62%	0.06%	3.68%
343.00	Prime Movers	3.64%	0.06%	3.70%	1.77%	0.03%	1.80%
344.00	Generators and Devices	0.16%	0.00%	0.16%	-0.41%	-0.01%	-0.42%
345.00	Accessory Electric Equipment	1.37%	0.03%	1.40%	0.13%	0.01%	0.14%
346.00	Miscellaneous Power Plant Equipment	0.00%	0.00%	0.00%	-1.29%	-0.02%	-1.31%
	Total Sundt Gas	0.96%	0.01%	0.97%	-0.02%	0.00%	-0.02%
Sundt Gas Unit 1							
341.00	Structures and Improvements	0.10%	0.00%	0.10%	-0.11%	-0.01%	-0.12%
342.00	Fuel Holders, Products and Accessories	8.42%	0.14%	8.56%	3.65%	0.06%	3.71%
343.00	Prime Movers	3.51%	0.06%	3.57%	1.81%	0.03%	1.84%
344.00	Generators and Devices	0.00%	0.00%	0.00%	-0.43%	-0.01%	-0.44%
345.00	Accessory Electric Equipment	1.06%	0.02%	1.08%	0.09%	0.01%	0.10%
346.00	Miscellaneous Power Plant Equipment	0.00%	0.00%	0.00%	-1.25%	-0.02%	-1.27%
	Total Sundt Gas Unit 1	0.77%	0.01%	0.78%	-0.05%	0.00%	-0.05%
Sundt Gas Unit 2							
341.00	Structures and Improvements	0.41%	0.01%	0.42%	-0.21%	-0.02%	-0.23%
342.00	Fuel Holders, Products and Accessories	8.59%	0.16%	8.75%	3.59%	0.06%	3.65%
343.00	Prime Movers	3.77%	0.06%	3.83%	1.73%	0.03%	1.76%
344.00	Generators and Devices	0.32%	0.00%	0.32%	-0.38%	-0.01%	-0.39%
345.00	Accessory Electric Equipment	1.65%	0.03%	1.68%	0.17%	0.01%	0.18%
346.00	Miscellaneous Power Plant Equipment	0.00%	0.00%	0.00%	-1.32%	-0.02%	-1.34%
	Total Sundt Gas Unit 2	1.15%	0.02%	1.17%	0.01%	0.00%	0.01%

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
STEAM PRODUCTION									
310.00	Rights-of-Way	$ 5,106,662	$ 154,751	$ 2	$ 154,753	$ 134,879	$ 5	$ 134,884	$ (19,869)
311.00	Structures and Improvements	205,277,689	6,925,225	672,414	7,597,639	6,489,626	1,039,730	7,529,355	(68,284)
312.00	Boiler Plant Equipment	1,091,953,161	31,609,169	4,124,981	35,734,150	34,372,860	3,868,017	38,240,877	2,506,727
314.00	Turbogenerator Units	303,041,923	9,895,445	2,168,057	12,063,502	10,339,885	1,224,260	11,564,145	(499,357)
315.00	Accessory Electric Equipment	144,581,471	5,383,758	1,355,199	6,738,957	4,458,194	728,268	5,186,462	(1,552,495)
316.00	Miscellaneous Power Plant Equipment	25,222,863	842,395	101,717	944,112	757,388	77,712	835,100	(109,012)
	Total Steam Production Plant	$ 1,775,183,769	$ 54,810,743	$ 8,422,370	$ 63,233,113	$ 56,552,831	$ 6,937,992	$ 63,490,823	$ 257,710
OTHER PRODUCTION									
Non-Solar									
341.00	Structures and Improvements	$ 23,403,461	$ 587,238	$ 72,042	$ 659,280	$ 598,468	$ 45,172	$ 643,640	$ (15,640)
342.00	Fuel Holders, Products and Accessories	19,977,187	541,762	62,185	603,947	526,902	38,488	565,390	(38,557)
343.00	Prime Movers	202,005,134	4,774,207	83,405	4,857,612	4,970,656	246,674	5,217,330	359,718
344.00	Generators and Devices	105,487,225	2,241,822	156,008	2,397,830	2,005,149	101,703	2,106,852	(290,978)
345.00	Accessory Electric Equipment	13,809,819	322,600	10,605	333,205	283,240	12,950	296,190	(37,015)
346.00	Miscellaneous Power Plant Equipment	15,307,160	374,821	41,324	416,145	380,059	27,437	407,496	(8,649)
	Total Non-Solar	$ 379,989,986	$ 8,842,450	$ 425,569	$ 9,268,019	$ 8,764,474	$ 472,424	$ 9,236,898	$ (31,121)
Solar									
344.00	Generators and Devices	$ 170,320,932	$ 8,737,463	$ -	$ 8,737,463	$ 5,856,756	$ 295,265	$ 6,152,021	$ (2,585,442)
	Total Solar	$ 170,320,932	$ 8,737,463	$ -	$ 8,737,463	$ 5,856,756	$ 295,265	$ 6,152,021	$ (2,585,442)
	Total Other Production Plant	$ 550,310,918	$ 17,579,913	$ 425,569	$ 18,005,482	$ 14,621,230	$ 767,689	$ 15,388,919	$ (2,616,563)
DISTRIBUTION PLANT									
360.RW	Rights-of-Way	$ 7,865,073	$ 112,471	$ -	$ 112,471	$ 83,545	$ -	$ 83,545	$ (28,926)
361.00	Structures and Improvements	11,402,474	196,123	0	196,123	$ 165,590	0	165,590	(30,533)
362.00	Station Equipment	157,067,530	2,403,133	0	2,403,133	$ 2,155,331	0	2,155,331	(247,802)
364.00	Poles, Towers and Fixtures	222,006,967	3,862,921	0	3,862,921	$ 3,046,450	0	3,046,450	(816,471)
365.00	Overhead Conductors and Devices	175,675,966	2,863,518	0	2,863,518	$ 2,340,411	0	2,340,411	(523,107)
366.00	Underground Conduit	58,725,355	792,792	0	792,792	$ 617,926	0	617,926	(174,866)
367.00	Underground Conductors and Devices	297,183,135	5,557,325	0	5,557,325	$ 4,286,070	0	4,286,070	(1,271,255)
368.OH	Line Transformers - Overhead	103,657,922	1,938,403	0	1,938,403	$ 1,474,256	0	1,474,256	(464,147)
368.UG	Line Transformers - Underground	172,890,932	3,613,420	0	3,613,420	$ 2,804,692	0	2,804,692	(808,728)
369.OH	Services - Overhead	17,542,236	324,531	0	324,531	$ 254,754	0	254,754	(69,777)
369.UG	Services - Underground	112,947,714	1,716,805	0	1,716,805	$ 1,391,778	0	1,391,778	(325,027)
370.00	Meters	44,869,823	1,476,217	0	1,476,217	$ 1,898,995	0	1,898,995	422,778
373.00	Street Lighting and Signal Systems	11,778,362	208,477	0	208,477	$ 166,337	0	166,337	(42,140)
	Total Distribution Plant	$ 1,393,613,489	$ 25,066,136	$ -	$ 25,066,136	$ 20,686,134	$ -	$ 20,686,134	$ (4,380,002)
GENERAL PLANT									
Depreciable									
390.00	Structures and Improvements	$ 135,680,348	$ 3,378,441	$ 203,521	$ 3,581,962	$ 3,432,713	$ 203,521	$ 3,636,234	$ 54,272
392.C0	Transportation - Class 0	1,238,946	61,452	(9,044)	52,408	63,682	(10,655)	53,027	619
392.C1	Transportation - Class 1	7,718,183	959,370	(139,699)	819,671	1,001,048	(169,800)	831,248	11,577
392.C2	Transportation - Class 2	3,839,907	470,389	(68,350)	402,039	494,580	(85,630)	408,950	6,911

TUCSON ELECTRIC POWER COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

	Account Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
	A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
392.C3	Transportation - Class 3	2,076,936	222,440	(32,400)	190,040	238,640	(41,954)	196,686	6,646
392.C4	Transportation - Class 4	2,935,027	206,332	(29,937)	176,395	222,769	(39,623)	183,146	6,751
392.C5	Transportation - Class 5	7,982,715	583,536	(86,213)	497,323	628,240	(104,574)	523,666	26,343
392.C6	Transportation - Class 6	365,200	24,286	(3,652)	20,634	24,761	(3,689)	21,072	438
392.C7	Transportation - Class 7	1,047,216	73,096	(10,891)	62,205	75,400	(11,310)	64,090	1,885
392.C8	Transportation - Class 8	9,957,500	746,813	(112,520)	634,293	781,664	(118,494)	663,170	28,877
392.C9	Transportation - Class 9	4,252,286	198,157	(29,766)	168,391	170,942	(25,939)	145,003	(23,388)
396.00	Power Operatied Equipment	11,860,940	768,589	(28,466)	740,123	797,055	(7,117)	789,938	49,815
397.EM	EMS and SCADA Equipment	11,304,371	560,697	0	560,697	578,784	0	578,784	18,087
	Total Depreciable	$ 200,259,575	$ 8,253,598	$ (347,417)	$ 7,906,181	$ 8,510,278	$ (415,264)	$ 8,095,014	$ 188,833
	Amortizable								
391.00	Furniture and Office Equipment	$ 23,964,411	$ 993,514	$ -	$ 993,514	$ 993,514	$ -	$ 993,514	$ -
391.20	Network and Data Equipment	29,359,636	5,484,102	0	5,484,102	5,484,102	0	5,484,102	0
393.00	Stores Equipment	1,852,479	117,635	0	117,635	117,635	0	117,635	0
394.00	Tools, Shop and Garage Equipment	6,934,368	396,576	0	396,576	396,576	0	396,576	0
395.00	Laboratory Equipment	5,091,270	294,185	0	294,185	294,185	0	294,185	0
397.20	Telecommunications Equipment	57,456,141	3,785,287	0	3,785,287	3,785,287	0	3,785,287	0
398.00	Miscellaneous Equipment	4,348,209	217,244	0	217,244	217,244	0	217,244	0
	Total Amortizable	$ 129,006,514	$ 11,288,543	$ -	$ 11,288,543	$ 11,288,543	$ -	$ 11,288,543	$ -
	Total General Plant	$ 329,266,089	$ 19,542,141	$ (347,417)	$ 19,194,724	$ 19,798,821	$ (415,264)	$ 19,383,557	$ 188,833
	SUBTOTAL	$ 4,048,374,265	$ 116,998,933	$ 8,500,522	$ 125,499,455	$ 111,659,017	$ 7,290,417	$ 118,949,433	$ (6,550,022)
	NET SALVAGE						0		
108.02	Distribution	$ 1,393,613,489	$ -	$ 3,762,756	$ 3,762,756	$ -	$ 1,114,891	$ 1,114,891	$ (2,647,865)
	Total Net Salvage	$ 1,393,613,489	$ -	$ 3,762,756	$ 3,762,756	$ -	$ 1,114,891	$ 1,114,891	$ (2,647,865)
	TOTAL UTILITY	$ 4,048,374,265	$ 116,998,933	$ 12,263,278	$ 129,262,211	$ 111,659,017	$ 8,405,308	$ 120,064,324	$ (9,197,887)
	STEAM PRODUCTION (by Unit)								
	Four Corners								
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	2,982,777	65,429	5,210	70,639	72,097	3,427	75,524	4,885
312.00	Boiler Plant Equipment	76,402,061	1,219,616	111,205	1,330,821	1,149,446	73,286	1,222,732	(108,089)
314.00	Turbogenerator Units	12,359,480	287,585	16,903	304,488	246,553	8,970	255,523	(48,965)
315.00	Accessory Electric Equipment	4,390,980	153,002	8,523	161,525	175,856	6,751	182,607	21,082
316.00	Miscellaneous Power Plant Equipment	3,832,234	91,767	6,700	98,467	86,387	3,446	89,833	(8,634)
	Total Four Corners	$ 99,967,532	$ 1,817,399	$ 148,541	$ 1,965,940	$ 1,730,339	$ 95,880	$ 1,826,219	$ (139,721)
	Four Corners Unit 4								
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	1,524,414	32,470	2,439	34,909	34,909	1,677	36,586	1,677
312.00	Boiler Plant Equipment	39,609,538	594,143	63,375	657,518	538,690	47,531	586,221	(71,297)
314.00	Turbogenerator Units	7,179,362	175,176	8,615	183,791	145,023	4,308	149,331	(34,460)
315.00	Accessory Electric Equipment	2,274,836	88,036	3,867	91,903	88,036	2,730	90,766	(1,137)
316.00	Miscellaneous Power Plant Equipment	1,929,161	45,142	2,894	48,036	41,284	1,543	42,827	(5,209)
	Total Four Corners Unit 4	$ 52,517,311	$ 934,967	$ 81,190	$ 1,016,157	$ 847,942	$ 57,789	$ 905,731	$ (110,426)

TUCSON ELECTRIC POWER COMPANY

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Statement B

Account	Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Four Corners Unit 5									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	1,458,363	32,959	2,771	35,730	37,188	1,750	38,938	3,208
312.00	Boiler Plant Equipment	36,792,523	625,473	47,830	673,303	610,756	25,755	636,511	(36,792)
314.00	Turbogenerator Units	5,180,118	112,409	8,288	120,697	101,530	4,662	106,192	(14,505)
315.00	Accessory Electric Equipment	2,116,144	64,966	4,656	69,622	87,820	4,021	91,841	22,219
316.00	Miscellaneous Power Plant Equipment	1,903,073	46,625	3,806	50,431	45,103	1,903	47,006	(3,425)
	Total Four Corners Unit 5	$ 47,450,221	$ 882,432	$ 67,351	$ 949,783	$ 882,397	$ 38,091	$ 920,488	$ (29,295)
Navajo									
310.00	Rights-of-Way	$ 12,229	$ 35	$ 2	$ 37	$ 84	$ 5	$ 89	$ 52
311.00	Structures and Improvements	18,655,156	266,935	19,407	286,342	468,945	23,277	492,222	205,880
312.00	Boiler Plant Equipment	88,544,201	1,470,251	90,473	1,560,724	2,745,446	122,428	2,867,874	1,307,150
314.00	Turbogenerator Units	20,255,526	305,780	19,622	325,402	630,353	28,542	658,895	333,493
315.00	Accessory Electric Equipment	14,829,858	277,041	19,470	296,511	569,278	26,756	596,034	299,523
316.00	Miscellaneous Power Plant Equipment	4,518,597	71,350	4,862	76,212	126,598	5,904	132,502	56,290
	Total Navajo	$ 146,815,567	$ 2,391,392	$ 153,836	$ 2,545,228	$ 4,540,704	$ 206,912	$ 4,747,616	$ 2,202,388
Navajo Unit 1									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	3,190,563	22,015	1,595	23,610	130,494	6,381	136,875	113,265
312.00	Boiler Plant Equipment	27,198,582	475,975	32,638	508,613	1,623,755	78,876	1,702,631	1,194,018
314.00	Turbogenerator Units	6,860,989	108,404	6,175	114,579	411,659	18,525	430,184	315,605
315.00	Accessory Electric Equipment	3,544,300	53,519	3,190	56,709	299,493	13,823	313,316	256,607
316.00	Miscellaneous Power Plant Equipment	471,227	3,157	236	3,393	18,708	895	19,603	16,210
	Total Navajo Unit 1	$ 41,265,661	$ 663,070	$ 43,834	$ 706,904	$ 2,484,109	$ 118,500	$ 2,602,609	$ 1,895,705
Navajo Unit 2									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	1,802,685	17,847	1,262	19,109	24,336	1,082	25,418	6,309
312.00	Boiler Plant Equipment	26,882,286	408,611	24,194	432,805	440,869	16,129	456,998	24,193
314.00	Turbogenerator Units	6,926,050	110,817	8,311	119,128	121,206	6,233	127,439	8,311
315.00	Accessory Electric Equipment	3,172,330	51,392	3,490	54,882	63,129	3,172	66,301	11,419
316.00	Miscellaneous Power Plant Equipment	515,874	4,540	310	4,850	4,591	206	4,797	(53)
	Total Navajo Unit 2	$ 39,299,225	$ 593,207	$ 37,567	$ 630,774	$ 654,131	$ 26,822	$ 680,953	$ 50,179
Navajo Unit 3									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	3,681,511	36,447	2,577	39,024	38,656	1,841	40,497	1,473
312.00	Boiler Plant Equipment	27,718,514	437,953	22,175	460,128	490,618	16,631	507,249	47,121
314.00	Turbogenerator Units	6,178,944	75,383	4,325	79,708	83,416	3,089	86,505	6,797
315.00	Accessory Electric Equipment	5,139,872	68,360	5,654	74,014	77,612	4,112	81,724	7,710
316.00	Miscellaneous Power Plant Equipment	549,362	4,010	439	4,449	4,889	330	5,219	770
	Total Navajo Unit 3	$ 43,268,203	$ 622,153	$ 35,170	$ 657,323	$ 695,191	$ 26,003	$ 721,194	$ 63,871

TUCSON ELECTRIC POWER COMPANY

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement B

Account	Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Navajo Common									
310.00	Rights-of-Way	$ 12,229	$ 35	$ 2	$ 37	$ 84	$ 5	$ 89	$ 52
311.00	Structures and Improvements	9,980,397	190,626	13,973	204,599	275,459	13,973	289,432	84,833
312.00	Boiler Plant Equipment	6,744,819	147,712	11,466	159,178	190,204	10,792	200,996	41,818
314.00	Turbogenerator Units	289,543	11,176	811	11,987	14,072	695	14,767	2,780
315.00	Accessory Electric Equipment	2,973,356	103,770	7,136	110,906	129,044	5,649	134,693	23,787
316.00	Miscellaneous Power Plant Equipment	2,982,134	59,643	3,877	63,520	98,410	4,473	102,883	39,363
	Total Navajo Common	$ 22,982,478	$ 512,962	$ 37,265	$ 550,227	$ 707,273	$ 35,587	$ 742,860	$ 192,633
San Juan									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	14,437,744	248,228	21,674	269,902	1,277,377	100,086	1,377,462	1,107,560
312.00	Boiler Plant Equipment	154,506,908	3,788,408	1,148,165	4,936,573	13,868,619	1,346,691	15,215,310	10,278,737
314.00	Turbogenerator Units	44,295,673	912,491	79,732	992,223	3,922,178	310,873	4,233,051	3,240,828
315.00	Accessory Electric Equipment	10,063,526	210,328	19,121	229,449	901,575	70,990	972,565	743,116
316.00	Miscellaneous Power Plant Equipment	2,009,555	31,839	2,411	34,250	179,507	13,572	193,079	158,829
	Total San Juan	$ 225,313,406	$ 5,191,294	$ 1,271,103	$ 6,462,397	$ 20,149,255	$ 1,842,212	$ 21,991,467	$ 15,529,070
San Juan Unit 1									
310.00	Rights-of-Way	$ -	$ -	$ -		$ -	$ -	$ -	$ -
311.00	Structures and Improvements	14,268,404	245,417	21,403	266,820	$ 1,260,558	$ 100,044	1,360,602	1,093,782
312.00	Boiler Plant Equipment	146,453,029	3,485,582	366,133	3,851,715	$ 13,128,918	$ 1,051,002	14,179,920	10,328,205
314.00	Turbogenerator Units	44,295,673	912,491	79,732	992,223	$ 3,922,178	$ 310,873	4,233,051	3,240,828
315.00	Accessory Electric Equipment	10,063,526	210,328	19,121	229,449	$ 901,575	$ 70,990	972,565	743,116
316.00	Miscellaneous Power Plant Equipment	1,960,172	31,167	2,352	33,519	$ 174,602	$ 13,572	188,175	154,656
	Total San Juan Unit 1	$ 217,040,804	$ 4,884,985	$ 488,741	$ 5,373,726	$ 19,387,831	$ 1,546,481	$ 20,934,313	$ 15,560,587
San Juan Common									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	169,340	2,811	271	3,082	$ 16,818	$ 42	16,860	13,778
312.00	Boiler Plant Equipment	8,053,879	302,826	782,032	1,084,858	$ 739,701	$ 295,689	1,035,390	(49,468)
314.00	Turbogenerator Units	0	0	0	0	$ -	$ -	0	0
315.00	Accessory Electric Equipment	0	0	0	0	$ -	$ -	0	0
316.00	Miscellaneous Power Plant Equipment	49,383	672	59	731	$ 4,905	$ -	4,905	4,174
	Total San Juan Common	$ 8,272,602	$ 306,309	$ 782,362	$ 1,088,671	$ 761,424	$ 295,731	$ 1,057,155	$ (31,516)
Springerville									
310.00	Rights-of-Way	$ 5,094,433	$ 154,716	$ -	$ 154,716	$ 134,795	$ -	$ 134,795	$ (19,921)
311.00	Structures and Improvements	141,726,641	5,270,099	65,329	5,335,428	3,882,897	650,632	4,533,529	(801,899)
312.00	Boiler Plant Equipment	641,687,365	20,250,799	469,997	20,720,796	13,155,201	1,324,484	14,479,685	(6,241,111)
314.00	Turbogenerator Units	173,649,915	5,159,622	146,103	5,305,725	3,723,773	155,623	3,879,396	(1,426,329)
315.00	Accessory Electric Equipment	75,864,618	2,506,161	57,172	2,563,333	1,393,448	90,179	1,483,627	(1,079,706)
316.00	Miscellaneous Power Plant Equipment	12,528,984	500,165	7,287	507,452	274,826	20,102	294,928	(212,524)
	Total Springerville	$ 1,050,551,956	$ 33,841,562	$ 745,888	$ 34,587,450	$ 22,564,940	$ 2,241,020	$ 24,805,960	$ (9,781,490)

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Springerville Unit 1									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	20,076,015	1,600,058	2,008	1,602,066	405,536	10,038	415,574	(1,186,492)
312.00	Boiler Plant Equipment	185,682,490	11,419,473	55,705	11,475,178	3,602,240	74,273	3,676,513	(7,798,665)
314.00	Turbogenerator Units	49,547,312	2,858,880	(24,774)	2,834,106	956,263	19,819	976,082	(1,858,024)
315.00	Accessory Electric Equipment	21,214,167	1,289,821	2,121	1,291,942	356,398	10,607	367,005	(924,937)
316.00	Miscellaneous Power Plant Equipment	3,277,742	284,836	0	284,836	69,160	1,311	70,471	(214,365)
	Total Springerville Unit 1	$ 279,797,726	$ 17,453,068	$ 35,060	$ 17,488,128	$ 5,389,597	$ 116,048	$ 5,505,645	$ (11,982,483)
Springerville Unit 1 Common									
310.00	Rights-of-Way	$ 1,143,496	$ -	$ -	$ -	$ 21,955	$ -	$ 21,955	$ 21,955
311.00	Structures and Improvements	52,492,826	1,574,785	5,249	1,580,034	1,013,112	62,991	1,076,103	(503,931)
312.00	Boiler Plant Equipment	14,854,799	629,843	0	629,843	279,270	20,797	300,067	(329,776)
314.00	Turbogenerator Units	1,264,322	23,137	0	23,137	22,884	1,770	24,654	1,517
315.00	Accessory Electric Equipment	9,627,097	418,779	0	418,779	161,735	15,403	177,138	(241,641)
316.00	Miscellaneous Power Plant Equipment	1,959,012	72,875	0	72,875	33,303	2,939	36,242	(36,633)
	Total Springerville Unit 1 Common	$ 81,341,552	$ 2,719,419	$ 5,249	$ 2,724,668	$ 1,532,259	$ 103,900	$ 1,636,159	$ (1,088,509)
Springerville Unit 2									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	36,540,030	679,645	54,810	734,455	774,649	32,886	807,535	73,080
312.00	Boiler Plant Equipment	295,922,545	5,563,344	414,292	5,977,636	6,155,189	295,923	6,451,112	473,476
314.00	Turbogenerator Units	122,055,348	2,245,818	170,877	2,416,695	2,709,629	122,055	2,831,684	414,989
315.00	Accessory Electric Equipment	42,346,939	715,663	55,051	770,714	774,949	29,643	804,592	33,878
316.00	Miscellaneous Power Plant Equipment	6,624,669	113,282	7,287	120,569	139,118	4,637	143,755	23,186
	Total Springerville Unit 2	$ 503,489,531	$ 9,317,752	$ 702,317	$ 10,020,069	$ 10,553,534	$ 485,144	$ 11,038,678	$ 1,018,609
Springerville Unit 2 Common (Leasehold Imp.)									
310.00	Rights-of-Way	$ 2,280,838	$ 63,863	$ -	$ 63,863	$ 82,110	$ -	$ 82,110	$ 18,247
311.00	Structures and Improvements	32,617,770	1,415,611	3,262	1,418,873	1,689,600	544,717	2,234,317	815,444
312.00	Boiler Plant Equipment	6,282,729	345,550	0	345,550	395,184	113,717	508,901	163,351
314.00	Turbogenerator Units	782,933	31,787	0	31,787	34,997	11,979	46,976	15,189
315.00	Accessory Electric Equipment	2,676,415	81,898	0	81,898	100,366	34,526	134,892	52,994
316.00	Miscellaneous Power Plant Equipment	667,561	29,172	0	29,172	33,245	11,215	44,460	15,288
	Total Springerville Unit 2 Common	$ 45,308,246	$ 1,967,881	$ 3,262	$ 1,971,143	$ 2,335,502	$ 716,154	$ 3,051,656	$ 1,080,513
Springerville Coal Handling									
310.00	Rights-of-Way	$ 1,670,099	$ 90,853	$ -	$ 90,853	$ 30,730	$ -	$ 30,730	$ (60,123)
311.00	Structures and Improvements	0	0	0	0	0	0	0	0
312.00	Boiler Plant Equipment	138,944,802	2,292,589	0	2,292,589	2,723,318	819,774	3,543,092	1,250,503
314.00	Turbogenerator Units	0	0	0	0	0	0	0	0
315.00	Accessory Electric Equipment	0	0	0	0	0	0	0	0
316.00	Miscellaneous Power Plant Equipment	0	0	0	0	0	0	0	0
	Total Springerville Coal Handling	$ 140,614,901	$ 2,383,442	$ -	$ 2,383,442	$ 2,754,048	$ 819,774	$ 3,573,822	$ 1,190,380

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Sundt									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	27,475,371	1,074,534	560,794	1,635,328	788,310	262,308	1,050,618	(584,710)
312.00	Boiler Plant Equipment	130,812,626	4,880,095	2,305,141	7,185,236	3,454,148	1,001,128	4,455,276	(2,729,960)
314.00	Turbogenerator Units	52,481,329	3,229,967	1,905,697	5,135,664	1,817,028	720,252	2,537,280	(2,598,384)
315.00	Accessory Electric Equipment	39,432,489	2,237,226	1,250,913	3,488,139	1,418,037	533,592	1,951,629	(1,536,510)
316.00	Miscellaneous Power Plant Equipment	2,333,493	147,274	80,457	227,731	90,070	34,688	124,758	(102,973)
	Total Sundt	$ 252,535,308	$ 11,569,096	$ 6,103,002	$ 17,672,098	$ 7,567,593	$ 2,551,968	$ 10,119,561	$ (7,552,537)
Sundt Unit 1									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	3,926,062	390,643	210,830	601,473	183,740	80,877	264,617	(336,856)
312.00	Boiler Plant Equipment	13,782,181	1,433,347	691,865	2,125,212	574,717	235,675	810,392	(1,314,820)
314.00	Turbogenerator Units	10,237,507	1,195,741	630,630	1,826,371	478,092	204,750	682,842	(1,143,529)
315.00	Accessory Electric Equipment	6,536,315	858,872	466,039	1,324,911	390,872	171,905	562,777	(762,134)
316.00	Miscellaneous Power Plant Equipment	490,578	59,801	31,888	91,689	27,521	12,363	39,884	(51,805)
	Total Sundt Unit 1	$ 34,972,643	$ 3,938,404	$ 2,031,252	$ 5,969,656	$ 1,654,942	$ 705,570	$ 2,360,512	$ (3,609,144)
Sundt Unit 2									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	2,812,689	236,266	149,916	386,182	135,009	63,004	198,013	(188,169)
312.00	Boiler Plant Equipment	14,371,609	1,185,658	771,755	1,957,413	541,810	267,312	809,122	(1,148,291)
314.00	Turbogenerator Units	8,451,923	694,748	438,655	1,133,403	302,579	144,528	447,107	(686,296)
315.00	Accessory Electric Equipment	6,205,700	624,914	394,062	1,018,976	340,693	166,933	507,626	(511,350)
316.00	Miscellaneous Power Plant Equipment	383,824	36,732	22,838	59,570	19,997	9,634	29,631	(29,939)
	Total Sundt Unit 2	$ 32,225,745	$ 2,778,318	$ 1,777,226	$ 4,555,544	$ 1,340,088	$ 651,411	$ 1,991,499	$ (2,564,045)
Sundt Unit 3									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	2,762,012	183,398	135,339	318,737	108,271	55,516	163,787	(154,950)
312.00	Boiler Plant Equipment	11,980,831	739,217	559,505	1,298,722	436,102	231,230	667,332	(631,390)
314.00	Turbogenerator Units	14,830,615	1,011,448	754,878	1,766,326	568,013	295,129	863,142	(903,184)
315.00	Accessory Electric Equipment	6,140,139	439,020	316,831	755,851	230,255	116,663	346,918	(408,933)
316.00	Miscellaneous Power Plant Equipment	404,717	31,973	22,462	54,435	18,091	9,106	27,197	(27,238)
	Total Sundt Unit 3	$ 36,118,314	$ 2,405,056	$ 1,789,015	$ 4,194,071	$ 1,360,732	$ 707,644	$ 2,068,376	$ (2,125,695)
Sundt Unit 4									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	17,974,608	264,227	64,709	328,936	361,290	62,911	424,201	95,265
312.00	Boiler Plant Equipment	80,576,055	1,184,468	282,016	1,466,484	1,587,348	265,901	1,853,249	386,765
314.00	Turbogenerator Units	18,961,284	328,030	81,534	409,564	468,344	75,845	544,189	134,625
315.00	Accessory Electric Equipment	20,550,335	314,420	73,981	388,401	456,217	78,091	534,308	145,907
316.00	Miscellaneous Power Plant Equipment	1,054,374	18,768	3,269	22,037	24,461	3,585	28,046	6,009
	Total Sundt Unit 4	$ 139,116,656	$ 2,109,913	$ 505,509	$ 2,615,422	$ 2,897,660	$ 486,333	$ 3,383,993	$ 768,571

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Sundt Solar Booster (Areva)									
310.00	Rights-of-Way	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311.00	Structures and Improvements	0	0	0	0	0	0	0	0
312.00	Boiler Plant Equipment	10,101,950	337,405	0	337,405	314,171	1,010	315,181	(22,224)
314.00	Turbogenerator Units	0	0	0	0	0	0	0	0
315.00	Accessory Electric Equipment	0	0	0	0	0	0	0	0
316.00	Miscellaneous Power Plant Equipment	0	0	0	0	0	0	0	0
	Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 337,405	$ -	$ 337,405	$ 314,171	$ 1,010	$ 315,181	$ (22,224)
	OTHER PRODUCTION (by Unit)								
	DeMoss Petrie Gas Unit 1								
341.00	Structures and Improvements	$ 761,988	$ 18,745	$ 1,448	$ 20,193	$ 19,888	$ 762	$ 20,650	$ 457
342.00	Fuel Holders, Products and Accessories	750,386	17,259	1,576	18,835	16,358	825	17,183	(1,652)
343.00	Prime Movers	76,766	2,226	207	2,433	2,180	0	2,180	(253)
344.00	Generators and Devices	30,772,866	707,776	64,623	772,399	673,926	33,850	707,776	(64,623)
345.00	Accessory Electric Equipment	861,492	19,814	1,809	21,623	19,297	258	19,555	(2,068)
346.00	Miscellaneous Power Plant Equipment	376,605	8,963	829	9,792	8,737	414	9,151	(641)
	Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 774,783	$ 70,492	$ 845,275	$ 740,386	$ 36,109	$ 776,495	$ (68,780)
	Gila River								
341.00	Structures and Improvements	$ 8,508,950	$ 192,303	$ -	$ 192,303	$ 203,077	$ 9,264	$ 212,341	$ 20,038
342.00	Fuel Holders, Products and Accessories	6,783,045	153,296	0	153,296	160,848	7,461	168,309	15,013
343.00	Prime Movers	188,744,730	4,265,631	0	4,265,631	4,542,785	207,619	4,750,404	484,773
344.00	Generators and Devices	32,783,434	740,906	0	740,906	767,132	36,062	803,194	62,288
345.00	Accessory Electric Equipment	9,030,698	204,094	0	204,094	213,558	9,248	222,806	18,712
346.00	Miscellaneous Power Plant Equipment	6,799,960	153,679	0	153,679	161,839	7,480	169,319	15,640
	Total Gila River	$ 252,650,817	$ 5,709,909	$ -	$ 5,709,909	$ 6,049,239	$ 277,134	$ 6,326,373	$ 616,464
	Gila River Unit 3								
341.00	Structures and Improvements	$ 957,417	$ 21,638	$ -	$ 21,638	$ 22,595	$ 957	$ 23,552	$ 1,914
342.00	Fuel Holders, Products and Accessories	178,424	4,032	0	4,032	4,318	196	4,514	482
343.00	Prime Movers	181,571,712	4,103,521	0	4,103,521	4,357,721	199,729	4,557,450	453,929
344.00	Generators and Devices	32,783,434	740,906	0	740,906	767,132	36,062	803,194	62,288
345.00	Accessory Electric Equipment	6,860,554	155,049	0	155,049	161,909	6,861	168,770	13,721
346.00	Miscellaneous Power Plant Equipment	135,558	3,064	0	3,064	3,226	149	3,375	311
	Total Gila River Unit 3	$ 222,487,099	$ 5,028,210	$ -	$ 5,028,210	$ 5,316,901	$ 243,954	$ 5,560,855	$ 532,645
	Gila River Common								
341.00	Structures and Improvements	$ 7,551,533	$ 170,665	$ -	$ 170,665	$ 180,482	$ 8,307	$ 188,789	$ 18,124
342.00	Fuel Holders, Products and Accessories	6,604,621	149,264	0	149,264	156,530	7,265	163,795	14,531
343.00	Prime Movers	7,173,018	162,110	0	162,110	185,064	7,890	192,954	30,844
344.00	Generators and Devices	0	0	0	0	0	0	0	0
345.00	Accessory Electric Equipment	2,170,144	49,045	0	49,045	51,649	2,387	54,036	4,991
346.00	Miscellaneous Power Plant Equipment	6,664,402	150,615	0	150,615	158,613	7,331	165,944	15,329
	Total Gila River Common	$ 30,163,718	$ 681,699	$ -	$ 681,699	$ 732,338	$ 33,180	$ 765,518	$ 83,819

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Luna									
341.00	Structures and Improvements	$ 13,232,832	$ 348,023	$ 67,487	$ 415,510	$ 366,549	$ 34,405	$ 400,954	$ (14,556)
342.00	Fuel Holders, Products and Accessories	11,352,383	297,432	59,032	356,464	314,461	29,516	343,977	(12,487)
343.00	Prime Movers	11,151,074	295,503	56,870	352,373	315,575	28,993	344,568	(7,805)
344.00	Generators and Devices	9,486,694	249,500	47,433	296,933	264,679	23,717	288,396	(8,537)
345.00	Accessory Electric Equipment	9,647	248	0	248	276	27	303	55
346.00	Miscellaneous Power Plant Equipment	7,424,592	194,524	38,608	233,132	205,661	19,304	224,965	(8,167)
	Total Luna	$ 52,657,222	$ 1,385,230	$ 269,430	$ 1,654,660	$ 1,467,201	$ 135,962	$ 1,603,163	$ (51,497)
North Loop Gas									
341.00	Structures and Improvements	$ 888,601	$ 28,138	$ 3,106	$ 31,244	$ 8,972	$ 743	$ 9,715	$ (21,529)
342.00	Fuel Holders, Products and Accessories	303,037	6,727	394	7,121	6,697	212	6,909	(212)
343.00	Prime Movers	1,890,946	205,693	26,244	231,937	107,609	10,020	117,629	(114,308)
344.00	Generators and Devices	24,062,187	530,628	43,952	574,580	333,421	8,913	342,334	(232,246)
345.00	Accessory Electric Equipment	2,829,171	83,689	8,524	92,213	48,688	3,309	51,997	(40,216)
346.00	Miscellaneous Power Plant Equipment	656,253	17,655	1,887	19,542	4,465	249	4,714	(14,828)
	Total North Loop Gas	$ 30,630,195	$ 872,530	$ 84,107	$ 956,637	$ 509,852	$ 23,446	$ 533,298	$ (423,339)
North Loop Gas Unit 1									
341.00	Structures and Improvements	$ 411,070	$ 18,046	$ 2,014	$ 20,060	$ 5,303	$ 617	$ 5,920	$ (14,140)
342.00	Fuel Holders, Products and Accessories	0	0	0	0	0	0	0	0
343.00	Prime Movers	678,545	65,140	7,193	72,333	24,970	2,714	27,684	(44,649)
344.00	Generators and Devices	3,582,271	94,930	10,389	105,319	1,433	0	1,433	(103,886)
345.00	Accessory Electric Equipment	790,955	32,429	3,559	35,988	10,836	1,028	11,864	(24,124)
346.00	Miscellaneous Power Plant Equipment	306,369	13,051	1,471	14,522	3,186	337	3,523	(10,999)
	Total North Loop Gas Unit 1	$ 5,769,210	$ 223,596	$ 24,626	$ 248,222	$ 45,728	$ 4,696	$ 50,424	$ (197,798)
North Loop Gas Unit 2									
341.00	Structures and Improvements	$ 196,078	$ 3,882	$ 608	$ 4,490	$ 1,176	$ 176	$ 1,352	$ (3,138)
342.00	Fuel Holders, Products and Accessories	0	0	0	0	0	0	0	0
343.00	Prime Movers	263,450	13,963	2,160	16,123	35,381	1,423	36,804	20,681
344.00	Generators and Devices	3,239,719	59,935	8,423	68,358	15,227	1,296	16,523	(51,835)
345.00	Accessory Electric Equipment	504,895	13,531	1,969	15,500	7,826	1,010	8,836	(6,664)
346.00	Miscellaneous Power Plant Equipment	128,559	1,144	167	1,311	(154)	(26)	(180)	(1,491)
	Total North Loop Gas Unit 2	$ 4,332,701	$ 92,455	$ 13,327	$ 105,782	$ 59,456	$ 3,879	$ 63,335	$ (42,447)
North Loop Gas Unit 3									
341.00	Structures and Improvements	$ 196,078	$ 4,255	$ 569	$ 4,824	$ 529	$ 78	$ 607	$ (4,217)
342.00	Fuel Holders, Products and Accessories	0	0	0	0	0	0	0	0
343.00	Prime Movers	948,951	126,590	16,891	143,481	47,258	5,883	53,141	(90,340)
344.00	Generators and Devices	3,030,531	60,308	6,667	66,975	2,727	(909)	1,818	(65,157)
345.00	Accessory Electric Equipment	503,907	14,361	1,864	16,225	6,349	756	7,105	(9,120)
346.00	Miscellaneous Power Plant Equipment	128,559	1,401	193	1,594	(617)	(90)	(707)	(2,301)
	Total North Loop Gas Unit 3	$ 4,808,026	$ 206,915	$ 26,184	$ 233,099	$ 56,246	$ 5,718	$ 61,964	$ (171,135)

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
North Loop Gas Unit 4									
341.00	Structures and Improvements	$ 85,375	$ 1,955	$ (85)	$ 1,870	$ 1,964	$ (128)	$ 1,836	$ (34)
342.00	Fuel Holders, Products and Accessories	303,037	6,727	394	7,121	6,697	212	6,909	(212)
343.00	Prime Movers	0	0	0	0	0	0	0	0
344.00	Generators and Devices	14,209,666	315,455	18,473	333,928	314,034	8,526	322,560	(11,368)
345.00	Accessory Electric Equipment	1,029,414	23,368	1,132	24,500	23,677	515	24,192	(308)
346.00	Miscellaneous Power Plant Equipment	92,766	2,059	56	2,115	2,050	28	2,078	(37)
	Total North Loop Gas Unit 4	$ 15,720,258	$ 349,564	$ 19,970	$ 369,534	$ 348,422	$ 9,153	$ 357,575	$ (11,959)
Solar Units (Generators and Devices)									
344.00	DeMoss Petrie	$ 1,146,081	$ 58,794	$ -	$ 58,794	$ 34,955	$ 1,719	$ 36,674	$ (22,120)
344.00	Fort Huachuca	36,709,538	1,883,199	0	1,883,199	1,306,860	66,077	1,372,937	(510,262)
344.00	HQ Rooftop	303,184	15,553	0	15,553	10,611	546	11,157	(4,396)
344.00	OH Rooftop	2,594,590	133,102	0	133,102	90,032	4,411	94,443	(38,659)
344.00	OH Test Yard	388,459	19,928	0	19,928	12,042	583	12,625	(7,303)
344.00	Prairie Fire	19,036,520	976,573	0	976,573	666,278	34,266	700,544	(276,029)
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	1,475,727	0	1,475,727	877,381	43,150	920,531	(555,196)
344.00	Springerville Site 4	7,873,874	403,930	0	403,930	270,074	14,173	284,247	(119,683)
343.00	Tucson	87,198	4,473	0	4,473	2,267	113	2,380	(2,093)
344.00	U of A Tech Park Site 1	7,723,832	396,233	0	396,233	264,927	13,903	278,830	(117,403)
345.00	U of A Tech Park Site 2	19,191,952	984,547	0	984,547	665,961	32,626	698,587	(285,960)
346.00	White Mountain	46,499,099	2,385,404	0	2,385,404	1,655,368	83,698	1,739,066	(646,338)
	Total Solar Units	$ 170,320,932	$ 8,737,463	$ -	$ 8,737,463	$ 5,856,756	$ 295,265	$ 6,152,021	$ (2,585,442)
Sundt Gas									
341.00	Structures and Improvements	$ 11,090	$ 29	$ 1	$ 30	$ (18)	$ (2)	$ (20)	$ (50)
342.00	Fuel Holders, Products and Accessories	788,336	67,048	1,183	68,231	28,538	474	29,012	(39,219)
343.00	Prime Movers	141,618	5,154	84	5,238	2,507	42	2,549	(2,689)
344.00	Generators and Devices	8,382,044	13,012	0	13,012	(34,009)	(839)	(34,848)	(47,860)
345.00	Accessory Electric Equipment	1,078,811	14,755	272	15,027	1,421	108	1,529	(13,498)
346.00	Miscellaneous Power Plant Equipment	49,750	0	0	0	(643)	(10)	(653)	(653)
	Total Sundt Gas	$ 10,451,649	$ 99,998	$ 1,540	$ 101,538	$ (2,204)	$ (227)	$ (2,431)	$ (103,969)
Sundt Gas Unit 1									
341.00	Structures and Improvements	$ 5,545	$ 6	$ -	$ 6	$ (6)	$ (1)	$ (7)	$ (13)
342.00	Fuel Holders, Products and Accessories	394,168	33,189	552	33,741	14,387	237	14,624	(19,117)
343.00	Prime Movers	70,809	2,485	42	2,527	1,282	21	1,303	(1,224)
344.00	Generators and Devices	4,315,668	0	0	0	(18,557)	(432)	(18,989)	(18,989)
345.00	Accessory Electric Equipment	516,231	5,472	103	5,575	465	52	517	(5,058)
346.00	Miscellaneous Power Plant Equipment	19,906	0	0	0	(249)	(4)	(253)	(253)
	Total Sundt Gas Unit 1	$ 5,322,327	$ 41,152	$ 697	$ 41,849	$ (2,678)	$ (127)	$ (2,805)	$ (44,654)

TUCSON ELECTRIC POWER COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account	Description	12/31/14 Investment	Current December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Proposed December 31, 2014 Annualized Accrual Investment	Net Salvage	Total	Difference
A		B	C	D	E=C+D	F	G	H=F+G	I=H-E
Sundt Gas Unit 2									
341.00	Structures and Improvements	$ 5,545	$ 23	$ 1	$ 24	$ (12)	$ (1)	$ (13)	$ (37)
342.00	Fuel Holders, Products and Accessories	394,168	33,859	631	34,490	14,151	237	14,388	(20,102)
343.00	Prime Movers	70,809	2,669	42	2,711	1,225	21	1,246	(1,465)
344.00	Generators and Devices	4,066,376	13,012	0	13,012	(15,452)	(407)	(15,859)	(28,871)
345.00	Accessory Electric Equipment	562,580	9,283	169	9,452	956	56	1,012	(8,440)
346.00	Miscellaneous Power Plant Equipment	29,844	0	0	0	(394)	(6)	(400)	(400)
	Total Sundt Gas Unit 2	$ 5,129,322	$ 58,846	$ 843	$ 59,689	$ 474	$ (100)	$ 374	$ (59,315)

TUCSON ELECTRIC POWER COMPANY

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2014

Account	Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G	H=G/B
STEAM PRODUCTION								
310.00	Rights-of-Way	$ 5,106,662	$ 3,694,243	72.34%	$ 2,875,689	56.31%	$ 2,656,223	52.01%
311.00	Structures and Improvements	205,277,689	105,373,653	51.33%	103,208,787	50.28%	103,435,696	50.39%
312.00	Boiler Plant Equipment	1,091,953,161	430,944,377	39.47%	505,722,558	46.31%	505,937,359	46.33%
314.00	Turbogenerator Units	303,041,923	108,786,141	35.90%	127,791,352	42.17%	127,082,280	41.94%
315.00	Accessory Electric Equipment	144,581,471	67,267,210	46.53%	65,526,527	45.32%	66,299,420	45.86%
316.00	Miscellaneous Power Plant Equipment	25,222,863	11,455,994	45.42%	11,016,388	43.68%	12,110,638	48.01%
	Total Steam Production Plant	$ 1,775,183,769	$ 727,521,616	40.98%	$ 816,141,300	45.98%	$ 817,521,616	46.05%
OTHER PRODUCTION								
Non-Solar								
341.00	Structures and Improvements	$ 23,403,461	$ 4,517,794	19.30%	$ 5,492,024	23.47%	$ 3,645,629	15.58%
342.00	Fuel Holders, Products and Accessories	19,977,187	3,821,601	19.13%	4,623,704	23.14%	2,980,546	14.92%
343.00	Prime Movers	202,005,134	45,871,980	22.71%	46,328,780	22.93%	45,939,884	22.74%
344.00	Generators and Devices	105,487,225	42,523,497	40.31%	37,775,136	35.81%	44,585,627	42.27%
345.00	Accessory Electric Equipment	13,809,819	5,672,963	41.08%	4,779,519	34.61%	5,702,433	41.29%
346.00	Miscellaneous Power Plant Equipment	15,307,160	3,234,180	21.13%	3,787,826	24.75%	2,787,896	18.21%
	Total Non-Solar	$ 379,989,986	$ 105,642,014	27.80%	$ 102,786,989	27.05%	$ 105,642,014	27.80%
Solar								
344.00	Generators and Devices	$ 170,320,932	$ 26,892,332	15.79%	$ 22,416,079	13.16%	$ 26,892,332	15.79%
	Total Solar	$ 170,320,932	$ 26,892,332	15.79%	$ 22,416,079	13.16%	$ 26,892,332	15.79%
	Total Other Production Plant	$ 550,310,918	$ 132,534,346	24.08%	$ 125,203,068	22.75%	$ 132,534,346	24.08%
DISTRIBUTION PLANT								
360.RW	Rights-of-Way	$ 7,865,073	$ 3,685,111	46.85%	$ 2,967,754	37.73%	$ 3,489,207	44.36%
361.00	Structures and Improvements	11,402,474	2,440,911	21.41%	1,927,786	16.91%	2,266,510	19.88%
362.00	Station Equipment	157,067,530	44,816,223	28.53%	38,291,794	24.38%	45,019,901	28.66%
364.00	Poles, Towers and Fixtures	222,006,967	71,565,728	32.24%	53,853,971	24.26%	63,316,449	28.52%
365.00	Overhead Conductors and Devices	175,675,966	59,385,788	33.80%	50,923,833	28.99%	59,871,468	34.08%
366.00	Underground Conduit	58,725,355	23,125,320	39.38%	18,680,394	31.81%	21,962,656	37.40%
367.00	Underground Conductors and Devices	297,183,135	119,413,016	40.18%	92,262,153	31.05%	108,473,188	36.50%
368.OH	Line Transformers - Overhead	103,657,922	45,498,501	43.89%	31,691,984	30.57%	37,260,464	35.95%
368.UG	Line Transformers - Underground	172,890,932	71,195,629	41.18%	52,540,781	30.39%	61,772,524	35.73%
369.OH	Services - Overhead	17,542,236	8,133,240	46.36%	6,372,639	36.33%	7,492,586	42.71%
369.UG	Services - Underground	112,947,714	35,019,387	31.00%	28,664,832	25.38%	33,701,422	29.84%
370.00	Meters	44,869,823	(225,711)	-0.50%	8,648,279	19.27%	10,167,835	22.66%
373.00	Street Lighting and Signal Systems	11,778,362	4,929,241	41.85%	3,992,908	33.90%	4,694,486	39.86%
	Total Distribution Plant	$ 1,393,613,489	$ 488,982,384	35.09%	$ 390,819,309	28.04%	$ 459,488,696	32.97%

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GENERAL PLANT								
Depreciable								
390.00	Structures and Improvements	$ 135,680,348	$ 22,140,915	16.32%	$ 23,121,989	17.04%	$ 21,696,815	15.98%
392.C0	Transportation - Class 0	1,238,946	537,462	43.38%	430,858	34.78%	404,302	32.63%
392.C1	Transportation - Class 1	7,718,183	3,370,156	43.67%	3,085,389	39.98%	2,895,214	37.51%
392.C2	Transportation - Class 2	3,839,907	1,471,770	38.33%	1,512,999	39.40%	1,419,742	36.97%
392.C3	Transportation - Class 3	2,076,936	1,040,386	50.09%	982,304	47.30%	921,757	44.38%
392.C4	Transportation - Class 4	2,935,027	748,506	25.50%	1,119,503	38.14%	1,050,500	35.79%
392.C5	Transportation - Class 5	7,982,715	2,758,719	34.56%	3,223,932	40.39%	3,025,218	37.90%
392.C6	Transportation - Class 6	365,200	71,788	19.66%	72,748	19.92%	68,264	18.69%
392.C7	Transportation - Class 7	1,047,216	431,484	41.20%	371,401	35.47%	348,508	33.28%
392.C8	Transportation - Class 8	9,957,500	3,320,461	33.35%	3,285,253	32.99%	3,082,759	30.96%
392.C9	Transportation - Class 9	4,252,286	1,578,200	37.11%	1,139,077	26.79%	1,068,867	25.14%
396.00	Power Operatied Equipment	11,860,940	2,437,035	20.55%	2,664,204	22.46%	2,499,990	21.08%
397.EM	EMS and SCADA Equipment	11,304,371	3,197,149	28.28%	3,314,518	29.32%	3,110,221	27.51%
	Total Depreciable	$ 200,259,575	$ 43,104,031	21.52%	$ 44,324,175	22.13%	$ 41,592,158	20.77%
Amortizable								
391.00	Furniture and Office Equipment	$ 23,964,411	$ 7,694,941	32.11%	$ 7,698,753	32.13%	$ 7,698,753	32.13%
391.20	Network and Data Equipment	29,359,636	14,970,053	50.99%	14,913,970	50.80%	14,913,970	50.80%
393.00	Stores Equipment	1,852,479	820,258	44.28%	840,197	45.36%	840,197	45.36%
394.00	Tools, Shop and Garage Equipment	6,934,368	2,860,187	41.25%	2,858,589	41.22%	2,858,589	41.22%
395.00	Laboratory Equipment	5,091,270	2,395,517	47.05%	2,395,826	47.06%	2,395,826	47.06%
397.20	Telecommunications Equipment	57,456,141	18,113,523	31.53%	19,662,636	34.22%	19,662,636	34.22%
398.00	Miscellaneous Equipment	4,348,209	1,818,966	41.83%	1,815,347	41.75%	1,815,347	41.75%
	Total Amortizable	$ 129,006,514	$ 48,673,445	37.73%	$ 50,185,318	38.90%	$ 50,185,318	38.90%
	Total General Plant	$ 329,266,089	$ 91,777,476	27.87%	$ 94,509,493	28.70%	$ 91,777,476	27.87%
	SUBTOTAL	$ 4,048,374,265	$ 1,440,815,822	35.59%	$ 1,426,673,169	35.24%	$ 1,501,322,134	37.08%
NET SALVAGE								
108.02	Distribution	$ 1,393,613,489	$ 85,838,400	6.16%	$ 21,546,273	1.55%	$ 25,332,087	1.82%
	Total Net Salvage	$ 1,393,613,489	$ 85,838,400	6.16%	$ 21,546,273	1.55%	$ 25,332,087	1.82%
	TOTAL UTILITY	$ 4,048,374,265	$ 1,526,654,221	37.71%	$ 1,448,219,442	35.77%	$ 1,526,654,221	37.71%
STEAM PRODUCTION (by Unit)								
Four Corners								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	2,982,777	1,813,087	60.79%	1,386,686	46.49%	1,909,591	64.02%
312.00	Boiler Plant Equipment	76,402,061	60,687,020	79.43%	43,813,191	57.35%	60,348,163	78.99%
314.00	Turbogenerator Units	12,359,480	8,806,344	71.25%	6,389,905	51.70%	8,829,293	71.44%
315.00	Accessory Electric Equipment	4,390,980	1,422,016	32.38%	1,201,366	27.36%	1,657,254	37.74%
316.00	Miscellaneous Power Plant Equipment	3,832,234	2,573,936	67.17%	1,858,755	48.50%	2,558,102	66.75%
	Total Four Corners	$ 99,967,532	$ 75,302,403	75.33%	$ 54,649,901	54.67%	$ 75,302,403	75.33%

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Four Corners Unit 4								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	1,524,414	957,081	62.78%	706,782	46.36%	1,004,754	65.91%
312.00	Boiler Plant Equipment	39,609,538	32,129,841	81.12%	22,479,492	56.75%	31,956,649	80.68%
314.00	Turbogenerator Units	7,179,362	5,095,340	70.97%	3,585,427	49.94%	5,097,011	71.00%
315.00	Accessory Electric Equipment	2,274,836	782,000	34.38%	643,902	28.31%	915,365	40.24%
316.00	Miscellaneous Power Plant Equipment	1,929,161	1,331,723	69.03%	930,087	48.21%	1,322,204	68.54%
	Total Four Corners Unit 4	$ 52,517,311	$ 40,295,985	76.73%	$ 28,345,690	53.97%	$ 40,295,985	76.73%
Four Corners Unit 5								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	1,458,363	856,006	58.70%	679,904	46.62%	904,837	62.04%
312.00	Boiler Plant Equipment	36,792,523	28,557,180	77.62%	21,333,699	57.98%	28,391,514	77.17%
314.00	Turbogenerator Units	5,180,118	3,711,004	71.64%	2,804,478	54.14%	3,732,282	72.05%
315.00	Accessory Electric Equipment	2,116,144	640,016	30.24%	557,463	26.34%	741,889	35.06%
316.00	Miscellaneous Power Plant Equipment	1,903,073	1,242,213	65.27%	928,667	48.80%	1,235,898	64.94%
	Total Four Corners Unit 5	$ 47,450,221	$ 35,006,419	73.78%	$ 26,304,212	55.44%	$ 35,006,419	73.78%
Navajo								
310.00	Rights-of-Way	$ 12,229	$ 12,671	103.62%	$ 9,014	73.71%	$ 11,457	93.69%
311.00	Structures and Improvements	18,655,156	13,989,522	74.99%	11,418,700	61.21%	13,563,269	72.71%
312.00	Boiler Plant Equipment	88,544,201	67,034,406	75.71%	58,764,504	66.37%	67,570,842	76.31%
314.00	Turbogenerator Units	20,255,526	16,002,717	79.00%	13,884,439	68.55%	15,851,479	78.26%
315.00	Accessory Electric Equipment	14,829,858	9,777,819	65.93%	8,366,375	56.42%	9,857,500	66.47%
316.00	Miscellaneous Power Plant Equipment	4,518,597	2,967,546	65.67%	2,412,911	53.40%	2,930,135	64.85%
	Total Navajo	$ 146,815,567	$ 109,784,682	74.78%	$ 94,855,944	64.61%	$ 109,784,682	74.78%
Navajo Unit 1								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	3,190,563	3,081,399	96.58%	2,935,896	92.02%	2,732,415	85.64%
312.00	Boiler Plant Equipment	27,198,582	20,390,194	74.97%	22,456,967	82.57%	20,900,519	76.84%
314.00	Turbogenerator Units	6,860,989	5,372,911	78.31%	5,658,353	82.47%	5,266,184	76.76%
315.00	Accessory Electric Equipment	3,544,300	2,315,538	65.33%	2,485,976	70.14%	2,313,678	65.28%
316.00	Miscellaneous Power Plant Equipment	471,227	458,551	97.31%	436,017	92.53%	405,798	86.12%
	Total Navajo Unit 1	$ 41,265,661	$ 31,618,592	76.62%	$ 33,973,209	82.33%	$ 31,618,592	76.62%
Navajo Unit 2								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	1,802,665	1,519,996	84.32%	1,166,605	64.71%	1,509,303	83.73%
312.00	Boiler Plant Equipment	26,882,286	21,334,917	79.36%	16,484,126	61.32%	21,326,441	79.33%
314.00	Turbogenerator Units	6,926,050	5,347,290	77.21%	4,134,480	59.69%	5,349,010	77.23%
315.00	Accessory Electric Equipment	3,172,330	2,305,054	72.66%	1,803,196	56.84%	2,332,896	73.54%
316.00	Miscellaneous Power Plant Equipment	515,874	478,584	92.77%	361,885	70.15%	468,191	90.76%
	Total Navajo Unit 2	$ 39,299,225	$ 30,985,841	78.85%	$ 23,950,293	60.94%	$ 30,985,841	78.85%

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Navajo Unit 3								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	3,681,511	3,289,429	89.35%	2,533,202	68.81%	3,242,242	88.07%
312.00	Boiler Plant Equipment	27,718,514	21,206,074	76.51%	16,659,767	60.10%	21,322,809	76.93%
314.00	Turbogenerator Units	6,178,944	5,218,613	84.46%	4,029,105	65.21%	5,156,845	83.46%
315.00	Accessory Electric Equipment	5,139,872	4,138,011	80.51%	3,234,223	62.92%	4,139,477	80.54%
316.00	Miscellaneous Power Plant Equipment	549,362	503,918	91.73%	386,493	70.35%	494,672	90.04%
	Total Navajo Unit 3	$ 43,268,203	$ 34,356,045	79.40%	$ 26,842,790	62.04%	$ 34,356,045	79.40%
Navajo Common								
310.00	Rights-of-Way	$ 12,229	$ 12,671	103.62%	$ 9,014	73.71%	$ 11,457	93.69%
311.00	Structures and Improvements	9,980,397	6,098,698	61.11%	4,782,996	47.92%	6,079,309	60.91%
312.00	Boiler Plant Equipment	6,744,819	4,103,220	60.84%	3,163,645	46.90%	4,021,073	59.62%
314.00	Turbogenerator Units	289,543	63,903	22.07%	62,501	21.59%	79,441	27.44%
315.00	Accessory Electric Equipment	2,973,356	1,019,217	34.28%	842,980	28.35%	1,071,449	36.04%
316.00	Miscellaneous Power Plant Equipment	2,982,134	1,526,493	51.19%	1,228,515	41.20%	1,561,474	52.36%
	Total Navajo Common	$ 22,982,478	$ 12,824,203	55.80%	$ 10,089,652	43.90%	$ 12,824,203	55.80%
San Juan								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	14,437,744	3,437,723	23.81%	8,972,935	62.15%	7,343,597	50.86%
312.00	Boiler Plant Equipment	154,506,908	6,056,700	3.92%	85,966,325	55.64%	70,356,244	45.54%
314.00	Turbogenerator Units	44,295,673	6,542,378	14.77%	27,386,524	61.83%	22,413,578	50.60%
315.00	Accessory Electric Equipment	10,063,526	(132,385)	-1.32%	5,660,586	56.25%	4,632,716	46.03%
316.00	Miscellaneous Power Plant Equipment	2,009,555	(208,748)	-10.39%	1,160,207	57.73%	949,533	47.25%
	Total San Juan	$ 225,313,406	$ 15,695,668	6.97%	$ 129,146,577	57.32%	$ 105,695,668	46.91%
San Juan Unit 1								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	14,268,404	3,436,921	24.09%	8,966,435	62.84%	7,338,277	51.43%
312.00	Boiler Plant Equipment	146,453,029	1,499,790	1.02%	81,149,969	55.41%	66,414,460	45.35%
314.00	Turbogenerator Units	44,295,673	6,542,378	14.77%	27,386,524	61.83%	22,413,578	50.60%
315.00	Accessory Electric Equipment	10,063,526	(132,385)	-1.32%	5,660,586	56.25%	4,632,716	46.03%
316.00	Miscellaneous Power Plant Equipment	1,960,172	(209,009)	-10.66%	1,158,316	59.09%	947,984	48.36%
	Total San Juan Unit 1	$ 217,040,804	$ 11,137,695	5.13%	$ 124,321,829	57.28%	$ 101,747,016	46.88%
San Juan Common								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	169,340	803	0.47%	6,501	3.84%	5,320	3.14%
312.00	Boiler Plant Equipment	8,053,879	4,556,910	56.58%	4,816,355	59.80%	3,941,784	48.94%
314.00	Turbogenerator Units	0	0	0.00%	0	0.00%	-	0.00%
315.00	Accessory Electric Equipment	0	0	0.00%	0	0.00%	-	0.00%
316.00	Miscellaneous Power Plant Equipment	49,383	261	0.53%	1,892	3.83%	1,548	3.14%
	Total San Juan Common	$ 8,272,602	$ 4,557,973	55.10%	$ 4,824,748	58.32%	$ 3,948,653	47.73%

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Springerville								
310.00	Rights-of-Way	$ 5,094,433	$ 3,681,571	72.27%	$ 2,866,675	56.27%	$ 2,644,766	51.91%
311.00	Structures and Improvements	141,726,641	69,753,908	49.22%	67,443,147	47.59%	67,999,520	47.98%
312.00	Boiler Plant Equipment	641,687,365	245,587,975	38.27%	248,338,250	38.70%	245,667,845	38.28%
314.00	Turbogenerator Units	173,649,915	50,485,589	29.07%	52,076,344	29.99%	54,676,760	31.49%
315.00	Accessory Electric Equipment	75,864,618	36,828,958	48.55%	34,122,060	44.98%	35,557,418	46.87%
316.00	Miscellaneous Power Plant Equipment	12,528,984	5,054,564	40.34%	4,668,322	37.26%	4,846,255	38.68%
	Total Springerville	$ 1,050,551,956	$ 411,392,565	39.16%	$ 409,514,798	38.98%	$ 411,392,565	39.16%
Springerville Unit 1								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	20,076,015	8,646,215	43.07%	7,772,710	38.72%	8,562,949	42.65%
312.00	Boiler Plant Equipment	185,682,490	82,449,685	44.40%	76,209,273	41.04%	83,957,350	45.22%
314.00	Turbogenerator Units	49,547,312	24,720,176	49.89%	20,501,134	41.38%	22,585,452	45.58%
315.00	Accessory Electric Equipment	21,214,167	10,429,780	49.16%	10,138,966	47.79%	11,169,779	52.65%
316.00	Miscellaneous Power Plant Equipment	3,277,742	1,342,432	40.96%	1,191,608	36.35%	1,312,757	40.05%
	Total Springerville Unit 1	$ 279,797,726	$ 127,588,287	45.60%	$ 115,813,690	41.39%	$ 127,588,287	45.60%
Springerville Unit 1 Common								
310.00	Rights-of-Way	$ 1,143,496	$ 878,769	76.85%	$ 472,348	41.31%	$ 501,934	43.89%
311.00	Structures and Improvements	52,492,826	26,956,787	51.35%	24,529,260	46.73%	26,065,636	49.66%
312.00	Boiler Plant Equipment	14,854,799	7,017,428	47.24%	7,102,335	47.81%	7,547,186	50.81%
314.00	Turbogenerator Units	1,264,322	677,581	53.59%	628,652	49.72%	668,027	52.84%
315.00	Accessory Electric Equipment	9,627,097	4,747,620	49.32%	5,063,206	52.59%	5,380,337	55.89%
316.00	Miscellaneous Power Plant Equipment	1,959,012	968,707	49.45%	1,019,892	52.06%	1,083,772	55.32%
	Total Springerville Unit 1 Common	$ 81,341,552	$ 41,246,892	50.71%	$ 38,815,693	47.72%	$ 41,246,892	50.71%
Springerville Unit 2								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	36,540,030	11,419,075	31.25%	10,347,690	28.32%	10,528,415	28.81%
312.00	Boiler Plant Equipment	295,922,545	90,766,387	30.67%	86,660,209	29.28%	88,173,753	29.80%
314.00	Turbogenerator Units	122,055,348	24,457,076	20.04%	30,283,382	24.81%	30,812,289	25.24%
315.00	Accessory Electric Equipment	42,346,939	19,274,032	45.51%	16,392,415	38.71%	16,678,713	39.39%
316.00	Miscellaneous Power Plant Equipment	6,624,669	2,247,196	33.92%	1,936,771	29.24%	1,970,597	29.75%
	Total Springerville Unit 2	$ 503,489,531	$ 148,163,767	29.43%	$ 145,620,467	28.92%	$ 148,163,767	29.43%
Springerville Unit 2 Common (Leasehold Imp.)								
310.00	Rights-of-Way	$ 2,280,838	$ 1,997,938	87.60%	$ 1,638,561	71.84%	$ 1,509,624	66.19%
311.00	Structures and Improvements	32,617,770	22,731,831	69.69%	24,793,488	76.01%	22,842,521	70.03%
312.00	Boiler Plant Equipment	6,282,729	3,192,901	50.82%	3,968,612	63.17%	3,656,327	58.20%
314.00	Turbogenerator Units	782,933	630,756	80.56%	663,177	84.70%	610,992	78.04%
315.00	Accessory Electric Equipment	2,676,415	2,377,526	88.83%	2,527,473	94.44%	2,328,589	87.00%
316.00	Miscellaneous Power Plant Equipment	667,561	496,229	74.33%	520,051	77.90%	479,129	71.77%
	Total Springerville Unit 2 Common	$ 45,308,246	$ 31,427,182	69.36%	$ 34,111,361	75.29%	$ 31,427,182	69.36%

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Springerville Coal Handling								
310.00	Rights-of-Way	$ 1,670,099	$ 804,864	48.19%	$ 755,766	45.25%	$ 633,208	37.91%
311.00	Structures and Improvements	0	0	0.00%	0	0.00%	0	0.00%
312.00	Boiler Plant Equipment	138,944,802	62,161,574	44.74%	74,397,821	53.54%	62,333,229	44.86%
314.00	Turbogenerator Units	0	0	0.00%	0	0.00%	0	0.00%
315.00	Accessory Electric Equipment	0	0	0.00%	0	0.00%	0	0.00%
316.00	Miscellaneous Power Plant Equipment	0	0	0.00%	0	0.00%	0	0.00%
	Total Springerville Coal Handling	$ 140,614,901	$ 62,966,438	44.78%	$ 75,153,587	53.45%	$ 62,966,438	44.78%
Sundt								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	27,475,371	16,379,412	59.61%	13,987,319	50.91%	12,619,720	45.93%
312.00	Boiler Plant Equipment	130,812,626	51,578,275	39.43%	68,840,288	52.63%	61,994,264	47.39%
314.00	Turbogenerator Units	52,481,329	26,949,112	51.35%	28,054,141	53.46%	25,311,170	48.23%
315.00	Accessory Electric Equipment	39,432,489	19,370,802	49.12%	16,176,141	41.02%	14,594,532	37.01%
316.00	Miscellaneous Power Plant Equipment	2,333,493	1,068,696	45.80%	916,192	39.26%	826,612	35.42%
	Total Sundt	$ 252,535,308	$ 115,346,298	45.68%	$ 127,974,081	50.68%	$ 115,346,298	45.68%
Sundt Unit 1								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	3,926,062	2,175,028	55.40%	2,511,021	63.96%	2,265,508	57.70%
312.00	Boiler Plant Equipment	13,782,181	10,318,349	74.87%	10,572,601	76.71%	9,538,873	69.21%
314.00	Turbogenerator Units	10,237,507	6,554,053	64.02%	6,654,384	65.00%	6,003,757	58.64%
315.00	Accessory Electric Equipment	6,536,315	2,644,455	40.46%	2,391,512	36.59%	2,157,684	33.01%
316.00	Miscellaneous Power Plant Equipment	490,578	230,468	46.98%	213,005	43.42%	192,179	39.17%
	Total Sundt Unit 1	$ 34,972,643	$ 21,922,353	62.68%	$ 22,342,522	63.89%	$ 20,158,000	57.64%
Sundt Unit 2								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	2,812,689	1,133,428	40.30%	1,383,645	49.19%	1,248,360	44.38%
312.00	Boiler Plant Equipment	14,371,609	9,423,263	65.57%	10,473,487	72.88%	9,449,450	65.75%
314.00	Turbogenerator Units	8,451,923	5,713,503	67.60%	6,636,078	78.52%	5,987,241	70.84%
315.00	Accessory Electric Equipment	6,205,700	1,836,537	29.59%	1,856,264	29.91%	1,674,769	26.99%
316.00	Miscellaneous Power Plant Equipment	383,824	148,170	38.60%	143,875	37.48%	129,808	33.82%
	Total Sundt Unit 2	$ 32,225,745	$ 18,254,901	56.65%	$ 20,493,349	63.59%	$ 18,489,628	57.38%
Sundt Unit 3								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	2,762,012	1,386,818	50.21%	1,676,755	60.71%	1,512,811	54.77%
312.00	Boiler Plant Equipment	11,980,831	6,673,757	55.70%	8,103,293	67.64%	7,311,000	61.02%
314.00	Turbogenerator Units	14,830,615	8,326,645	56.14%	9,327,567	62.89%	8,415,571	56.74%
315.00	Accessory Electric Equipment	6,140,139	4,200,198	68.41%	4,059,051	66.11%	3,662,181	59.64%
316.00	Miscellaneous Power Plant Equipment	404,717	182,169	45.01%	184,767	45.65%	166,701	41.19%
	Total Sundt Unit 3	$ 36,118,314	$ 20,769,587	57.50%	$ 23,351,432	64.65%	$ 21,068,265	58.33%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Summary
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Statement C

Account	Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
Sundt Unit 4								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	17,974,608	11,684,139	65.00%	8,415,899	46.82%	7,593,041	42.24%
312.00	Boiler Plant Equipment	80,576,055	25,148,847	31.21%	39,547,619	49.08%	35,680,882	44.28%
314.00	Turbogenerator Units	18,981,284	6,354,911	33.52%	5,436,112	28.67%	4,904,600	25.87%
315.00	Accessory Electric Equipment	20,550,335	10,689,612	52.02%	7,869,313	38.29%	7,099,897	34.55%
316.00	Miscellaneous Power Plant Equipment	1,054,374	507,889	48.17%	374,546	35.52%	337,925	32.05%
	Total Sundt Unit 4	$ 139,116,656	$ 54,385,398	39.09%	$ 61,643,488	44.31%	$ 55,616,346	39.98%
Sundt Solar Booster (Areva)								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	0	0	0.00%	0	0.00%	0	0.00%
312.00	Boiler Plant Equipment	10,101,950	14,059	0.14%	143,289	1.42%	14,059	0.14%
314.00	Turbogenerator Units	0	0	0.00%	0	0.00%	0	0.00%
315.00	Accessory Electric Equipment	0	0	0.00%	0	0.00%	0	0.00%
316.00	Miscellaneous Power Plant Equipment	0	0	0.00%	0	0.00%	0	0.00%
	Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 14,059	0.14%	$ 143,289	1.42%	$ 14,059	0.14%
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00	Structures and Improvements	$ 761,988	$ 154,938	20.33%	$ 152,019	19.95%	$ 176,938	23.22%
342.00	Fuel Holders, Products and Accessories	750,386	261,338	34.83%	231,033	30.79%	268,903	35.84%
343.00	Prime Movers	76,766	8,524	11.10%	12,723	16.57%	14,809	19.29%
344.00	Generators and Devices	30,772,866	11,025,994	35.83%	9,399,288	30.54%	10,939,994	35.55%
345.00	Accessory Electric Equipment	861,492	268,405	31.16%	270,764	31.43%	315,147	36.58%
346.00	Miscellaneous Power Plant Equipment	376,605	115,469	30.66%	102,136	27.12%	118,877	31.57%
	Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 11,834,668	35.22%	$ 10,167,964	30.26%	$ 11,834,668	35.22%
Gila River								
341.00	Structures and Improvements	$ 8,508,950	$ 2,126,825	25.00%	$ 2,132,690	25.06%	$ 2,085,222	24.51%
342.00	Fuel Holders, Products and Accessories	6,783,045	1,695,243	24.99%	1,739,367	25.64%	1,695,857	25.00%
343.00	Prime Movers	188,744,730	45,163,873	23.93%	44,747,359	23.71%	44,920,085	23.80%
344.00	Generators and Devices	32,783,434	8,295,028	25.30%	8,494,355	25.91%	8,534,905	26.03%
345.00	Accessory Electric Equipment	9,030,698	2,242,691	24.83%	2,298,438	25.45%	2,292,546	25.39%
346.00	Miscellaneous Power Plant Equipment	6,799,960	1,679,659	24.70%	1,717,914	25.26%	1,674,704	24.63%
	Total Gila River	$ 252,650,817	$ 61,203,319	24.22%	$ 61,130,123	24.20%	$ 61,203,319	24.22%
Gila River Unit 3								
341.00	Structures and Improvements	$ 957,417	$ 259,052	27.06%	$ 243,633	25.45%	$ 244,796	25.57%
342.00	Fuel Holders, Products and Accessories	178,424	40,583	22.75%	41,504	23.26%	41,702	23.37%
343.00	Prime Movers	181,571,712	43,892,641	24.17%	43,407,520	23.91%	43,614,738	24.02%
344.00	Generators and Devices	32,783,434	8,295,028	25.30%	8,494,355	25.91%	8,534,905	26.03%
345.00	Accessory Electric Equipment	6,860,554	1,703,384	24.83%	1,745,799	25.45%	1,754,133	25.57%
346.00	Miscellaneous Power Plant Equipment	135,558	32,986	24.33%	33,242	24.52%	33,400	24.64%
	Total Gila River Unit 3	$ 222,487,099	$ 54,223,675	24.37%	$ 53,966,052	24.26%	$ 54,223,675	24.37%

TUCSON ELECTRIC POWER COMPANY

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Account	Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
Gila River Common								
341.00	Structures and Improvements	$ 7,551,533	$ 1,867,772	24.73%	$ 1,889,057	25.02%	$ 1,840,426	24.37%
342.00	Fuel Holders, Products and Accessories	6,604,621	1,654,660	25.05%	1,697,863	25.71%	1,654,154	25.05%
343.00	Prime Movers	7,173,018	1,271,232	17.72%	1,339,839	18.68%	1,305,347	18.20%
344.00	Generators and Devices	0	0	0.00%	0	0.00%	0	0.00%
345.00	Accessory Electric Equipment	2,170,144	539,307	24.85%	552,639	25.47%	538,413	24.81%
346.00	Miscellaneous Power Plant Equipment	6,664,402	1,646,673	24.71%	1,684,672	25.28%	1,641,303	24.63%
	Total Gila River Common	$ 30,163,718	$ 6,979,644	23.14%	$ 7,164,070	23.75%	$ 6,979,644	23.14%
Luna								
341.00	Structures and Improvements	$ 13,232,832	$ 1,357,037	10.26%	$ 2,594,010	19.60%	$ 533,012	4.03%
342.00	Fuel Holders, Products and Accessories	11,352,383	1,178,720	10.38%	2,268,599	19.98%	466,147	4.11%
343.00	Prime Movers	11,151,074	(115,314)	-1.03%	1,019,584	9.14%	209,502	1.88%
344.00	Generators and Devices	9,486,694	(1,277,620)	-13.47%	1,829,905	19.29%	376,005	3.96%
345.00	Accessory Electric Equipment	9,647	114	1.18%	138	1.43%	28	0.29%
346.00	Miscellaneous Power Plant Equipment	7,424,592	744,049	10.02%	1,471,160	19.81%	302,291	4.07%
	Total Luna	$ 52,657,222	$ 1,886,985	3.58%	$ 9,183,395	17.44%	$ 1,886,985	3.58%
North Loop Gas								
341.00	Structures and Improvements	$ 888,601	$ 867,104	97.58%	$ 605,720	68.17%	$ 838,939	94.41%
342.00	Fuel Holders, Products and Accessories	303,037	104,139	34.37%	91,403	30.16%	104,311	34.42%
343.00	Prime Movers	1,890,946	675,327	35.71%	474,852	25.11%	682,733	36.11%
344.00	Generators and Devices	24,062,187	15,675,191	65.14%	12,150,912	50.50%	15,777,788	65.57%
345.00	Accessory Electric Equipment	2,829,171	2,090,869	73.90%	1,499,434	53.00%	2,015,349	71.23%
346.00	Miscellaneous Power Plant Equipment	656,253	639,873	97.50%	458,043	69.80%	633,383	96.52%
	Total North Loop Gas	$ 30,630,195	$ 20,052,503	65.47%	$ 15,280,365	49.89%	$ 20,052,503	65.47%
North Loop Gas Unit 1								
341.00	Structures and Improvements	$ 411,070	$ 406,569	98.90%	$ 263,424	64.08%	$ 383,683	93.34%
342.00	Fuel Holders, Products and Accessories	0	0	0.00%	0	0.00%	0	0.00%
343.00	Prime Movers	678,545	506,913	74.71%	283,346	41.76%	412,700	60.82%
344.00	Generators and Devices	3,582,271	3,792,993	105.88%	2,717,946	75.87%	3,958,749	110.51%
345.00	Accessory Electric Equipment	790,955	763,625	96.54%	502,239	63.50%	731,522	92.49%
346.00	Miscellaneous Power Plant Equipment	306,369	313,164	102.22%	203,642	66.47%	296,610	96.81%
	Total North Loop Gas Unit 1	$ 5,769,210	$ 5,783,263	100.24%	$ 3,970,596	68.82%	$ 5,783,263	100.24%
North Loop Gas Unit 2								
341.00	Structures and Improvements	$ 196,078	$ 215,565	109.94%	$ 157,789	80.47%	$ 208,106	106.13%
342.00	Fuel Holders, Products and Accessories	0	0	0.00%	0	0.00%	0	0.00%
343.00	Prime Movers	263,450	(327,630)	-124.36%	(114,339)	-43.40%	(150,799)	-57.24%
344.00	Generators and Devices	3,239,719	3,643,451	112.46%	2,659,958	82.10%	3,508,173	108.29%
345.00	Accessory Electric Equipment	504,895	505,786	100.18%	356,625	70.63%	470,347	93.16%
346.00	Miscellaneous Power Plant Equipment	128,559	148,230	115.30%	113,410	88.22%	149,575	116.35%
	Total North Loop Gas Unit 2	$ 4,332,701	$ 4,185,401	96.60%	$ 3,173,444	73.24%	$ 4,185,401	96.60%

TUCSON ELECTRIC POWER COMPANY

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Depreciation Reserve Summary
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Account	Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
North Loop Gas Unit 3								
341.00	Structures and Improvements	$ 196,078	$ 212,395	108.32%	$ 155,862	79.49%	$ 214,460	109.38%
342.00	Fuel Holders, Products and Accessories	0	0	0.00%	0	0.00%	0	0.00%
343.00	Prime Movers	948,951	496,044	52.27%	305,845	32.23%	420,832	44.35%
344.00	Generators and Devices	3,030,531	3,333,807	110.01%	2,476,626	81.72%	3,407,755	112.45%
345.00	Accessory Electric Equipment	503,907	493,376	97.91%	351,228	69.70%	483,279	95.91%
346.00	Miscellaneous Power Plant Equipment	128,559	144,847	112.67%	112,025	87.14%	154,143	119.90%
	Total North Loop Gas Unit 3	$ 4,808,026	$ 4,680,469	97.35%	$ 3,401,586	70.75%	$ 4,680,469	97.35%
North Loop Gas Unit 4								
341.00	Structures and Improvements	$ 85,375	$ 32,575	38.16%	$ 28,645	33.55%	$ 32,680	38.29%
342.00	Fuel Holders, Products and Accessories	303,037	104,139	34.37%	91,403	30.16%	104,311	34.42%
343.00	Prime Movers	0	0	0.00%	0	0.00%	0	0.00%
344.00	Generators and Devices	14,209,666	4,904,940	34.52%	4,296,382	30.24%	4,903,110	34.51%
345.00	Accessory Electric Equipment	1,029,414	328,082	31.87%	289,342	28.11%	330,202	32.08%
346.00	Miscellaneous Power Plant Equipment	92,766	33,632	36.26%	28,965	31.22%	33,056	35.63%
	Total North Loop Gas Unit 4	$ 15,720,258	$ 5,403,369	34.37%	$ 4,734,737	30.12%	$ 5,403,369	34.37%
Solar Units (Generators and Devices)								
344.00	DeMoss Petrie	$ 1,146,081	$ 334,209	29.16%	$ 509,290	44.44%	$ 610,990	53.31%
344.00	Fort Huachuca	36,709,538	73,938	0.20%	688,304	1.88%	825,751	2.25%
344.00	HQ Rooftop	303,184	45,437	14.99%	28,424	9.38%	34,099	11.25%
344.00	OH Rooftop	2,594,590	399,653	15.40%	340,540	13.13%	408,542	15.75%
344.00	OH Test Yard	388,459	233,584	60.13%	162,716	41.89%	195,208	50.25%
344.00	Prairie Fire	19,036,520	1,980,433	10.40%	1,784,674	9.38%	2,141,054	11.25%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	17,515,266	60.89%	12,826,310	44.59%	15,387,588	53.49%
344.00	Springerville Site 4	7,873,874	1,606,533	20.40%	1,328,716	16.88%	1,594,047	20.24%
343.00	Tucson	87,198	71,385	81.86%	52,907	60.68%	63,472	72.79%
344.00	U of A Tech Park Site 1	7,723,832	1,576,302	20.41%	1,303,397	16.88%	1,563,671	20.24%
345.00	U of A Tech Park Site 2	19,191,952	2,956,201	15.40%	2,518,944	13.13%	3,021,950	15.75%
346.00	White Mountain	46,499,099	99,392	0.21%	871,858	1.88%	1,045,959	2.25%
	Total Solar Units	$ 170,320,932	$ 26,892,332	15.79%	$ 22,416,079	13.16%	$ 26,892,332	15.79%
Sundt Gas								
341.00	Structures and Improvements	$ 11,090	$ 11,891	107.22%	$ 7,586	68.41%	$ 11,518	103.86%
342.00	Fuel Holders, Products and Accessories	788,336	582,161	73.85%	293,301	37.21%	445,328	56.49%
343.00	Prime Movers	141,618	139,570	98.55%	74,262	52.44%	112,755	79.62%
344.00	Generators and Devices	8,382,044	8,804,904	105.04%	5,900,676	70.40%	8,956,936	106.86%
345.00	Accessory Electric Equipment	1,078,811	1,070,884	99.27%	710,745	65.88%	1,079,362	100.05%
346.00	Miscellaneous Power Plant Equipment	49,750	55,130	110.81%	38,573	77.53%	58,640	117.87%
	Total Sundt Gas	$ 10,451,649	$ 10,664,539	102.04%	$ 7,025,144	67.22%	$ 10,664,539	102.04%

TUCSON ELECTRIC POWER COMPANY

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Account	Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
Sundt Gas Unit 1								
341.00	Structures and Improvements	$ 5,545	$ 5,964	107.55%	$ 3,791	68.37%	$ 5,720	103.15%
342.00	Fuel Holders, Products and Accessories	394,168	291,435	73.94%	146,579	37.19%	221,129	56.10%
343.00	Prime Movers	70,809	70,514	99.58%	37,113	52.41%	55,989	79.07%
344.00	Generators and Devices	4,315,668	4,541,928	105.24%	3,063,372	70.98%	4,621,415	107.08%
345.00	Accessory Electric Equipment	516,231	514,444	99.65%	343,965	66.63%	518,907	100.52%
346.00	Miscellaneous Power Plant Equipment	19,906	22,217	111.61%	15,473	77.73%	23,342	117.26%
	Total Sundt Gas Unit 1	$ 5,322,327	$ 5,446,501	102.33%	$ 3,610,292	67.83%	$ 5,446,501	102.33%
Sundt Gas Unit 2								
341.00	Structures and Improvements	$ 5,545	$ 5,927	106.89%	$ 3,795	68.44%	$ 5,799	104.58%
342.00	Fuel Holders, Products and Accessories	394,168	290,725	73.76%	146,723	37.22%	224,199	56.88%
343.00	Prime Movers	70,809	69,056	97.52%	37,149	52.46%	56,766	80.17%
344.00	Generators and Devices	4,066,376	4,262,976	104.83%	2,837,304	69.77%	4,335,521	106.62%
345.00	Accessory Electric Equipment	562,580	556,440	98.91%	366,780	65.20%	560,456	99.62%
346.00	Miscellaneous Power Plant Equipment	29,844	32,913	110.28%	23,100	77.40%	35,298	118.28%
	Total Sundt Gas Unit 2	$ 5,129,322	$ 5,218,038	101.73%	$ 3,414,852	66.58%	$ 5,218,038	101.73%

TUCSON ELECTRIC POWER COMPANY

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Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account Description		Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
A		B	C	D=C/B	E	F=E/B	G=C+E	H=G/B
STEAM PRODUCTION								
310.00	Rights-of-Way	$ 5,106,662	$ 2,655,709	52.00%	$ 514	0.01%	$ 2,656,223	52.01%
311.00	Structures and Improvements	205,277,689	89,164,321	43.44%	14,271,376	6.95%	103,435,696	50.39%
312.00	Boiler Plant Equipment	1,091,953,161	456,919,837	41.84%	49,017,521	4.49%	505,937,359	46.33%
314.00	Turbogenerator Units	303,041,923	113,868,317	37.58%	13,213,963	4.36%	127,082,280	41.94%
315.00	Accessory Electric Equipment	144,581,471	59,238,282	40.97%	7,061,138	4.88%	66,299,420	45.86%
316.00	Miscellaneous Power Plant Equipment	25,222,863	11,180,207	44.33%	930,431	3.69%	12,110,638	48.01%
Total Steam Production Plant		$ 1,775,183,769	$ 733,026,674	41.29%	$ 84,494,943	4.76%	$ 817,521,616	46.05%
OTHER PRODUCTION								
Non-Solar								
341.00	Structures and Improvements	$ 23,403,461	$ 3,397,218	14.52%	$ 248,411	1.06%	$ 3,645,629	15.58%
342.00	Fuel Holders, Products and Accessories	19,977,187	2,842,156	14.23%	138,389	0.69%	2,980,546	14.92%
343.00	Prime Movers	202,005,134	43,832,017	21.70%	2,107,866	1.04%	45,939,884	22.74%
344.00	Generators and Devices	105,487,225	41,976,745	39.79%	2,608,882	2.47%	44,585,627	42.27%
345.00	Accessory Electric Equipment	13,809,819	5,340,441	38.67%	361,992	2.62%	5,702,433	41.29%
346.00	Miscellaneous Power Plant Equipment	15,307,160	2,613,980	17.08%	173,915	1.14%	2,787,896	18.21%
Total Non-Solar		$ 379,989,986	$ 100,002,557	26.32%	$ 5,639,457	1.48%	$ 105,642,014	27.80%
Solar								
344.00	Generators and Devices	$ 170,320,932	$ 25,611,745	15.04%	$ 1,280,587	0.75%	$ 26,892,332	15.79%
Total Solar		$ 170,320,932	$ 25,611,745	15.04%	$ 1,280,587	0.75%	$ 26,892,332	15.79%
Total Other Production Plant		$ 550,310,918	$ 125,614,302	22.83%	$ 6,920,044	1.26%	$ 132,534,346	24.08%
DISTRIBUTION PLANT								
360.RW	Rights-of-Way	$ 7,865,073	$ 3,489,207	44.36%	$ -	0.00%	$ 3,489,207	44.36%
361.00	Structures and Improvements	11,402,474	$ 2,266,510	19.88%	0	0.00%	2,266,510	19.88%
362.00	Station Equipment	157,067,530	$ 45,019,901	28.66%	0	0.00%	45,019,901	28.66%
364.00	Poles, Towers and Fixtures	222,006,967	$ 63,316,449	28.52%	0	0.00%	63,316,449	28.52%
365.00	Overhead Conductors and Devices	175,675,966	$ 59,871,468	34.08%	0	0.00%	59,871,468	34.08%
366.00	Underground Conduit	58,725,355	$ 21,962,656	37.40%	0	0.00%	21,962,656	37.40%
367.00	Underground Conductors and Devices	297,183,135	$ 108,473,188	36.50%	0	0.00%	108,473,188	36.50%
368.OH	Line Transformers - Overhead	103,657,922	$ 37,260,464	35.95%	0	0.00%	37,260,464	35.95%
368.UG	Line Transformers - Underground	172,890,932	$ 61,772,524	35.73%	0	0.00%	61,772,524	35.73%
369.OH	Services - Overhead	17,542,236	$ 7,492,586	42.71%	0	0.00%	7,492,586	42.71%
369.UG	Services - Underground	112,947,714	$ 33,701,422	29.84%	0	0.00%	33,701,422	29.84%
370.00	Meters	44,869,823	$ 10,167,835	22.66%	0	0.00%	10,167,835	22.66%

TUCSON ELECTRIC POWER COMPANY

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
373.00	Street Lighting and Signal Systems	11,778,362	$ 4,694,486	39.86%	0	0.00%	4,694,486	39.86%
	Total Distribution Plant	$ 1,393,613,489	$ 459,488,696	32.97%	$ -	0.00%	$ 459,488,696	32.97%
	GENERAL PLANT							
	Depreciable							
390.00	Structures and Improvements	$ 135,680,348	$ 21,570,039	15.90%	$ 126,776	0.09%	$ 21,696,815	15.99%
392.C0	Transportation - Class 0	1,238,946	458,248	36.99%	(53,946)	-4.35%	404,302	32.63%
392.C1	Transportation - Class 1	7,718,183	3,304,203	42.81%	(408,989)	-5.30%	2,895,214	37.51%
392.C2	Transportation - Class 2	3,839,907	1,609,294	41.91%	(189,552)	-4.94%	1,419,742	36.97%
392.C3	Transportation - Class 3	2,076,936	1,052,793	50.69%	(131,035)	-6.31%	921,757	44.38%
392.C4	Transportation - Class 4	2,935,027	1,180,337	40.22%	(129,837)	-4.42%	1,050,500	35.79%
392.C5	Transportation - Class 5	7,982,715	3,474,021	43.52%	(448,803)	-5.62%	3,025,218	37.90%
392.C6	Transportation - Class 6	365,200	80,311	21.99%	(12,047)	-3.30%	68,264	18.69%
392.C7	Transportation - Class 7	1,047,216	410,010	39.15%	(61,501)	-5.87%	348,508	33.28%
392.C8	Transportation - Class 8	9,957,500	3,613,292	36.29%	(530,533)	-5.33%	3,082,759	30.96%
392.C9	Transportation - Class 9	4,252,286	1,247,812	29.34%	(178,945)	-4.21%	1,068,867	25.14%
396.00	Power Operatied Equipment	11,860,940	2,412,819	20.34%	87,170	0.73%	2,499,990	21.08%
397.EM	EMS and SCADA Equipment	11,304,371	3,110,221	27.51%	0	0.00%	3,110,221	27.51%
	Total Depreciable	$ 200,259,575	$ 43,523,399	21.73%	$ (1,931,242)	-0.96%	$ 41,592,158	20.77%
	Amortizable							
391.00	Furniture and Office Equipment	$ 23,964,411	$ 7,698,753	32.13%	$ -	0.00%	$ 7,698,753	32.13%
391.20	Network and Data Equipment	29,359,636	14,913,970	50.80%	0	0.00%	14,913,970	50.80%
393.00	Stores Equipment	1,852,479	840,197	45.36%	0	0.00%	840,197	45.36%
394.00	Tools, Shop and Garage Equipment	6,934,368	2,858,589	41.22%	0	0.00%	2,858,589	41.22%
395.00	Laboratory Equipment	5,091,270	2,395,826	47.06%	0	0.00%	2,395,826	47.06%
397.20	Telecommunications Equipment	57,456,141	19,662,636	34.22%	0	0.00%	19,662,636	34.22%
398.00	Miscellaneous Equipment	4,348,209	1,815,347	41.75%	0	0.00%	1,815,347	41.75%
	Total Amortizable	$ 129,006,514	$ 50,185,318	38.90%	$ -	0.00%	$ 50,185,318	38.90%
	Total General Plant	$ 329,266,089	$ 93,708,717	28.46%	$ (1,931,242)	-0.59%	$ 91,777,476	27.87%
	SUBTOTAL	$ 4,048,374,265	$ 1,411,838,389	34.87%	$ 89,483,745	2.21%	$ 1,501,322,134	37.08%
	NET SALVAGE							
108.02	Distribution	$ 1,393,613,489	$ -	0.00%	$ 25,332,087	1.82%	$ 25,332,087	1.82%
	Total Net Salvage	$ 1,393,613,489	$ -	0.00%	$ 25,332,087	1.82%	$ 25,332,087	1.82%
	TOTAL UTILITY	$ 4,048,374,265	$ 1,411,838,389	34.87%	$ 114,815,832	2.84%	$ 1,526,654,221	37.71%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
STEAM PRODUCTION (by Unit)								
Four Corners								
310.00	Rights-of-Way	$ -	$ -	#DIV/0!	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	2,982,777	1,818,284	60.96%	91,307	3.06%	1,909,591	64.02%
312.00	Boiler Plant Equipment	76,402,061	57,866,410	75.74%	2,481,753	3.25%	60,348,163	78.99%
314.00	Turbogenerator Units	12,359,480	8,375,330	67.76%	453,963	3.67%	8,829,293	71.44%
315.00	Accessory Electric Equipment	4,390,980	1,550,168	35.30%	107,086	2.44%	1,657,254	37.74%
316.00	Miscellaneous Power Plant Equipment	3,832,234	2,439,226	63.65%	118,876	3.10%	2,558,102	66.75%
	Total Four Corners	$ 99,967,532	$ 72,049,418	72.07%	$ 3,252,985	3.25%	$ 75,302,403	75.33%
Four Corners Unit 4								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	1,524,414	959,414	62.94%	45,341	2.97%	1,004,754	65.91%
312.00	Boiler Plant Equipment	39,609,538	30,915,436	78.05%	1,041,213	2.63%	31,956,649	80.68%
314.00	Turbogenerator Units	7,179,362	4,836,928	67.37%	260,083	3.62%	5,097,011	71.00%
315.00	Accessory Electric Equipment	2,274,836	852,342	37.47%	63,023	2.77%	915,365	40.24%
316.00	Miscellaneous Power Plant Equipment	1,929,161	1,263,646	65.50%	58,558	3.04%	1,322,204	68.54%
	Total Four Corners Unit 4	$ 52,517,311	$ 38,827,767	73.93%	$ 1,468,218	2.80%	$ 40,295,985	76.73%
Four Corners Unit 5								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	1,458,363	858,870	58.89%	45,966	3.15%	904,837	62.04%
312.00	Boiler Plant Equipment	36,792,523	26,950,973	73.25%	1,440,540	3.92%	28,391,514	77.17%
314.00	Turbogenerator Units	5,180,118	3,538,401	68.31%	193,880	3.74%	3,732,282	72.05%
315.00	Accessory Electric Equipment	2,116,144	697,826	32.98%	44,063	2.08%	741,889	35.06%
316.00	Miscellaneous Power Plant Equipment	1,903,073	1,175,580	61.77%	60,318	3.17%	1,235,898	64.94%
	Total Four Corners Unit 5	$ 47,450,221	$ 33,221,651	70.01%	$ 1,784,767	3.76%	$ 35,006,419	73.78%
Navajo								
310.00	Rights-of-Way	$ 12,229	$ 10,943	89.48%	$ 514	4.21%	$ 11,457	93.69%
311.00	Structures and Improvements	18,655,156	12,924,171	69.28%	639,098	3.43%	13,563,269	72.71%
312.00	Boiler Plant Equipment	88,544,201	64,261,410	72.58%	3,309,432	3.74%	67,570,842	76.31%
314.00	Turbogenerator Units	20,255,526	15,090,058	74.50%	761,421	3.76%	15,851,479	78.26%
315.00	Accessory Electric Equipment	14,829,858	9,396,746	63.36%	460,754	3.11%	9,857,500	66.47%
316.00	Miscellaneous Power Plant Equipment	4,518,597	2,798,421	61.93%	131,714	2.91%	2,930,135	64.85%
	Total Navajo	$ 146,815,567	$ 104,481,749	71.17%	$ 5,302,933	3.61%	$ 109,784,682	74.78%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
Navajo Unit 1								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	3,190,563	2,607,266	81.72%	125,149	3.92%	2,732,415	85.64%
312.00	Boiler Plant Equipment	27,198,582	19,943,243	73.32%	957,276	3.52%	20,900,519	76.84%
314.00	Turbogenerator Units	6,860,989	5,019,772	73.16%	246,412	3.59%	5,266,184	76.76%
315.00	Accessory Electric Equipment	3,544,300	2,205,622	62.23%	108,056	3.05%	2,313,678	65.28%
316.00	Miscellaneous Power Plant Equipment	471,227	387,582	82.25%	18,216	3.87%	405,798	86.12%
	Total Navajo Unit 1	$ 41,265,661	$ 30,163,484	73.10%	$ 1,455,108	3.53%	$ 31,618,592	76.62%
Navajo Unit 2								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	1,802,685	1,432,989	79.49%	76,314	4.23%	1,509,303	83.73%
312.00	Boiler Plant Equipment	26,882,286	20,203,004	75.15%	1,123,437	4.18%	21,326,441	79.33%
314.00	Turbogenerator Units	6,926,050	5,080,922	73.36%	268,088	3.87%	5,349,010	77.23%
315.00	Accessory Electric Equipment	3,172,330	2,213,989	69.79%	118,908	3.75%	2,332,896	73.54%
316.00	Miscellaneous Power Plant Equipment	515,874	446,111	86.48%	22,081	4.28%	468,191	90.76%
	Total Navajo Unit 2	$ 39,299,225	$ 29,377,014	74.75%	$ 1,608,827	4.09%	$ 30,985,841	78.85%
Navajo Unit 3								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	3,681,511	3,095,153	84.07%	147,089	4.00%	3,242,242	88.07%
312.00	Boiler Plant Equipment	27,718,514	20,263,915	73.11%	1,058,895	3.82%	21,322,809	76.93%
314.00	Turbogenerator Units	6,178,944	4,913,913	79.53%	242,932	3.93%	5,156,845	83.46%
315.00	Accessory Electric Equipment	5,139,872	3,963,645	77.12%	175,832	3.42%	4,139,477	80.54%
316.00	Miscellaneous Power Plant Equipment	549,362	475,548	86.56%	19,124	3.48%	494,672	90.04%
	Total Navajo Unit 3	$ 43,268,203	$ 32,712,174	75.60%	$ 1,643,871	3.80%	$ 34,356,045	79.40%
Navajo Common								
310.00	Rights-of-Way	$ 12,229	$ 10,943	89.48%	$ 514	4.21%	$ 11,457	93.69%
311.00	Structures and Improvements	9,980,397	5,788,763	58.00%	290,546	2.91%	6,079,309	60.91%
312.00	Boiler Plant Equipment	6,744,819	3,851,248	57.10%	169,825	2.52%	4,021,073	59.62%
314.00	Turbogenerator Units	289,543	75,451	26.06%	3,990	1.38%	79,441	27.44%
315.00	Accessory Electric Equipment	2,973,356	1,013,491	34.09%	57,958	1.95%	1,071,449	36.04%
316.00	Miscellaneous Power Plant Equipment	2,982,134	1,489,181	49.94%	72,293	2.42%	1,561,474	52.36%
	Total Navajo Common	$ 22,982,478	$ 12,229,077	53.21%	$ 595,126	2.59%	$ 12,824,203	55.80%

TUCSON ELECTRIC POWER COMPANY

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
San Juan								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	14,437,744	6,777,299	46.94%	566,297	3.92%	7,343,597	50.86%
312.00	Boiler Plant Equipment	154,506,908	64,501,547	41.75%	5,854,698	3.79%	70,356,244	45.54%
314.00	Turbogenerator Units	44,295,673	20,666,727	46.66%	1,746,852	3.94%	22,413,578	50.60%
315.00	Accessory Electric Equipment	10,063,526	4,271,195	42.44%	361,520	3.59%	4,632,716	46.03%
316.00	Miscellaneous Power Plant Equipment	2,009,555	874,153	43.50%	75,379	3.75%	949,533	47.25%
	Total San Juan	$ 225,313,406	$ 97,090,922	43.09%	$ 8,604,746	3.82%	$ 105,695,668	46.91%
San Juan Unit 1								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	14,268,404	$ 6,771,990	47.46%	$ 566,287	3.97%	7,338,277	51.43%
312.00	Boiler Plant Equipment	146,453,029	$ 61,817,328	42.21%	$ 4,597,133	3.14%	66,414,460	45.35%
314.00	Turbogenerator Units	44,295,673	$ 20,666,727	46.66%	$ 1,746,852	3.94%	22,413,578	50.60%
315.00	Accessory Electric Equipment	10,063,526	$ 4,271,195	42.44%	$ 361,520	3.59%	4,632,716	46.03%
316.00	Miscellaneous Power Plant Equipment	1,960,172	$ 872,605	44.52%	$ 75,379	3.85%	947,984	48.36%
	Total San Juan Unit 1	$ 217,040,804	$ 94,399,844	43.49%	$ 7,347,171	3.39%	$ 101,747,016	46.88%
San Juan Common								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	169,340	$ 5,310	3.14%	$ 11	0.01%	5,320	3.14%
312.00	Boiler Plant Equipment	8,053,879	$ 2,684,219	33.33%	$ 1,257,565	15.61%	3,941,784	48.94%
314.00	Turbogenerator Units	0	$ -	0.00%	$ -	0.00%	0	0.00%
315.00	Accessory Electric Equipment	0	$ -	0.00%	$ -	0.00%	0	0.00%
316.00	Miscellaneous Power Plant Equipment	49,383	$ 1,548	3.14%	$ -	0.00%	1,548	3.14%
	Total San Juan Common	$ 8,272,602	$ 2,691,077	32.53%	$ 1,257,575	15.20%	$ 3,948,653	47.73%
Springerville								
310.00	Rights-of-Way	$ 5,094,433	$ 2,644,766	51.91%	$ -	0.00%	$ 2,644,766	51.91%
311.00	Structures and Improvements	141,726,641	58,069,236	40.97%	9,930,284	7.01%	67,999,520	47.98%
312.00	Boiler Plant Equipment	641,687,365	223,625,040	34.85%	22,042,804	3.44%	245,667,845	38.28%
314.00	Turbogenerator Units	173,649,915	52,916,045	30.47%	1,760,716	1.01%	54,676,760	31.49%
315.00	Accessory Electric Equipment	75,864,618	33,501,347	44.16%	2,056,071	2.71%	35,557,418	46.87%
316.00	Miscellaneous Power Plant Equipment	12,528,984	4,496,598	35.89%	349,657	2.79%	4,846,255	38.68%
	Total Springerville	$ 1,050,551,956	$ 375,253,032	35.72%	$ 36,139,532	3.44%	$ 411,392,565	39.16%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
Springerville Unit 1								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	20,076,015	8,181,475	40.75%	381,474	1.90%	8,562,949	42.65%
312.00	Boiler Plant Equipment	185,682,490	80,313,040	43.25%	3,644,310	1.96%	83,957,350	45.22%
314.00	Turbogenerator Units	49,547,312	21,608,560	43.61%	976,892	1.97%	22,585,452	45.58%
315.00	Accessory Electric Equipment	21,214,167	10,788,591	50.86%	381,188	1.80%	11,169,779	52.65%
316.00	Miscellaneous Power Plant Equipment	3,277,742	1,255,155	38.29%	57,602	1.76%	1,312,757	40.05%
	Total Springerville Unit 1	$ 279,797,726	$ 122,146,821	43.66%	$ 5,441,466	1.94%	$ 127,588,287	45.60%
Springerville Unit 1 Common								
310.00	Rights-of-Way	$ 1,143,496	$ 501,934	43.89%	$ -	0.00%	$ 501,934	43.89%
311.00	Structures and Improvements	52,492,826	22,869,968	43.57%	3,195,668	6.09%	26,065,636	49.66%
312.00	Boiler Plant Equipment	14,854,799	6,682,908	44.99%	864,278	5.82%	7,547,186	50.81%
314.00	Turbogenerator Units	1,264,322	596,152	47.15%	71,875	5.68%	668,027	52.84%
315.00	Accessory Electric Equipment	9,627,097	4,895,266	50.85%	485,071	5.04%	5,380,337	55.89%
316.00	Miscellaneous Power Plant Equipment	1,959,012	982,614	50.16%	101,159	5.16%	1,083,772	55.32%
	Total Springerville Unit 1 Common	$ 81,341,552	$ 36,528,841	44.91%	$ 4,718,051	5.80%	$ 41,246,892	50.71%
Springerville Unit 2								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	36,540,030	10,256,607	28.07%	271,808	0.74%	10,528,415	28.81%
312.00	Boiler Plant Equipment	295,922,545	87,091,367	29.43%	1,082,385	0.37%	88,173,753	29.80%
314.00	Turbogenerator Units	122,055,348	30,256,387	24.79%	555,902	0.46%	30,812,289	25.24%
315.00	Accessory Electric Equipment	42,346,939	16,083,619	37.98%	595,094	1.41%	16,678,713	39.39%
316.00	Miscellaneous Power Plant Equipment	6,624,669	1,902,962	28.73%	67,635	1.02%	1,970,597	29.75%
	Total Springerville Unit 2	$ 503,489,531	$ 145,590,942	28.92%	$ 2,572,824	0.51%	$ 148,163,767	29.43%
Springerville Unit 2 Common (Leasehold Imp.)								
310.00	Rights-of-Way	$ 2,280,838	$ 1,509,624	66.19%	$ -	0.00%	$ 1,509,624	66.19%
311.00	Structures and Improvements	32,617,770	16,761,186	51.39%	6,081,335	18.64%	22,842,521	70.03%
312.00	Boiler Plant Equipment	6,282,729	2,574,121	40.97%	1,082,206	17.23%	3,656,327	58.20%
314.00	Turbogenerator Units	782,933	454,946	58.11%	156,046	19.93%	610,992	78.04%
315.00	Accessory Electric Equipment	2,676,415	1,733,871	64.78%	594,718	22.22%	2,328,589	87.00%
316.00	Miscellaneous Power Plant Equipment	667,561	355,867	53.31%	123,262	18.46%	479,129	71.77%
	Total Springerville Unit 2 Common	$ 45,308,246	$ 23,389,615	51.62%	$ 8,037,567	17.74%	$ 31,427,182	69.36%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
Springerville Coal Handling								
310.00	Rights-of-Way	$ 1,670,099	$ 633,208	37.91%	$ -	0.00%	$ 633,208	37.91%
311.00	Structures and Improvements	0	0	0.00%	0	0.00%	0	0.00%
312.00	Boiler Plant Equipment	138,944,802	46,963,604	33.80%	15,369,625	11.06%	62,333,229	44.86%
314.00	Turbogenerator Units	0	0	0.00%	0	0.00%	0	0.00%
315.00	Accessory Electric Equipment	0	0	0.00%	0	0.00%	0	0.00%
316.00	Miscellaneous Power Plant Equipment	0	0	0.00%	0	0.00%	0	0.00%
	Total Springerville Coal Handling	$ 140,614,901	$ 47,596,813	33.85%	$ 15,369,625	10.93%	$ 62,966,438	44.78%
Sundt								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	27,475,371	9,575,331	34.85%	3,044,389	11.08%	12,619,720	45.93%
312.00	Boiler Plant Equipment	130,812,626	46,665,430	35.67%	15,328,834	11.72%	61,994,264	47.39%
314.00	Turbogenerator Units	52,481,329	16,820,158	32.05%	8,491,011	16.18%	25,311,170	48.23%
315.00	Accessory Electric Equipment	39,432,489	10,518,825	26.68%	4,075,707	10.34%	14,594,532	37.01%
316.00	Miscellaneous Power Plant Equipment	2,333,493	571,808	24.50%	254,804	10.92%	826,612	35.42%
	Total Sundt	$ 252,535,308	$ 84,151,552	33.32%	$ 31,194,746	12.35%	$ 115,346,298	45.68%
Sundt Unit 1								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	3,926,062	1,485,986	37.85%	779,521	19.86%	2,265,508	57.70%
312.00	Boiler Plant Equipment	13,782,181	6,160,541	44.70%	3,378,333	24.51%	9,538,873	69.21%
314.00	Turbogenerator Units	10,237,507	3,893,521	38.03%	2,110,236	20.61%	6,003,757	58.64%
315.00	Accessory Electric Equipment	6,536,315	1,347,449	20.61%	810,235	12.40%	2,157,684	33.01%
316.00	Miscellaneous Power Plant Equipment	490,578	125,471	25.58%	66,708	13.60%	192,179	39.17%
	Total Sundt Unit 1	$ 34,972,643	$ 13,012,967	37.21%	$ 7,145,033	20.43%	$ 20,158,000	57.64%
Sundt Unit 2								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	2,812,689	760,485	27.04%	487,875	17.35%	1,248,360	44.38%
312.00	Boiler Plant Equipment	14,371,609	6,141,760	42.74%	3,307,690	23.02%	9,449,450	65.75%
314.00	Turbogenerator Units	8,451,923	3,852,514	45.58%	2,134,727	25.26%	5,987,241	70.84%
315.00	Accessory Electric Equipment	6,205,700	1,028,377	16.57%	646,392	10.42%	1,674,769	26.99%
316.00	Miscellaneous Power Plant Equipment	383,824	79,914	20.82%	49,893	13.00%	129,808	33.82%
	Total Sundt Unit 2	$ 32,225,745	$ 11,863,050	36.81%	$ 6,626,578	20.56%	$ 18,489,628	57.38%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
Sundt Unit 3								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	2,762,012	908,102	32.88%	604,709	21.89%	1,512,811	54.77%
312.00	Boiler Plant Equipment	11,980,831	4,532,980	37.84%	2,778,020	23.19%	7,311,000	61.02%
314.00	Turbogenerator Units	14,830,615	5,103,577	34.41%	3,311,994	22.33%	8,415,571	56.74%
315.00	Accessory Electric Equipment	6,140,139	2,206,560	35.94%	1,455,620	23.71%	3,662,181	59.64%
316.00	Miscellaneous Power Plant Equipment	404,717	95,386	23.57%	71,316	17.62%	166,701	41.19%
	Total Sundt Unit 3	$ 36,118,314	$ 12,846,606	35.57%	$ 8,221,659	22.76%	$ 21,068,265	58.33%
Sundt Unit 4								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	17,974,608	6,420,757	35.72%	1,172,284	6.52%	7,593,041	42.24%
312.00	Boiler Plant Equipment	80,576,055	29,816,147	37.00%	5,864,736	7.28%	35,680,882	44.28%
314.00	Turbogenerator Units	18,961,284	3,970,546	20.94%	934,054	4.93%	4,904,600	25.87%
315.00	Accessory Electric Equipment	20,550,335	5,936,438	28.89%	1,163,459	5.66%	7,099,897	34.55%
316.00	Miscellaneous Power Plant Equipment	1,054,374	271,037	25.71%	66,888	6.34%	337,925	32.05%
	Total Sundt Unit 4	$ 139,116,656	$ 46,414,926	33.36%	$ 9,201,420	6.61%	$ 55,616,346	39.98%
Sundt Solar Booster (Areva)								
310.00	Rights-of-Way	$ -	$ -	0.00%	$ -	0.00%	$ -	0.00%
311.00	Structures and Improvements	0	0	0.00%	0	0.00%	0	0.00%
312.00	Boiler Plant Equipment	10,101,950	14,003	0.14%	56	0.00%	14,059	0.14%
314.00	Turbogenerator Units	0	0	0.00%	0	0.00%	0	0.00%
315.00	Accessory Electric Equipment	0	0	0.00%	0	0.00%	0	0.00%
316.00	Miscellaneous Power Plant Equipment	0	0	0.00%	0	0.00%	0	0.00%
	Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 14,003	0.14%	$ 56	0.00%	$ 14,059	0.14%
OTHER PRODUCTION (by Unit)								
DeMoss Petrie Gas Unit 1								
341.00	Structures and Improvements	$ 761,988	$ 161,449	21.19%	$ 15,488	2.03%	$ 176,938	23.22%
342.00	Fuel Holders, Products and Accessories	750,386	255,266	34.02%	13,637	1.82%	268,903	35.84%
343.00	Prime Movers	76,766	10,802	14.07%	4,007	5.22%	14,809	19.29%
344.00	Generators and Devices	30,772,866	10,384,930	33.75%	555,064	1.80%	10,939,994	35.55%
345.00	Accessory Electric Equipment	861,492	277,783	32.24%	37,364	4.34%	315,147	36.58%
346.00	Miscellaneous Power Plant Equipment	376,605	113,109	30.03%	5,769	1.53%	118,877	31.57%
	Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 11,203,339	33.34%	$ 631,329	1.88%	$ 11,834,668	35.22%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
Gila River								
341.00	Structures and Improvements	$ 8,508,950	$ 1,995,428	23.45%	$ 89,794	1.06%	$ 2,085,222	24.51%
342.00	Fuel Holders, Products and Accessories	6,783,045	1,622,830	23.92%	73,027	1.08%	1,695,857	25.00%
343.00	Prime Movers	188,744,730	42,985,728	22.77%	1,934,358	1.02%	44,920,085	23.80%
344.00	Generators and Devices	32,783,434	8,167,373	24.91%	367,532	1.12%	8,534,905	26.03%
345.00	Accessory Electric Equipment	9,030,698	2,193,824	24.29%	98,722	1.09%	2,292,546	25.39%
346.00	Miscellaneous Power Plant Equipment	6,799,960	1,602,587	23.57%	72,116	1.06%	1,674,704	24.63%
	Total Gila River	$ 252,650,817	$ 58,567,769	23.18%	$ 2,635,550	1.04%	$ 61,203,319	24.22%
Gila River Unit 3								
341.00	Structures and Improvements	$ 957,417	$ 234,255	24.47%	$ 10,541	1.10%	$ 244,796	25.57%
342.00	Fuel Holders, Products and Accessories	178,424	39,907	22.37%	1,796	1.01%	41,702	23.37%
343.00	Prime Movers	181,571,712	41,736,592	22.99%	1,878,147	1.03%	43,614,738	24.02%
344.00	Generators and Devices	32,783,434	8,167,373	24.91%	367,532	1.12%	8,534,905	26.03%
345.00	Accessory Electric Equipment	6,860,554	1,678,596	24.47%	75,537	1.10%	1,754,133	25.57%
346.00	Miscellaneous Power Plant Equipment	135,558	31,962	23.58%	1,438	1.06%	33,400	24.64%
	Total Gila River Unit 3	$ 222,487,099	$ 51,888,684	23.32%	$ 2,334,991	1.05%	$ 54,223,675	24.37%
Gila River Common								
341.00	Structures and Improvements	$ 7,551,533	$ 1,761,174	23.32%	$ 79,253	1.05%	$ 1,840,426	24.37%
342.00	Fuel Holders, Products and Accessories	6,604,621	1,582,923	23.97%	71,232	1.08%	1,654,154	25.05%
343.00	Prime Movers	7,173,018	1,249,136	17.41%	56,211	0.78%	1,305,347	18.20%
344.00	Generators and Devices	0	0	0.00%	0	0.00%	0	0.00%
345.00	Accessory Electric Equipment	2,170,144	515,227	23.74%	23,185	1.07%	538,413	24.81%
346.00	Miscellaneous Power Plant Equipment	6,664,402	1,570,625	23.57%	70,678	1.06%	1,641,303	24.63%
	Total Gila River Common	$ 30,163,718	$ 6,679,085	22.14%	$ 300,559	1.00%	$ 6,979,644	23.14%
Luna								
341.00	Structures and Improvements	$ 13,232,832	$ 486,325	3.68%	$ 46,687	0.35%	$ 533,012	4.03%
342.00	Fuel Holders, Products and Accessories	11,352,383	425,317	3.75%	40,830	0.36%	466,147	4.11%
343.00	Prime Movers	11,151,074	158,063	1.42%	51,439	0.46%	209,502	1.88%
344.00	Generators and Devices	9,486,694	283,805	2.99%	92,200	0.97%	376,005	3.96%
345.00	Accessory Electric Equipment	9,647	26	0.27%	2	0.03%	28	0.29%
346.00	Miscellaneous Power Plant Equipment	7,424,592	275,813	3.71%	26,478	0.36%	302,291	4.07%
	Total Luna	$ 52,657,222	$ 1,629,348	3.09%	$ 257,637	0.49%	$ 1,886,985	3.58%

TUCSON ELECTRIC POWER COMPANY

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
North Loop Gas								
341.00	Structures and Improvements	$ 888,601	$ 742,706	83.58%	$ 96,232	10.83%	$ 838,939	94.41%
342.00	Fuel Holders, Products and Accessories	303,037	101,077	33.35%	3,234	1.07%	104,311	34.42%
343.00	Prime Movers	1,890,946	566,610	29.96%	116,123	6.14%	682,733	36.11%
344.00	Generators and Devices	24,062,187	14,343,394	59.61%	1,434,393	5.96%	15,777,788	65.57%
345.00	Accessory Electric Equipment	2,829,171	1,808,029	63.91%	207,320	7.33%	2,015,349	71.23%
346.00	Miscellaneous Power Plant Equipment	656,253	564,845	86.07%	68,538	10.44%	633,383	96.52%
	Total North Loop Gas	$ 30,630,195	$ 18,126,662	59.18%	$ 1,925,840	6.29%	$ 20,052,503	65.47%
North Loop Gas Unit 1								
341.00	Structures and Improvements	$ 411,070	$ 345,660	84.09%	$ 38,023	9.25%	$ 383,683	93.34%
342.00	Fuel Holders, Products and Accessories	0	0	0.00%	0	0.00%	0	0.00%
343.00	Prime Movers	678,545	371,246	54.71%	41,454	6.11%	412,700	60.82%
344.00	Generators and Devices	3,582,271	3,564,952	99.52%	393,797	10.99%	3,958,749	110.51%
345.00	Accessory Electric Equipment	790,955	658,139	83.21%	73,383	9.28%	731,522	92.49%
346.00	Miscellaneous Power Plant Equipment	306,369	267,216	87.22%	29,394	9.59%	296,610	96.81%
	Total North Loop Gas Unit 1	$ 5,769,210	$ 5,207,212	90.26%	$ 576,051	9.98%	$ 5,783,263	100.24%
North Loop Gas Unit 2								
341.00	Structures and Improvements	$ 196,078	$ 181,593	92.61%	$ 26,513	13.52%	$ 208,106	106.13%
342.00	Fuel Holders, Products and Accessories	0	0	0.00%	0	0.00%	0	0.00%
343.00	Prime Movers	263,450	(172,252)	-65.38%	21,453	8.14%	(150,799)	-57.24%
344.00	Generators and Devices	3,239,719	3,052,716	94.23%	455,457	14.06%	3,508,173	108.29%
345.00	Accessory Electric Equipment	504,895	408,947	81.00%	61,400	12.16%	470,347	93.16%
346.00	Miscellaneous Power Plant Equipment	128,559	130,519	101.52%	19,056	14.82%	149,575	116.35%
	Total North Loop Gas Unit 2	$ 4,332,701	$ 3,601,523	83.12%	$ 583,879	13.48%	$ 4,185,401	96.60%
North Loop Gas Unit 3								
341.00	Structures and Improvements	$ 196,078	$ 189,453	96.62%	$ 25,008	12.75%	$ 214,460	109.38%
342.00	Fuel Holders, Products and Accessories	0	0	0.00%	0	0.00%	0	0.00%
343.00	Prime Movers	948,951	367,616	38.74%	53,216	5.61%	420,832	44.35%
344.00	Generators and Devices	3,030,531	2,996,914	98.89%	410,842	13.56%	3,407,755	112.45%
345.00	Accessory Electric Equipment	503,907	425,980	84.54%	57,299	11.37%	483,279	95.91%
346.00	Miscellaneous Power Plant Equipment	128,559	136,168	105.92%	17,974	13.98%	154,143	119.90%
	Total North Loop Gas Unit 3	$ 4,808,026	$ 4,116,131	85.61%	$ 564,338	11.74%	$ 4,680,469	97.35%

TUCSON ELECTRIC POWER COMPANY
Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Statement D

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
North Loop Gas Unit 4								
341.00	Structures and Improvements	$ 85,375	$ 26,001	30.45%	$ 6,689	7.84%	$ 32,690	38.29%
342.00	Fuel Holders, Products and Accessories	303,037	101,077	33.35%	3,234	1.07%	104,311	34.42%
343.00	Prime Movers	0	0	0.00%	0	0.00%	0	0.00%
344.00	Generators and Devices	14,209,666	4,728,813	33.28%	174,297	1.23%	4,903,110	34.51%
345.00	Accessory Electric Equipment	1,029,414	314,964	30.60%	15,238	1.48%	330,202	32.08%
346.00	Miscellaneous Power Plant Equipment	92,766	30,942	33.35%	2,114	2.28%	33,056	35.63%
	Total North Loop Gas Unit 4	$ 15,720,258	$ 5,201,796	33.09%	$ 201,573	1.28%	$ 5,403,369	34.37%
Solar Units (Generators and Devices)								
344.00	DeMoss Petrie	$ 1,146,081	$ 581,895	50.77%	$ 29,095	2.54%	$ 610,990	53.31%
344.00	Fort Huachuca	36,709,538	786,429	2.14%	39,321	0.11%	825,751	2.25%
344.00	HQ Rooftop	303,184	32,476	10.71%	1,624	0.54%	34,099	11.25%
344.00	OH Rooftop	2,594,590	389,088	15.00%	19,454	0.75%	408,542	15.75%
344.00	OH Test Yard	388,459	185,913	47.86%	9,296	2.39%	195,208	50.25%
344.00	Prairie Fire	19,036,520	2,039,099	10.71%	101,955	0.54%	2,141,054	11.25%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	14,654,846	50.94%	732,742	2.55%	15,387,588	53.49%
344.00	Springerville Site 4	7,873,874	1,518,140	19.28%	75,907	0.96%	1,594,047	20.24%
343.00	Tucson	87,198	60,450	69.32%	3,022	3.47%	63,472	72.79%
344.00	U of A Tech Park Site 1	7,723,832	1,489,211	19.28%	74,461	0.96%	1,563,671	20.24%
345.00	U of A Tech Park Site 2	19,191,952	2,878,048	15.00%	143,902	0.75%	3,021,950	15.75%
346.00	White Mountain	46,499,099	996,151	2.14%	49,808	0.11%	1,045,959	2.25%
	Total Solar Units	$ 170,320,932	$ 25,611,745	15.04%	$ 1,280,587	0.75%	$ 26,892,332	15.79%
Sundt Gas								
341.00	Structures and Improvements	$ 11,090	$ 11,309	101.98%	$ 209	1.88%	$ 11,518	103.86%
342.00	Fuel Holders, Products and Accessories	788,336	437,667	55.52%	7,661	0.97%	445,328	56.49%
343.00	Prime Movers	141,618	110,815	78.25%	1,940	1.37%	112,755	79.62%
344.00	Generators and Devices	8,382,044	8,797,242	104.95%	159,694	1.91%	8,956,936	106.86%
345.00	Accessory Electric Equipment	1,078,811	1,060,779	98.33%	18,584	1.72%	1,079,362	100.05%
346.00	Miscellaneous Power Plant Equipment	49,750	57,626	115.83%	1,014	2.04%	58,640	117.87%
	Total Sundt Gas	$ 10,451,649	$ 10,475,438	100.23%	$ 189,101	1.81%	$ 10,664,539	102.04%

TUCSON ELECTRIC POWER COMPANY

Statement D

Depreciation Reserve Components
Redistributed Reserve
December 31, 2014

Account	Description	Plant Investment	Investment Reserve Amount	Investment Reserve Ratio	Net Salvage Reserve Amount	Net Salvage Reserve Ratio	Total Reserve Amount	Total Reserve Ratio
Sundt Gas Unit 1								
341.00	Structures and Improvements	$ 5,545	$ 5,619	101.33%	$ 101	1.82%	$ 5,720	103.15%
342.00	Fuel Holders, Products and Accessories	394,168	217,433	55.16%	3,696	0.94%	221,129	56.10%
343.00	Prime Movers	70,809	55,053	77.75%	936	1.32%	55,989	79.07%
344.00	Generators and Devices	4,315,668	4,542,228	105.25%	79,186	1.83%	4,621,415	107.08%
345.00	Accessory Electric Equipment	516,231	510,233	98.84%	8,674	1.68%	518,907	100.52%
346.00	Miscellaneous Power Plant Equipment	19,906	22,952	115.30%	390	1.96%	23,342	117.26%
	Total Sundt Gas Unit 1	$ 5,322,327	$ 5,353,518	100.59%	$ 92,984	1.75%	$ 5,446,501	102.33%
Sundt Gas Unit 2								
341.00	Structures and Improvements	$ 5,545	$ 5,691	102.63%	$ 108	1.95%	$ 5,799	104.58%
342.00	Fuel Holders, Products and Accessories	394,168	220,234	55.87%	3,964	1.01%	224,199	56.88%
343.00	Prime Movers	70,809	55,762	78.75%	1,004	1.42%	56,766	80.17%
344.00	Generators and Devices	4,066,376	4,255,014	104.64%	80,507	1.98%	4,335,521	106.62%
345.00	Accessory Electric Equipment	562,580	550,546	97.86%	9,910	1.76%	560,456	99.62%
346.00	Miscellaneous Power Plant Equipment	29,844	34,674	116.18%	624	2.09%	35,298	118.28%
	Total Sundt Gas Unit 2	$ 5,129,322	$ 5,121,921	99.86%	$ 96,117	1.87%	$ 5,218,038	101.73%

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
STEAM PRODUCTION										
310.00	Rights-of-Way	$ 6,273,568	$ 1,166,906	$ 5,106,662		0.0%	$ -	$ (575)	$ (575)	
311.00	Structures and Improvements	241,715,429	36,437,740	205,277,689	-0.7%	-13.9%	(254,013)	(28,592,453)	(28,846,466)	-11.9%
312.00	Boiler Plant Equipment	1,269,797,647	177,844,486	1,091,953,161	-5.3%	-11.2%	(9,352,892)	(121,902,304)	(131,255,196)	-10.3%
314.00	Turbogenerator Units	364,977,004	61,935,081	303,041,923	-3.6%	-10.8%	(2,209,759)	(32,578,923)	(34,788,682)	-9.5%
315.00	Accessory Electric Equipment	151,813,441	7,231,970	144,581,471	-0.8%	-13.3%	(54,707)	(19,278,983)	(19,333,690)	-12.7%
316.00	Miscellaneous Power Plant Equipment	27,947,025	2,724,162	25,222,863	-0.1%	-8.4%	(1,619)	(2,107,159)	(2,108,778)	-7.5%
	Total Steam Production Plant	$ 2,062,524,114	$ 287,340,345	$ 1,775,183,769	-4.1%	-11.5%	$ (11,872,989)	$ (204,460,398)	$ (216,333,387)	-10.5%
OTHER PRODUCTION										
Non-Solar										
341.00	Structures and Improvements	$ 23,624,549	$ 221,088	$ 23,403,461	3.3%	-7.7%	$ 7,192	$ (1,794,769)	$ (1,787,577)	-7.6%
342.00	Fuel Holders, Products and Accessories	19,985,288	8,101	19,977,187		-7.3%		(1,456,829)	(1,456,829)	-7.3%
343.00	Prime Movers	205,281,935	3,276,801	202,005,134		-4.9%		(9,809,038)	(9,809,038)	-4.8%
344.00	Generators and Devices	115,467,853	9,980,628	105,487,225	-0.4%	-5.5%	(43,629)	(5,823,743)	(5,867,372)	-5.1%
345.00	Accessory Electric Equipment	15,595,403	1,785,584	13,809,819		-5.3%	(318)	(730,828)	(731,146)	-4.7%
346.00	Miscellaneous Power Plant Equipment	15,414,670	107,510	15,307,160		-7.3%		(1,111,250)	(1,111,250)	-7.2%
	Total Non-Solar	$ 395,369,698	$ 15,379,712	$ 379,989,986	-0.2%	-5.5%	$ (36,755)	$ (20,726,456)	$ (20,763,211)	-5.3%
Solar										
344.00	Generators and Devices	$ 170,320,932	$ -	$ 170,320,932		-5.0%	$ -	$ (8,516,047)	$ (8,516,047)	-5.0%
	Total Solar	$ 170,320,932	$ -	$ 170,320,932		-5.0%	$ -	$ (8,516,047)	$ (8,516,047)	-5.0%
	Total Other Production Plant	$ 565,690,630	$ 15,379,712	$ 550,310,918	-0.2%	-5.3%	$ (36,755)	$ (29,242,503)	$ (29,279,258)	-5.2%
DISTRIBUTION PLANT										
360.RW	Rights-of-Way	$ 7,882,488	$ 17,415	$ 7,865,073			$ -	$ -	$ -	
361.00	Structures and Improvements	12,185,407	782,933	11,402,474						
362.00	Station Equipment	170,550,706	13,483,176	157,067,530						
364.00	Poles, Towers and Fixtures	233,941,047	11,934,080	222,006,967						
365.00	Overhead Conductors and Devices	185,805,025	10,129,059	175,675,966						
366.00	Underground Conduit	60,132,553	1,407,198	58,725,355						
367.00	Underground Conductors and Devices	304,814,478	7,631,343	297,183,135						
368.OH	Line Transformers - Overhead	122,002,086	18,344,164	103,657,922						
368.UG	Line Transformers - Underground	183,763,798	10,872,866	172,890,932						
369.OH	Services - Overhead	20,027,424	2,485,188	17,542,236						
369.UG	Services - Underground	113,190,446	242,732	112,947,714						
370.00	Meters	83,815,254	38,945,431	44,869,823						
373.00	Street Lighting and Signal Systems	12,730,933	952,571	11,778,362						
	Total Distribution Plant	$ 1,510,841,645	$ 117,228,156	$ 1,393,613,489			$ -	$ -	$ -	

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT										
Depreciable										
390.00	Structures and Improvements	$ 142,216,884	$ 6,536,536	$ 135,680,348	-25.1%	-5.0%	$ (1,640,671)	$ (6,784,017)	$ (8,424,688)	-5.9%
392.C0	Transportation - Class 0	2,693,017	1,454,071	1,238,946	18.8%	15.0%	273,365	185,842	459,207	17.1%
392.C1	Transportation - Class 1	18,234,904	10,516,721	7,718,183	18.8%	15.0%	1,977,144	1,157,727	3,134,871	17.2%
392.C2	Transportation - Class 2	11,814,454	7,974,547	3,839,907	18.8%	15.0%	1,499,215	575,986	2,075,201	17.6%
392.C3	Transportation - Class 3	9,677,240	7,600,304	2,076,936	18.8%	15.0%	1,428,857	311,540	1,740,398	18.0%
392.C4	Transportation - Class 4	14,756,225	11,821,198	2,935,027	18.8%	15.0%	2,222,385	440,254	2,662,639	18.0%
392.C5	Transportation - Class 5	15,016,948	7,034,233	7,982,715	18.8%	15.0%	1,322,436	1,197,407	2,519,843	16.8%
392.C6	Transportation - Class 6	365,200		365,200	18.8%	15.0%		54,780	54,780	15.0%
392.C7	Transportation - Class 7	1,047,216		1,047,216	18.8%	15.0%		157,082	157,082	15.0%
392.C8	Transportation - Class 8	10,369,813	412,313	9,957,500	18.8%	15.0%	77,515	1,493,625	1,571,140	15.2%
392.C9	Transportation - Class 9	4,607,987	355,701	4,252,286	18.8%	15.0%	66,872	637,843	704,715	15.3%
396.00	Power Operatied Equipment	20,256,159	8,395,219	11,860,940	2.3%		193,090		193,090	1.0%
397.EM	EMS and SCADA Equipment	11,481,719	177,348	11,304,371						
	Total Depreciable	$ 262,537,766	$ 62,278,191	$ 200,259,575	11.9%	-0.3%	$ 7,420,208	$ (571,930)	$ 6,848,278	2.6%
Amortizable										
391.00	Furniture and Office Equipment	$ 29,004,709	$ 5,040,298	$ 23,964,411			$ -	$ -	$ -	
391.20	Network and Data Equipment	87,362,414	58,002,778	29,359,636						
393.00	Stores Equipment	4,720,343	2,867,864	1,852,479						
394.00	Tools, Shop and Garage Equipment	13,766,165	6,831,797	6,934,368						
395.00	Laboratory Equipment	8,948,263	3,856,993	5,091,270						
397.20	Telecommunications Equipment	84,671,141	27,215,000	57,456,141						
398.00	Miscellaneous Equipment	6,295,272	1,947,063	4,348,209						
	Total Amortizable	$ 234,768,307	$ 105,761,793	$ 129,006,514			$ -	$ -	$ -	
	Total General Plant	$ 497,306,073	$ 168,039,984	$ 329,266,089	4.4%	-0.2%	$ 7,420,208	$ (571,930)	$ 6,848,278	1.4%
	SUBTOTAL	$ 4,636,362,462	$ 587,988,197	$ 4,048,374,265	-0.8%	-5.8%	$ (4,489,536)	$ (234,274,831)	$ (238,764,367)	-5.1%
NET SALVAGE										
108.02	Distribution	$ 1,511,081,011	$ 117,467,522	$ 1,393,613,489	-2.9%	-5.0%	$ (3,406,558)	$ (69,680,674)	$ (73,087,233)	-4.8%
	Total Net Salvage	$ 1,511,081,011	$ 117,467,522	$ 1,393,613,489	-2.9%	-5.0%	$ (3,406,558)	$ (69,680,674)	$ (73,087,233)	-4.8%
	TOTAL UTILITY	$ 6,147,443,473	$ 705,455,719	$ 5,441,987,754	-1.1%	-5.6%	$ (7,896,094)	$ (303,955,505)	$ (311,851,600)	-5.1%
STEAM PRODUCTION (by Unit)										
Four Corners										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,073,950	91,173	2,982,777		-4.8%		(144,500)	(144,500)	-4.7%
312.00	Boiler Plant Equipment	83,264,815	6,862,754	76,402,061	-12.4%	-4.8%	(851,462)	(3,698,457)	(4,549,919)	-5.5%
314.00	Turbogenerator Units	13,995,637	1,636,157	12,359,480		-4.8%		(594,437)	(594,437)	-4.2%
315.00	Accessory Electric Equipment	5,176,981	786,001	4,390,980		-4.8%		(212,566)	(212,566)	-4.1%
316.00	Miscellaneous Power Plant Equipment	4,006,877	174,643	3,832,234		-4.6%		(178,134)	(178,134)	-4.4%
	Total Four Corners	$ 109,518,260	$ 9,550,728	$ 99,967,532	-8.9%	-4.8%	$ (851,462)	$ (4,828,093)	$ (5,679,555)	-5.2%

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Four Corners Unit 4										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,568,186	43,772	1,524,414		-4.6%		(70,123)	(70,123)	-4.5%
312.00	Boiler Plant Equipment	43,976,009	4,366,471	39,609,538	-19.5%	-4.6%	(851,462)	(1,822,039)	(2,673,501)	-6.1%
314.00	Turbogenerator Units	8,391,807	1,212,445	7,179,362		-4.6%		(330,251)	(330,251)	-3.9%
315.00	Accessory Electric Equipment	2,867,113	592,277	2,274,836		-4.6%		(104,642)	(104,642)	-3.6%
316.00	Miscellaneous Power Plant Equipment	2,037,484	108,323	1,929,161		-4.4%		(84,883)	(84,883)	-4.2%
	Total Four Corners Unit 4	$ 58,840,599	$ 6,323,288	$ 52,517,311	-13.5%	-4.6%	$ (851,462)	$ (2,411,938)	$ (3,263,400)	-5.5%
Four Corners Unit 5										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,505,764	47,401	1,458,363		-5.1%		(74,377)	(74,377)	-4.9%
312.00	Boiler Plant Equipment	39,288,806	2,496,283	36,792,523		-5.1%		(1,876,419)	(1,876,419)	-4.8%
314.00	Turbogenerator Units	5,603,830	423,712	5,180,118		-5.1%		(264,186)	(264,186)	-4.7%
315.00	Accessory Electric Equipment	2,309,868	193,724	2,116,144		-5.1%		(107,923)	(107,923)	-4.7%
316.00	Miscellaneous Power Plant Equipment	1,969,393	66,320	1,903,073		-4.9%		(93,251)	(93,251)	-4.7%
	Total Four Corners Unit 5	$ 50,677,661	$ 3,227,440	$ 47,450,221		-5.1%	$ -	$ (2,416,155)	$ (2,416,155)	-4.8%
Navajo										
310.00	Rights-of-Way	$ 12,229	$ -	$ 12,229		-4.7%	$ -	$ (575)	$ (575)	-4.7%
311.00	Structures and Improvements	19,133,681	478,525	18,655,156	-0.6%	-4.9%	(2,794)	(908,957)	(911,751)	-4.8%
312.00	Boiler Plant Equipment	93,542,762	4,998,561	88,544,201	1.6%	-4.9%	78,293	(4,336,677)	(4,258,384)	-4.6%
314.00	Turbogenerator Units	21,695,188	1,439,662	20,255,526	-0.5%	-4.9%	(7,076)	(994,080)	(1,001,156)	-4.6%
315.00	Accessory Electric Equipment	14,944,456	114,598	14,829,858	2.9%	-4.9%	3,374	(722,356)	(718,982)	-4.8%
316.00	Miscellaneous Power Plant Equipment	4,527,877	9,280	4,518,597	-17.4%	-4.7%	(1,619)	(212,307)	(213,926)	-4.7%
	Total Navajo	$ 153,856,193	$ 7,040,626	$ 146,815,567	1.0%	-4.9%	$ 70,179	$ (7,174,952)	$ (7,104,773)	-4.6%
Navajo Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,183,276	(7,287)	3,190,563		-4.8%		(153,147)	(153,147)	-4.8%
312.00	Boiler Plant Equipment	28,591,944	1,393,362	27,198,582	-4.9%	-4.8%	(68,275)	(1,305,532)	(1,373,807)	-4.8%
314.00	Turbogenerator Units	7,568,560	707,571	6,860,989	-1.0%	-4.8%	(7,076)	(329,327)	(336,403)	-4.4%
315.00	Accessory Electric Equipment	3,763,595	219,295	3,544,300	-0.6%	-4.8%	(1,316)	(170,126)	(171,442)	-4.6%
316.00	Miscellaneous Power Plant Equipment	492,993	21,766	471,227	-4.0%	-4.7%	(871)	(22,148)	(23,018)	-4.7%
	Total Navajo Unit 1	$ 43,600,368	$ 2,334,707	$ 41,265,661	-3.3%	-4.8%	$ (77,537)	$ (1,980,281)	$ (2,057,817)	-4.7%
Navajo Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,882,084	79,399	1,802,685		-5.2%		(93,740)	(93,740)	-5.0%
312.00	Boiler Plant Equipment	28,261,337	1,379,051	26,882,286	4.9%	-5.2%	67,573	(1,397,879)	(1,330,305)	-4.7%
314.00	Turbogenerator Units	7,024,429	98,379	6,926,050		-5.2%		(360,155)	(360,155)	-5.1%
315.00	Accessory Electric Equipment	3,352,457	180,127	3,172,330	-0.6%	-5.2%	(1,081)	(164,961)	(166,042)	-5.0%
316.00	Miscellaneous Power Plant Equipment	539,942	24,068	515,874	-3.6%	-4.9%	(866)	(25,278)	(26,144)	-4.8%
	Total Navajo Unit 2	$ 41,060,249	$ 1,761,024	$ 39,299,225	3.7%	-5.2%	$ 65,626	$ (2,042,012)	$ (1,976,386)	-4.8%

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Navajo Unit 3										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,738,690	57,179	3,681,511		-4.7%		(173,031)	(173,031)	-4.6%
312.00	Boiler Plant Equipment	29,815,550	2,097,036	27,718,514	5.3%	-4.7%	111,143	(1,302,770)	(1,191,627)	-4.0%
314.00	Turbogenerator Units	6,805,747	626,803	6,178,944		-4.7%		(290,410)	(290,410)	-4.3%
315.00	Accessory Electric Equipment	4,794,821	(345,051)	5,139,872	0.3%	-4.7%	(1,035)	(241,574)	(242,609)	-5.1%
316.00	Miscellaneous Power Plant Equipment	455,762	(93,600)	549,362	0.3%	-4.5%	(281)	(24,721)	(25,002)	-5.5%
	Total Navajo Unit 3	$ 45,610,570	$ 2,342,367	$ 43,268,203	4.7%	-4.7%	$ 109,827	$ (2,032,507)	$ (1,922,680)	-4.2%
Navajo Common										
310.00	Rights-of-Way	$ 12,229	$ -	$ 12,229		-4.7%	$ -	$ (575)	$ (575)	-4.7%
311.00	Structures and Improvements	10,329,631	349,234	9,980,397	-0.8%	-4.9%	(2,794)	(489,039)	(491,833)	-4.8%
312.00	Boiler Plant Equipment	6,873,931	129,112	6,744,819	-24.9%	-4.9%	(32,149)	(330,496)	(362,645)	-5.3%
314.00	Turbogenerator Units	296,452	6,909	289,543		-4.9%		(14,188)	(14,188)	-4.8%
315.00	Accessory Electric Equipment	3,033,583	60,227	2,973,356	11.3%	-4.9%	6,806	(145,694)	(138,889)	-4.6%
316.00	Miscellaneous Power Plant Equipment	3,039,180	57,046	2,982,134	0.7%	-4.7%	399	(140,160)	(139,761)	-4.6%
	Total Navajo Common	$ 23,585,006	$ 602,528	$ 22,982,478	-4.6%	-4.9%	$ (27,738)	$ (1,120,153)	$ (1,147,890)	-4.9%
San Juan										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	15,360,481	922,737	14,437,744		-7.9%		(1,141,811)	(1,141,811)	-7.4%
312.00	Boiler Plant Equipment	179,068,616	24,561,708	154,506,908	-10.9%	-9.7%	(2,682,943)	(14,961,956)	(17,644,899)	-9.9%
314.00	Turbogenerator Units	47,886,955	3,591,282	44,295,673		-8.0%		(3,543,654)	(3,543,654)	-7.4%
315.00	Accessory Electric Equipment	10,694,978	631,452	10,063,526		-8.0%		(805,082)	(805,082)	-7.5%
316.00	Miscellaneous Power Plant Equipment	2,285,721	276,166	2,009,555		-7.6%		(152,893)	(152,893)	-6.7%
	Total San Juan	$ 255,296,751	$ 29,983,345	$ 225,313,406	-8.9%	-9.1%	$ (2,682,943)	$ (20,605,396)	$ (23,288,339)	-9.1%
San Juan Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	15,191,141	922,737	14,268,404		-8.0%		(1,141,472)	(1,141,472)	-7.5%
312.00	Boiler Plant Equipment	170,696,078	24,243,049	146,453,029	-12.1%	-8.0%	(2,933,409)	(11,716,242)	(14,649,651)	-8.6%
314.00	Turbogenerator Units	47,886,955	3,591,282	44,295,673		-8.0%		(3,543,654)	(3,543,654)	-7.4%
315.00	Accessory Electric Equipment	10,694,978	631,452	10,063,526		-8.0%		(805,082)	(805,082)	-7.5%
316.00	Miscellaneous Power Plant Equipment	2,236,338	276,166	1,960,172		-7.8%		(152,893)	(152,893)	-6.8%
	Total San Juan Unit 1	$ 246,705,490	$ 29,664,686	$ 217,040,804	-9.9%	-8.0%	$ (2,933,409)	$ (17,359,344)	$ (20,292,753)	-8.2%
San Juan Common										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	169,340		169,340		-0.2%		(339)	(339)	-0.2%
312.00	Boiler Plant Equipment	8,372,538	318,659	8,053,879	78.6%	-40.3%	250,466	(3,245,713)	(2,995,247)	-35.8%
314.00	Turbogenerator Units									
315.00	Accessory Electric Equipment									
316.00	Miscellaneous Power Plant Equipment	49,383		49,383						
	Total San Juan Common	$ 8,591,261	$ 318,659	$ 8,272,602	78.6%	-39.2%	$ 250,466	$ (3,246,052)	$ (2,995,586)	-34.9%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Not Amended for Settlement Provisions

Statement E

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Springerville										
310.00	Rights-of-Way	$ 6,261,339	$ 1,166,906	$ 5,094,433			$ -	$ -	$ -	
311.00	Structures and Improvements	175,350,915	33,624,274	141,726,641	-0.7%	-12.9%	(251,219)	(18,346,682)	(18,597,901)	-10.6%
312.00	Boiler Plant Equipment	772,876,714	131,189,349	641,687,365	-4.5%	-10.0%	(5,896,780)	(53,899,236)	(69,796,016)	-9.0%
314.00	Turbogenerator Units	223,365,420	49,715,505	173,649,915	-4.4%	-3.8%	(2,202,683)	(6,543,559)	(8,746,242)	-3.9%
315.00	Accessory Electric Equipment	78,903,325	3,038,707	75,864,618	-1.9%	-5.4%	(58,081)	(4,128,370)	(4,186,451)	-5.3%
316.00	Miscellaneous Power Plant Equipment	14,477,485	1,948,501	12,528,984		-5.8%		(726,122)	(726,122)	-5.0%
	Total Springerville	$ 1,271,235,198	$ 220,683,242	$ 1,050,551,956	-3.8%	-8.9%	$ (8,408,763)	$ (93,643,968)	$ (102,052,731)	-8.0%
Springerville Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	26,483,850	6,407,835	20,076,015		-3.3%		(662,508)	(662,508)	-2.5%
312.00	Boiler Plant Equipment	243,028,846	57,346,356	185,682,490		-3.3%		(6,127,522)	(6,127,522)	-2.5%
314.00	Turbogenerator Units	65,088,339	15,541,027	49,547,312		-3.3%		(1,635,061)	(1,635,061)	-2.5%
315.00	Accessory Electric Equipment	22,841,460	1,627,293	21,214,167		-3.3%		(700,068)	(700,068)	-3.1%
316.00	Miscellaneous Power Plant Equipment	4,778,042	1,500,300	3,277,742		-2.9%		(95,055)	(95,055)	-2.0%
	Total Springerville Unit 1	$ 362,220,537	$ 82,422,811	$ 279,797,726		-3.3%	$ -	$ (9,220,214)	$ (9,220,214)	-2.5%
Springerville Unit 1 Common										
310.00	Rights-of-Way	$ 2,310,402	$ 1,166,906	$ 1,143,496			$ -	$ -	$ -	
311.00	Structures and Improvements	74,990,847	22,498,021	52,492,826		-9.8%		(5,144,297)	(5,144,297)	-6.9%
312.00	Boiler Plant Equipment	19,321,712	4,466,913	14,854,799		-9.8%		(1,455,770)	(1,455,770)	-7.5%
314.00	Turbogenerator Units	1,551,370	287,048	1,264,322		-9.8%		(123,904)	(123,904)	-8.0%
315.00	Accessory Electric Equipment	9,774,817	147,720	9,627,097		-9.8%		(943,456)	(943,456)	-9.7%
316.00	Miscellaneous Power Plant Equipment	2,140,360	181,348	1,959,012		-9.4%		(184,147)	(184,147)	-8.6%
	Total Springerville Unit 1 Common	$ 110,089,508	$ 28,747,956	$ 81,341,552		-9.7%	$ -	$ (7,851,573)	$ (7,851,573)	-7.1%
Springerville Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	38,669,006	2,128,976	36,540,030	-11.8%	-3.7%	(251,219)	(1,351,981)	(1,603,200)	-4.1%
312.00	Boiler Plant Equipment	358,654,246	62,731,701	295,922,545	-9.4%	-3.7%	(5,896,780)	(10,949,134)	(16,845,914)	-4.7%
314.00	Turbogenerator Units	155,942,778	33,887,430	122,055,348	-6.5%	-3.7%	(2,202,683)	(4,516,048)	(6,718,731)	-4.3%
315.00	Accessory Electric Equipment	43,609,568	1,262,629	42,346,939	-4.6%	-3.7%	(58,081)	(1,566,837)	(1,624,918)	-3.7%
316.00	Miscellaneous Power Plant Equipment	6,879,594	254,925	6,624,669		-3.3%		(218,614)	(218,614)	-3.2%
	Total Springerville Unit 2	$ 603,755,192	$ 100,265,661	$ 503,489,531	-8.4%	-3.7%	$ (8,408,763)	$ (18,602,614)	$ (27,011,377)	-4.5%
Springerville Unit 2 Common (Leasehold Imp.)										
310.00	Rights-of-Way	$ 2,280,838	$ -	$ 2,280,838			$ -	$ -	$ -	
311.00	Structures and Improvements	35,207,212	2,589,442	32,617,770		-34.3%		(11,187,895)	(11,187,895)	-31.8%
312.00	Boiler Plant Equipment	7,670,230	1,387,501	6,282,729		-34.3%		(2,154,976)	(2,154,976)	-28.1%
314.00	Turbogenerator Units	782,933		782,933		-34.3%		(268,546)	(268,546)	-34.3%
315.00	Accessory Electric Equipment	2,677,480	1,065	2,676,415		-34.3%		(918,010)	(918,010)	-34.3%
316.00	Miscellaneous Power Plant Equipment	679,489	11,928	667,561		-34.2%		(228,306)	(228,306)	-33.6%
	Total Springerville Unit 2 Common	$ 49,298,182	$ 3,989,936	$ 45,308,246		-32.6%	$ -	$ (14,757,733)	$ (14,757,733)	-29.9%

TUCSON ELECTRIC POWER COMPANY
Average Net Salvage

Not Amended for Settlement Provisions

Statement E

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
		A	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/C
Springerville Coal Handling										
310.00	Rights-of-Way	$ 1,670,099	$ -	$ 1,670,099			$ -	$ -	$ -	
311.00	Structures and Improvements	144,201,680	5,256,878	138,944,802		-31.1%		(43,211,833)	(43,211,833)	-30.0%
312.00	Boiler Plant Equipment									
314.00	Turbogenerator Units									
315.00	Accessory Electric Equipment									
316.00	Miscellaneous Power Plant Equipment									
	Total Springerville Coal Handling	$ 145,871,779	$ 5,256,878	$ 140,614,901		-30.7%	$ -	$ (43,211,833)	$ (43,211,833)	-29.6%
Sundt										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	28,796,402	1,321,031	27,475,371		-29.3%		(8,050,504)	(8,050,504)	-28.0%
312.00	Boiler Plant Equipment	141,044,740	10,232,114	130,812,626		-26.8%		(35,005,978)	(35,005,978)	-24.8%
314.00	Turbogenerator Units	58,033,804	5,552,475	52,481,329		-39.8%		(20,903,194)	(20,903,194)	-36.0%
315.00	Accessory Electric Equipment	42,093,701	2,661,212	39,432,489		-34.0%		(13,410,609)	(13,410,609)	-31.9%
316.00	Miscellaneous Power Plant Equipment	2,649,065	315,572	2,333,493		-35.9%		(837,704)	(837,704)	-31.6%
	Total Sundt	$ 272,617,712	$ 20,082,404	$ 252,535,308		-31.0%	$ -	$ (78,207,989)	$ (78,207,989)	-28.7%
Sundt Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	4,268,893	342,831	3,926,062		-47.2%		(1,853,101)	(1,853,101)	-43.4%
312.00	Boiler Plant Equipment	16,399,259	2,617,078	13,782,181		-47.2%		(6,505,189)	(6,505,189)	-39.7%
314.00	Turbogenerator Units	11,467,321	1,229,814	10,237,507		-47.2%		(4,832,103)	(4,832,103)	-42.1%
315.00	Accessory Electric Equipment	7,107,197	570,882	6,536,315		-47.3%		(3,091,677)	(3,091,677)	-43.5%
316.00	Miscellaneous Power Plant Equipment	516,709	26,131	490,578		-47.1%		(231,062)	(231,062)	-44.7%
	Total Sundt Unit 1	$ 39,759,379	$ 4,786,736	$ 34,972,643		-47.2%	$ -	$ (16,513,133)	$ (16,513,133)	-41.5%
Sundt Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,151,250	338,561	2,812,689		-51.3%		(1,442,909)	(1,442,909)	-45.8%
312.00	Boiler Plant Equipment	15,058,926	687,317	14,371,609		-51.3%		(7,372,635)	(7,372,635)	-49.0%
314.00	Turbogenerator Units	9,232,349	780,426	8,451,923		-51.2%		(4,327,385)	(4,327,385)	-46.9%
315.00	Accessory Electric Equipment	6,531,575	325,875	6,205,700		-51.3%		(3,183,524)	(3,183,524)	-48.7%
316.00	Miscellaneous Power Plant Equipment	411,098	27,274	383,824		-51.1%		(196,134)	(196,134)	-47.7%
	Total Sundt Unit 2	$ 34,385,198	$ 2,159,453	$ 32,225,745		-51.3%	$ -	$ (16,522,588)	$ (16,522,588)	-48.1%
Sundt Unit 3										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,083,662	321,650	2,762,012		-56.3%		(1,555,013)	(1,555,013)	-50.4%
312.00	Boiler Plant Equipment	12,808,330	827,499	11,980,831		-56.3%		(6,745,208)	(6,745,208)	-52.7%
314.00	Turbogenerator Units	16,380,197	1,549,582	14,830,615		-56.3%		(8,349,636)	(8,349,636)	-51.0%
315.00	Accessory Electric Equipment	6,922,100	781,961	6,140,139		-56.3%		(3,456,898)	(3,456,898)	-49.9%
316.00	Miscellaneous Power Plant Equipment	458,756	54,039	404,717		-56.1%		(227,046)	(227,046)	-49.5%
	Total Sundt Unit 3	$ 39,653,045	$ 3,534,731	$ 36,118,314		-56.3%	$ -	$ (20,333,801)	$ (20,333,801)	-51.3%

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Sundt Unit 4										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	18,292,597	317,989	17,974,608		-17.8%		(3,199,480)	(3,199,480)	-17.5%
312.00	Boiler Plant Equipment	86,676,275	6,100,220	80,576,055		-17.8%		(14,342,538)	(14,342,538)	-16.5%
314.00	Turbogenerator Units	20,953,937	1,992,653	18,961,284		-17.9%		(3,394,070)	(3,394,070)	-16.2%
315.00	Accessory Electric Equipment	21,532,829	982,494	20,550,335		-17.9%		(3,678,510)	(3,678,510)	-17.1%
316.00	Miscellaneous Power Plant Equipment	1,262,502	208,128	1,054,374		-17.4%		(183,461)	(183,461)	-14.5%
	Total Sundt Unit 4	$ 148,718,140	$ 9,601,484	$ 139,116,656		-17.8%	$ -	$ (24,798,059)	$ (24,798,059)	-16.7%
Sundt Solar Booster (Areva)										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements									
312.00	Boiler Plant Equipment	10,101,950		10,101,950		-0.4%		(40,408)	(40,408)	-0.4%
314.00	Turbogenerator Units									
315.00	Accessory Electric Equipment									
316.00	Miscellaneous Power Plant Equipment									
	Total Sundt Solar Booster (Areva)	$ 10,101,950	$ -	$ 10,101,950		-0.4%	$ -	$ (40,408)	$ (40,408)	-0.4%
OTHER PRODUCTION (by Unit)										
DeMoss Petrie Gas Unit 1										
341.00	Structures and Improvements	$ 941,331	$ 179,343	$ 761,988		-5.1%	$ -	$ (38,861)	$ (38,861)	-4.1%
342.00	Fuel Holders, Products and Accessories	758,487	8,101	750,386		-5.1%		(38,270)	(38,270)	-5.0%
343.00	Prime Movers	528,037	451,271	76,766		-5.1%		(3,915)	(3,915)	-0.7%
344.00	Generators and Devices	31,682,855	909,989	30,772,866		-5.1%		(1,569,416)	(1,569,416)	-5.0%
345.00	Accessory Electric Equipment	2,300,817	1,439,325	861,492		-5.1%		(43,936)	(43,936)	-1.9%
346.00	Miscellaneous Power Plant Equipment	379,346	2,741	376,605		-5.1%		(19,207)	(19,207)	-5.1%
	Total DeMoss Petrie Gas Unit 1	$ 36,590,873	$ 2,990,770	$ 33,600,103		-5.1%	$ -	$ (1,713,605)	$ (1,713,605)	-4.7%
Gila River										
341.00	Structures and Improvements	$ 8,508,950	$ -	$ 8,508,950		-4.5%	$ -	$ (382,903)	$ (382,903)	-4.5%
342.00	Fuel Holders, Products and Accessories	6,783,045		6,783,045		-4.5%		(305,237)	(305,237)	-4.5%
343.00	Prime Movers	188,744,730		188,744,730		-4.5%		(8,493,513)	(8,493,513)	-4.5%
344.00	Generators and Devices	32,783,434		32,783,434		-4.5%		(1,475,255)	(1,475,255)	-4.5%
345.00	Accessory Electric Equipment	9,030,698		9,030,698		-4.5%		(406,381)	(406,381)	-4.5%
346.00	Miscellaneous Power Plant Equipment	6,799,960		6,799,960		-4.5%		(305,998)	(305,998)	-4.5%
	Total Gila River	$ 252,650,817	$ -	$ 252,650,817		-4.5%	$ -	$ (11,369,287)	$ (11,369,287)	-4.5%
Gila River Unit 3										
341.00	Structures and Improvements	$ 957,417	$ -	$ 957,417		-4.5%	$ -	$ (43,084)	$ (43,084)	-4.5%
342.00	Fuel Holders, Products and Accessories	178,424		178,424		-4.5%		(8,029)	(8,029)	-4.5%
343.00	Prime Movers	181,571,712		181,571,712		-4.5%		(8,170,727)	(8,170,727)	-4.5%
344.00	Generators and Devices	32,783,434		32,783,434		-4.5%		(1,475,255)	(1,475,255)	-4.5%
345.00	Accessory Electric Equipment	6,860,554		6,860,554		-4.5%		(308,725)	(308,725)	-4.5%
346.00	Miscellaneous Power Plant Equipment	135,558		135,558		-4.5%		(6,100)	(6,100)	-4.5%
	Total Gila River Unit 3	$ 222,487,099	$ -	$ 222,487,099		-4.5%	$ -	$ (10,011,919)	$ (10,011,919)	-4.5%

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Gila River Common										
341.00	Structures and Improvements	$ 7,551,533	$ -	$ 7,551,533		-4.5%	$ -	$ (339,819)	$ (339,819)	-4.5%
342.00	Fuel Holders, Products and Accessories	6,604,621		6,604,621		-4.5%		(297,208)	(297,208)	-4.5%
343.00	Prime Movers	7,173,018		7,173,018		-4.5%		(322,786)	(322,786)	-4.5%
344.00	Generators and Devices									
345.00	Accessory Electric Equipment	2,170,144		2,170,144		-4.5%		(97,656)	(97,656)	-4.5%
346.00	Miscellaneous Power Plant Equipment	6,664,402		6,664,402		-4.5%		(299,898)	(299,898)	-4.5%
	Total Gila River Common	$ 30,163,718	$ -	$ 30,163,718		-4.5%	$ -	$ (1,357,367)	$ (1,357,367)	-4.5%
Luna										
341.00	Structures and Improvements	$ 13,269,836	$ 37,004	$ 13,232,832		-9.6%	$ -	$ (1,270,352)	$ (1,270,352)	-9.6%
342.00	Fuel Holders, Products and Accessories	11,352,383		11,352,383		-9.6%		(1,089,829)	(1,089,829)	-9.6%
343.00	Prime Movers	13,516,063	2,364,989	11,151,074		-9.6%		(1,070,503)	(1,070,503)	-7.9%
344.00	Generators and Devices	16,114,883	6,628,189	9,486,694		-9.6%		(910,723)	(910,723)	-5.7%
345.00	Accessory Electric Equipment	9,647		9,647		-9.6%		(926)	(926)	-9.6%
346.00	Miscellaneous Power Plant Equipment	7,449,920	25,328	7,424,592		-9.6%		(712,761)	(712,761)	-9.6%
	Total Luna	$ 61,712,732	$ 9,055,510	$ 52,657,222		-9.6%	$ -	$ (5,055,093)	$ (5,055,093)	-8.2%
North Loop Gas										
341.00	Structures and Improvements	$ 891,728	$ 3,127	$ 888,601	230.0%	-11.5%	$ 7,192	$ (102,459)	$ (95,267)	-10.7%
342.00	Fuel Holders, Products and Accessories	303,037		303,037		-3.2%		(9,697)	(9,697)	-3.2%
343.00	Prime Movers	2,351,487	460,541	1,890,946		-12.6%		(238,629)	(238,629)	-10.1%
344.00	Generators and Devices	25,738,500	1,676,313	24,062,187	-2.6%	-7.2%	(43,629)	(1,721,788)	(1,765,417)	-6.9%
345.00	Accessory Electric Equipment	3,144,306	315,135	2,829,171	-0.1%	-9.2%	(318)	(260,682)	(261,000)	-8.3%
346.00	Miscellaneous Power Plant Equipment	735,694	79,441	656,253		-11.0%		(72,409)	(72,409)	-9.8%
	Total North Loop Gas	$ 33,164,752	$ 2,534,557	$ 30,630,195	-1.5%	-7.9%	$ (36,755)	$ (2,405,663)	$ (2,442,418)	-7.4%
North Loop Gas Unit 1										
341.00	Structures and Improvements	$ 411,070	$ -	$ 411,070		-11.0%	$ -	$ (45,218)	$ (45,218)	-11.0%
342.00	Fuel Holders, Products and Accessories									
343.00	Prime Movers	685,193	6,648	678,545		-11.0%		(74,640)	(74,640)	-10.9%
344.00	Generators and Devices	3,956,176	373,905	3,582,271	-10.0%	-11.0%	(37,391)	(394,050)	(431,440)	-10.9%
345.00	Accessory Electric Equipment	808,620	17,665	790,955	-0.6%	-11.0%	(106)	(87,005)	(87,111)	-10.8%
346.00	Miscellaneous Power Plant Equipment	306,369		306,369		-11.0%		(33,701)	(33,701)	-11.0%
	Total North Loop Gas Unit 1	$ 6,167,428	$ 398,218	$ 5,769,210	-9.4%	-11.0%	$ (37,496)	$ (634,613)	$ (672,110)	-10.9%
North Loop Gas Unit 2										
341.00	Structures and Improvements	$ 196,078	$ -	$ 196,078		-14.6%	$ -	$ (28,627)	$ (28,627)	-14.6%
342.00	Fuel Holders, Products and Accessories									
343.00	Prime Movers	676,560	413,110	263,450		-14.7%		(38,727)	(38,727)	-5.7%
344.00	Generators and Devices	3,441,312	201,593	3,239,719	-1.5%	-14.6%	(3,024)	(472,999)	(476,023)	-13.8%
345.00	Accessory Electric Equipment	522,560	17,665	504,895	-0.6%	-14.7%	(106)	(74,220)	(74,326)	-14.2%
346.00	Miscellaneous Power Plant Equipment	128,559		128,559		-14.6%		(18,770)	(18,770)	-14.6%
	Total North Loop Gas Unit 2	$ 4,965,069	$ 632,368	$ 4,332,701	-0.5%	-14.6%	$ (3,130)	$ (633,343)	$ (636,473)	-12.8%

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
North Loop Gas Unit 3										
341.00	Structures and Improvements	$ 196,078	$ -	$ 196,078		-13.2%	$ -	$ (25,882)	$ (25,882)	-13.2%
342.00	Fuel Holders, Products and Accessories									
343.00	Prime Movers	989,734	40,783	948,951		-13.2%		(125,262)	(125,262)	-12.7%
344.00	Generators and Devices	3,387,718	357,187	3,030,531	-0.9%	-13.2%	(3,215)	(400,030)	(403,245)	-11.9%
345.00	Accessory Electric Equipment	521,572	17,665	503,907	-0.6%	-13.2%	(106)	(66,516)	(66,622)	-12.8%
346.00	Miscellaneous Power Plant Equipment	128,559		128,559		-13.2%		(16,970)	(16,970)	-13.2%
	Total North Loop Gas Unit 3	$ 5,223,661	$ 415,635	$ 4,808,026	-0.8%	-13.2%	$ (3,321)	$ (634,659)	$ (637,980)	-12.2%
North Loop Gas Unit 4										
341.00	Structures and Improvements	$ 88,502	$ 3,127	$ 85,375	230.0%	-3.2%	$ 7,192	$ (2,732)	$ 4,460	5.0%
342.00	Fuel Holders, Products and Accessories	303,037		303,037		-3.2%		(9,697)	(9,697)	-3.2%
343.00	Prime Movers									
344.00	Generators and Devices	14,953,294	743,628	14,209,666		-3.2%		(454,709)	(454,709)	-3.0%
345.00	Accessory Electric Equipment	1,291,554	262,140	1,029,414		-3.2%		(32,941)	(32,941)	-2.6%
346.00	Miscellaneous Power Plant Equipment	172,207	79,441	92,766		-3.2%		(2,969)	(2,969)	-1.7%
	Total North Loop Gas Unit 4	$ 16,808,594	$ 1,088,336	$ 15,720,258	0.7%	-3.2%	$ 7,192	$ (503,048)	$ (495,856)	-3.0%
Solar Units (Generators and Devices)										
344.00	DeMoss Petrie	$ 1,146,081	$ -	$ 1,146,081		-5.0%	$ -	$ (57,304)	$ (57,304)	-5.0%
344.00	Fort Huachuca	36,709,538		36,709,538		-5.0%		(1,835,477)	(1,835,477)	-5.0%
344.00	HQ Rooftop	303,184		303,184		-5.0%		(15,159)	(15,159)	-5.0%
344.00	OH Rooftop	2,594,590		2,594,590		-5.0%		(129,730)	(129,730)	-5.0%
344.00	OH Test Yard	388,459		388,459		-5.0%		(19,423)	(19,423)	-5.0%
344.00	Prairie Fire	19,036,520		19,036,520		-5.0%		(951,826)	(951,826)	-5.0%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605		28,766,605		-5.0%		(1,438,330)	(1,438,330)	-5.0%
344.00	Springerville Site 4	7,873,874		7,873,874		-5.0%		(393,694)	(393,694)	-5.0%
343.00	Tucson	87,198		87,198		-5.0%		(4,360)	(4,360)	-5.0%
344.00	U of A Tech Park Site 1	7,723,832		7,723,832		-5.0%		(386,192)	(386,192)	-5.0%
345.00	U of A Tech Park Site 2	19,191,952		19,191,952		-5.0%		(959,598)	(959,598)	-5.0%
346.00	White Mountain	46,499,099		46,499,099		-5.0%		(2,324,955)	(2,324,955)	-5.0%
	Total Solar Units	$ 170,320,932	$ -	$ 170,320,932		-5.0%	$ -	$ (8,516,047)	$ (8,516,047)	-5.0%
Sundt Gas										
341.00	Structures and Improvements	$ 12,704	$ 1,614	$ 11,090		-1.8%	$ -	$ (194)	$ (194)	-1.5%
342.00	Fuel Holders, Products and Accessories	788,336		788,336		-1.8%		(13,796)	(13,796)	-1.8%
343.00	Prime Movers	141,618		141,618		-1.8%		(2,478)	(2,478)	-1.8%
344.00	Generators and Devices	9,148,181	766,137	8,382,044		-1.7%		(146,561)	(146,561)	-1.6%
345.00	Accessory Electric Equipment	1,109,935	31,124	1,078,811		-1.8%		(18,902)	(18,902)	-1.7%
346.00	Miscellaneous Power Plant Equipment	49,750		49,750		-1.8%		(876)	(876)	-1.8%
	Total Sundt Gas	$ 11,250,524	$ 798,875	$ 10,451,649		-1.7%	$ -	$ (182,807)	$ (182,807)	-1.6%

Account	Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A		B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Sundt Gas Unit 1										
341.00	Structures and Improvements	$ 6,352	$ 807	$ 5,545		-1.7%	$ -	$ (94)	$ (94)	-1.5%
342.00	Fuel Holders, Products and Accessories	394,168		394,168		-1.7%		(6,701)	(6,701)	-1.7%
343.00	Prime Movers	70,809		70,809		-1.7%		(1,204)	(1,204)	-1.7%
344.00	Generators and Devices	4,531,439	215,771	4,315,668		-1.7%		(73,366)	(73,366)	-1.6%
345.00	Accessory Electric Equipment	531,793	15,562	516,231		-1.7%		(8,776)	(8,776)	-1.7%
346.00	Miscellaneous Power Plant Equipment	19,906		19,906		-1.7%		(338)	(338)	-1.7%
	Total Sundt Gas Unit 1	$ 5,554,467	$ 232,140	$ 5,322,327		-1.7%	$ -	$ (90,480)	$ (90,480)	-1.6%
Sundt Gas Unit 2										
341.00	Structures and Improvements	$ 6,352	$ 807	$ 5,545		-1.8%	$ -	$ (100)	$ (100)	-1.6%
342.00	Fuel Holders, Products and Accessories	394,168		394,168		-1.8%		(7,095)	(7,095)	-1.8%
343.00	Prime Movers	70,809		70,809		-1.8%		(1,275)	(1,275)	-1.8%
344.00	Generators and Devices	4,616,742	550,366	4,066,376		-1.8%		(73,195)	(73,195)	-1.6%
345.00	Accessory Electric Equipment	578,142	15,562	562,580		-1.8%		(10,126)	(10,126)	-1.8%
346.00	Miscellaneous Power Plant Equipment	29,844		29,844		-1.8%		(537)	(537)	-1.8%
	Total Sundt Gas Unit 2	$ 5,696,057	$ 566,735	$ 5,129,322		-1.8%	$ -	$ (92,328)	$ (92,328)	-1.6%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Not Amended for Settlement Provisions

Statement F

Account Description	12/31/14 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
		Interim	Final	Interim	Final	Interim	Final	Total	
A	B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
STEAM PRODUCTION (by Unit)									
Four Corners									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	2,982,777	125,729	2,857,048	-5.0%	-4.8%	(6,286)	(138,452)	(144,738)	-4.9%
312.00 Boiler Plant Equipment	76,402,061	3,267,354	73,134,707	-5.0%	-4.8%	(163,368)	(3,541,453)	(3,704,820)	-4.8%
314.00 Turbogenerator Units	12,359,480	523,849	11,835,631	-5.0%	-4.8%	(26,192)	(569,486)	(595,678)	-4.8%
315.00 Accessory Electric Equipment	4,390,980	180,525	4,210,455	-5.0%	-4.8%	(9,026)	(203,893)	(212,920)	-4.8%
316.00 Miscellaneous Power Plant Equipment	3,832,234	160,207	3,672,027		-4.8%		(178,084)	(178,084)	-4.6%
Total Four Corners	$ 99,967,532	$ 4,257,665	$ 95,709,867	-4.8%	-4.8%	$ (204,873)	$ (4,631,368)	$ (4,836,241)	-4.8%
Four Corners Unit 4									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	1,524,414	64,249	1,460,165	-5.0%	-4.6%	(3,212)	(67,248)	(70,461)	-4.6%
312.00 Boiler Plant Equipment	39,609,538	1,694,925	37,914,613	-5.0%	-4.6%	(84,746)	(1,746,171)	(1,830,917)	-4.6%
314.00 Turbogenerator Units	7,179,362	303,478	6,875,884	-5.0%	-4.6%	(15,174)	(316,671)	(331,845)	-4.6%
315.00 Accessory Electric Equipment	2,274,836	93,584	2,181,252	-5.0%	-4.6%	(4,679)	(100,458)	(105,138)	-4.6%
316.00 Miscellaneous Power Plant Equipment	1,929,161	80,629	1,848,532		-4.6%		(85,135)	(85,135)	-4.4%
Total Four Corners Unit 4	$ 52,517,311	$ 2,236,864	$ 50,280,447	-4.8%	-4.6%	$ (107,812)	$ (2,315,684)	$ (2,423,496)	-4.6%
Four Corners Unit 5									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	1,458,363	61,481	1,396,882	-5.0%	-5.1%	(3,074)	(71,204)	(74,278)	-5.1%
312.00 Boiler Plant Equipment	36,792,523	1,572,430	35,220,093	-5.0%	-5.1%	(78,621)	(1,795,282)	(1,873,903)	-5.1%
314.00 Turbogenerator Units	5,180,118	220,371	4,959,747	-5.0%	-5.1%	(11,019)	(252,814)	(263,833)	-5.1%
315.00 Accessory Electric Equipment	2,116,144	86,942	2,029,202	-5.0%	-5.1%	(4,347)	(103,435)	(107,782)	-5.1%
316.00 Miscellaneous Power Plant Equipment	1,903,073	79,578	1,823,495		-5.1%		(92,949)	(92,949)	-4.9%
Total Four Corners Unit 5	$ 47,450,221	$ 2,020,801	$ 45,429,420	-4.8%	-5.1%	$ (97,061)	$ (2,315,684)	$ (2,412,745)	-5.1%
Navajo									
310.00 Rights-of-Way	$ 12,229	$ 506	$ 11,723		-4.9%	$ -	$ (570)	$ (570)	-4.7%
311.00 Structures and Improvements	18,655,156	647,268	18,007,888	-5.0%	-4.8%	(32,363)	(871,426)	(903,789)	-4.8%
312.00 Boiler Plant Equipment	88,544,201	2,742,632	85,801,569	-5.0%	-4.9%	(137,132)	(4,175,660)	(4,312,791)	-4.9%
314.00 Turbogenerator Units	20,255,526	611,609	19,643,917	-5.0%	-4.9%	(30,580)	(957,892)	(988,472)	-4.9%
315.00 Accessory Electric Equipment	14,829,858	486,654	14,343,204	-5.0%	-4.8%	(24,333)	(694,363)	(718,696)	-4.8%
316.00 Miscellaneous Power Plant Equipment	4,518,597	164,224	4,354,373		-4.9%		(211,800)	(211,800)	-4.7%
Total Navajo	$ 146,815,567	$ 4,652,894	$ 142,162,673	-4.8%	-4.9%	$ (224,408)	$ (6,911,709)	$ (7,136,117)	-4.9%
Navajo Unit 1									
310.00 Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00 Structures and Improvements	3,190,563	35,076	3,155,487	-5.0%	-4.8%	(1,754)	(150,404)	(152,157)	-4.8%
312.00 Boiler Plant Equipment	27,198,582	289,406	26,909,176	-5.0%	-4.8%	(14,470)	(1,282,604)	(1,297,074)	-4.8%
314.00 Turbogenerator Units	6,860,989	73,135	6,787,854	-5.0%	-4.8%	(3,657)	(323,537)	(327,194)	-4.8%
315.00 Accessory Electric Equipment	3,544,300	37,858	3,506,442	-5.0%	-4.8%	(1,893)	(167,132)	(169,025)	-4.8%
316.00 Miscellaneous Power Plant Equipment	471,227	5,200	466,027		-4.8%		(22,213)	(22,213)	-4.7%
Total Navajo Unit 1	$ 41,265,661	$ 440,676	$ 40,824,985	-4.9%	-4.8%	$ (21,774)	$ (1,945,889)	$ (1,967,663)	-4.8%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Not Amended for Settlement Provisions

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Navajo Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	1,802,685	73,142	1,729,543	-5.0%	-5.2%	(3,657)	(89,224)	(92,881)	-5.2%
312.00	Boiler Plant Equipment	26,882,286	1,080,667	25,801,619	-5.0%	-5.2%	(54,033)	(1,331,054)	(1,385,088)	-5.2%
314.00	Turbogenerator Units	6,926,050	277,187	6,648,863	-5.0%	-5.2%	(13,859)	(343,002)	(356,861)	-5.2%
315.00	Accessory Electric Equipment	3,172,330	127,256	3,045,074	-5.0%	-5.2%	(6,363)	(157,089)	(163,452)	-5.2%
316.00	Miscellaneous Power Plant Equipment	515,874	21,188	494,686		-5.2%		(25,520)	(25,520)	-4.9%
	Total Navajo Unit 2	$ 39,299,225	$ 1,579,440	$ 37,719,785	-4.9%	-5.2%	$ (77,913)	$ (1,945,889)	$ (2,023,802)	-5.1%
Navajo Unit 3										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,681,511	150,256	3,531,255	-5.0%	-4.7%	(7,513)	(165,471)	(172,983)	-4.7%
312.00	Boiler Plant Equipment	27,718,514	1,110,320	26,608,194	-5.0%	-4.7%	(55,516)	(1,246,830)	(1,302,346)	-4.7%
314.00	Turbogenerator Units	6,178,944	250,312	5,928,632	-5.0%	-4.7%	(12,516)	(277,809)	(290,325)	-4.7%
315.00	Accessory Electric Equipment	5,139,872	208,272	4,931,600	-5.0%	-4.7%	(10,414)	(231,089)	(241,503)	-4.7%
316.00	Miscellaneous Power Plant Equipment	549,362	22,448	526,914		-4.7%		(24,691)	(24,691)	-4.5%
	Total Navajo Unit 3	$ 43,268,203	$ 1,741,608	$ 41,526,595	-4.9%	-4.7%	$ (85,958)	$ (1,945,889)	$ (2,031,847)	-4.7%
Navajo Common										
310.00	Rights-of-Way	$ 12,229	$ 506	$ 11,723		-4.9%	$ -	$ (570)	$ (570)	-4.7%
311.00	Structures and Improvements	9,980,397	388,794	9,591,603	-5.0%	-4.9%	(19,440)	(466,328)	(485,767)	-4.9%
312.00	Boiler Plant Equipment	6,744,819	262,239	6,482,580	-5.0%	-4.9%	(13,112)	(315,172)	(328,284)	-4.9%
314.00	Turbogenerator Units	289,543	10,974	278,569	-5.0%	-4.9%	(549)	(13,544)	(14,092)	-4.9%
315.00	Accessory Electric Equipment	2,973,356	113,268	2,860,088	-5.0%	-4.9%	(5,663)	(139,053)	(144,716)	-4.9%
316.00	Miscellaneous Power Plant Equipment	2,982,134	115,388	2,866,746		-4.9%		(139,376)	(139,376)	-4.7%
	Total Navajo Common	$ 22,982,478	$ 891,170	$ 22,091,308	-4.3%	-4.9%	$ (38,764)	$ (1,074,042)	$ (1,112,806)	-4.8%
San Juan										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	14,437,744	463,504	13,974,240	-5.0%	-8.0%	(23,175)	(1,114,553)	(1,137,728)	-7.9%
312.00	Boiler Plant Equipment	154,506,908	4,871,333	149,635,575	-5.0%	-9.8%	(243,567)	(14,676,449)	(14,920,015)	-9.7%
314.00	Turbogenerator Units	44,295,673	1,411,705	42,883,968	-5.0%	-8.1%	(70,585)	(3,461,006)	(3,531,591)	-8.0%
315.00	Accessory Electric Equipment	10,063,526	319,494	9,744,032	-5.0%	-8.1%	(15,975)	(786,405)	(802,379)	-8.0%
316.00	Miscellaneous Power Plant Equipment	2,009,555	63,827	1,945,728		-7.9%		(153,167)	(153,167)	-7.6%
	Total San Juan	$ 225,313,406	$ 7,129,861	$ 218,183,545	-5.0%	-9.3%	$ (353,302)	$ (20,191,578)	$ (20,544,880)	-9.1%
San Juan Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	14,268,404	458,417	13,809,987	-5.0%	-8.1%	(22,921)	(1,114,553)	(1,137,474)	-8.0%
312.00	Boiler Plant Equipment	146,453,029	4,622,894	141,830,135	-5.0%	-8.1%	(231,145)	(11,446,582)	(11,677,727)	-8.0%
314.00	Turbogenerator Units	44,295,673	1,411,705	42,883,968	-5.0%	-8.1%	(70,585)	(3,461,006)	(3,531,591)	-8.0%
315.00	Accessory Electric Equipment	10,063,526	319,494	9,744,032	-5.0%	-8.1%	(15,975)	(786,405)	(802,379)	-8.0%
316.00	Miscellaneous Power Plant Equipment	1,960,172	62,343	1,897,829		-8.1%		(153,167)	(153,167)	-7.8%
	Total San Juan Unit 1	$ 217,040,804	$ 6,874,853	$ 210,165,951	-5.0%	-8.1%	$ (340,625)	$ (16,961,712)	$ (17,302,337)	-8.0%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Not Amended for Settlement Provisions

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements		Net Salvage Rate		Future Net Salvage			Future Rate
			Interim	Final	Interim	Final	Interim	Final	Total	
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
San Juan Common										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	169,340	5,087	164,253	-5.0%		(254)		(254)	-0.2%
312.00	Boiler Plant Equipment	8,053,879	248,439	7,805,440	-5.0%	-41.4%	(12,422)	(3,229,866)	(3,242,288)	-40.3%
314.00	Turbogenerator Units									
315.00	Accessory Electric Equipment									
316.00	Miscellaneous Power Plant Equipment	49,383	1,483	47,900						
	Total San Juan Common	$ 8,272,602	$ 255,009	$ 8,017,593	-5.0%	-41.4%	$ (12,676)	$ (3,317,655)	$ (3,242,543)	-39.2%
Springerville										
310.00	Rights-of-Way	$ 5,094,433	$ 303,737	$ 4,790,696			$ -	$ -	$ -	
311.00	Structures and Improvements	141,726,641	9,894,361	131,832,280	-5.0%	-13.6%	(494,718)	(17,879,952)	(18,374,670)	-13.0%
312.00	Boiler Plant Equipment	641,687,365	56,287,561	585,399,804	-5.0%	-10.5%	(2,814,378)	(61,192,579)	(64,006,957)	-10.0%
314.00	Turbogenerator Units	173,649,915	15,167,291	158,482,624	-5.0%	-3.7%	(758,365)	(5,805,252)	(6,563,617)	-3.8%
315.00	Accessory Electric Equipment	75,864,618	6,485,462	69,379,156	-5.0%	-5.5%	(324,273)	(3,815,063)	(4,139,336)	-5.5%
316.00	Miscellaneous Power Plant Equipment	12,528,984	1,039,506	11,489,478		-6.3%		(723,989)	(723,989)	-5.8%
	Total Springerville	$ 1,050,551,956	$ 89,177,919	$ 961,374,037	-4.9%	-9.3%	$ (4,391,734)	$ (89,416,835)	$ (93,808,569)	-8.9%
Springerville Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	20,076,015	1,594,824	18,481,191	-5.0%	-3.2%	(79,741)	(582,912)	(662,653)	-3.3%
312.00	Boiler Plant Equipment	185,682,490	14,793,478	170,889,012	-5.0%	-3.2%	(739,674)	(5,389,976)	(6,129,650)	-3.3%
314.00	Turbogenerator Units	49,547,312	3,948,245	45,599,067	-5.0%	-3.2%	(197,412)	(1,438,231)	(1,635,643)	-3.3%
315.00	Accessory Electric Equipment	21,214,167	1,711,130	19,503,037	-5.0%	-3.2%	(85,557)	(615,141)	(700,698)	-3.3%
316.00	Miscellaneous Power Plant Equipment	3,277,742	259,549	3,018,193		-3.2%		(95,196)	(95,196)	-2.9%
	Total Springerville Unit 1	$ 279,797,726	$ 22,307,227	$ 257,490,499	-4.9%	-3.2%	$ (1,102,384)	$ (8,121,456)	$ (9,223,840)	-3.3%
Springerville Unit 1 Common										
310.00	Rights-of-Way	$ 1,143,496	$ 90,874	$ 1,052,622			$ -	$ -	$ -	
311.00	Structures and Improvements	52,492,826	4,192,244	48,300,582	-5.0%	-10.3%	(209,612)	(4,950,846)	(5,160,458)	-9.8%
312.00	Boiler Plant Equipment	14,854,799	1,188,740	13,666,059	-5.0%	-10.3%	(59,437)	(1,400,781)	(1,460,218)	-9.8%
314.00	Turbogenerator Units	1,264,322	101,482	1,162,840	-5.0%	-10.3%	(5,074)	(119,192)	(124,266)	-9.8%
315.00	Accessory Electric Equipment	9,627,097	778,804	8,848,293	-5.0%	-10.3%	(38,940)	(906,957)	(945,897)	-9.8%
316.00	Miscellaneous Power Plant Equipment	1,959,012	158,119	1,800,893		-10.3%		(184,593)	(184,593)	-9.4%
	Total Springerville Unit 1 Common	$ 81,341,552	$ 6,510,263	$ 74,831,289	-4.8%	-10.3%	$ (313,063)	$ (7,670,264)	$ (7,875,433)	-9.7%
Springerville Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	36,540,030	3,339,714	33,200,316	-5.0%	-3.6%	(166,986)	(1,190,915)	(1,357,901)	-3.7%
312.00	Boiler Plant Equipment	295,922,545	27,119,399	268,803,146	-5.0%	-3.6%	(1,355,970)	(9,642,129)	(10,998,099)	-3.7%
314.00	Turbogenerator Units	122,055,348	11,099,142	110,956,206	-5.0%	-3.6%	(554,957)	(3,980,065)	(4,535,023)	-3.7%
315.00	Accessory Electric Equipment	42,346,939	3,931,538	38,415,401	-5.0%	-3.6%	(196,577)	(1,377,983)	(1,574,560)	-3.7%
316.00	Miscellaneous Power Plant Equipment	6,624,669	606,145	6,018,524		-3.6%		(215,888)	(215,888)	-3.3%
	Total Springerville Unit 2	$ 503,489,531	$ 46,095,938	$ 457,393,593	-4.9%	-3.6%	$ (2,274,490)	$ (16,406,981)	$ (18,681,471)	-3.7%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Not Amended for Settlement Provisions

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Springerville Unit 2 Common (Leasehold Imp.)										
310.00	Rights-of-Way	$ 2,280,838	$ 54,667	$ 2,226,171			$ -	$ -	$ -	
311.00	Structures and Improvements	32,617,770	767,579	31,850,191	-5.0%	-35.0%	(38,379)	(11,155,279)	(11,193,658)	-34.3%
312.00	Boiler Plant Equipment	6,282,729	145,696	6,137,033	-5.0%	-35.0%	(7,285)	(2,149,448)	(2,156,732)	-34.3%
314.00	Turbogenerator Units	782,933	18,422	764,511	-5.0%	-35.0%	(921)	(267,764)	(268,685)	-34.3%
315.00	Accessory Electric Equipment	2,676,415	63,990	2,612,425	-5.0%	-35.0%	(3,199)	(914,981)	(918,181)	-34.3%
316.00	Miscellaneous Power Plant Equipment	667,561	15,693	651,868		-35.0%		(228,312)	(228,312)	-34.2%
	Total Springerville Unit 2 Common	$ 45,308,246	$ 1,066,047	$ 44,242,199	-4.7%	-35.0%	$ (49,784)	$ (15,495,482)	$ (14,765,568)	-32.6%
Springerville Coal Handling										
310.00	Rights-of-Way	$ 1,670,099	$ 158,196	$ 1,511,903			$ -	$ -	$ -	
311.00	Structures and Improvements					-33.8%				
312.00	Boiler Plant Equipment	138,944,802	13,040,248	125,904,554	-5.0%	-33.8%	(652,012)	(42,610,245)	(43,262,257)	-31.1%
314.00	Turbogenerator Units					-33.8%				
315.00	Accessory Electric Equipment					-33.8%				
316.00	Miscellaneous Power Plant Equipment					-33.8%				
	Total Springerville Coal Handling	$ 140,614,901	$ 13,198,444	$ 127,416,457	-4.9%	-33.8%	$ (652,012)	$ (43,121,922)	$ (43,262,257)	-30.8%
Sundt										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	27,475,371	1,952,799	25,522,572	-5.0%	-31.2%	(97,640)	(7,958,788)	(8,056,428)	-29.3%
312.00	Boiler Plant Equipment	130,812,626	9,546,882	121,265,744	-5.0%	-28.5%	(477,344)	(34,548,214)	(35,025,558)	-26.8%
314.00	Turbogenerator Units	52,481,329	2,986,121	49,495,208	-5.0%	-41.9%	(149,306)	(20,752,980)	(20,902,286)	-39.8%
315.00	Accessory Electric Equipment	39,432,489	2,508,542	36,923,947	-5.0%	-36.0%	(125,427)	(13,277,987)	(13,403,415)	-34.0%
316.00	Miscellaneous Power Plant Equipment	2,333,493	139,906	2,193,587		-38.2%		(838,233)	(838,233)	-35.9%
	Total Sundt	$ 252,535,308	$ 17,134,249	$ 235,401,059	-5.0%	-32.9%	$ (849,717)	$ (77,376,202)	$ (78,225,919)	-31.0%
Sundt Unit 1										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	3,926,062	136,193	3,789,869	-5.0%	-48.7%	(6,810)	(1,846,443)	(1,853,253)	-47.2%
312.00	Boiler Plant Equipment	13,782,181	471,482	13,310,699	-5.0%	-48.7%	(23,574)	(6,485,041)	(6,508,615)	-47.2%
314.00	Turbogenerator Units	10,237,507	350,214	9,887,293	-5.0%	-48.7%	(17,511)	(4,817,140)	(4,834,651)	-47.2%
315.00	Accessory Electric Equipment	6,536,315	216,751	6,319,564	-5.0%	-48.7%	(10,838)	(3,078,924)	(3,089,762)	-47.3%
316.00	Miscellaneous Power Plant Equipment	490,578	16,412	474,166		-48.7%		(231,016)	(231,016)	-47.1%
	Total Sundt Unit 1	$ 34,972,643	$ 1,191,052	$ 33,781,591	-4.9%	-48.7%	$ (58,732)	$ (16,458,565)	$ (16,517,297)	-47.2%
Sundt Unit 2										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	2,812,689	110,169	2,702,520	-5.0%	-53.2%	(5,508)	(1,437,153)	(1,442,661)	-51.3%
312.00	Boiler Plant Equipment	14,371,609	571,825	13,799,784	-5.0%	-53.2%	(28,591)	(7,338,485)	(7,367,076)	-51.3%
314.00	Turbogenerator Units	8,451,923	342,504	8,109,419	-5.0%	-53.2%	(17,125)	(4,312,448)	(4,329,573)	-51.2%
315.00	Accessory Electric Equipment	6,205,700	236,730	5,968,970	-5.0%	-53.2%	(11,837)	(3,174,194)	(3,186,031)	-51.3%
316.00	Miscellaneous Power Plant Equipment	383,824	14,718	369,106		-53.2%		(196,284)	(196,284)	-51.1%
	Total Sundt Unit 2	$ 32,225,745	$ 1,275,947	$ 30,949,798	-4.9%	-53.2%	$ (63,061)	$ (16,458,565)	$ (16,521,626)	-51.3%

TUCSON ELECTRIC POWER COMPANY

Not Amended for Settlement Provisions

Statement F

Future Net Salvage
Steam and Other Production

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Sundt Unit 3										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	2,762,012	124,459	2,637,553	-5.0%	-58.7%	(6,223)	(1,548,491)	(1,554,714)	-56.3%
312.00	Boiler Plant Equipment	11,980,831	543,246	11,437,585	-5.0%	-58.7%	(27,162)	(6,714,937)	(6,742,099)	-56.3%
314.00	Turbogenerator Units	14,830,615	662,973	14,167,642	-5.0%	-58.7%	(33,149)	(8,317,737)	(8,350,886)	-56.3%
315.00	Accessory Electric Equipment	6,140,139	271,786	5,868,353	-5.0%	-58.7%	(13,589)	(3,445,275)	(3,458,864)	-56.3%
316.00	Miscellaneous Power Plant Equipment	404,717	17,752	386,965		-58.7%		(227,185)	(227,185)	-56.1%
	Total Sundt Unit 3	$ 36,118,314	$ 1,620,216	$ 34,498,098	-4.9%	-58.7%	$ (80,123)	$ (20,253,625)	$ (20,333,748)	-56.3%
Sundt Unit 4										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements	17,974,608	1,581,977	16,392,631	-5.0%	-19.1%	(79,099)	(3,126,700)	(3,205,799)	-17.8%
312.00	Boiler Plant Equipment	80,576,055	7,125,872	73,450,183	-5.0%	-19.1%	(356,294)	(14,009,751)	(14,366,045)	-17.8%
314.00	Turbogenerator Units	18,961,284	1,630,429	17,330,855	-5.0%	-19.1%	(81,521)	(3,305,655)	(3,387,176)	-17.9%
315.00	Accessory Electric Equipment	20,550,335	1,783,275	18,767,060	-5.0%	-19.1%	(89,164)	(3,579,594)	(3,668,758)	-17.9%
316.00	Miscellaneous Power Plant Equipment	1,054,374	91,024	963,350		-19.1%		(183,748)	(183,748)	-17.4%
	Total Sundt Unit 4	$ 139,116,656	$ 12,212,578	$ 126,904,078	-5.0%	-19.1%	$ (606,078)	$ (24,205,448)	$ (24,811,525)	-17.8%
Sundt Solar Booster (Areva)										
310.00	Rights-of-Way	$ -	$ -	$ -			$ -	$ -	$ -	
311.00	Structures and Improvements									
312.00	Boiler Plant Equipment	10,101,950	834,456	9,267,494	-5.0%		(41,723)		(41,723)	-0.4%
314.00	Turbogenerator Units									
315.00	Accessory Electric Equipment									
316.00	Miscellaneous Power Plant Equipment									
	Total Sundt Solar Booster (Areva)	$ 10,101,950	$ 834,456	$ 9,267,494	-5.0%		$ (41,723)	$ -	$ (41,723)	-0.4%
OTHER PRODUCTION (by Unit)										
DeMoss Petrie Gas Unit 1										
341.00	Structures and Improvements	$ 761,988	$ 60,324	$ 701,664		-5.5%	$ -	$ (38,733)	$ (38,733)	-5.1%
342.00	Fuel Holders, Products and Accessories	750,386	60,186	690,200		-5.5%		(38,101)	(38,101)	-5.1%
343.00	Prime Movers	76,766	6,017	70,749		-5.5%		(3,906)	(3,906)	-5.1%
344.00	Generators and Devices	30,772,866	2,467,553	28,305,313		-5.5%		(1,562,517)	(1,562,517)	-5.1%
345.00	Accessory Electric Equipment	861,492	68,973	792,519		-5.5%		(43,749)	(43,749)	-5.1%
346.00	Miscellaneous Power Plant Equipment	376,605	30,058	346,547		-5.5%		(19,130)	(19,130)	-5.1%
	Total DeMoss Petrie Gas Unit 1	$ 33,600,103	$ 2,693,110	$ 30,906,993		-5.5%	$ -	$ (1,706,136)	$ (1,706,136)	-5.1%

TUCSON ELECTRIC POWER COMPANY

Not Amended for Settlement Provisions

Statement F

Future Net Salvage
Steam and Other Production

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Gila River										
341.00	Structures and Improvements	$ 8,508,950	$ 722,006	$ 7,786,944		-4.9%	$ -	$ (384,369)	$ (384,369)	-4.5%
342.00	Fuel Holders, Products and Accessories	6,783,045	575,960	6,207,085		-4.9%		(306,538)	(306,538)	-4.5%
343.00	Prime Movers	188,744,730	15,990,013	172,754,717		-4.9%		(8,485,805)	(8,485,805)	-4.5%
344.00	Generators and Devices	32,783,434	2,784,699	29,998,735		-4.9%		(1,473,232)	(1,473,232)	-4.5%
345.00	Accessory Electric Equipment	9,030,698	766,677	8,264,021		-4.9%		(406,406)	(406,406)	-4.5%
346.00	Miscellaneous Power Plant Equipment	6,799,960	577,149	6,222,811		-4.9%		(307,325)	(307,325)	-4.5%
	Total Gila River	$ 252,650,817	$ 21,416,503	$ 231,234,314		-4.9%	$ -	$ (11,363,674)	$ (11,363,674)	-4.5%
Gila River Unit 3										
341.00	Structures and Improvements	$ 957,417	$ 81,280	$ 876,137		-4.9%	$ -	$ (43,027)	$ (43,027)	-4.5%
342.00	Fuel Holders, Products and Accessories	178,424	15,110	163,314		-4.9%		(8,020)	(8,020)	-4.5%
343.00	Prime Movers	181,571,712	15,386,002	166,185,710		-4.9%		(8,161,345)	(8,161,345)	-4.5%
344.00	Generators and Devices	32,783,434	2,784,699	29,998,735		-4.9%		(1,473,232)	(1,473,232)	-4.5%
345.00	Accessory Electric Equipment	6,860,554	582,436	6,278,118		-4.9%		(308,317)	(308,317)	-4.5%
346.00	Miscellaneous Power Plant Equipment	135,558	11,493	124,065		-4.9%		(6,093)	(6,093)	-4.5%
	Total Gila River Unit 3	$ 222,487,099	$ 18,861,018	$ 203,626,081		-4.9%	$ -	$ (10,000,034)	$ (10,000,034)	-4.5%
Gila River Common										
341.00	Structures and Improvements	$ 7,551,533	$ 640,726	$ 6,910,807		-4.9%	$ -	$ (341,342)	$ (341,342)	-4.5%
342.00	Fuel Holders, Products and Accessories	6,604,621	560,850	6,043,771		-4.9%		(298,517)	(298,517)	-4.5%
343.00	Prime Movers	7,173,018	604,011	6,569,007		-4.9%		(324,460)	(324,460)	-4.5%
344.00	Generators and Devices					-4.9%				
345.00	Accessory Electric Equipment	2,170,144	184,242	1,985,902		-4.9%		(98,089)	(98,089)	-4.5%
346.00	Miscellaneous Power Plant Equipment	6,664,402	565,656	6,098,746		-4.9%		(301,233)	(301,233)	-4.5%
	Total Gila River Common	$ 30,163,718	$ 2,555,485	$ 27,608,233		-4.9%	$ -	$ (1,363,641)	$ (1,363,641)	-4.5%
Luna										
341.00	Structures and Improvements	$ 13,232,832	$ 1,216,311	$ 12,016,521		-10.6%	$ -	$ (1,268,864)	$ (1,268,864)	-9.6%
342.00	Fuel Holders, Products and Accessories	11,352,383	1,043,899	10,308,484		-10.6%		(1,088,506)	(1,088,506)	-9.6%
343.00	Prime Movers	11,151,074	1,011,828	10,139,246		-10.6%		(1,070,636)	(1,070,636)	-9.6%
344.00	Generators and Devices	9,486,694	871,757	8,614,937		-10.6%		(909,679)	(909,679)	-9.6%
345.00	Accessory Electric Equipment	9,647	869	8,778		-10.6%		(927)	(927)	-9.6%
346.00	Miscellaneous Power Plant Equipment	7,424,592	682,593	6,741,999		-10.6%		(711,910)	(711,910)	-9.6%
	Total Luna	$ 52,657,222	$ 4,827,258	$ 47,829,964		-10.6%	$ -	$ (5,050,522)	$ (5,050,522)	-9.6%
North Loop Gas										
341.00	Structures and Improvements	$ 888,601	$ 32,853	$ 855,748		-12.0%	$ -	$ (102,603)	$ (102,603)	-11.5%
342.00	Fuel Holders, Products and Accessories	303,037	24,306	278,731		-3.5%		(9,789)	(9,789)	-3.2%
343.00	Prime Movers	1,890,946	57,217	1,833,729		-13.0%		(239,103)	(239,103)	-12.6%
344.00	Generators and Devices	24,062,187	1,464,066	22,598,121		-7.6%		(1,727,387)	(1,727,387)	-7.2%
345.00	Accessory Electric Equipment	2,829,171	140,177	2,688,994		-9.7%		(260,868)	(260,868)	-9.2%
346.00	Miscellaneous Power Plant Equipment	656,253	25,875	630,378		-11.5%		(72,489)	(72,489)	-11.0%
	Total North Loop Gas	$ 30,630,195	$ 1,744,493	$ 28,885,702		-8.4%	$ -	$ (2,412,240)	$ (2,412,240)	-7.9%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Not Amended for Settlement Provisions

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
North Loop Gas Unit 1										
341.00	Structures and Improvements	$ 411,070	$ 13,106	$ 397,964		-11.4%	$ -	$ (45,248)	$ (45,248)	-11.0%
342.00	Fuel Holders, Products and Accessories					-11.4%				
343.00	Prime Movers	678,545	20,776	657,769		-11.4%		(74,788)	(74,788)	-11.0%
344.00	Generators and Devices	3,582,271	117,192	3,465,079		-11.4%		(393,978)	(393,978)	-11.0%
345.00	Accessory Electric Equipment	790,955	25,195	765,760		-11.4%		(87,067)	(87,067)	-11.0%
346.00	Miscellaneous Power Plant Equipment	306,369	9,806	296,563		-11.4%		(33,719)	(33,719)	-11.0%
	Total North Loop Gas Unit 1	$ 5,769,210	$ 186,076	$ 5,583,134		-11.4%	$ -	$ (634,800)	$ (634,800)	-11.0%
North Loop Gas Unit 2										
341.00	Structures and Improvements	$ 196,078	$ 6,462	$ 189,616		-15.1%	$ -	$ (28,720)	$ (28,720)	-14.6%
342.00	Fuel Holders, Products and Accessories					-15.1%				
343.00	Prime Movers	263,450	7,568	255,882		-15.1%		(38,757)	(38,757)	-14.7%
344.00	Generators and Devices	3,239,719	106,945	3,132,774		-15.1%		(474,505)	(474,505)	-14.6%
345.00	Accessory Electric Equipment	504,895	16,336	488,559		-15.1%		(73,999)	(73,999)	-14.7%
346.00	Miscellaneous Power Plant Equipment	128,559	4,314	124,245		-15.1%		(18,819)	(18,819)	-14.6%
	Total North Loop Gas Unit 2	$ 4,332,701	$ 141,626	$ 4,191,075		-15.1%	$ -	$ (634,800)	$ (634,800)	-14.7%
North Loop Gas Unit 3										
341.00	Structures and Improvements	$ 196,078	$ 6,462	$ 189,616		-13.6%	$ -	$ (25,876)	$ (25,876)	-13.2%
342.00	Fuel Holders, Products and Accessories					-13.6%				
343.00	Prime Movers	948,951	28,872	920,079		-13.6%		(125,558)	(125,558)	-13.2%
344.00	Generators and Devices	3,030,531	100,299	2,930,232		-13.6%		(399,871)	(399,871)	-13.2%
345.00	Accessory Electric Equipment	503,907	16,306	487,601		-13.6%		(66,540)	(66,540)	-13.2%
346.00	Miscellaneous Power Plant Equipment	128,559	4,314	124,245		-13.6%		(16,955)	(16,955)	-13.2%
	Total North Loop Gas Unit 3	$ 4,808,026	$ 156,254	$ 4,651,772		-13.6%	$ -	$ (634,800)	$ (634,800)	-13.2%
North Loop Gas Unit 4										
341.00	Structures and Improvements	$ 85,375	$ 6,822	$ 78,553		-3.5%	$ -	$ (2,759)	$ (2,759)	-3.2%
342.00	Fuel Holders, Products and Accessories	303,037	24,306	278,731		-3.5%		(9,789)	(9,789)	-3.2%
343.00	Prime Movers					-3.5%				
344.00	Generators and Devices	14,209,666	1,139,629	13,070,037		-3.5%		(459,033)	(459,033)	-3.2%
345.00	Accessory Electric Equipment	1,029,414	82,340	947,074		-3.5%		(33,262)	(33,262)	-3.2%
346.00	Miscellaneous Power Plant Equipment	92,766	7,441	85,325		-3.5%		(2,997)	(2,997)	-3.2%
	Total North Loop Gas Unit 4	$ 15,720,258	$ 1,260,537	$ 14,459,721		-3.5%	$ -	$ (507,840)	$ (507,840)	-3.2%

TUCSON ELECTRIC POWER COMPANY
Future Net Salvage
Steam and Other Production

Not Amended for Settlement Provisions

Statement F

Account	Description	12/31/14 Plant Investment	Future Retirements Interim	Future Retirements Final	Net Salvage Rate Interim	Net Salvage Rate Final	Future Net Salvage Interim	Future Net Salvage Final	Future Net Salvage Total	Future Rate
A		B	C	D=B-C	E	F	G=C*E	H=D*F	I=G+H	J=I/B
Solar Units (Generators and Devices)										
344.00	DeMoss Petrie	$ 1,146,081	$ 1,146,081	$ -	-5.0%		$ (57,304)	$ -	$ (57,304)	-5.0%
344.00	Fort Huachuca	36,709,538	36,709,538		-5.0%		(1,835,477)		(1,835,477)	-5.0%
344.00	HQ Rooftop	303,184	303,184		-5.0%		(15,159)		(15,159)	-5.0%
344.00	OH Rooftop	2,594,590	2,594,590		-5.0%		(129,730)		(129,730)	-5.0%
344.00	OH Test Yard	388,459	388,459		-5.0%		(19,423)		(19,423)	-5.0%
344.00	Prairie Fire	19,036,520	19,036,520		-5.0%		(951,826)		(951,826)	-5.0%
344.00	Springerville Sites 1-3 (Legacy)	28,766,605	28,766,605		-5.0%		(1,438,330)		(1,438,330)	-5.0%
344.00	Springerville Site 4	7,873,874	7,873,874		-5.0%		(393,694)		(393,694)	-5.0%
343.00	Tucson	87,198	87,198		-5.0%		(4,360)		(4,360)	-5.0%
344.00	U of A Tech Park Site 1	7,723,832	7,723,832		-5.0%		(386,192)		(386,192)	-5.0%
345.00	U of A Tech Park Site 2	19,191,952	19,191,952		-5.0%		(959,598)		(959,598)	-5.0%
346.00	White Mountain	46,499,099	46,499,099		-5.0%		(2,324,955)		(2,324,955)	-5.0%
	Total Solar Units	$ 170,320,932	$ 170,320,932	$ -	-5.0%		$ (8,516,047)	$ -	$ (8,516,047)	-5.0%
Sundt Gas										
341.00	Structures and Improvements	$ 11,090	$ 360	$ 10,730		-1.8%	$ -	$ (194)	$ (194)	-1.8%
342.00	Fuel Holders, Products and Accessories	788,336	24,187	764,149		-1.8%		(13,824)	(13,824)	-1.8%
343.00	Prime Movers	141,618	4,397	137,221		-1.8%		(2,482)	(2,482)	-1.8%
344.00	Generators and Devices	8,382,044	274,685	8,107,359		-1.8%		(146,585)	(146,585)	-1.7%
345.00	Accessory Electric Equipment	1,078,811	35,096	1,043,715		-1.8%		(18,896)	(18,896)	-1.8%
346.00	Miscellaneous Power Plant Equipment	49,750	1,662	48,088		-1.8%		(873)	(873)	-1.8%
	Total Sundt Gas	$ 10,451,649	$ 340,387	$ 10,111,262		-1.8%	$ -	$ (182,855)	$ (182,855)	-1.7%
Sundt Gas Unit 1										
341.00	Structures and Improvements	$ 5,545	$ 180	$ 5,365		-1.8%	$ -	$ (95)	$ (95)	-1.7%
342.00	Fuel Holders, Products and Accessories	394,168	12,093	382,075		-1.8%		(6,785)	(6,785)	-1.7%
343.00	Prime Movers	70,809	2,198	68,611		-1.8%		(1,218)	(1,218)	-1.7%
344.00	Generators and Devices	4,315,668	141,569	4,174,099		-1.8%		(74,120)	(74,120)	-1.7%
345.00	Accessory Electric Equipment	516,231	16,832	499,399		-1.8%		(8,868)	(8,868)	-1.7%
346.00	Miscellaneous Power Plant Equipment	19,906	666	19,240		-1.8%		(342)	(342)	-1.7%
	Total Sundt Gas Unit 1	$ 5,322,327	$ 173,539	$ 5,148,788		-1.8%	$ -	$ (91,427)	$ (91,427)	-1.7%
Sundt Gas Unit 2										
341.00	Structures and Improvements	$ 5,545	$ 180	$ 5,365		-1.8%	$ -	$ (99)	$ (99)	-1.8%
342.00	Fuel Holders, Products and Accessories	394,168	12,093	382,075		-1.8%		(7,039)	(7,039)	-1.8%
343.00	Prime Movers	70,809	2,198	68,611		-1.8%		(1,264)	(1,264)	-1.8%
344.00	Generators and Devices	4,066,376	133,116	3,933,260		-1.8%		(72,465)	(72,465)	-1.8%
345.00	Accessory Electric Equipment	562,580	18,264	544,316		-1.8%		(10,028)	(10,028)	-1.8%
346.00	Miscellaneous Power Plant Equipment	29,844	996	28,848		-1.8%		(531)	(531)	-1.8%
	Total Sundt Gas Unit 2	$ 5,129,322	$ 166,848	$ 4,962,474		-1.8%	$ -	$ (91,427)	$ (91,427)	-1.8%

Dismantlement Costs
Steam and Other Production

Unit	Capacity (MW)	Ownership Share	Shared Cost	Final Retirement	Distributed Cost	Inflation Rate	Spend Year	Trended Cost	Accrual Rate
A	B	C	D	E	F	G	H	I	J=I/E
STEAM PRODUCTION (by Unit)									
Four Corners (2009 Cost)									
4	785	7.00%		$ 50,280,447	$ 2,225,763	2.00%	2017	$ 2,315,684	4.6%
5	785	7.00%		45,429,420	2,225,763	2.00%	2017	2,315,684	5.1%
C		5.07%							
	1570		$ 4,451,526	$ 95,709,867	$ 4,451,526			$ 4,631,368	4.8%
	Allocated to Common:								
	Allocated to Units:		$ 4,451,526						
Navajo (2011 Cost)									
1	750	7.50%		$ 40,824,985	$ 1,727,894	2.00%	2017	$ 1,945,889	4.8%
2	750	7.50%		37,719,785	1,727,894	2.00%	2017	1,945,889	5.2%
3	750	7.50%		41,526,595	1,727,894	2.00%	2017	1,945,889	4.7%
C				22,091,308	953,719	2.00%	2017	1,074,042	4.9%
	2250		$ 6,137,400	$ 142,162,673	$ 6,137,400			$ 6,911,709	4.9%
	Allocated to Common:		953,719						
	Allocated to Units:		$ 5,183,681						
San Juan (2011 Cost)									
1	340	50.00%		$ 210,165,951	$ 15,670,000	2.00%	2017	$ 16,961,712	8.1%
C		50.00%		8,017,593	3,065,000	2.00%	2017	3,317,655	41.4%
	340		$ 18,735,000	$ 218,183,545	$ 18,735,000			$ 20,279,367	9.3%
	Allocated to Common:		3,065,000						
	Allocated to Units:		$ 15,670,000						
Springerville (2011 Cost)									
1	387	49.50%	$ 7,211,620	$ 257,490,499	$ 7,211,620	2.00%	2017	$ 8,121,456	3.2%
1C		49.50%	6,810,975	74,831,289	6,810,975	2.00%	2017	7,670,264	10.3%
2	390	100.00%	14,568,930	457,393,593	14,568,930	2.00%	2017	16,406,981	3.6%
2C		100.00%	13,759,545	44,242,199	13,759,545	2.00%	2017	15,495,482	35.0%
CH		49.28%	38,291,033	127,416,457	38,291,033	2.00%	2017	43,121,922	33.8%
	777		$ 80,642,103	$ 961,374,037	$ 80,642,103			$ 90,816,106	9.4%
	Allocated to Common:								
	Allocated to Units:		$ 80,642,103						
Sundt (2011 Cost)									
1	81	100.00%	$ 5,501,274	$ 33,781,591	$ 14,614,734	2.00%	2017	$ 16,458,565	48.7%
2	81	100.00%	5,501,274	30,949,798	14,614,734	2.00%	2017	16,458,565	53.2%
3	104	100.00%	6,283,406	34,498,098	17,984,639	2.00%	2017	20,253,625	58.7%
4	120	100.00%	7,992,322	126,904,078	21,493,745	2.00%	2017	24,205,448	19.1%
C			43,429,577						
	386		$ 68,707,853	$ 226,133,565	$ 68,707,853			$ 77,376,202	34.2%
	Allocated to Common:								
	Allocated to Units:		$ 68,707,853						

Unit	Capacity (MW)	Ownership Share	Shared Cost	Final Retirement	Distributed Cost	Inflation Rate	Spend Year	Trended Cost	Accrual Rate
A	B	C	D	E	F	G	H	I	J=I/E
OTHER PRODUCTION (by Unit)									
DeMoss Petrie (2011 Cost)									
1	75	100.00%	$ 1,515,000	$ 30,906,993	$ 1,515,000	2.00%	2017	$ 1,706,136	5.5%
C									
	75		$ 1,515,000	$ 30,906,993	$ 1,515,000			$ 1,706,136	5.5%
	Allocated to Common:								
	Allocated to Units:		$ 1,515,000						
Gila River (2011 Costs)									
3	550	75.00%		$ 203,626,081	$ 8,879,744	2.00%	2017	$ 10,000,034	4.9%
C		75.00%	1,614,499	27,608,233	1,210,874	2.00%	2017	1,363,641	4.9%
	550		$ 10,090,618	$ 231,234,314	$ 10,090,618			$ 11,363,674	4.9%
	Allocated to Common:		1,210,874						
	Allocated to Units:		$ 8,879,744						
Luna (2011 Costs)									
1	555	33.33%		$ 47,829,964	$ 4,484,719	2.00%	2017	$ 5,050,522	10.6%
C									
	555		$ 4,484,719	$ 47,829,964	$ 4,484,719			$ 5,050,522	10.6%
	Allocated to Common:								
	Allocated to Units:		$ 4,484,719						
North Loop (2011 Costs)									
1	25	100.00%		$ 5,583,134	$ 563,684	2.00%	2017	$ 634,800	11.4%
2	25	100.00%		4,191,075	563,684	2.00%	2017	634,800	15.1%
3	25	100.00%		4,651,772	563,684	2.00%	2017	634,800	13.6%
4	20	100.00%		14,459,721	450,947	2.00%	2017	507,840	3.5%
C									
	95		$ 2,142,000	$ 28,885,702	$ 2,142,000			$ 2,412,240	8.4%
	Allocated to Common:								
	Allocated to Units:		$ 2,142,000						
Solar Units									
1			$ -	$ -	$ -			$ -	
C									
			$ -	$ -	$ -			$ -	
	Allocated to Common:								
	Allocated to Units:		$ -						
Sundt Gas (2011 Costs)									
1	25	100.00%	$ 81,185	$ 5,148,788	$ 81,185	2.00%	2017	$ 91,427	1.8%
2	25	100.00%	81,185	4,962,474	81,185	2.00%	2017	91,427	1.8%
C									
	50		$ 162,370	$ 10,111,262	$ 162,370			$ 182,855	1.8%
	Allocated to Common:								
	Allocated to Units:		$ 162,370						

TUCSON ELECTRIC POWER COMPANY
Not Amended for Settlement Provisions
Current and Proposed Parameters
Vintage Group Procedure

Account	Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A		B	C	D	E	F	G	H	I	J	K	L	M
STEAM PRODUCTION													
310.00	Rights-of-Way									43.02	18.80		0.0
311.00	Structures and Improvements									35.83	20.41	-11.9	-13.9
312.00	Boiler Plant Equipment									39.35	23.05	-10.3	-11.2
314.00	Turbogenerator Units									37.19	23.25	-9.5	-10.8
315.00	Accessory Electric Equipment									35.88	21.47	-12.7	-13.3
316.00	Miscellaneous Power Plant Equipment									34.83	20.88	-7.5	-8.4
	Total Steam Production Plant									38.17	22.58	-10.5	-11.5
OTHER PRODUCTION													
Non-Solar													
341.00	Structures and Improvements									41.75	32.67	-7.6	-7.7
342.00	Fuel Holders, Products and Accessories									40.63	31.82	-7.3	-7.3
343.00	Prime Movers									40.57	31.72	-4.8	-4.9
344.00	Generators and Devices									42.10	28.01	-5.1	-5.5
345.00	Accessory Electric Equipment									39.56	26.72	-4.7	-5.3
346.00	Miscellaneous Power Plant Equipment									42.19	32.46	-7.2	-7.3
	Total Non-Solar									41.08	30.62	-5.3	-5.5
Solar													
344.00	Generators and Devices									28.00	24.49	-5.0	-5.0
	Total Solar									28.00	24.49	-5.0	-5.0
	Total Other Production Plant									35.89	28.19	-5.2	-5.3
DISTRIBUTION PLANT													
360.RW	Rights-of-Way							60.00	R5	60.00	37.36		
361.00	Structures and Improvements	55.00	R1	55.46	47.86			55.00	R1	55.54	46.15		
362.00	Station Equipment	60.00	R2.5	59.84	45.73			55.00	R2	55.17	41.72		
364.00	Poles, Towers and Fixtures	50.00	R2.5	50.44	35.24			55.00	R2.5	55.24	41.84		
365.00	Overhead Conductors and Devices	55.00	R3	54.84	39.69			55.00	R4	54.61	38.78		
366.00	Underground Conduit	65.00	R4	64.79	45.02			65.00	R4	64.76	44.16		
367.00	Underground Conductors and Devices	47.00	R4	46.86	32.68			50.00	R4	49.83	34.36		
368.OH	Line Transformers - Overhead	45.00	R2.5	45.48	29.84			50.00	R1.5	50.73	35.22		
368.UG	Line Transformers - Underground	42.00	S2	42.05	29.51			45.00	R2.5	45.18	31.45		
369.OH	Services - Overhead	45.00	S3	44.69	27.66			47.00	S3	46.63	29.69		
369.UG	Services - Underground	60.00	S3	60.04	45.69			60.00	S3	60.05	44.81		
370.00	Meters	27.00	L1	27.43	20.37			20.00	L0.5	20.39	16.46		

Account	Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A		B	C	D	E	F	G	H	I	J	K	L	M
373.00	Street Lighting and Signal Systems	50.00	R3	49.40	34.26			50.00	R3	49.38	32.64		
	Total Distribution Plant									50.03	36.00		
GENERAL PLANT													
	Depreciable												
390.00	Structures and Improvements	40.00	R4	39.94	34.92	-5.7	-5.0	40.00	R3	39.96	33.19	-5.9	-5.0
392.C0	Transportation - Class 0	18.00	O2	19.87	12.63	14.7	15.0	18.00	O2	20.22	12.25	17.1	15.0
392.C1	Transportation - Class 1	8.00	L2	7.92	4.99	14.6	15.0	8.00	L2	8.11	4.41	17.2	15.0
392.C2	Transportation - Class 2	8.00	L1.5	8.03	4.98	14.6	15.0	8.00	L1.5	8.15	4.51	17.6	15.0
392.C3	Transportation - Class 3	9.00	L3	9.07	4.33	14.6	15.0	9.00	L2	9.33	4.29	18.0	15.0
392.C4	Transportation - Class 4	14.00	L1.5	13.94	7.99	14.6	15.0	14.00	L1.5	13.79	7.88	18.0	15.0
392.C5	Transportation - Class 5	13.00	S2	13.38	7.21	14.7	15.0	13.00	S2	13.39	7.18	16.8	15.0
392.C6	Transportation - Class 6	15.00	L2	15.00	13.52	15.0	15.0	15.00	L2	15.02	11.50	15.0	15.0
392.C7	Transportation - Class 7	14.00	L1.5	14.15	9.74	15.0	15.0	14.00	L1.5	14.50	8.45	15.0	15.0
392.C8	Transportation - Class 8	13.00	S2	13.18	9.15	15.0	15.0	13.00	S2	13.24	8.12	15.2	15.0
392.C9	Transportation - Class 9	20.00	S2	21.00	11.54	15.0	15.0	25.00	L2	25.55	17.56	15.3	15.0
396.00	Power Operatied Equipment	15.00	L2	15.22	10.00	3.7	5.0	15.00	L2	15.13	11.85	1.0	
397.EM	EMS and SCADA Equipment	20.00	S3	20.01	15.57			20.00	S3	20.02	14.15		
	Total Depreciable									24.20	18.60	2.6	-0.3
	Amortizable												
391.00	Furniture and Office Equipment	24.00	SQ	24.00	17.60			24.00	SQ	24.00	16.29		
391.20	Network and Data Equipment	5.00	SQ	5.00	2.76			5.00	SQ	5.00	2.46		
393.00	Stores Equipment	15.00	SQ	15.00	9.74			15.00	SQ	15.00	8.20		
394.00	Tools, Shop and Garage Equipment	17.00	SQ	17.00	9.39			17.00	SQ	17.00	9.99		
395.00	Laboratory Equipment	17.00	SQ	17.00	9.19			17.00	SQ	17.00	9.00		
397.20	Telecommunications Equipment	15.00	SQ	15.00	9.12			15.00	SQ	15.00	9.87		
398.00	Miscellaneous Equipment	20.00	SQ	20.00	10.60			20.00	SQ	20.00	11.65		
	Total Amortizable									10.98	6.71		
	Total General Plant									16.44	11.62	1.4	-0.2
	SUBTOTAL									36.90	24.77	-5.1	-5.8

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
NET SALVAGE												
108.02 Distribution			48.80	34.76	-14.8	-15.0			50.03	36.00	-4.8	-5.0
Total Net Salvage									50.03	36.00	-4.8	-5.5
TOTAL UTILITY									29.43	27.04	-5.1	-5.6
STEAM PRODUCTION (by Unit)												
Four Corners												
310.00 Rights-of-Way												
311.00 Structures and Improvements			31.54	17.56	-7.9	-8.0			28.98	16.15	-4.7	-4.8
312.00 Boiler Plant Equipment			36.50	17.55	-8.4	-8.0			35.84	16.14	-5.5	-4.8
314.00 Turbogenerator Units			30.52	17.47	-7.0	-7.9			31.67	16.14	-4.2	-4.8
315.00 Accessory Electric Equipment			24.13	17.46	-6.4	-7.9			21.71	16.15	-4.1	-4.8
316.00 Miscellaneous Power Plant Equipment			30.17	17.57	-7.5	-7.8			30.04	16.15	-4.4	-4.6
Total Four Corners									33.83	16.14	-5.2	-4.8
Four Corners Unit 4												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2029	200-SC	30.90	17.10	-7.5	-7.5	2031	200-SC	28.98	16.15	-4.5	-4.6
312.00 Boiler Plant Equipment	2029	200-SC	35.85	17.10	-8.8	-7.5	2031	200-SC	35.79	16.14	-6.1	-4.6
314.00 Turbogenerator Units	2029	200-SC	28.99	17.10	-6.4	-7.5	2031	200-SC	30.68	16.14	-3.9	-4.6
315.00 Accessory Electric Equipment	2029	200-SC	22.43	17.11	-5.6	-7.5	2031	200-SC	21.93	16.15	-3.6	-4.6
316.00 Miscellaneous Power Plant Equipment	2029	200-SC	29.57	17.10	-6.9	-7.3	2031	200-SC	29.95	16.15	-4.2	-4.4
Total Four Corners Unit 4									33.63	16.14	-5.5	-4.6
Four Corners Unit 5												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2030	200-SC	32.23	18.06	-8.5	-8.5	2031	200-SC	28.97	16.15	-4.9	-5.1
312.00 Boiler Plant Equipment	2030	200-SC	37.23	18.05	-8.0	-8.5	2031	200-SC	35.90	16.14	-4.8	-5.1
314.00 Turbogenerator Units	2030	200-SC	32.97	18.05	-7.9	-8.5	2031	200-SC	33.16	16.14	-4.7	-5.1
315.00 Accessory Electric Equipment	2030	200-SC	26.99	18.06	-7.7	-8.5	2031	200-SC	21.47	16.15	-4.7	-5.1
316.00 Miscellaneous Power Plant Equipment	2030	200-SC	30.81	18.06	-8.1	-8.3	2031	200-SC	30.14	16.15	-4.7	-4.9
Total Four Corners Unit 5									34.06	16.14	-4.8	-5.1

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Navajo												
310.00 Rights-of-Way			56.14	23.68	-7.0	-7.0			51.25	15.17	-4.7	-4.7
311.00 Structures and Improvements			41.75	23.36	-7.2	-7.2			32.54	13.56	-4.8	-4.9
312.00 Boiler Plant Equipment			39.61	22.84	-6.7	-7.2			28.93	10.66	-4.6	-4.9
314.00 Turbogenerator Units			41.38	22.72	-6.8	-7.2			29.14	10.12	-4.6	-4.9
315.00 Accessory Electric Equipment			37.59	23.16	-7.1	-7.2			23.29	10.77	-4.8	-4.9
316.00 Miscellaneous Power Plant Equipment			40.69	23.43	-7.0	-6.9			29.26	14.34	-4.7	-4.7
Total Navajo									28.67	11.04	-4.6	-4.9
Navajo Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2034	200-SC	52.47	21.81	-7.2	-7.1	2019	200-SC	36.65	4.47	-4.8	-4.8
312.00 Boiler Plant Equipment	2034	200-SC	37.97	21.84	-7.0	-7.1	2019	200-SC	21.07	4.47	-4.8	-4.8
314.00 Turbogenerator Units	2034	200-SC	39.73	21.84	-6.5	-7.1	2019	200-SC	20.90	4.47	-4.4	-4.8
315.00 Accessory Electric Equipment	2034	200-SC	40.48	21.83	-6.7	-7.1	2019	200-SC	13.49	4.47	-4.6	-4.8
316.00 Miscellaneous Power Plant Equipment	2034	200-SC	52.74	21.81	-6.7	-6.8	2019	200-SC	38.45	4.47	-4.7	-4.7
Total Navajo Unit 1									20.83	4.47	-4.7	-4.8
Navajo Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2035	200-SC	48.57	22.76	-7.4	-7.5	2030	200-SC	39.37	15.18	-5.0	-5.2
312.00 Boiler Plant Equipment	2035	200-SC	41.28	22.77	-6.9	-7.5	2030	200-SC	36.22	15.18	-4.7	-5.2
314.00 Turbogenerator Units	2035	200-SC	40.38	22.78	-7.4	-7.5	2030	200-SC	35.06	15.18	-5.1	-5.2
315.00 Accessory Electric Equipment	2035	200-SC	40.14	22.78	-7.2	-7.5	2030	200-SC	32.96	15.18	-5.0	-5.2
316.00 Miscellaneous Power Plant Equipment	2035	200-SC	50.34	22.75	-7.0	-7.2	2030	200-SC	45.75	15.17	-4.8	-4.9
Total Navajo Unit 2									35.95	15.18	-4.8	-5.2
Navajo Unit 3												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2036	200-SC	49.65	23.69	-6.9	-7.0	2030	200-SC	44.24	15.18	-4.6	-4.7
312.00 Boiler Plant Equipment	2036	200-SC	41.42	23.71	-6.1	-7.0	2030	200-SC	35.40	15.18	-4.0	-4.7
314.00 Turbogenerator Units	2036	200-SC	46.13	23.70	-6.4	-7.0	2030	200-SC	40.09	15.18	-4.3	-4.7
315.00 Accessory Electric Equipment	2036	200-SC	44.62	23.70	-7.5	-7.0	2030	200-SC	38.19	15.18	-5.1	-4.7
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	54.62	23.69	-8.1	-6.6	2030	200-SC	46.90	15.18	-5.5	-4.5
Total Navajo Unit 3									37.09	15.18	-4.2	-4.7

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Navajo Common												
310.00 Rights-of-Way	2036	200-SC	56.14	23.68	-7.0	-7.0	2030	200-SC	51.25	15.17	-4.7	-4.7
311.00 Structures and Improvements	2036	200-SC	35.95	23.72	-7.3	-7.3	2030	200-SC	27.94	15.19	-4.8	-4.9
312.00 Boiler Plant Equipment	2036	200-SC	33.84	23.73	-7.6	-7.3	2030	200-SC	27.58	15.19	-5.3	-4.9
314.00 Turbogenerator Units	2036	200-SC	25.06	23.75	-7.3	-7.3	2030	200-SC	19.12	15.20	-4.8	-4.9
315.00 Accessory Electric Equipment	2036	200-SC	26.57	23.74	-7.0	-7.3	2030	200-SC	20.77	15.20	-4.6	-4.9
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	35.23	23.73	-6.9	-7.0	2030	200-SC	25.02	15.19	-4.6	-4.7
Total Navajo Common									26.13	15.19	-4.9	-4.9
San Juan												
310.00 Rights-of-Way												
311.00 Structures and Improvements			43.50	22.50	-9.7	-9.6			28.84	12.30	-7.4	-7.9
312.00 Boiler Plant Equipment			33.25	22.30	-14.3	-15.1			25.11	12.30	-9.9	-9.7
314.00 Turbogenerator Units			35.64	22.18	-8.9	-9.6			28.61	12.30	-7.4	-8.0
315.00 Accessory Electric Equipment			37.69	22.02	-9.3	-9.5			25.55	12.30	-7.5	-8.0
316.00 Miscellaneous Power Plant Equipment			47.93	21.62	-8.7	-9.1			26.25	12.30	-6.7	-7.6
Total San Juan									25.98	12.30	-9.1	-9.1
San Juan Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2036	200-SC	43.21	23.71	-9.4	-9.9	2027	200-SC	29.28	12.30	-7.5	-8.0
312.00 Boiler Plant Equipment	2036	200-SC	35.47	23.72	-10.2	-9.9	2027	200-SC	25.40	12.30	-8.6	-8.0
314.00 Turbogenerator Units	2036	200-SC	38.79	23.72	-9.2	-9.9	2027	200-SC	28.61	12.30	-7.4	-8.0
315.00 Accessory Electric Equipment	2036	200-SC	38.47	23.72	-9.4	-9.9	2027	200-SC	25.55	12.30	-7.5	-8.0
316.00 Miscellaneous Power Plant Equipment	2036	200-SC	45.09	23.70	-8.5	-9.6	2027	200-SC	26.97	12.30	-6.8	-7.8
Total San Juan Unit 1									26.25	12.30	-8.2	-8.0
San Juan Common												
310.00 Rights-of-Way												
311.00 Structures and Improvements			43.50	22.50	-9.7	-9.6	2027	200-SC	12.79	12.30	-0.2	-0.2
312.00 Boiler Plant Equipment	2036	200-SC	33.17	23.73	-247.3	-263.1	2027	200-SC	20.75	12.30	-35.8	-40.3
314.00 Turbogenerator Units												
315.00 Accessory Electric Equipment												
316.00 Miscellaneous Power Plant Equipment			47.93	21.62	-8.7	-9.1	2027	200-SC	12.79	12.30		
Total San Juan Common									20.41	12.30	-34.9	-39.2

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Springerville												
310.00 Rights-of-Way									43.00	18.81		
311.00 Structures and Improvements									37.20	22.18	-10.6	-12.9
312.00 Boiler Plant Equipment									48.69	31.72	-9.0	-10.0
314.00 Turbogenerator Units									45.66	32.41	-3.9	-3.8
315.00 Accessory Electric Equipment									53.00	30.58	-5.3	-5.4
316.00 Miscellaneous Power Plant Equipment									44.94	29.44	-5.0	-5.8
Total Springerville									46.44	30.06	-8.0	-8.9
Springerville Unit 1												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2021	200-SC	11.16	9.39	-0.1	-0.1	2045	200-SC	46.47	29.28	-2.5	-3.3
312.00 Boiler Plant Equipment	2021	200-SC	12.80	9.39	-0.3	-0.1	2045	200-SC	48.19	29.27	-2.5	-3.3
314.00 Turbogenerator Units	2021	200-SC	13.20	9.39	0.4	-0.1	2045	200-SC	48.45	29.27	-2.5	-3.3
315.00 Accessory Electric Equipment	2021	200-SC	12.87	9.39	-0.1	-0.1	2045	200-SC	54.33	29.25	-3.1	-3.3
316.00 Miscellaneous Power Plant Equipment	2021	200-SC	10.62	9.39			2045	200-SC	44.88	29.28	-2.0	-2.9
Total Springerville Unit 1									48.48	29.27	-2.5	-3.3
Springerville Unit 1 Common												
310.00 Rights-of-Way	2021	200-SC	28.42	9.38			2045	200-SC	49.87	29.27		
311.00 Structures and Improvements	2021	200-SC	17.98	9.38	-0.1	-0.1	2045	200-SC	49.61	29.27	-6.9	-9.8
312.00 Boiler Plant Equipment	2021	200-SC	15.67	9.39	-0.1	-0.1	2045	200-SC	50.76	29.27	-7.5	-9.8
314.00 Turbogenerator Units	2021	200-SC	20.92	9.38	-0.1	-0.1	2045	200-SC	52.60	29.26	-8.0	-9.8
315.00 Accessory Electric Equipment	2021	200-SC	15.50	9.39	-0.1	-0.1	2045	200-SC	56.09	29.25	-9.7	-9.8
316.00 Miscellaneous Power Plant Equipment	2021	200-SC	16.57	9.39			2045	200-SC	55.40	29.25	-8.6	-9.4
Total Springerville Unit 1 Common									50.69	29.27	-7.1	-9.7
Springerville Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2050	200-SC	50.98	36.57	-8.1	-7.6	2050	200-SC	46.76	33.86	-4.1	-3.7
312.00 Boiler Plant Equipment	2050	200-SC	50.50	36.57	-7.3	-7.6	2050	200-SC	47.64	33.86	-4.7	-3.7
314.00 Turbogenerator Units	2050	200-SC	51.50	36.56	-8.0	-7.6	2050	200-SC	44.78	33.87	-4.3	-3.7
315.00 Accessory Electric Equipment	2050	200-SC	55.14	36.55	-7.5	-7.6	2050	200-SC	53.98	33.83	-3.7	-3.7
316.00 Miscellaneous Power Plant Equipment	2050	200-SC	54.63	36.55	-6.8	-7.1	2050	200-SC	47.18	33.86	-3.2	-3.3
Total Springerville Unit 2									47.30	33.86	-4.5	-3.7

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Sundt Unit 2												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2020	200-SC	19.23	8.41	-62.0	-64.2	2030	200-SC	21.69	15.19	-45.8	-51.3
312.00 Boiler Plant Equipment	2020	200-SC	20.39	8.41	-67.2	-64.2	2030	200-SC	28.86	15.19	-49.0	-51.3
314.00 Turbogenerator Units	2020	200-SC	20.59	8.41	-60.5	-64.2	2030	200-SC	30.70	15.19	-46.9	-51.2
315.00 Accessory Electric Equipment	2020	200-SC	11.91	8.41	-61.5	-64.3	2030	200-SC	18.62	15.20	-48.7	-51.3
316.00 Miscellaneous Power Plant Equipment	2020	200-SC	13.45	8.41	-59.4	-64.2	2030	200-SC	19.76	15.20	-47.7	-51.1
Total Sundt Unit 2									25.66	15.19	-48.1	-51.3
Sundt Unit 3												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2022	200-SC	24.07	10.36	-71.5	-75.2	2032	200-SC	26.92	17.11	-50.4	-56.3
312.00 Boiler Plant Equipment	2022	200-SC	30.31	10.35	-76.9	-75.2	2032	200-SC	29.45	17.10	-52.7	-56.3
314.00 Turbogenerator Units	2022	200-SC	22.27	10.36	-73.2	-75.3	2032	200-SC	27.66	17.11	-51.0	-56.3
315.00 Accessory Electric Equipment	2022	200-SC	19.68	10.36	-67.5	-75.3	2032	200-SC	28.42	17.10	-49.9	-56.3
316.00 Miscellaneous Power Plant Equipment	2022	200-SC	15.48	10.36	-64.1	-75.2	2032	200-SC	23.16	17.11	-49.5	-56.1
Total Sundt Unit 3									28.24	17.11	-51.3	-56.3
Sundt Unit 4												
310.00 Rights-of-Way												
311.00 Structures and Improvements	2048	200-SC	54.34	34.74	-24.5	-24.6	2048	200-SC	52.99	32.01	-17.5	-17.8
312.00 Boiler Plant Equipment	2048	200-SC	54.34	34.74	-24.1	-24.6	2048	200-SC	54.25	32.00	-16.5	-17.8
314.00 Turbogenerator Units	2048	200-SC	49.18	34.76	-24.7	-24.6	2048	200-SC	41.75	32.06	-16.2	-17.9
315.00 Accessory Electric Equipment	2048	200-SC	53.12	34.75	-23.9	-24.6	2048	200-SC	47.13	32.04	-17.1	-17.9
316.00 Miscellaneous Power Plant Equipment	2048	200-SC	48.38	34.77	-20.0	-24.2	2048	200-SC	44.82	32.05	-14.5	-17.4
Total Sundt Unit 4									50.81	32.02	-16.7	-17.8
Sundt Solar Booster (Areva)												
310.00 Rights-of-Way												
311.00 Structures and Improvements	30.00	SQ	30.00									
312.00 Boiler Plant Equipment	30.00	SQ	30.00				2048	200-SC	32.56	32.10	-0.4	-0.4
314.00 Turbogenerator Units	30.00	SQ	30.00									
315.00 Accessory Electric Equipment	30.00	SQ	30.00									
316.00 Miscellaneous Power Plant Equipment	30.00	SQ	30.00									
Total Sundt Solar Booster (Areva)									32.56	32.10	-0.4	-0.4

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
OTHER PRODUCTION (by Unit)												
DeMoss Petrie Gas Unit 1												
341.00 Structures and Improvements	2046	200-SC	40.04	32.98	-7.9	-9.2	2046	200-SC	36.97	30.24	-4.1	-5.1
342.00 Fuel Holders, Products and Accessories	2046	200-SC	42.61	32.97	-9.2	-9.2	2046	200-SC	42.70	30.22	-5.0	-5.1
343.00 Prime Movers	2046	200-SC	34.38	33.01	-9.2	-9.2	2046	200-SC	34.41	30.25	-0.7	-5.1
344.00 Generators and Devices	2046	200-SC	42.59	32.97	-9.2	-9.2	2046	200-SC	42.56	30.22	-5.0	-5.1
345.00 Accessory Electric Equipment	2046	200-SC	42.54	32.97	-9.2	-9.2	2046	200-SC	41.80	30.22	-1.9	-5.1
346.00 Miscellaneous Power Plant Equipment	2046	200-SC	41.25	32.98	-9.2	-9.2	2046	200-SC	40.73	30.22	-5.1	-5.1
Total DeMoss Petrie Gas Unit 1									42.35	30.22	-4.7	-5.1
Gila River												
341.00 Structures and Improvements									42.18	32.06	-4.5	-4.5
342.00 Fuel Holders, Products and Accessories									42.49	32.06	-4.5	-4.5
343.00 Prime Movers									41.47	32.06	-4.5	-4.5
344.00 Generators and Devices									42.63	32.06	-4.5	-4.5
345.00 Accessory Electric Equipment									42.38	32.06	-4.5	-4.5
346.00 Miscellaneous Power Plant Equipment									42.28	32.06	-4.5	-4.5
Total Gila River									41.72	32.06	-4.5	-4.5
Gila River Unit 3												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-4.5	-4.5
342.00 Fuel Holders, Products and Accessories	45.00	SQ	45.00				2048	200-SC	41.24	32.06	-4.5	-4.5
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	41.57	32.06	-4.5	-4.5
344.00 Generators and Devices	45.00	SQ	45.00				2048	200-SC	42.63	32.06	-4.5	-4.5
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.38	32.06	-4.5	-4.5
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	41.89	32.06	-4.5	-4.5
Total Gila River Unit 3									41.75	32.06	-4.5	-4.5
Gila River Common												
341.00 Structures and Improvements	45.00	SQ	45.00				2048	200-SC	42.15	32.06	-4.5	-4.5
342.00 Fuel Holders, Products and Accessories	45.00	SQ	45.00				2048	200-SC	42.52	32.06	-4.5	-4.5
343.00 Prime Movers	45.00	SQ	45.00				2048	200-SC	39.05	32.07	-4.5	-4.5
344.00 Generators and Devices												
345.00 Accessory Electric Equipment	45.00	SQ	45.00				2048	200-SC	42.39	32.06	-4.5	-4.5
346.00 Miscellaneous Power Plant Equipment	45.00	SQ	45.00				2048	200-SC	42.29	32.06	-4.5	-4.5
Total Gila River Common									41.49	32.06	-4.5	-4.5

Account	Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A		B	C	D	E	F	G	H	I	J	K	L	M
Luna													
341.00	Structures and Improvements	2051	200-SC	42.47	37.52	-19.5	-19.6	2051	200-SC	42.38	34.80	-9.6	-9.6
342.00	Fuel Holders, Products and Accessories	2051	200-SC	42.51	37.52	-19.6	-19.6	2051	200-SC	42.56	34.80	-9.6	-9.6
343.00	Prime Movers	2051	200-SC	39.20	37.54	-16.3	-19.7	2051	200-SC	37.40	34.82	-7.9	-9.6
344.00	Generators and Devices	2051	200-SC	41.74	37.52	-14.5	-19.6	2051	200-SC	40.73	34.80	-5.7	-9.6
345.00	Accessory Electric Equipment	40.00		40.00				2051	200-SC	35.29	34.83	-9.6	-9.6
346.00	Miscellaneous Power Plant Equipment	2051	200-SC	42.48	37.52	-19.6	-19.6	2051	200-SC	42.48	34.80	-9.6	-9.6
	Total Luna									40.97	34.80	-8.2	-9.6
North Loop Gas													
341.00	Structures and Improvements			24.42	7.02	-11.2	-12.1			34.58	13.74	-10.7	-11.5
342.00	Fuel Holders, Products and Accessories			43.49	33.88	-5.9	-5.9			42.70	30.22	-3.2	-3.2
343.00	Prime Movers			8.36	5.46	-12.5	-12.5			15.51	12.30	-10.1	-12.6
344.00	Generators and Devices			36.87	19.70	-8.5	-8.9			42.21	22.77	-6.9	-7.2
345.00	Accessory Electric Equipment			27.62	12.41	-9.3	-10.3			33.62	17.60	-8.3	-9.2
346.00	Miscellaneous Power Plant Equipment			27.71	8.02	-10.4	-11.7			38.64	14.59	-9.8	-11.0
	Total North Loop Gas									37.09	20.31	-7.4	-7.9
North Loop Gas Unit 1													
341.00	Structures and Improvements	2017	200-SC	19.02	5.46	-11.1	-11.1	2027	200-SC	29.10	12.30	-11.0	-11.0
342.00	Fuel Holders, Products and Accessories												
343.00	Prime Movers	2017	200-SC	9.86	5.46	-11.1	-11.1	2027	200-SC	19.70	12.30	-10.9	-11.0
344.00	Generators and Devices	2017	200-SC	27.57	5.46	-11.0	-11.1	2027	200-SC	38.80	12.29	-10.9	-11.0
345.00	Accessory Electric Equipment	2017	200-SC	20.04	5.46	-10.9	-11.1	2027	200-SC	28.69	12.30	-10.8	-11.0
346.00	Miscellaneous Power Plant Equipment	2017	200-SC	19.46	5.46	-11.1	-11.1	2027	200-SC	30.66	12.30	-11.0	-11.0
	Total North Loop Gas Unit 1									32.33	12.29	-10.9	-11.0
North Loop Gas Unit 2													
341.00	Structures and Improvements	2017	200-SC	30.61	5.46	-15.5	-15.5	2027	200-SC	41.27	12.29	-14.6	-14.6
342.00	Fuel Holders, Products and Accessories												
343.00	Prime Movers	2017	200-SC	15.82	5.46	-15.5	-15.5	2027	200-SC	8.23	12.31	-5.7	-14.7
344.00	Generators and Devices	2017	200-SC	31.80	5.46	-14.7	-15.5	2027	200-SC	43.04	12.29	-13.8	-14.6
345.00	Accessory Electric Equipment	2017	200-SC	25.59	5.46	-15.1	-15.5	2027	200-SC	31.85	12.29	-14.2	-14.7
346.00	Miscellaneous Power Plant Equipment	2017	200-SC	44.27	5.46	-15.5	-15.5	2027	200-SC	53.34	12.28	-14.6	-14.6
	Total North Loop Gas Unit 2									33.25	12.29	-12.8	-14.6

Account	Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A		B	C	D	E	F	G	H	I	J	K	L	M
North Loop Gas Unit 3													
341.00	Structures and Improvements	2017	200-SC	30.61	5.46	-13.3	-13.3	2027	200-SC	41.27	12.29	-13.2	-13.2
342.00	Fuel Holders, Products and Accessories												
343.00	Prime Movers	2017	200-SC	7.31	5.46	-13.3	-13.3	2027	200-SC	17.12	12.30	-12.7	-13.2
344.00	Generators and Devices	2017	200-SC	32.28	5.46	-12.0	-13.3	2027	200-SC	43.69	12.29	-11.9	-13.2
345.00	Accessory Electric Equipment	2017	200-SC	25.63	5.46	-13.0	-13.3	2027	200-SC	31.87	12.29	-12.8	-13.2
346.00	Miscellaneous Power Plant Equipment	2017	200-SC	44.27	5.46	-13.3	-13.3	2027	200-SC	53.34	12.28	-13.2	-13.2
	Total North Loop Gas Unit 3									32.54	12.29	-12.2	-13.2
North Loop Gas Unit 4													
341.00	Structures and Improvements	2047	200-SC	42.41	33.89	2.7	-5.9	2046	200-SC	41.22	30.22	5.0	-3.2
342.00	Fuel Holders, Products and Accessories	2047	200-SC	43.49	33.88	-5.9	-5.9	2046	200-SC	42.70	30.22	-3.2	-3.2
343.00	Prime Movers												
344.00	Generators and Devices	2047	200-SC	43.46	33.88	-5.6	-5.9	2046	200-SC	42.66	30.22	-3.0	-3.2
345.00	Accessory Electric Equipment	2047	200-SC	42.61	33.89	-4.7	-5.9	2046	200-SC	41.29	30.22	-2.6	-3.2
346.00	Miscellaneous Power Plant Equipment	2047	200-SC	43.49	33.88	-3.2	-5.9	2046	200-SC	42.70	30.22	-1.7	-3.2
	Total North Loop Gas Unit 4									42.56	30.22	-3.0	-3.2
Solar Units (Generators and Devices)													
344.00	DeMoss Petrie	20.00	S4	20.00	17.06			28.00	S6	28.00	16.15	-5.0	-5.0
344.00	Fort Huachuca	20.00	S4	20.00	17.06			28.00	S6	28.00	27.50	-5.0	-5.0
344.00	HQ Rooftop	20.00	S4	20.00	17.06			28.00	S6	28.00	25.50	-5.0	-5.0
344.00	OH Rooftop	20.00	S4	20.00	17.06			28.00	S6	28.00	24.50	-5.0	-5.0
344.00	OH Test Yard	20.00	S4	20.00	17.06			28.00	S6	28.00	16.83	-5.0	-5.0
344.00	Prairie Fire	20.00	S4	20.00	17.06			28.00	S6	28.00	25.50	-5.0	-5.0
344.00	Springerville Sites 1-3 (Legacy)	20.00	S4	20.00	17.06			28.00	S6	28.00	16.11	-5.0	-5.0
344.00	Springerville Site 4	20.00	S4	20.00	17.06			28.00	S6	28.00	23.50	-5.0	-5.0
343.00	Tucson	20.00	S4	20.00	17.06			28.00	S6	28.00	11.82	-5.0	-5.0
344.00	U of A Tech Park Site 1	20.00	S4	20.00	17.06			28.00	S6	28.00	23.50	-5.0	-5.0
345.00	U of A Tech Park Site 2	20.00	S4	20.00	17.06			28.00	S6	28.00	24.50	-5.0	-5.0
346.00	White Mountain	20.00	S4	20.00	17.06			28.00	S6	28.00	27.50	-5.0	-5.0
	Total Solar Units									28.00	24.49	-5.0	-5.0

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters (at December 31, 2014) P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Sundt Gas												
341.00 Structures and Improvements			28.10	5.46	-1.8	-1.8			37.43	12.29	-1.5	-1.8
342.00 Fuel Holders, Products and Accessories			9.71	5.46	-1.8	-1.8			19.39	12.30	-1.8	-1.8
343.00 Prime Movers			15.82	5.46	-1.8	-1.8			25.38	12.30	-1.8	-1.8
344.00 Generators and Devices			30.02	5.46	-1.7	-1.7			39.83	12.29	-1.6	-1.7
345.00 Accessory Electric Equipment			22.40	5.46	-1.7	-1.8			34.86	12.29	-1.7	-1.8
346.00 Miscellaneous Power Plant Equipment			42.42	5.46	-1.8	-1.8			51.58	12.28	-1.8	-1.8
Total Sundt Gas									36.18	12.29	-1.6	-1.7
Sundt Gas Unit 1												
341.00 Structures and Improvements	2017	200-SC	28.10	5.46	-1.7	-1.7	2027	200-SC	37.43	12.29	-1.5	-1.7
342.00 Fuel Holders, Products and Accessories	2017	200-SC	9.71	5.46	-1.7	-1.7	2027	200-SC	19.39	12.30	-1.7	-1.7
343.00 Prime Movers	2017	200-SC	15.82	5.46	-1.7	-1.7	2027	200-SC	25.38	12.30	-1.7	-1.7
344.00 Generators and Devices	2017	200-SC	31.37	5.46	-1.7	-1.7	2027	200-SC	40.65	12.29	-1.6	-1.7
345.00 Accessory Electric Equipment	2017	200-SC	23.05	5.46	-1.7	-1.7	2027	200-SC	35.64	12.29	-1.7	-1.7
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	42.93	5.46	-1.7	-1.7	2027	200-SC	52.10	12.28	-1.7	-1.7
Total Sundt Gas Unit 1									36.88	12.29	-1.6	-1.7
Sundt Gas Unit 2												
341.00 Structures and Improvements	2017	200-SC	28.10	5.46	-1.8	-1.8	2027	200-SC	37.43	12.29	-1.6	-1.8
342.00 Fuel Holders, Products and Accessories	2017	200-SC	9.71	5.46	-1.8	-1.8	2027	200-SC	19.39	12.30	-1.8	-1.8
343.00 Prime Movers	2017	200-SC	15.82	5.46	-1.8	-1.8	2027	200-SC	25.38	12.30	-1.8	-1.8
344.00 Generators and Devices	2017	200-SC	28.72	5.46	-1.7	-1.8	2027	200-SC	38.99	12.29	-1.6	-1.8
345.00 Accessory Electric Equipment	2017	200-SC	21.84	5.46	-1.8	-1.8	2027	200-SC	34.18	12.29	-1.8	-1.8
346.00 Miscellaneous Power Plant Equipment	2017	200-SC	42.08	5.46	-1.8	-1.8	2027	200-SC	51.24	12.28	-1.8	-1.8
Total Sundt Gas Unit 2									35.47	12.29	-1.6	-1.8

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-_____

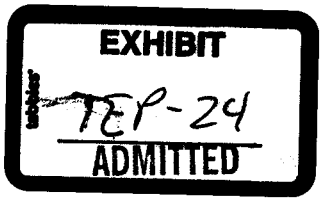
Direct Testimony of

Michael E. Sheehan

on behalf of

Tucson Electric Power Company

November 5, 2015



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EXHIBITS

Exhibit MES-1	TEP Plan of Administration
Exhibit MES-2	TEP Revised PPFAC Schedules 1-4
Exhibit MES-3	TEP Hedging Policy, August 2015-Confidential
Exhibit MES-4	Energy Hedge Plan - September 2015-Confidential
Exhibit MES-5	TEP Plan of Administration (Redline)

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Michael E. Sheehan. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. What is your position with Tucson Electric Power Company ("TEP" or the "Company")?

A. I am the Senior Director of Fuels and Resource Planning.

Q. Please describe your education and experience.

A. I received a Bachelor of Science degree in Management Information Systems from the University of Arizona in 1991. I was hired by TEP in 1993. In 1996, I moved into TEP's Resource Planning Department as a Supply-Side Analyst. I was promoted to Manager of Resource Planning in 2001 and Director in 2011. I have been in my current role as Senior Director of Fuels and Resource Planning since February 2015.

Q. What is the purpose of your Direct Testimony?

A. My testimony provides an overview of TEP's generating plant operations summarizing the Company's plant maintenance practices, plant reliability and safety performance. I also provide an update on recent environmental regulations impacting TEP's generation fleet and summarize some of the capital expenditures and Operation and Maintenance ("O&M") required for compliance. I also provide recommendations on changes to TEP's generation plant service lives and an overview on the Company's resource planning activities. In addition, I discuss TEP's acquisition of a 75% share of Unit 3 at the Gila River Power Plant ("Gila River") and testify to the expected benefits and cost savings to both TEP and its customers. Finally, I provide an estimate on TEP's base cost of fuel and provide an

overview on proposed changes to TEP's PPFAC, and discuss the proposed treatment of the 50.5% co-owner share of Springerville Generating Stations ("Springerville") Unit 1.

II. OVERVIEW OF TEP'S GENERATING PLANT OPERATIONS.

Q. Please provide an overview of TEP's generation assets.

A. TEP currently owns 2,454 MW of generating capacity, of which 50% is coal fired and 50% is gas fired. The specific generating source, fuel type and ownership of these units are set forth in Table 1 below:

Table 1 - TEP Thermal Generating Resources[1]

Station	Unit No.	Date In Service	Fuel Type	Net Capability MW	Operating Agent	TEP's Share	
						%	MW
Four Corners	4	1969	Coal	785	APS	7%	55
Four Corners	5	1970	Coal	785	APS	7%	55
Navajo	1	1974	Coal	750	SRP	7.5%	56
Navajo	2	1975	Coal	750	SRP	7.5%	56
Navajo	3	1976	Coal	750	SRP	7.5%	56
Gila River Power	3	2014	Gas	550	Ethos Energy	75%	413
Luna Energy Facility	1	2006	Gas	555	NAES	33%	185
San Juan	1	1976	Coal	340	PNM	50%	170
San Juan	2	1973	Coal	340	PNM	50%	170
Sundt	1	1958	Gas/Oil	81	TEP	100%	81
Sundt	2	1960	Gas/Oil	81	TEP	100%	81
Sundt	3	1962	Gas/Oil	104	TEP	100%	104
Sundt	4	1967	Gas	156	TEP	100%	156
Springerville	1	1985	Coal	387	TEP	50%	192
Springerville	2	1990	Coal	406	TEP	100%	406
Sundt CTs	1	1972	Gas/Oil	50	TEP	100%	50
North Loop CTs	1-3	1972	Gas/Oil	73	TEP	100%	73
North Loop CTs	4	2001	Gas	21	TEP	100%	21
DeMoss Petrie CTs	1	2001	Gas	75	TEP	100%	75
TEP Capacity, MW							**2,454**

[1] TEP generation capacity as of June 30, 2015.

Q. Please provide an overview of TEP's utility scale renewable generation resources?

A. TEP currently owns 42 MW-ac of solar generating capacity at ten different projects located at different locations throughout the state. Through the execution of 12 separate purchase power agreements ("PPA"), TEP has contracted for 221 MW-ac of various solar, wind and biogas resources in Arizona and New Mexico. The project name, technology, in-service date and capacity of these resources are set forth in Tables 2 and 3 below:

Table 2 - TEP Owned Renewable Projects (Utility Scale)[2]

Project Name	Technology	In Service	Capacity (AC), MW
Fort Huachuca Phase I	Fixed PV	2014	13.60
Solon Prairie Fire	Fixed PV	2012	4.00
Springerville Solar	Fixed PV	2004	3.68
Springerville Expansion Phase 2	Fixed PV	2010	1.45
Sundt Augmentation	Solar Thermal	2014	5.00
SunPower HQ	Fixed PV	2012	0.04
SunPower OH	Fixed PV	2012	0.40
UA Science Tech Park I	Single-Axis PV	2010	1.28
UA Science Tech Park III	Fixed PV	2011	4.00
White Mountain Solar	Fixed / Low Concentration PV	2014	8.25
Total Owned Capacity (AC), MW			**41.7**

[2] TEP owned renewable project capacity as of June 30, 2015.

Table 3 - TEP PPA Renewable Projects (Utility Scale)[3]

Project Name	Technology	In Service	Capacity (AC), MW
Amonix	Concentrating PV	2011	1.20
Avalon Solar	Fixed PV	2014	28.34
Avra Valley	Fixed PV	2012	25.00
Cogenera	Concentrating PV	2014	1.10
E.On Tech Park	Single-Axis PV	2012	4.80
Gato Montes Solar, LLC	Fixed PV	2012	4.92
Macho Springs	Wind	2011	50.40
Picture Rocks	Fixed PV	2012	20.00
Red Horse Solar	Fixed PV	2015	41.00
Red Horse Wind	Wind	2015	30.00
Sundt - Los Reales	Biogas	1998	4.00
Valencia Solar, LLC	Single-Axis PV	2013	10.00
Total PPA Capacity (AC), MW			**220.8**

III. GENERATING PLANT O&M AND RELIABILITY.

Q. Can you provide an overview of how TEP manages the plant operations and maintenance for its generation fleet?

A. TEP is the plant operator at the Springerville and H.W. Sundt Generating Stations ("Sundt").[4] The Company directly manages the O&M that is performed at these facilities. To manage the day-to-day operations and on-going maintenance at its jointly owned coal fired facilities at the Four Corners Power Plant ("Four Corners"), the Navajo Generating Station ("Navajo") and the San Juan Generation Station ("San Juan"), the Company relies on other utility operators. TEP also relies on O&M providers such as the NAES Corporation[5] and Ethos Energy to oversee the operations and maintenance programs at the Luna Energy Facility ("Luna") and the Gila River, respectively. For the facilities that are

[3] TEP renewable PPA capacity as of September 30, 2015.

[4] TEP also directly manages the operations and maintenance performed on its natural gas combustion turbine fleet that is located at the Sundt, DeMoss Petrie and North Loop stations in Tucson, AZ.

[5] Formerly North American Energy Services.

managed by third-party operators, TEP's participation in the station's Engineering and Operating ("E&O") committees enables TEP to have direct input into the day-to-day operations and on-going O&M decisions. The participants of the E&O committees have direct voting rights to influence the outcome of O&M budgeting decisions at each facility. Table 4 below summarizes the plant operators for each station.

Table 4 – Plant Operator Summary

Plant	Plant Type	Plant Operator
TEP Operated		
Springerville	Coal Steam	Tucson Electric Power
Sundt	Natural Gas Steam	Tucson Electric Power
Third-Party Operators		
Four Corners	Coal Steam	Arizona Public Service
Navajo	Coal Steam	Salt River Project
San Juan	Coal Steam	Public Service of New Mexico
Gila River Power	Natural Gas Combined Cycle	Ethos Energy
Luna Energy Facility	Natural Gas Combined Cycle	NAES

Q. Can you provide an overview of TEP's maintenance programs that are utilized across its generation fleet?

A. The Company along with its third-party operators employ a variety of industry proven maintenance practices that reduce on-going plant O&M spending while maintaining high unit availability targets. TEP's preventative O&M programs combine the original equipment manufacturers' ("OEM") recommendations, industry experience, plant operations and equipment history to create cyclic work orders for inspecting, adjusting, and maintaining equipment. TEP's plant operators utilize computerized asset management systems such as Maximo[6] that creates work orders on a weekly, monthly, and annual basis. Plant maintenance crews then perform the required tasks and track the results. If problems

[6] Maximo Asset Management is a comprehensive asset management tool for optimizing plant performance. Maximo Asset Management allows organizations to enforce best practices in inventory management, spare part procurement, workforce deployment and power production cost management.

are found, the frequency of preventive maintenance work is correspondingly increased to maintain reliability expectations. This schedule-based management system is further complemented by the Company's predictive maintenance programs, which assign work based on specialized tests of our generation equipment. Preventive maintenance programs through the use of oil analysis, motor electrical signatures, vibration measures, thermography scans can identify deteriorating equipment prior to failure. The use of predictive maintenance programs enable maintenance planners to strategically plan needed repairs around scheduled outages while optimizing spare part procurement and workforce management. The plant operators also are tasked with the responsibility of monitoring unit performance during their shifts and initiating work orders to address any needs for corrective action. TEP also employs specialized maintenance programs for certain critical power plant components. These include our boiler tube failure reduction program, critical piping and pipe hanger inspection program, flow-accelerated corrosion inspections, cathodic protection surveys, and corrosion monitoring efforts in various systems through the plants.

Finally, TEP schedules plant outages during periods of low retail customer demand and low wholesale market prices to accommodate inspections and repairs that can only be completed when units are offline. The need for planned outages are determined by OEM maintenance schedules, insurance requirements, reliability concerns and maintenance issues identified by plant operators. The duration of the planned outages are also optimized to minimize the cost of the outage while maximizing unit availability.

Q. How does TEP evaluate the reliability of its generation plants?

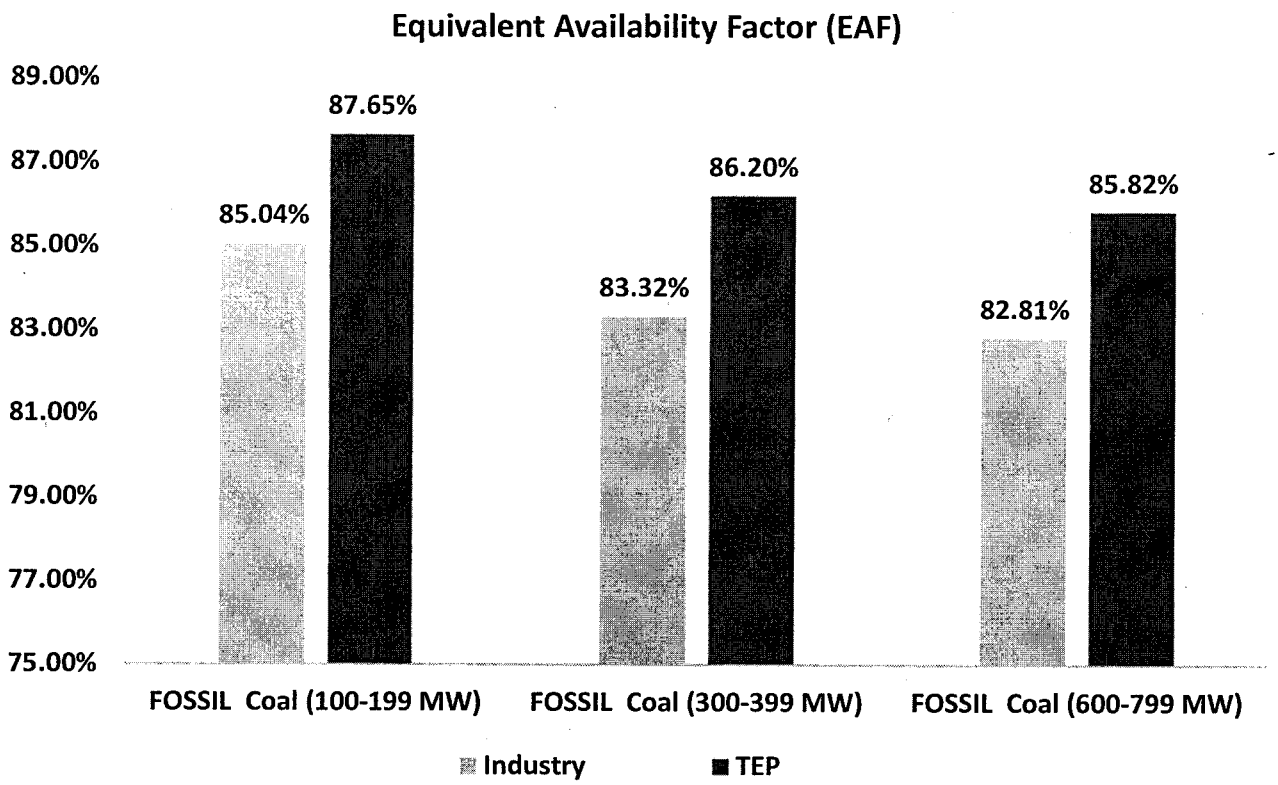
A. TEP measures the reliability of its coal-fired plants against North American Electric Reliability Corporation's ("NERC") Generating Availability Data System ("GADS") definition of Equivalent Availability Factor ("EAF"). EAF represents the percentage of

time during a given period that a unit is available to provide power at its maximum continuous rating ("MCR"). Therefore, EAF takes into account all scheduled and forced outages, as well as de-ratings when the unit is forced to run below its MCR. Table 5 below compares the reliability of the TEP coal generation fleet against other generating units that are similar in size and construction to our own units, allowing us to accurately compare our performance with other coal generation plants across the country. From 2009 through 2013, TEP's weighted average EAF for its coal-fired facilities was 86.23%.

Table 5 – Plant Reliability Statistics

TEP Coal Generating Stations	NERC-GADS Fossil Coal Classification	Equivalent Availability Factor (EAF)[7]		
		Industry Average	Tucson Electric Power	EAF Delta
Sundt Unit 4	(100-199 MW)	85.04%	87.65%	+2.61%
Springerville & San Juan	(400-599 MW)	83.32%	86.20%	+2.88%
Four Corners & Navajo	(600-799 MW)	82.81%	85.82%	+3.01%
TEP Coal Weighted Average			**86.23%**	

[7] A five-year weighted average EAF (2009-2013) is used to normalize the effects of unit overhaul cycles. TEP's coal EAF average is weighted by unit capacity.



IV. GENERATING PLANT SAFETY.

Q. What efforts does TEP undertake to maintain its safety record at its power plants?

A. TEP is committed to integrating safety performance standards into every aspect of our business. The Company focuses its safety programs on making continuous improvements in safety leadership, increasing employee engagement at all levels of the organization and effectively executing on-going regulatory compliance and hazard control programs. The Company is actively engaged in maintaining high standards of safety performance and has in place a number of programs and procedures at both Sundt and Springerville to accomplish the Company's critical safety goals.

Q. Can you describe some of the initiatives undertaken to promote safety leadership?

A. Some of the annual safety leadership activities and programs include, but are not limited to, the following:

- Development and tracking of annual safety goals
- Participation in the safeLEADER[8] program for all management level employees
- Application of supervisor safety observations
- Use of on-site occupational health and safety specialists
- Safety rover programs

Q. Can you describe how the Company promotes safety through employee engagement?

A. Yes. Employee engagement is facilitated through a number of key safety initiatives such as:

- Employee-based safety observation programs
- Employee led safety committees
- Employee facilitated MoveSmart[9] programs
- Employee based job hazard analysis for critical tasks

Q. Can you describe what controls are currently in place to promote safety regulatory compliance?

A. Yes. Safety regulatory compliance is maintained with a number of programs and audit procedures, including the following:

- Programed facility safety audits
- Advanced root cause analysis programs
- On-going compliance audits
- Advanced first-aid and CPR training programs utilizing mock drills and scenarios
- Worksite hazard analysis and job risk assessment procedures

---

[8] The safeLEADER program is deployed as a set of modules via on-site sessions and computer-based e-learning programs. The program is aimed at training the workforce on new thinking and new approaches in safety. Additional program information can be found http://www.safemap.com/

[9] MoveSMART is a comprehensive training and reinforcement-based program that reduces injuries through heightened balance, body leverage, coordination, and de-concentration of forces in otherwise vulnerable areas. Additional program information can be found at http://movesmart.com/

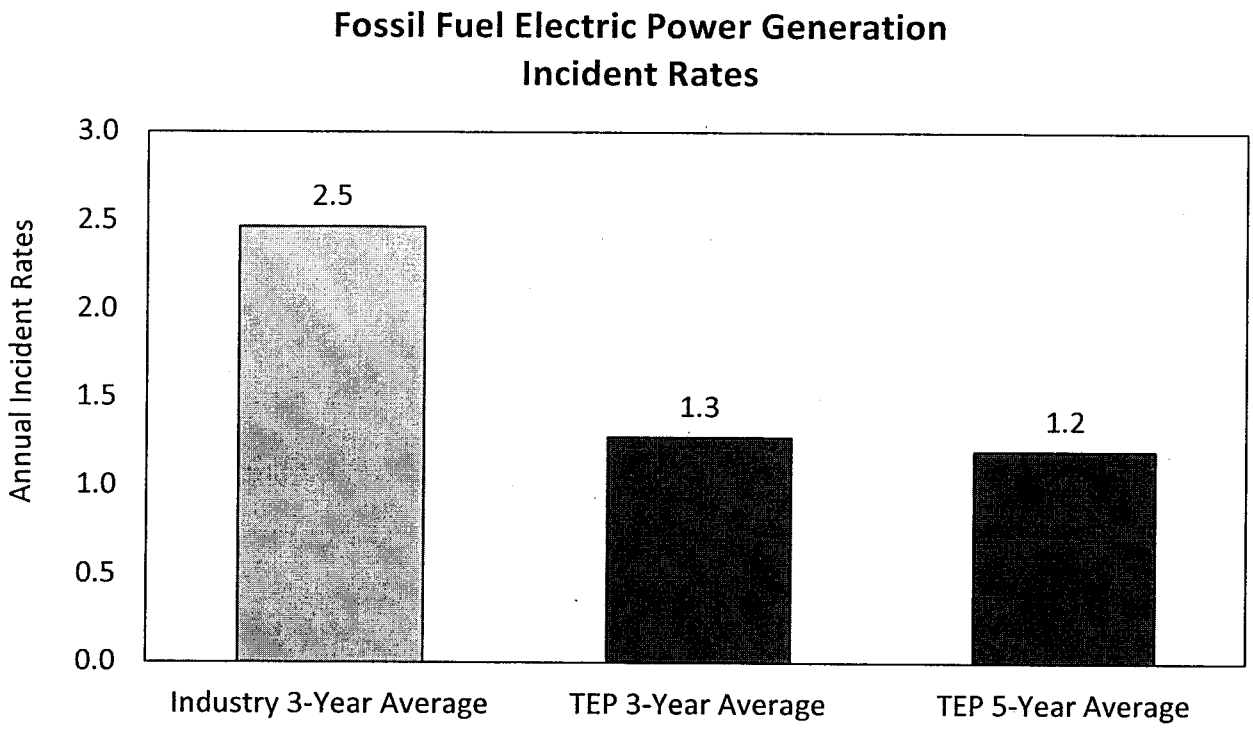
Q. How does TEP evaluate the effectiveness of safety programs at its generation plants?

A. The Company measures the effectiveness of its safety programs by comparing industry average Occupational Safety & Health Administration ("OSHA") recordable incident rates[10] against TEP recordable incident rates for a given year. For the 2015 test year,[11] TEP's recordable incident rate of 1.7 at its managed generation facilities was below the national average annual recordable incident rates published from 2011 through 2013 for the industry classification Fossil Fuel Electric Power Generation. Table 6 below shows the published national average annual recordable incident rate data from the U.S. Department of Labor, Bureau of Labor Statistics[12] compared against TEP's average annual incident rates. The industry three-year average annual incident rate for 2011 through 2013 was 2.5, whereas TEP's average annual incident rate for the same period was roughly half the industry average at 1.3. Factoring in safety performance from 2014 and the 2015 test year, TEP's five year average incident rate was 1.1. These three-and-five-year average incident rates are well below the national average and clearly demonstrate TEP's commitment to safety.

Table 6 – OSHA Recordable Incident Rate Statistics
Industry Classification: Fossil Fuel Electric Power Generation

Recordable Incident Rates	Industry Average[13]	Tucson Electric Power
2011	3.5	1.2
2012	2.1	1.0
2013	1.8	1.7
2014	Not Available	0.7
Test Year	Not Available	1.7
3 Year Average	2.5	1.3
5 Year Average[14]	Not Available	1.2

[10] The Bureau of Labor Statistics incidence rates represent the number of injuries per 100 full-time workers and were calculated as: (N/EH) x 200,000, where N = number of injuries and illnesses EH = total hours worked by all employees during the calendar year 200,000 = base for 100 equivalent full-time workers (working 40 hours per week, 50 weeks per year).
[11] The test year is defined as July 2014 – June 2015.
[12] http://www.bls.gov/iif/home.htm
[13] 2014 and 2015 incident rates were not available from the U.S. Department of Labor, Bureau of Labor Statistics as of November 1, 2015.
[14] The five year average is defined as July 2011 – June 2015.



V. OVERVIEW OF FUTURE ENVIRONMENTAL REGULATIONS IMPACTING TEP's GENERATION FLEET.

Q. Can you provide an overview on how future environmental regulations may impact TEP generation fleet?

A. Yes. TEP's generation resources are subject to numerous local, state, and federal environmental regulations relating to air quality, water quality, waste management and climate change. Fossil fuel power plants are particularly impacted by these regulations due primarily to their air emissions, and in the case of coal-fired power plants, the management of coal combustion residuals. Significant environmental regulations that may impact TEP's generation fleet include:

- Changes to National Ambient Air Quality Standards
- Emission Limitations on Hazardous Air Pollutants
- Regional Haze Rule Requirements

- Coal Combustion Residuals ("CCR") Regulations
- Electric Effluent Limitations Guidelines
- Greenhouse Gas Regulations

Q. Can you provide a summary of the potential impacts that the National Ambient Air Quality Standards ("NAAQS") regulations may have on TEP's generation resources?

A. On October 1, 2015, the Environmental Protections Agency ("EPA") released the final rule for the 8-hour Ozone NAAQS or Ozone Standard. The EPA lowered the standard from 75 parts per billion ("ppb") to 70 ppb. EPA had proposed to go as low as 60 ppb. Areas of the country that exceed the revised standard will be deemed non-attainment areas,[15] and will need to implement programs to reduce emissions, which can include emission limitations on power plants. Currently, TEP does not anticipate that the revised Ozone NAAQS will have a significant impact on TEP's existing facilities. At this point, it appears that Pima County may be able to maintain their status of attainment. If Pima County does not meet the standard, it will be designated as a non-attainment area and will need to develop a plan to bring the air-shed into compliance. A non-attainment designation may slow economic growth by limiting industrial facility expansions in the region and may also impact our ability to site new generation in Pima County. Additionally, the new ozone requirements will increase the development costs for new combustion turbines and combined cycle power plants within a non-attainment area. The only TEP generating facility that is in a non-attainment zone is Gila River Unit 3. Gila River Unit 3 is located within Maricopa County which is in violation of the current (2008) Ozone Standard and the new, more stringent standard will make it even more difficult for Maricopa County to reach attainment status. However, the facility has up-to-date NOx control technology and,

[15] EPA's NAAQS designations are classified as "nonattainment" (not meeting the standard), "attainment" (meeting the standard) or unclassifiable (insufficient data to make a determination).

therefore, is not expected to be materially impacted. Implementation of the rule is scheduled as follows:

- States are required to make recommendations on area designations (either attainment, non-attainment, or unclassified) by October 1, 2016.
- EPA responses to states' designation recommendations by June 1, 2017.
- EPA finalizes area designations by October 1, 2017, based on historical air quality data.[16]

Q. Can you provide a summary of the potential impacts that the Hazardous Air Pollutants regulations may have on TEP's generation resources?

A. On December 21, 2011, EPA issued the final Mercury and Air Toxics Standards ("MATS Rule") establishing limits on emissions of mercury, acid gasses and non-mercury metals from coal-fired power plants. The final compliance date for the MATS Rule was April 15, 2015, however, the rule allowed for plant operators to apply for an extension of up to one year. Extensions were requested and approved for the installation of mercury controls at Navajo, Sundt, Springerville, and Four Corners. San Juan is expected to meet the MATS Rule limits with existing equipment. The MATS Rule compliance strategy and estimated costs for TEP's generating fleet are summarized in Table 7 below:

[16] Final designations will determined by air quality data collected from 2014 through 2016.

Table 7 – MATS Rule Compliance Summary

Station	Unit	Technology	Capital Cost	Annual O&M
Four Corners	4 & 5	Computer Controls [17]	$100,000	None
Navajo	1 - 3	Coal Additives[18]	$525,000	$1,1 Million
Springerville	1	Activated Carbon Injection with Coal Additives[19]	$1,1 Million	$248,000
Springerville	2	Activated Carbon Injection with Coal Additives	$2,3 Million	$500,000
Sundt	4	Switch to Natural Gas by 2018	None	None

On June 29, 2015, the U.S. Supreme Court reversed a lower court ruling that had upheld the MATS Rule. The MATS Rule remains in full force and effect until the lower court rules on whether to vacate the rule or keep it in place under remand. In the event the Federal rule is ultimately vacated, Arizona has a back stop rule that became final in early 2015 that would require the installation of the mercury control equipment. Therefore, TEP does not believe there will be significant consequence on TEP's generation fleet from the U. S. Supreme Court's ruling.

Q. Can you provide a summary of the potential impacts that Regional Haze Rule regulations may have on TEP's generation resources?

A. The goal of the Regional Haze Rule is to reduce visibility impairment (i.e. haze) in national parks and wilderness areas to "natural conditions"[20] by 2064. States are required

[17] Units can meet MATS standard with existing controls; only minor hardware and software upgrades are needed for plant monitoring and emission control management.

[18] This cost estimate assumes a three unit configuration through 2019. On-going O&M costs beyond 2019 will be reduced by one third due to the closure of Navajo Unit 1.

[19] These estimates only account the Company's 49.5% ownership of Springerville Unit 1.

[20] The National Park Service monitors visibility trends in 155 of the 156 national parks and wilderness areas, where clear views are an important value for visitors ("Class I areas"). States are required to adopt progress goals every ten years for improving visibility, or visual range, from baseline conditions (represented by the five-year average conditions between 2000 and 2004). The ultimate goal is to achieve natural background conditions, or conditions which existed before manmade pollution, by 2064.

to achieve "reasonable progress"[21] toward this goal through implementation of programs in 10-year planning periods. During the first planning period (2008-2017), certain stationary sources built between 1962 and 1977, are required to install Best Available Retrofit Technology ("BART") to control emissions of haze causing pollutants, or implement an alternative to BART that achieves equal or better visibility improvement. The Table 8 below lists the compliance strategies used by TEP to meet the BART provisions of the Regional Haze Rule. Springerville Units 1 and 2, are not subject to BART requirements.

Table 8 – Regional Haze Compliance Summary

Station	Units	Technology	Capital Cost	Annual O&M	Compliance Date
Four Corners	4 - 5	SCR	$44 million	$2 million	July 2018
Navajo	1 - 3	LNB/SOFA[22]	None	$100,000	December 2019
Sundt	4	Switch to Natural Gas	None	None	December 2017
San Juan	1	SNCR and Balanced Draft Conversion[23]	$34 million	$1 million	January 2016

Technology: SCR = Selective Catalytic Reduction, LNB/SOFA = Low NOx Burners with Separated Overfire Air, SNCR = Selective Non-Catalytic Reduction

Q. Will the State of Arizona need to file a revised State Implementation Plan ("SIP") in 2017?

A. Yes. Arizona is required to submit a revised SIP in 2017 describing the measures that are needed to demonstrate reasonable progress toward the 2064 goal during the next 10-year planning period. TEP cannot predict what measures the state of Arizona will adopt as part

[21] States must establish Reasonable Progress Goals ("RPGs") for each Class I area for the purpose of improving visibility on the haziest days and ensuring no degradation in visibility on the clearest days over the period of each state implementation plan. RPGs are interim goals that represent incremental visibility improvements over time toward the goal of natural background conditions.

[22] The terms of EPA's final BART ruling that was issued for the Navajo on July 28, 2014, mandates that Navajo must cease operations on one of the three units by January 1, 2020. Installation of LNB/SOFA took place between 2009 and 2011. EPA's final BART ruling mandates that SCR, or an equivalent technology be installed on the remaining two units by 2031. Installation of SCR on two units is estimated at $28 million in capital expenses.

[23] EPA's final BART ruling that was issued for the San Juan on September 26, 2014 committed the San Juan participants to retire San Juan Unit 2 by December 31, 2017 and install SNCR controls on San Juan Unit 1.

of its regional haze SIP for the 2018-2027 planning period. However, on September 28, 2015, the Arizona Department of Environmental Quality issued for public comment and hearing, a 5-year progress report[24] required under 40 CFR 51.308(g) of the Regional Haze Rule. According to this report, Arizona is currently meeting its 2018 reasonable progress goals for each Class I area in the state.

Q. Can you summarize by plant, the potential impacts that the CCR regulations may have on TEP's generation resources?

A. On April 17, 2015, EPA published the final CCR Rule,[25] which establishes requirements for disposal of coal ash and other coal combustion residuals (e.g. scrubber waste) as a solid waste. EPA decided against regulating coal ash under more stringent hazardous waste provisions. The majority of coal ash generated at TEP owned facilities is disposed of as "dry ash" in landfills, while a portion of the coal ash is beneficially reused (i.e. recycled) as a product in cement manufacturing. Under the final rule, all new landfills, new surface impoundments, and lateral expansions must have composite liners to prevent contaminants in CCR from leaching from the unit and contaminating the groundwater. In addition, all facilities will need to install groundwater monitoring systems and specify procedures for sampling groundwater and for analyzing the data to detect the presence of hazardous constituents. From an operations perspective, facilities will need to develop and adhere to a dust control plan, and other various inspection and reporting requirements. The implications for TEP's coal-fired generation plants are summarized below.

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[24] Proposed Arizona State Implementation Plan Revision, Regional Haze 5-Year Progress Report, ADEQ Air Quality Division, September 2015, http://azdeq.gov/calendar/sip_regional_haze.pdf

[25] Fact Sheet: Final Rule on Coal Combustion Residuals Generated by Electric Utilities, http://www2.epa.gov/sites/production/files/2014-12/documents/factsheet_ccrfinal_2.pdf

Springerville:

All CCR generated at the Springerville Generation Station is disposed in a "dry ash" landfill. The existing landfill has capacity for at least another 20 years at current levels of operation, therefore, lateral expansions are not needed for the foreseeable future. Additional capital investments related to groundwater monitoring and site preparation may be required at a cost of approximately $446,000.

Four Corners:

The majority of fly ash and bottom ash generated at Four Corners Units 4 and 5 is disposed in a "dry ash" landfill, while approximately 16% is recycled. A surface impoundment associated with the operation of recently retired Units 1 - 3, solely owned by Arizona Public Service Company ("APS"), also collects scrubber sludge from Units 4 and 5. APS, as operator of Four Corners, intends to close these surface impoundments. TEP's share of these capital projects associated with the surface impoundment closure is expected to be approximately $4.75 million. TEP's share of recurring expenses is approximately $63,000 per year.

Navajo:

Close to 50% of the CCR generated at Navajo are recycled, and the remainder are disposed in a "dry ash" landfill on site. Additional groundwater monitoring wells may be required at an estimated capital cost of $860,000.

San Juan:

Essentially all CCR generated at San Juan is returned to the mine for reclamation. Mine placement of CCR falls under the jurisdiction of the U.S. Department of the Interior's Office of Surface Mining, Reclamation and Enforcement ("OSMRE"), therefore, the EPA's final CCR Rule does not apply to mine placement of CCR at San Juan. The

OSMRE issued an Advance Notice of Proposed Rulemaking for mine placement of CCR in 2007. While it is expected that the OSMRE will proceed with a formal rulemaking relating to mine placement of CCR, TEP cannot predict the timing or impact of those rules. Prior to mine placement, CCR was managed at the plant site in facilities that may be subject to the EPA's final CCR rule. TEP's compliance costs associated with these facilities are estimated at less than $1 million.

Q. Can you summarize the potential impacts that the Effluent Limitation Guidelines rule may have on TEP's generation resources?

A. In September 2015, as part of the Clean Water Act the EPA published the final Effluent Limitation Guidelines[26] setting technology standards and limitations for steam electric power plant discharges to waterways (including discharges to publicly owned treatment works that ultimately discharge to waterways). The rule sets the first federal limits on the levels of toxic metals in wastewater that can be discharged from power plants, based on technology improvements in the steam electric power industry over the last three decades. Since the majority of TEP's facilities are zero discharge, TEP does not anticipate a significant financial impact from this rule.

Q. Can you summarize the potential impacts that the Greenhouse Gas regulations may have on TEP's generation resources?

A. On August 3, 2015, EPA issued the final Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units regulating CO_2 emissions from new and existing power plants ("GHG Rules"). In the GHG Rules for new power

[26] Final Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Industry, http://www2.epa.gov/sites/production/files/2015-10/documents/steam-electric-final-rule-factsheet_10-01-2015.pdf

plants, issued pursuant to the Section 111(b) of the Clean Air Act, Table 9 below summarizes EPA's established emission limits by generation type.

Table 9 – Section 111(b) Emission Limit Summary

Generation Type	Emission Limit
New Coal-Fired Steam Generating Units	1,400 lbs. / MWh-Gross
Reconstructed Coal-Fired Steam Generating Units	1,800 lbs. / MWh - Gross (Large Units) 1,030 lbs. / MWh - Gross (Small Units)
Modified or Reconstructed Fossil-Fired Steam Generating Units	Unit Specific = Units Best Annual Rate Since 2002; Capped at Limit for Reconstructed Units
New and Reconstructed Stationary Combustion Turbines (Base Load)	1,000 lbs. / MWh - Gross 1,030 lbs. / MWh - Net
Limited Use Combustion Turbines (Non-Base Load) [27]	120 lbs. / MMBtu
Modified	No Standard Issued

While the new standards for new base load combustion turbines may impact the manner in which utilities operate these units (i.e. avoiding operating under low efficiency conditions), TEP does not anticipate these new emission limit changes on new natural gas resources will significantly change the way these resource are utilized in future resource plans.

The final GHG Rules for existing power plants, issued pursuant to the Section 111(d) of the Clean Air Act, are complex and it will be several months before TEP can accurately determine the impact that these rules will have on our power generation fleet. Because there are currently no cost-effective retrofit technologies for reducing CO_2 emissions from existing power plants, to determine the "Best System of Emission Reductions" for power plants, EPA relied in part on strategies that are applied on the grid level. These strategies, referred to by EPA as "building blocks" include:

[27] Applies to units with three-year rolling average net-electric sales less than or equal to its design efficiency time its potential electric output.

- Power plant heat rate improvements
- Unit redispatch[28]
- Greater use of zero-emission resources like renewables

Using these building blocks, EPA established national uniform emission rates for two subcategories of power plants, and using the relative proportion of generation for each subcategory in each state, established a state specific goal. The emission rates applicable to TEP owned power plants are presented in Table 10 below.

Table 10 – CO_2 Emission Goals by State or Tribal Lands

State or Tribal Lands	Final CPP Rates - lbs. CO_2 / MWh		Final CPP Mass (short tons)	
	Interim Goal 2022-2029	Final Goal	Interim Goal 2022-2029	Final Goal
Arizona	1,173	1,031	33,062,000	30,171,000
New Mexico	1,325	1,146	13,816,000	12,413,000
Navajo Nation	1,534	1,305	24,558,000	21,701,000

States are required to submit a plan describing how the affected units in their state will achieve the applicable emission limits. There are several threshold questions that states will need to decide in order to submit a plan. These include:

- Whether compliance will be based on the emission rates above or on mass-based limits that EPA derived from the emission rates and promulgated for each state.
- Whether affected units will be able to use intrastate and/or interstate trading,

Once these questions are answered, states can begin to evaluate details of the state plan and the potential impact those details have on compliance costs. The Arizona Department of Environmental Quality has initiated a stakeholder process to address these threshold questions and develop a plan for the state of Arizona. New Mexico will need to undertake a similar planning process. The Navajo Nation will likely be subject to the

[28] Shifting base load unit dispatch from high-emitting CO_2 sources like coal to lower-emitting CO_2 sources like natural gas.

final Federal Plan.[29] Compliance options for utilities will include greater utilization of renewable energy and energy efficiency, greater reliance on natural gas generation, and, or in combination with, reduced utilization of coal-fired resources. Utilities may also be able to utilize trading if market pricing provides a more cost-effective solution. TEP will seek the most cost-effective compliance strategy, however, until these jurisdictions make further progress in their planning efforts, TEP cannot quantify what impact the rule may have on TEP's generation fleet.

VI. GENERATION EXPECTED SERVICE LIVES.

Q. Please explain what you mean by the useful service lives for TEP generation assets.

A. Industry standard accounting depreciation methods provide the Company with a mechanism to systematically recover the installed cost of its capital assets (through Arizona Corporation Commission approved rates), including their estimated removal cost (net of salvage), over the projected useful service lives of those assets. The useful service life is a period that extends from the time an asset is placed in service to the point at which service ends and the asset is decommissioned.

Q. What criteria are considered in estimating the useful service lives of generation assets?

A. That process focuses upon a number of operational factors, including, but not limited to:

- The original design life;
- the operating and maintenance history of the generating units;

[29] EPA issued a proposed rule, *Federal Plan Requirements for Greenhouse Gas Emissions from Electric Utility Generating Units Constructed on or Before January 8, 2014; Model Trading Rules; Amendment to Framework Regulations*, on August 3, 2015. The proposed rule was published in the Federal Register on October 23, 2015, https://www.federalregister.gov/articles/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

- the current physical condition of the assets;
- equipment manufacturers' recommendations;
- water supply availability and discharge rights;
- fuel supplies and transportation;
- access to the transmission system;
- land use authorization;
- potential for life-extension from fuel conversion or repowering;
- potential reclassification of the unit in the Company's dispatching hierarchy;
- any significant capital expenditures that would be required to continue operations;
- legislation or regulatory actions affecting remaining plant economics.

Q. Are you making recommendations to change the expected service lives for any of TEP's generation resources?

A. Yes. Historically, the Company has set the expected service lives for all fossil fired steam-generating units either fully or jointly owned at 60 years. In addition, the Company sets the service life expectancy for natural gas-fired turbines or combined-cycle generating units at 45 years. TEP continues to acknowledge that these expected services lives are reasonable life expectancy targets given the current state of generating plant technologies. However, based on known outcomes around recent environmental regulations, the Company is making minor adjustments to its expected service lives to coincide to the terms and conditions of recently renegotiated project agreements.

Q. Can you summarize which generation resources retirement dates you are proposing to change?

A. TEP is proposing shortening the expected service lives for the units at Navajo and San Juan. At the same time, TEP is proposing to extend the expected service lives at Four Corners and for a number of TEP's local area must-run units at Sundt and North Loop by

ten years. The retirement dates for Luna, Springerville, DeMoss Petrie and North Loop Unit 4 will remain unchanged. Finally, TEP has added Gila River Unit 3 as a new generating unit with an expected service life of 45 years from its original 2003 in service date. Table 11 below details the respective in-service dates and the new recommendations for retirement dates for TEP owned generating assets as of June 30, 2015.

Table 11 – Plant Retirement Date Changes[30]

Station	Unit No.	Year In Service	Plant In-Service Year	Retirement Date in Current Depreciation Rates	New Retirement Year	Change in Retirement Year
Four Corners	4	1969	1969	2029	2031	+2
Four Corners	5	1970	1970	2030	2031	+1
Navajo	1	1974	1974	2034	2019	-15
Navajo	2	1975	1975	2035	2030	-5
Navajo	3	1976	1976	2036	2030	-6
Gila River Power	3	2014	2003	2048	2048	None
Luna Energy Facility	1	2006	2006	2051	2051	None
San Juan	1	1976	1976	2036	2027	-9
San Juan	2	1973	1973	2033	2017	-16
H.W Sundt	1	1958	1958	2018	2028	+10
H.W Sundt	2	1960	1960	2020	2030	+10
H.W Sundt	3	1962	1962	2022	2032	+10
H.W Sundt[31]	4	1967	1988	2048	2048	None
Springerville	1	1985	1985	2045	2045	None
Springerville	2	1990	1990	2050	2050	None
H.W Sundt CTs	1	1972	1972	2017	2027	+10
H.W Sundt CTs	2	1972	1972	2017	2027	+10
North Loop CTs	1	1970	1972	2017	2027	+10
North Loop CTs	2	1971	1972	2017	2027	+10
North Loop CTs	2	1972	1972	2017	2027	+10
North Loop CTs	4	2001	2001	2046	2046	None
DeMoss Petrie CTs	1	2001	2001	2046	2046	None

Indicates changes to the retirement date

[30] TEP owned generation facilities as of June 30, 2015.

[31] This excludes the early retirement of the coal handling facility assets including, but not limited to the rail spur, rotary car dumper, coal pulverizers, and coal conveyors.

Q. What is the basis of your depreciation life changes at the Four Corners Power Plant?

A. TEP is recommending a change to Four Corners retirement date based on the terms of the new Four Corners 2016 Coal Supply Agreement ("CSA") with the Navajo Mine Coal Company that goes into effect July 7, 2016. Per the terms of the CSA, it will be in effect through July 6, 2031. As a result, TEP is recommending July 7, 2031 as the new retirement date for Units 4 and 5 of Four Corners.

Q. Why is this retirement date for the Four Corners appropriate?

A. Setting the Four Corners retirement date to 2031 is appropriate, because it aligns the retirement date with the new CSA and follows the rate making matching principle by aligning the benefits of the Four Corners generation resources to the retail customers who will incur the O&M and capital costs associated with plant operations through 2031. If TEP's participation ends at Four Corners in 2031 then the matching principle is equably maintained. If future resource decisions are made to extend the life of the unit beyond 2031, per the terms of the new CSA, TEP must give the Navajo Mine Coal Company notice by July 6, 2026 to exercise that option. If TEP exercises this option to extend the CSA, TEP can adjust the retirement date in a subsequent rate case based on the termination date of a new CSA that extends beyond 2031. In 2031, Four Corners Unit 4 will be 62 years old and Four Corners Unit 5 will be 61 years old.

Q. What is the basis of your depreciation life changes at the Navajo Generating Station?

A. TEP is recommending a change to the Navajo retirement dates based on the terms of EPA's final BART ruling that was issued for Navajo on July 28, 2014. The final BART ruling commits the Navajo participants to two specific requirements. The first requirement mandates that Navajo must cease operations on one of the existing three

units by January 1, 2020. The second requirement mandates that the remaining two units install selective catalytic reduction ("SCR") emission controls by December 31, 2030. Given these requirements, TEP is recommending December 31, 2019 as the new retirement date for Navajo Unit 1 to coincide with this unit's planned retirement date. For Navajo Units 2 and 3, TEP is recommending December 31, 2030 as the new retirement date.

Q. Why are these retirement dates for the Navajo Generating Station appropriate?

A. First, changing the Navajo retirement date on Unit 1 to December 31, 2019 aligns with the actual closure date mandated by EPA's final BART ruling. Second, setting the Navajo retirement date for Units 2 and 3 to December 31, 2030 is appropriate based on the significant cost of the SCR investments that would be required to continue operating these units beyond 2030. Finally, aligning the retirement date to the final EPA BART ruling supports the rate making matching principle as described above in the case of the Four Corners Power Plant. In 2030, Navajo Unit 2 will be 55 years old and Navajo Unit 3 will be 54 years old.

Q. What is the basis of your depreciation life changes for San Juan Unit 2?

A. TEP is recommending a change to the San Juan retirement dates based on the terms of EPA's final BART ruling that was issued for San Juan on September 26, 2014. The final BART ruling committed the San Juan participants to retire San Juan Unit 2 by December 31, 2017 and install selective non catalytic reduction emission controls on San Juan Unit 1 by January 2016. Given these requirements, TEP is recommending December 31, 2017[32] as the new retirement date for San Juan Unit 2 to coincide with this unit's mandated retirement date under the EPA's final San Juan BART ruling.

[32] See the direct testimony of Company witness Frank Marino regarding the final accounting treatment regarding San Juan Unit 2.

Q. What is the basis of your depreciation life changes for San Juan Unit 1?

A. For San Juan Unit 1, TEP is recommending to change to the retirement date based on the feasibility of future coal supply agreement extensions.

Q. Can you provide details on the new 2016 San Juan Coal Supply Agreement?

A. On January 1, 2016, the new San Juan Coal Supply Agreement ("SJCSA")[33] will take effect between the new miner, Westmoreland Coal Company and PNM. The term of the new SJCSA is through June 30, 2022. In order for the coal supply to be extended beyond 2022, PNM will have to negotiate a new supply agreement with the current coal miner or potentially source coal from an alternative mine. Per the terms of the new SJCSA, PNM will have to negotiate an extension prior to January 1, 2019.

Q. What is the basis for your recommended retirement date for San Juan Unit 1?

A. Based on information obtained in San Juan's 2015 SJCSA RFP process, some bidders provided information on potential mine expansion options for both five and ten year extensions beyond 2022. Numerous factors, such as plant configuration,[34] mine expansion development costs and the cost of complying with future environmental regulations will ultimately determine if extending the life of San Juan beyond 2022 is in the best interests of TEP customers. However, given the degree of uncertainty, TEP is recommending the mid-point date of June 30, 2027[35] as the new retirement date for San Juan Unit 1. This new retirement date reduces the expected San Juan Unit 1 life by nine years. In 2027, San Juan Unit 1 will be 51 years old.

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[33] Subject to certain conditions precedent, including approval by New Mexico Public Regulatory Commission of the restructuring of the San Juan Generating Station, Case No. 13-00390-UT.

[34] From January 1, 2018 through June 30, 2022 the San Juan Generating Station will operate in a two unit configuration (847 MW). After June 30, 2022, some or all of the owner participants at San Juan may choose to exit the project, thus further reducing the plant configuration.

[35] The mid-point date assumes a five year versus a ten year CSA extension.

Q. Can you summarize the current retirement dates for the generating units TEP is proposing to make life extensions on at the Sundt and North Loop facilities?

A. Yes. Three natural gas fired steam units at Sundt (Units 1, 2, and 3) currently have retirement dates set for 2018, 2020 and 2022 respectively. In addition, two natural gas combustion turbines (Sundt CTs Units 1 and 2) have retirement dates set for 2017. Finally, three natural gas combustion turbines at North Loop (Units 1, 2, and 3) have retirement dates also set for 2017.

Q. What is the basis for your recommended life extensions?

A. Today all of the Sundt and North Loop facilities noted above account for approximately 390 MW or 16% of TEP's total thermal generating capacity. These resources provide necessary must-run reliability services throughout the year and contribute to the Company's peaking capacity requirements in order to meet TEP's summer peak reserve margin obligations.

Q. Has the Company considered the reliability and cost impacts associated with retiring these local area units?

A. Yes. Both the Company's Resource Planning and Transmission Planning groups have routinely studied scenarios where local area generation was retired early in an effort to reduce fuel and on-going O&M costs. In all cases, the study results showed that TEP's system reliability could only be maintained with the replacement of new-build transmission or new-build generation resources. As a result, the economics supported the continued operations of the existing local area generation resources versus retirement.

Q. What is the Company's recommendation on the retirement dates for the Sundt and North Loop generating resources?

A. The Company is recommending extending the retirement dates on all of the local area

units[36] by ten years. The Company has chosen a ten-year timeframe in order to properly determine the long-term viability of these older natural gas generation resources in the context of TEP's future resource planning environment.

Q. How will these changes affect TEP's future retail customers now and in the future?

A. Today, these life extension changes will provide TEP's retail customers with the least cost alternative that maintains the Company's must-run reliability and reserve margin requirements. Longer term, TEP plans to answer two key questions; first, what potential role will these resources play in the Company's compliance with the Clean Power Plan and second, how well will these resources effectively increase TEP's ability to integrate higher levels of zero emission renewable resources.

VII. OVERVIEW ON TEP'S RESOURCE PLANNING ACTIVITIES.

Q. Please provide an overview of TEP's customer base and load growth projections.

A. TEP provides electric utility service to a diverse group of residential, commercial, industrial, and public sector customers. Major industries served include copper mining, cement manufacturing, defense, health care, education, military bases, and other governmental entities. TEP's retail sales are influenced by several factors, including regional economic conditions, seasonal weather patterns, increasing energy efficiency practices of end-use customers, and opportunities for customers to generate their own electricity, which to-date has been primarily solar rooftop installations. Chart 1 shows TEP's 2015 test year retail sales percentage by customer class.

[36] North Loop Unit 4 and Sundt Unit 4 are excluded from this recommendation since these units currently have retirement dates of 2046 and 2048 respectively.

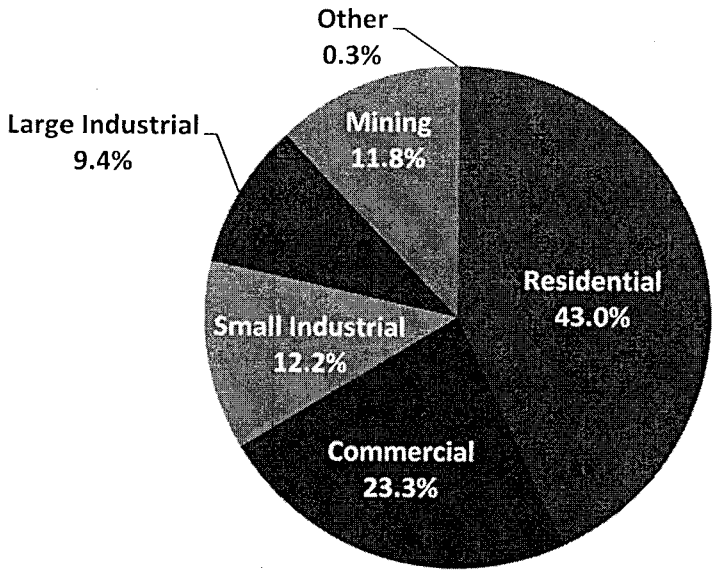
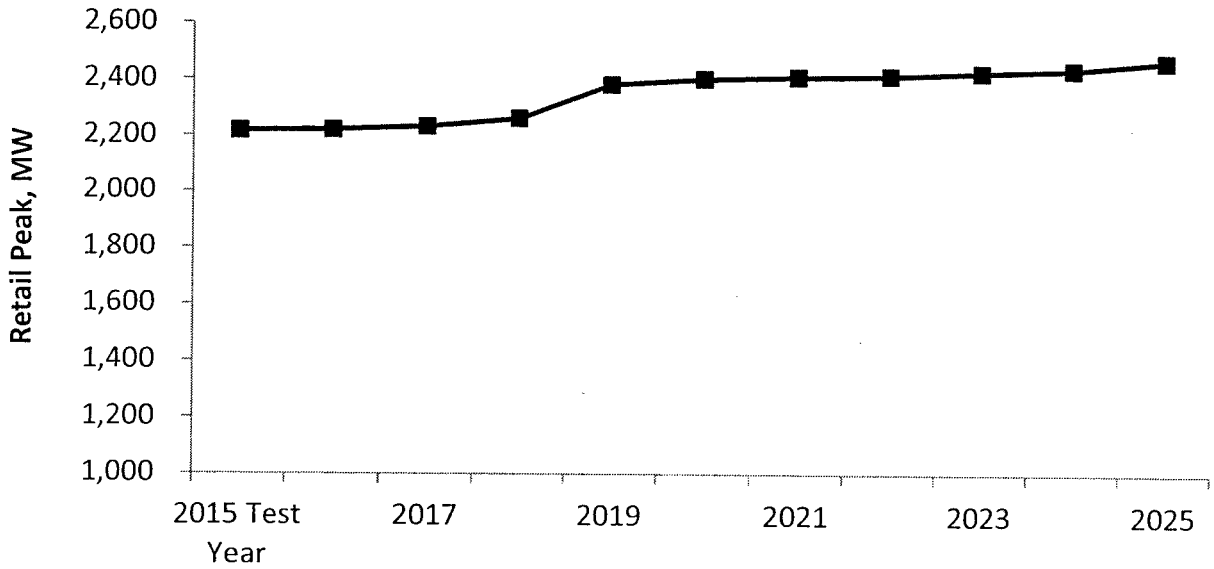


Chart 1 – 2015 Test Year Retail Sales by Customer Class

TEP's peak demand net of energy efficiency and distributed generation is expected to grow on average by approximately 1% per year over the next 10 years. Chart 2 below forecasts TEP retail peak demand from the 2015 test year through 2025.

Chart 2 – Net Retail Load, Peak Demand, MW



Q. Please provide an overview of TEP's 2014 Integrated Resource Plan ("2014 IRP") Reference Case.

A. The 2014 IRP Reference Case[37] emphasized TEP's long-term portfolio diversification strategy to reduce long term environmental risks associated with coal fired generation. The Reference Case detailed TEP's planned commitments to reduce its overall coal capacity by 492 MW (32% of TEP's existing coal fleet) by 2018. This diversification strategy also included a joint acquisition in December 2014 with UNS Electric, Inc. ("UNS Electric") for a 550 MW natural gas combined cycle generation unit located at the Gila River Power Station in Gila Bend, Arizona. The 2014 IRP plan also underscored TEP's efforts to develop a well-diversified renewable resource portfolio that in recent years has exceeded Arizona's Renewable Energy Standard and Tariff ("REST") requirements. TEP is committed to the development of a low cost, sustainable generation portfolio that minimizes negative impacts to the environment and provides long-term value to TEP's retail customers.

Q. Can you provide a summary of the TEP's planned resource commitments that were filed in the 2014 IRP?

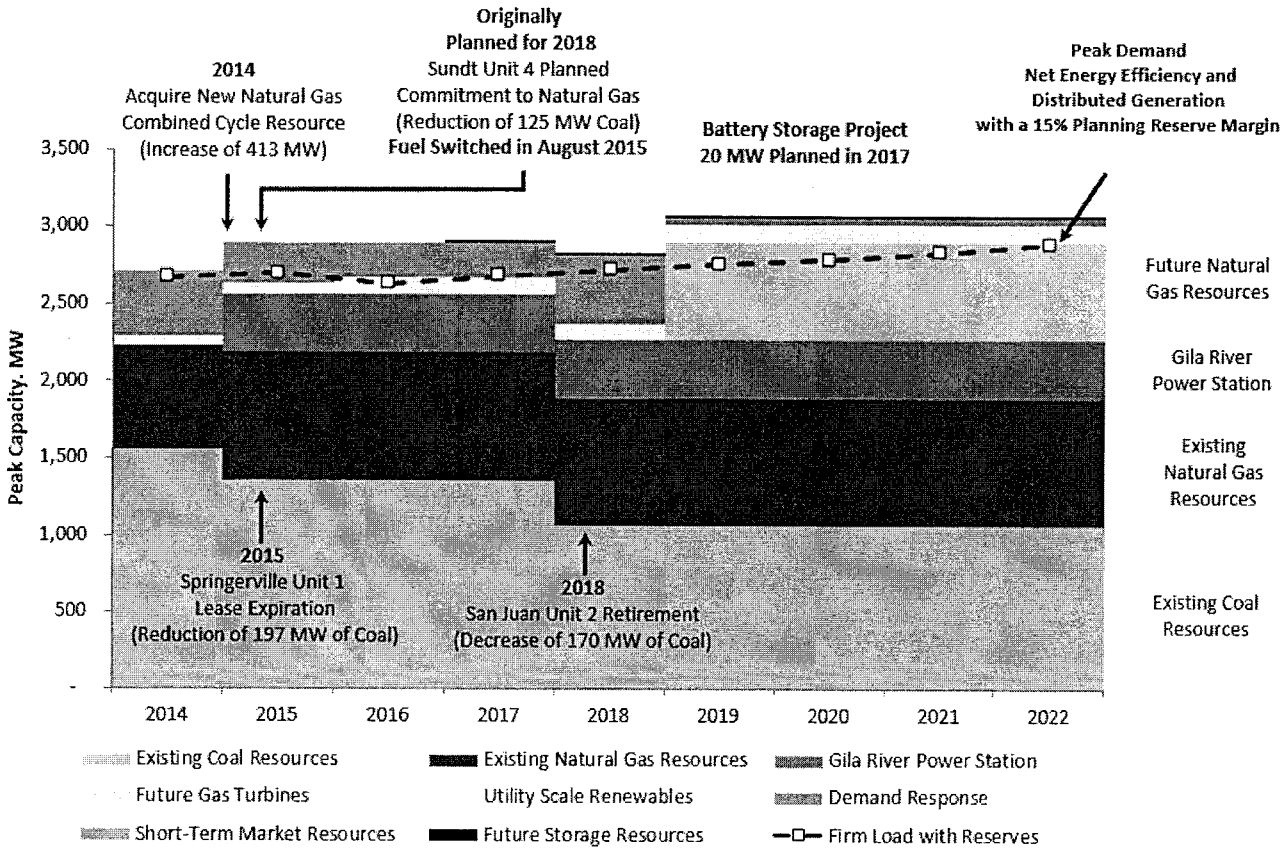
A. Chart 3 below shows a modified version of the loads and resource chart from the 2014 IRP.[38] These modifications reflect actual changes in resources that have occurred after the 2014 IRP filing in April 2014. In December 2014, TEP acquired 413 MW in natural gas combined cycle capacity from Gila River Unit 3. In January 2015, TEP reduced its share of capacity on Springerville Unit 1 from 387 MW to 192 MW. The 2014 IRP originally targeted December of 2017 as the date in which TEP would no longer utilize coal as a fuel source at Sundt. However, in August 2015 due to exhausted coal inventory and

[37] 2014 TEP IRP (filed in Docket No. E-00000A-13-0070)
[38] 2014 TEP IRP at 14.

historically low forward natural gas prices, TEP stopped burning coal on Sundt Unit 4 and currently expects to operate the station solely on natural gas.

At San Juan, TEP is currently committed to reduce its coal capacity from 340 MW to 170 MW by the end of 2017. Over the next few years, TEP plans to procure 250 MW to 350 MW of capacity from the wholesale market to cover its near term load obligations. Longer term, TEP will continue to execute on its resource portfolio diversification strategy through increased commitments in natural gas, utility scale renewables, energy efficiency and new technologies such as battery storage.

Chart 3 - 2014 IRP Loads and Resource Chart[39]



[39] Chart 3 was modified to reflect the switch to natural gas at Sundt in 2015. In addition, TEP has advanced its planned integration of battery storage by two years from 2019 to 2017 with a 20 MW lithium ion battery storage project (subject to final Commission approval).

Q. As part of TEP's next filed Integrated Resource Plan, is the Company proposing any additional commitments in regards to its future renewable energy goals with respect to the TEP resource portfolio?

A. Yes. As described in the testimony of Company witness David G. Hutchens, TEP plans to increase its renewable energy commitments to 30% by 2030.[40] This commitment will double the level the Company must achieve by 2025 under the current REST Rules.[41] This higher renewable energy commitment will be reflected in the Company's next IRP.[42]

VIII. OVERVIEW ON GILA RIVER UNIT 3 AND THE ACQUISITION PROCESS.

Q. Please provide a general description of the Gila River Power Plant.

A. The Gila River Power Plant is located approximately 75 miles southwest of Phoenix and about 30 miles south of the Palo Verde trading hub. The Gila River Power Plant is a modern, efficient natural-gas combined-cycle facility that is geographically situated to provide reliable, base load and intermediate power to TEP's customers in Pima County. It is sited on approximately 1,100 acres within the town of Gila Bend. The plant consists of four power blocks or units, with each representing 550 MW of nominal capacity. At 2,200 MW of combined capacity, Gila River is the largest natural gas-fired generating facility in the WECC market zone. Gila River went into commercial operation in July 2003.

Q. Please describe the procurement process for Gila River Unit 3.

A. In the Company's 2012 Resource Plan, TEP made a commitment to monitor the merchant

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[40] The Company plans to source 30% of its retail customer energy obligations from renewable resources by 2030.

[41] Under Arizona's current REST Rules, load serving entities must serve 15% of their retail customer's energy needs by 2025 with renewable resources. TEP's proposed commitment will target a 30% energy requirement by 2030.

[42] The Company's next IRP is due April 4, 2017 based on Decision No. 75269 (filed in Docket No. E-00000V-15-0094) Resource Planning and Procurement in 2015 and 2016.

wholesale market for potential resource alternatives as part of its on-going resource procurement plans. In anticipation of TEP's August 2013 deadline for exercising its purchase options on Springerville Unit 1, TEP conducted a Request for Proposal ("2013 RFP") in May 2013 to evaluate the market for potential capacity alternatives. As a result of the 2013 RFP process, TEP received 14 different proposals from nine different bidders. Based on the bid analysis, Gila River Power LLC's proposal for Gila River Unit 3 was chosen as the final bid due to its economic and operational advantages. The combination of both TEP's and UNS Electric's capacity needs enabled TEP to jointly acquire an appropriately-sized resource at a clear and significant discount to other alternatives. The purchase price for TEP's share was approximately $164 million, or approximately $398 per kW, for 412.5 MW of capacity. Gila River Unit 3 was the lowest cost resource bid from the 2013 RFP and is about one third the cost of building a comparable new facility.

Q. You mentioned that there were additional operational benefits associated with the Gila River Unit 3 acquisition.

A. Yes. In addition to being the lowest cost resource option, Gila River Unit 3 is strategically situated to take advantage of gas transportation from both the El Paso Natural Gas and Transwestern Pipeline Company pipelines, providing access to both the Permian and San Juan supply basins. The ability to source fuel for Gila River from two different supply basins as well as two different gas pipeline companies offers significant operational advantages from a cost and reliability standpoint. Further, Gila River's interconnection to the Palo Verde market hub and existing transmission rights to Jojoba Switchyard also resulted in lower transmission costs relative to other proposals. Finally, with the acquisition of Gila River in December 2014, work was completed to transfer Gila River into TEP's balancing authority. This coordination with TEP's balancing authority will enable the Company to fully optimize the dispatch of the unit for TEP's retail customers.

Q. Did TEP use an independent monitor in the 2013 RFP?

A. Yes. The Accion Group, Inc. ("Accion") was selected by TEP to serve as the Independent Monitor ("IM") for the 2013 RFP. Accion provided oversight on the 2013 RFP process and reviewed the analysis on the final evaluations. The results of the final report from the IM were provided to Staff in UNS Electric's recent financing docket (Docket No. E-04204A-13-0447):

> "Staff also reviewed, under a protective agreement, TEP's RFP for a Power Plant Purchase and related results as well as a report by UNS Electric on its analysis of purchasing a 25 percent interest in Gila River. TEP used an independent monitor to ensure fair and equal treatment of all bidders, ensuring all potential bidders had access to the same information at the same time. A number of proposals for existing and new facilities, offering both ownership and short-term power purchase agreements with options to purchase the power plant at a later time were received by TEP. Based upon TEPs analysis of all alternatives, TEP selected Gila River because it found it to be the lowest cost intermediate/baseload plant offered in the RFP"[43]

IX. GILA RIVER UNIT 3 FINANCIAL ANALYSIS.

Q. Did the Company perform an analysis comparing the purchase of Gila River with the construction of a new facility?

A. Yes. TEP's 2014 IRP compared the acquisition of Gila River Unit 3 with the cost of building a similar unit. A comparison of the levelized cost of electricity ("LCOE")[44] of the proposed acquisition versus new build construction is shown below. Exhibit 1 and 2 shows the levelized cost for Gila River Unit 3 is estimated at approximately $79.53/MWh whereas the levelized cost for new build construction is estimated at $112.51/MWh. In addition, TEP's share of Gila River is much less expensive than a similar interest in a

[43] Id. at 9.

[44] LCOE is a measure of the overall competiveness of different generating technologies. It represents the per-megawatt hour cost of owning and operating a generating plant over an assumed life and duty cycle. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable O&M costs, financing costs, and an assumed utilization rate for each plant type.

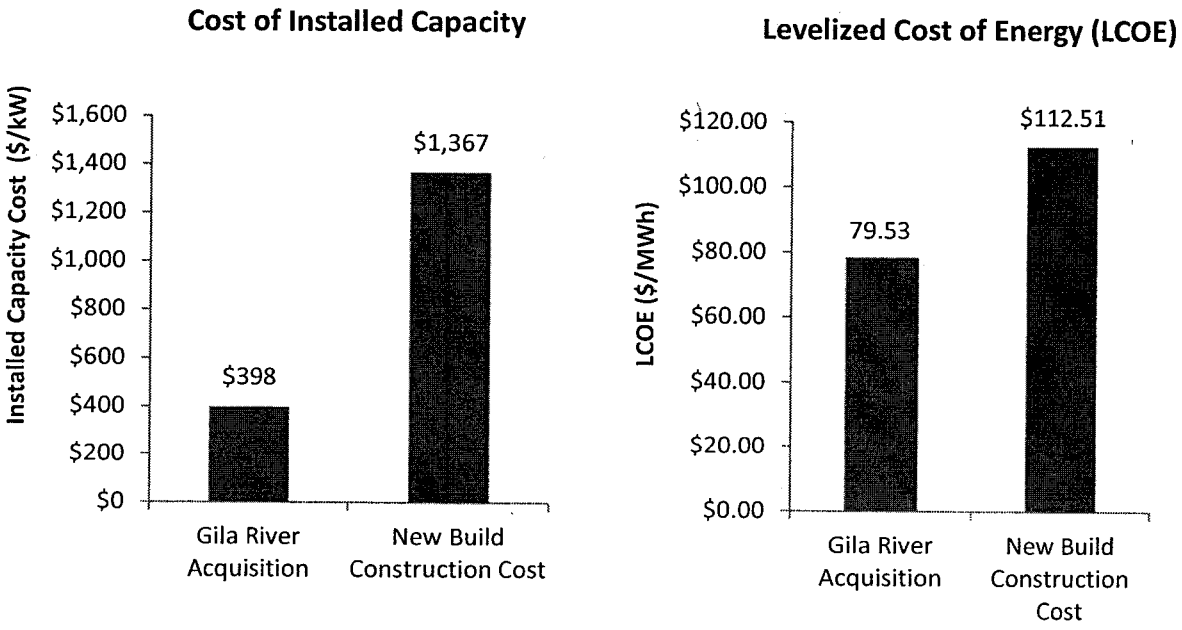
newly constructed combined cycle plant. As shown in the tables below the Gila River Unit 3 purchase price of $398/kW is approximately one-third the cost of new construction at $1,367/kW.

Exhibit 1 - Gila River Unit 3 vs. New Construction Cost Comparison

Unit Capacity, MW	412.5
Weighted Average Cost of Capital, WACC	7.26%
Levelized Cost of Fuel, $/mmBtu	$6.54
Average Capacity Factor, %	41.7%

15 Year NPV and LCOE (2015-2029)	Gila River Unit 3	New Construction
Cost of Installed Capacity	$164,250,000	$563,887,500
Cost of Installed Capacity, $/kW	$398	$1,367
Levelized Cost of Energy, LCOE, $/MWh	$79.53	$112.51

Exhibit 2 - Gila River Unit 3 vs. New Construction Cost Comparison



Q. In addition to the LCOE analysis, did TEP perform a net present value revenue requirement calculation as part of the 2014 IRP?

A. As part of the 2014 IRP review process, Staff's consultants requested that TEP provide a net present value ("NPV") revenue requirement calculation supporting the value of the Gila River Unit 3 acquisition. Based on this calculation, the acquisition of Gila River Unit 3 was projected to save TEP's retail customers approximately $218.5 million on 15-year NPV basis. Exhibit 3 below shows the comparison between the "Reference Case" that includes Gila River Unit 3 and the "Gila River Unit 3 Out" scenario that excluded the acquisition of Gila River Unit 3.

Exhibit 3 –NPV Revenue Requirement for Gila River Unit 3[45]

Non Fuel Revenue Requirements	2014 Reference Case	Gila River Unit 3 Out
Existing T&D Resources	$3,630,009	$3,630,009
Existing Generation Resources	$3,136,139	$2,811,889
New Generation Resources	$765,489	$1,231,230
Storage Resources	$19,270	$19,270
New Transmission Resources	$196,076	$196,076
Total Non-Fuel Revenue Requirements	**$7,746,983**	**$7,888,474**

Fuel and Purchase Power Requirements	2014 Reference Case	Gila River Unit 3 Out
PPFAC Cost, Fuel & Purchase Power	$3,233,216	$3,314,662
PPFAC Cost, Renewable (Above MCCCG)	$264,742	$264,742
Total Gas Transportation	$150,283	$130,480
PPFAC Cost, Demand Charges	$12,936	$28,316
Total PPFAC Costs	$3,661,177	$3,738,200
Environmental Compliance	$488,929	$488,945
PPFAC Cost including Environmental Compliance	**$4,150,106**	**$4,227,145**

Energy Efficiency	$213,307	$213,307
Demand Response	$37,689	$37,689
Utility Scale Renewables	$518,752	$518,752
Distributed Generation	$68,793	$68,793
System Total	**$12,735,629**	**$12,954,144**

Delta 2014 Reference Case	**$218,515**

[45] Exhibit 2 was originally filed in Docket No. E-00000A-13-0070 in response to Staff's data request STF 3.1 as part of the 2014 Integrated Resource Plan.

Q. Was there any independent analysis done to validate TEP's assumptions on the installed cost of new combined cycle power plants?

A. Yes. As part of its analysis in Docket No. E-04204A-13-0447, Staff conducted its own independent review on new combined cycle cost assumptions, stating:

> "Staff's independent review of the installed cost of a new combined cycle power plant in the size range of Gila River found estimates ranging from $950/kW to $1,475/kW in 2014 dollars. While the cost of the new build construction estimate of $1,320/kW is at the higher end of this range, the price of $398/kW being paid for Gila River is about 60 percent below even the lowest estimate for a new plant identified by Staff."[46]

Q. Were there any recent plant acquisitions that could provide a market based comparison against the acquisition cost of Gila River?

A. Yes. As part of its analysis in Docket No. E-04204A-13-0477, Staff referenced the sale of Unit 1 at the Mesquite Generating Station located near Palo Verde. In 2012, Salt River Project acquired one of the two 600 MW natural gas combined cycle power blocks from Sempra Energy.

> "A point of reference for the capital cost of purchasing an existing plant is Salt River Project's ("SRP") acquisition of one power block at the Mesquite Generating Station combined cycle gas turbine plant located near Gila River and installed in 2002. SRP announced its intention to acquire Mesquite in December 2012. The acquisition price equated to approximately $594/kW, about 50 percent greater than the price agreed to by TEP and UNS Electric for Gila River."[47]

Relative to the acquisition price of $594/kW referenced above, TEP realized acquisition savings of approximately $81 million[48] with the purchase of Gila River Unit 3.

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[46] Staff Report, Attachment A, (Engineering Analysis) at 8 (UNS Electric Inc. Financing Application (Docket No. E-04204A-13-0447)).

[47] Id. at 9.

[48] Hypothetical market based acquisition savings - $80,850,000 = (594 $/KW - 398 $/kW) * 412,500 kW.

X. TEP'S ESTIMATE OF O&M FOR GILA RIVER UNIT 3.

Q. Is the Company providing an estimate of annual O&M for Gila River?

A. Yes. Due to the timing of the Gila River Unit 3 acquisition,[49] as well as differences in the operation and accounting for Gila River Unit 3 under the previous merchant ownership structure, TEP has not had adequate time to develop historical O&M spending levels for the unit to reflect anticipated O&M costs for future years. As a proxy for actual experience running Gila River Unit 3, TEP is relying on actual historical O&M costs from TEP's ownership interest in Luna to estimate Gila River's future O&M costs. TEP currently shares a one-third ownership share of Luna with Public Service of New Mexico ("PNM") and Freeport McMoRan Inc. ("FMI").[50] Luna is located in Deming, New Mexico and went into service in 2006.

Q. Why is the use of Luna O&M cost data appropriate?

A. Both Gila River Unit 3 and Luna are similarly sized natural gas-fired combined cycle generating facilities. Each facility is comprised of a single power block that consists of 2 combustion turbines and 1 steam turbine. Both power blocks are of similar nominal capacity. Gila River Unit 3 is a nominal 550 MW power block, while Luna is rated at a nominal 555 MW. Both facilities utilize General Electric ("GE") 7FA+e gas turbines with an associated heat recovery steam generator and one GE D11 steam turbine with accompanying cooling towers. TEP has a long-term service maintenance agreement ("LTSA") with GE and coordinates its maintenance with a third party O&M provider, NAES. Gila River utilizes a third party O&M provider Ethos Energy[51] to perform the full

[49] TEP's closing date for the Gila River acquisition was December 10, 2014.

[50] In October 2014, Samchully Asset Management and Macquarie Funds Group entered into an agreement to acquire FMI's share of the Luna Energy Facility. Under this agreement, FMI will retain the ability to purchase up to the full amount of its previous ownership share of the Luna facility of approximately 185 MW, thereby continuing to be active participant in the operations of the facility.

[51] Ethos Energy Power Plant Services, LLC, a Nevada limited liability company (f/k/a Wood Group Power Plant Services, LLC).

range of annual preventative and routine maintenance. Both O&M providers follow similar OEM maintenance practices for both the major and non-major maintenance requirements. Non-major maintenance for the gas turbines are performed primarily utilizing the OEM recommendations from GE and GE technical information letters ("TILS") as guidelines. The turbine's major maintenance is performed in compliance with the GE's Heavy-Duty Gas Turbine Operating and Maintenance Considerations publication, GER 3620L, which provides the hours and starts criteria recommendations to identify the timing of the inspections and major overhauls. The balance of plant maintenance activities (boiler feed pumps, condensate system, cooling water systems, continuing emissions monitoring systems and fire protection systems) are conducted in accordance with OEM recommendations and on an as needed corrective maintenance basis. Table 12 below details each plant's similarities between the two plants.

Table 12

Unit Characteristics	Luna Energy Facility	Gila River Unit 3
Year in Service	2006	2003
Unit Capacity	555	550
Manufacturer	General Electric	General Electric
Configuration	2x1 Combined Cycle	2x1 Combined Cycle
O&M Provider	NAES	Ethos Energy
Ownership Share	33%	75%

Q. What are the annual O&M costs associated with operating Luna?

A. For TEP's ownership share, historical non-fuel O&M expenses at Luna have averaged approximately $4.6 million per year from 2009-2014. The O&M costs account for annual routine and preventive maintenance on the power block, the plant common facilities and the switchyard. O&M costs associated with unit overhauls and major maintenance are also included in this amount. Table 13 below summarizes the total annual O&M costs in dollars and dollars per kW-year at Luna.[52]

[52] These costs reflect the average annual O&M costs incurred from 2009 through 2014 (FERC Form 1).

Table 13

TEP's Share of O&M (2008-2013)	Luna Energy Facility
Annual O&M, $	$4,607,034
Luna Nominal Capacity, MW	185
Luna Annual O&M, $/kW-year.	$24.90

Q. How do the Luna O&M costs translate into O&M costs for TEP's share of Gila River?

A. The O&M costs for TEP's share of Gila River Unit 3 are derived by multiplying Luna's costs expressed on a $/kW-year basis by TEP's 412.5 MW ownership in Gila River. This results in an estimated cost of approximately $10.3 million per year. These cost estimates are shown below in Table 14 below.

Table 14

Gila River O&M Proforma Adjustment	Gila River
TEP's Gila River Nominal Capacity, MW	412.5
Luna Annual O&M, $/kW-year	$24.90
TEP's Share of Annual O&M, $	$10,272,441

XI. TEP'S ESTIMATE OF THE BASE COST OF FUEL.

Q. Does the Company have an estimate on the average cost of fuel and purchase power for the timeframe that the proposed TEP rates are likely to go into effect?

A. Yes. As part of this rate case filing, TEP's Resource Planning group updated its long term production cost model AuroraXMP.[53] AuroraXMP is currently used for determining the forward pricing projection for TEP's cost of fuel and purchase power. Based on forecasts of forward natural gas and wholesale power prices as of August 2015 prepared by the

[53] AuroraXMP, Power Generation Forecasting Software by EPIS, http://epis.com/.

energy consulting firm Wood MacKenzie.[54] TEP forecasts the average base rate of fuel and purchase power to be approximately 3.3692 ¢/kWh. The cost estimate in Table 15 is based on a forecast of PPFAC eligible costs from January 1, 2017 through December 31, 2017.

Table 15 – 2017 Base Cost of Fuel and Purchase Power

	January 2017 - December 2017
Base Cost of Fuel and Purchase Power	$302,564
TEP Electric Retail Sales, GWh	8,980
Average Annual Cost, ¢/kWh	3.3692

Forward Market Prices	January 2017 - December 2017
Palo Verde (7x24) Market, $/MWh	$35.63
Permian Natural Gas, $/mmBtu	$ 3.57

Q. Did the Company make any proforma adjustments to the base cost of fuel estimate?

A. Yes. Included in the estimate in Table 15 above, is a proforma adjustment that credits the margins associated with a firm wholesale sale agreement between TEP and Shell Energy North America.[55] This proforma adjustment reduced the 2017 base cost of fuel and purchase power by approximately $2.7 million. This adjustment reflects the forecasted wholesale sale margins[56] from this contract for 2017. Although this is a long-term wholesale contract that is not subject to PPFAC cost reconciliation, TEP is proposing this adjustment since less than one year will be remaining on the contract when new retail rates are proposed to be implemented.

[54] Wood MacKenzie, WECC Power & Renewables Markets Long-Term Outlook H1 2015 (August 2015).
[55] On December 12, 2014, the Company entered into a day-ahead index call option with Shell Energy North America. The term of this wholesale call option expires December 31, 2017.
[56] Wholesale sale margins equal revenues less the allocated cost of fuel and purchase power to serve this contract.

XII. OVERVIEW ON PROPOSED CHANGES FOR TEP'S PPFAC.

Q. How is the Company proposing to modify its PPFAC?

A. The PPFAC rate is currently based on three components; the base rate, the forward component, and the true-up component. The forward component is estimated once annually, and this fixed estimate of costs is then charged for an entire year. Balances of over or under collections resulting from the forward component are charged and then moved to a true-up component in the following year. TEP is proposing to modify its PPFAC to consist of a base rate and a PPFAC percentage rate. The sum of the base rate and the PPFAC percentage rate will be derived by using the prior twelve month's weighted average fuel and purchased power costs, net of short-term wholesale revenues. Each month, the calculation will fluctuate based upon actual net costs of the prior 12-month period. The monthly movement in the total average fuel and purchased power rate will be implemented by changing the PPFAC rate, while the base rate will remain fixed (as approved by the Commission). The Company proposes to allocate the PPFAC costs, as currently calculated, on a percentage of the average base fuel rate established in this rate case. The monthly PPFAC charge will be a single percentage adjustment applied to all base fuel rates for all customer classes.

Q. Why has TEP proposed moving from a rate that is adjusted annually with a forward component to a twelve month historical rolling average rate?

A. Historically, TEP's resource portfolio was sourced from a high percentage of coal based generation as compared to its affiliates; UNS Electric and UNS Gas. Both UNS Electric and UNS Gas utilize a twelve month rolling average based rate in their respective PPFAC and Purchased Gas Adjuster ("PGA") surcharges as a method of smoothing fuel cost volatility to customers. In the last year, TEP has transitioned a significant portion of its resource portfolio away from coal-fired generation, and is currently on track with further

reductions associated with the San Juan Unit 2 closure by the end of 2017. Even though TEP has historically had less volatile fuel and power costs, the annual reset of the PPFAC has, in a couple of instances, created a significant bill impact. This transition to a twelve month rolling average, combined with the use of effective hedging, will lower the potential for PPFAC volatility and smooth potential bill impacts.

Q. Is the Company proposing making any changes to the list of PFFAC allowable costs?

A. Yes. The Company is requesting to recover the related chemical costs used to remove mercury and associated compounds resulting from the combustion of coal. Like sulfur, mercury is present in coal and it becomes volatilized during combustion, entering the flue gas stream as elemental mercury or as an ionic compound. Emissions of mercury are limited under the EPA's MATS Rule[57] and the Company will begin to incur expenses associated with mercury control at Springerville and Navajo in 2016. Both of these plants will use one or a combination of *coal additives* or *adsorbents* to limit emissions of mercury. The primary coal additive in use at power plants is calcium bromide, which when applied to coal prior to combustion, promotes the capture of mercury in wet scrubbers (Navajo) or fabric filters (Springerville). The primary mercury adsorbent is powdered activated carbon ("PAC").[58] PAC is injected into the flue gas stream after combustion where mercury present in the flue gas can adsorb to the PAC surface. The mercury-infused PAC is then captured along with other coal combustion residuals. TEP may incur ongoing chemical additive costs at its other coal-fired facilities which would also be included in future PPFAC filings. These costs would be recorded in FERC Account 502 in a similar fashion as both the lime costs and sulfur credits that are associated with the coal used at Springerville.

[57] The MATS Rule and costs associated with mercury control at Navajo and Springerville are summarized on Page 13 in Section V.

[58] TEP has also performed testing with amended silicates, which is a proprietary, non-carbon based adsorbent, and may also be used depending on performance and economics.

Q. Is the Company proposing making any changes to the list of PFFAC allowable credits?

A. Yes. The Company is proposing including two additional credits. First, the Company is seeking authority to pass through its PPFAC any reasonable and prudent outside professional expenses it incurs in pursuing PPFAC tax refunds.[59] Second, per Condition 3 of the Fortis Settlement,[60] the Company is adding specific language to TEP's PPFAC Plan of Administration ("POA") that authorizes the Company to credit the revenues from processed refined coal used in the production of steam generation for TEP's retail customers against the PPFAC. Currently, TEP receives a $2.00 per ton revenue payment from the processing of refined coal in Units 1 and 2 at San Juan.[61] The Company is currently pursuing other potential refined coal projects at Springerville, Navajo and Four Corners facilities.

Q. What is refined coal?

A. Refined coal is a term used to describe an additive process which mixes certain chemical or other additives with existing coal in order to achieve emission reductions that qualify for the refined coal tax credit under Section 45 of the Internal Revenue Tax Code. The required emission reduction must reduce the emissions of nitrogen oxide (NO) by 40 percent and at least reduce the emissions of either sulfur dioxide (SO2) or mercury (Hg) by 40 percent as compared to the emissions of the coal prior to treatment. While the Company doesn't receive the actual tax credits, it does receive a revenue payment from the

[59] As summarized in the Company's October 2, 2015 application request to credit potential tax refunds associated with prior period coal, natural gas and lime purchases through the PPFAC in Docket No. E-1933A-15-0344.

[60] See Attachment A - Settlement Conditions, Customer Benefits and Protections A.3. Docket Nos. E-04230A-14-0011 and E-O1933A-14-0011.

[61] The San Juan refined coal project went into service in January 2015. As of August 31, 2015, the Company has credited back approximately $2.5 million dollars in refined coal revenues from San Juan through TEP's PPFAC.

third party owner-operator of the refined coal facility sited at the plant. The current term of the refined coal tax credit under Section 45 will be available through December 2021.

Q. Are there other changes being proposed for the PFFAC?

A. Yes. TEP is also proposing a new methodology in applying the PPFAC to the various classes of customers. This change is discussed in detail in the Direct Testimony of Craig A. Jones. Additionally, I discuss PPFAC changes related to the co-ownership share of Springerville Unit 1 in my next section.

Q. Is TEP proposing revisions to the existing PPFAC POA?

A. Yes. The Company is submitting a revised PPFAC POA[62] as well a PPFAC Schedules 1 through 4 that reflect these changes.[63]

XIII. PROPOSED TREATEMENT OF 50.5% SHARE OF SPRINGERVILLE UNIT 1

Q. Is TEP proposing any adjustments to the PPFAC with respect to the 50.5% share of Springerville Unit 1 owned by third parties?

A. Yes. As described in the testimony of Company witness Kentton C. Grant, TEP is engaged in litigation with the co-owners, and former lessors, of Springerville Unit 1. The Company is presently dispatching this share of Springerville Unit 1 for purposes of generating wholesale margins. To the extent this generating capacity is available to TEP for dispatch, TEP is proposing to dispatch this 50.5% share of Springerville Unit 1 for the benefit of TEP's retail customers. In return, TEP is proposing that the Company be allowed to recover the related fuel and non-fuel operating costs for this share of Springerville Unit 1 through the Company's PPFAC.

[62] See Exhibit MES-1 (TEP Plan of Administration).docx
[63] See Exhibit MES-2 (TEP Revised PPFAC Schedules 1-4).xlsm

Q. What are the specific non-fuel Springerville 1 operating costs the Company is proposing to recover through the PPFAC that are related to the 50.5% share of Springerville Unit 1?

A. The Company is proposing to recover 50.5% of the direct O&M costs, property taxes and insurance costs for Springerville Unit 1 and related common facilities. Additionally, the Company is proposing to recover coal handling facility costs that are allocable to this portion of Springerville Unit 1. Any short-term wholesale revenues realized as a result of the dispatch of this capacity would also be credited to the PPFAC.

Q. Does the Company have an estimate of the 2017 non-fuel operating costs associated with the 50.5% share of Springerville Unit 1?

A. Yes. The Company is estimating that the non-fuel operating costs associated with co-owners share of Unit 1 will be approximately $17.3 million in 2017. On a retail jurisdictional basis, these costs are estimated to be approximately $16.6 million in 2017. Table 16 below provides a breakdown of these estimated operating costs.

Table 16 – Non Fuel O&M associated with the 50.5% Share of Springerville Unit 1

Non-Fuel Operating and Maintenance Costs, $000	50.5% Share of SGS Unit 1
Direct O&M[64]	$12,368
Coal Handling Facilities Allocation[65]	$3,682
Property Tax Unit 1 & Common	$922
Insurance Unit 1 & Common	$322
Total 2017 Non-Fuel Operating Costs	$17,294
Jurisdictional Allocated Non-Fuel O&M	$16,291

[64] These estimates excludes lime costs associated with the Springerville's flue gas desulfurization process. Lime costs and the associated sulfur credits are PPFAC eligible expenses and are not recovered in direct O&M. In addition, this direct O&M estimate includes approximately $700,000 in activated carbon injection costs associated with planned emission control upgrades on Unit 1.

[65] See the derivation of the monthly facilities charge for 50.5% of Springerville Unit 1 (approximately $307,000 per month) as described in the direct testimony of Company witness Kentton C. Grant.

Q. Why would it be appropriate to allow TEP to recover the non-fuel costs associated with the 50.5% share of Springerville Unit 1?

A. Springerville Unit 1 has significant value to TEP as a system resource due to its operating reliability, its location on the Company's transmission system and its ability to deliver power directly into the TEP load pocket, and its relatively low operating cost. Through the use of the Company's production cost model AuroraXMP, it is estimated that utilization of this capacity (195 MW) for the purpose of serving retail customers will reduce TEP's current PPFAC-eligible expenses by approximately $17.1 million in 2017.

Q. Does the TEP have an estimate of the total fuel and purchase power rate if the Company was allowed to recover the non-fuel O&M costs associated with the 50.5% share of Springerville Unit 1 in the PPFAC?

A. Yes. Since the requested non-fuel costs ($16.6 million) are estimated to be nearly the same as the projected fuel and purchased power savings ($17.1 million), very little impact on the Company's PPFAC rate is anticipated. As shown in Table 17 below, TEP's base cost of fuel and purchase power decreases by 0.0058 ¢/kWh, or approximately $525,000, in 2017 assuming recovery of both the fuel and non-fuel costs associated with the 50.5% share of Springerville Unit 1.

Table 17
2017 Comparison of the Base Cost of Fuel and Purchase Power

Base Cost of Fuel and Purchase Power, $000	2017
2017 Excluding 50.5% Share of Springerville Unit 1[66]	$302,564
2017 Including 50.5% Share of Springerville Unit 1[67]	$302,039
Decrease in Base Cost of Fuel & Purchase Power	-$525

TEP Electric Retail Sales, GWh	8,980
Decrease in Base Cost of Fuel & Purchase Power Rate, ¢/kWh	-0.0058

[66] This forecast assumes that the 50.5% share of Springerville Unit 1 was not dispatched for the purposes of TEP's retail customers. As a result, no costs or benefits are included in this projected 2017 base cost of fuel and purchase power estimate.
[67] See Footnote 40.

TEP's revised estimate of the base cost of fuel and purchase power rate is projected to be approximately 3.3634 ¢/kWh. The cost estimate in Table 18 below includes the incremental fuel and the estimated $17.3 million[68] in non-fuel O&M costs associated with dispatching the other 50.5% share of Springerville Unit 1 from January 1, 2017 through December 31, 2017.

Table 18
Projected Base Costs of Fuel and Purchase Power including the 50.5% Share of Springerville Unit 1

Base Cost of Fuel & Purchase Power	January 2017 - December 2017
Including 50.5% Share of Springerville Unit 1[69]	$302,039,000
TEP Electric Retail Sales, GWh	8,980
Base Cost of Fuel and Purchase Power Rate, ¢/kWh	3.3634

Forward Market Prices[70]	January 2017 - December 2017
Palo Verde (7x24) Market, $/MWh	$35.63
Permian Natural Gas, $/mmBtu	$ 3.57

Q. If TEP were to continue to dispatch this 50.5% share of Springerville Unit 1 on a longer-term basis, would the fuel and purchased power savings projected for 2017 be expected to continue?

A. Yes, and it is likely that future savings would be higher given today's historically low price estimates for natural gas and wholesale power, the two most significant costs avoided by TEP if this share of Springerville Unit 1 is dispatched to meet retail load.

[68] The 17.2 is based on the non-fuel O&M expenses shown in Table 16. These costs are estimated to be approximately $16.6 million in 2017 on a retail jurisdictional basis.
[69] This forecast assumes that the 50.5% share of Springerville Unit 1 is dispatched on behalf of TEP's retail customers and TEP is allowed to recover both the fuel costs and the $17.3 million in non-fuel operating and maintenance costs through its PPFAC.
[70] See Footnote 32.

Q. Why is the Company proposing to recover non-fuel costs associated with the co-owner share of Springerville Unit 1 through the PPFAC, instead of through non-fuel base rates?

A. Since it is unclear how long TEP will continue to have the ability to dispatch this capacity, it would be more appropriate to recover these costs through a variable PPFAC rate instead of through a fixed non-fuel rate.

Q. How would the recovery of these costs change if the 50.5% share of Springerville Unit 1 was no longer available to serve retail customer load?

A. If TEP was no longer able to dispatch this 50.5% share of Springerville Unit 1 as a system resource, the related fuel and operating costs would no longer be recoverable through the PPFAC. Additionally, to the extent that TEP is reimbursed by the co-owners for costs recovered through the PPFAC, the Company would credit such reimbursements to the PPFAC. The Company believes this is an appropriate approach, given the uncertain timing and outcome of the pending litigation with the co-owners.

Q. How does this situation with Springerville Unit 1 change TEP's resources plans?

A. While it is difficult to say with certainty, TEP has adequate time and flexibility within its resource planning and procurement processes to adjust its future resource plans to accommodate the range of outcomes around the co-owners 50.5% share of Springerville Unit 1. The Company continues to make its future resource decisions with these contingencies in mind. Once the status of the co-owner share of Springerville Unit 1 is resolved, the Company will submit as part of its next IRP[71] filing a plan that reflects the final outcome.

[71] Pursuant to Decision 75269 (September 16, 2015) in Docket No. E-00000V-15-0094, the 2016 Integrated Resource Plan timeline was modified to accommodate EPA's Clean Power Plan final rulemaking. As such, all Arizona load serving entities will need to file a preliminary resource plan by March 1, 2016 and a final resource plan by April 3, 2017.

XIV. PROCUREMENT COMMITMENTS FROM THE 2013 RATE CASE.

Q. Has TEP addressed the modifications to its energy procurement program that were set forth in the Settlement Agreement approved in Decision No. 73912?

A. Yes. In Section XI of the Settlement Agreement approved by Decision No. 73912, the Company agreed to adopt certain modifications its procurement program recommended by Staff. Those five modifications were set forth in Attachment H to the Settlement Agreement. Since the last rate case, the Company has addressed all five modifications.

Q. Can you summarize the five modifications set forth in Attachment H?

A. Those five modifications are as follows:

- H-1 TEP should prepare a complete natural gas hedging plan consistent with the requirements outlined in the TEP Hedging Manual.
- H-2 TEP should revise its hedging strategy for natural gas and power to reflect the fundamental changes in the energy markets.
- H-3 TEP should reduce the unit cost of coal in determining cost of coal in inventory by non-recurring costs and ash handling costs.
- H-4 TEP should add resources to the solid fuel group to develop additional support for current solid fuel activities.
- H-5 TEP should develop a plan to minimize the solid fuel cost consequences of any decisions to retire plants in response to regional haze requirements.

Q. Can you address how TEP complied with modification H-1?

A. Based on TEP's Hedging Policy,[72] the Company develops a compressive 36-month hedging plan ("Plan") based on TEP's forward looking projection of energy and capacity needs. The Plan is distributed to the Company's Risk Management Committee for approval in the fourth quarter of every year preceding the execution dates of the proposed three year Plan. On a quarterly basis, the Plan[73] is reviewed and any required changes are

[72] See Exhibit MES-3 (TEP Hedging Policy, August 2015-Confidential).docx.
[73] See Exhibit MES-4 (Energy Hedge Plan - September 2015-Confidential).xlsx.

managed and approved through the Risk Management Committee. TEP's Fuels Planning and Hedging department works directly with the Company's Resource Planning department to monitor forward looking natural gas prices, wholesale market fundamentals and the Company's resource plans to develop opportunities to reduce risk and procure fuel and purchase power at the lowest cost for its retail customers.

Q. Can you address how TEP complied with modification H-2?

A. TEP has made a number of improvements to its hedging strategy for both natural gas and purchase power, driven not only by the changes in wholesale energy markets and changing exposure in the Company's resource portfolio. Since the last rate case, TEP has ended the use of its hurricane season blackout period due to lower volatility provided by the natural gas industry's shift to horizontal onshore drilling. TEP has also expanded the use of day-ahead call options and costless collars in its current hedging plans and has increased the year-ahead hedge percentage target from 80% to 90%. The Company has also adjusted its hedging practices associated with the convergence of basis differential pricing in recent years as a result of natural gas supply surplus and lower price volatility in the Desert Southwest. Finally, TEP's hedging strategy was modified prior to 2015 to account for the planned coal capacity reductions at Springerville Unit 1 and Sundt Unit 4 as well as the increase in natural gas capacity associated with the acquisition of Gila River Unit 3 in December 2014.[74]

Q. Can you address how TEP complied with modification H-3?

A. TEP does not include non-recurring costs or ash handling costs in its determination of cost of coal in inventory. The cost of non-recurring items and ash handling are only

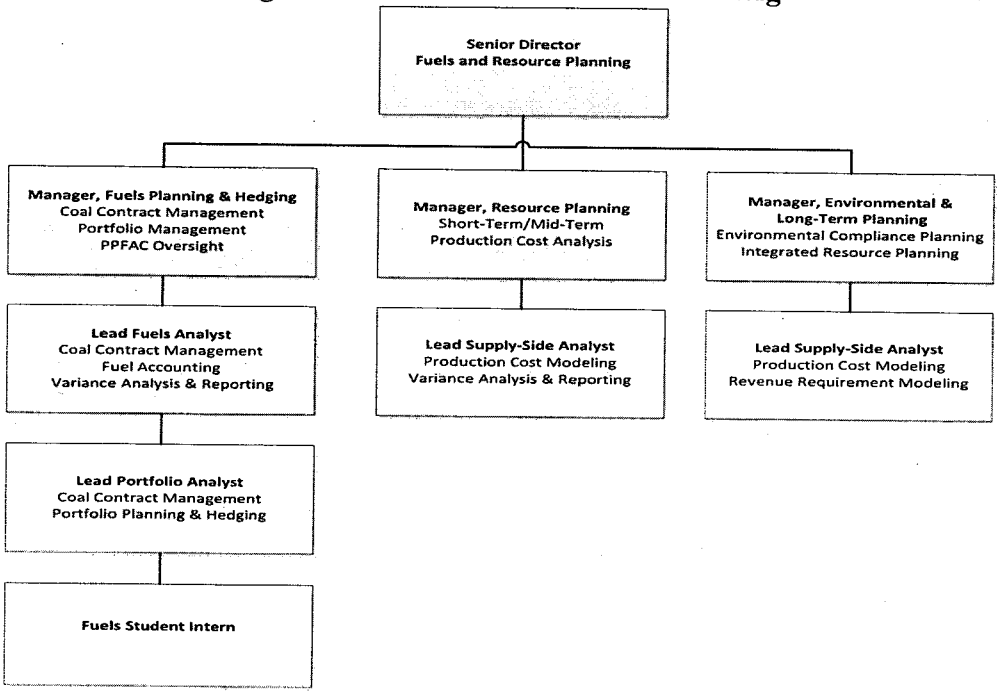
[74] In January 2015, TEP reduced its participation on Springerville Unit 1 from 387 MW to 192 MW and in August 2015, TEP permanently eliminated coal as a fuel source on Sundt Unit 4 (110 MW). Prior to these coal reduction commitments TEP acquired 413 MW of Gila River, Unit 3 (a natural gas combined cycle facility) in December 2014.

captured in the forecast for budget planning and dispatch purposes, but are not included in the cost of inventory.

Q. Can you address how TEP complied with modification H-4?

A. Since the last rate case, TEP has reorganized the Fuels and Resource Planning departments under a single member of senior management in order to better coordinate their efforts. Additionally, a member of the Environmental Compliance department was added to this group to enhance this aspect of the TEP's resource planning. The revised organization structure is shown in Figure 1 below. This group now coordinates the Company's short and long-term planning efforts around fuels management environmental compliance and portfolio hedging. In addition, TEP has increased the staffing levels of the Fuels department from two full-time employees to four full-time employees and a student intern. These changes in personnel have resulted in a more strategic focus on planning with an emphasis on the management of TEP's coal contracts, fuel accounting, and long term portfolio planning.

Figure 1 – Fuels and Resource Planning



Q. Can you address how TEP complied with modification H-5?

A. As part of TEP's reorganization with the Fuels department, TEP expanded its Resource Planning group to add a Manager of Environmental and Long-Term Planning. This new position added an additional layer of planning support directly associated with resource planning and environmental compliance. Currently, this position provides oversight in the company's environmental compliance strategies related to emission regulations under the NAAQS, Hazardous Air Pollutants Act, Regional Haze, CCR, and the Clean Power Plan. These compliance strategies are directly coordinated with the Fuels Hedging and Planning department under the reporting structure shown in Figure 1.

Q. Does this conclude your testimony?

A. Yes.

Exhibit MES-1

Tucson Electric Power Company
Purchased Power and Fuel Adjustment Clause
Plan of Administration

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1. GENERAL DESCRIPTION

This document describes the plan for administering the Purchased Power and Fuel Adjustment Clause ("PPFAC") the Arizona Corporation Commission ("Commission") approved for Tucson Electric Power Company ("TEP") in Decision No. 70628 (December 1, 2008) and amended by the Commission in Decision Nos. 73912 and Decision No. XXXXX.

The PPFAC described in this Plan of Administration ("POA") uses a historical twelve (12) month rolling average of actual fuel and purchased power costs to set the rate. This POA describes the application of the PPFAC.

2. DEFINITIONS

Applicable Interest - Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Applicable Twelve (12) Months – The historical 12-month period that ends two months prior to the monthly PPFAC rate change. For example, a January PPFAC rate is based on the 12 months ending November 30.

Base Cost of Fuel and Purchased Power - For each rate class it is an amount generally expressed as a rate per kilowatt-hour ("kWh"), which reflects the fuel and purchased power, and purchased transmission cost embedded in the base rates by class as approved by the Commission in TEP's most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes for each rate class.

Brokerage Fees – The costs attributable to the use of brokers recorded in Federal Energy Regulatory Commission ("FERC") Account 557.

Coal Additives or Adsorbents (FERC Account 502) – Chemicals such as calcium bromide, activated carbon, or amended silicates used in the removal of mercury for compliance under the MATS Rule.

Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by TEP to serve both Total Native Load Energy Sales and Short Term Sales. Transmission wheeling costs are also included.

Lime Costs (FERC Account 502) – The costs recorded for lime used to remove sulfur compounds formed during coal combustion.

Long Term Energy Sales - The portion of load from Total Native Load Energy Sales wholesale customers (currently Navajo Tribal Utility Authority, Tohono O'odham Utility Authority and TRICO) that is served by TEP, excluding the load served with Preference Power. New wholesale sales with a duration of one year or greater are also included.

MATS Rule - On December 21, 2011, EPA issued the final Mercury and Air Toxics Standards ("MATS Rule") establishing limits on emissions of mercury, acid gasses and non-mercury metals from coal-fired power plants. TEP's coal fired facilities will be subject to the MATS Rule starting April 1, 2016. TEP plans to comply with the MATS Rule with a combination of existing equipment, coal additives or adsorbents.

PPFAC - The Purchased Power and Fuel Adjustment Clause approved by the Commission in Decision No. 70628, and amended in Decision Nos. 73912 and XXXXX. The PPFAC rate tracks the changes in the cost of obtaining power supplies based upon a historical 12-month rolling average of fuel, purchased power, and purchased transmission costs. The PPFAC rate is adjusted monthly. The change in the PPFAC rate is banded, so the new monthly PPFAC rate cannot increase or decrease the Total Average Retail Fuel and Purchased Power Rate by more than 1% from the preceding month's rate, net of Wholesale Sales revenues, unless authorized by the Commission. Any over or under recovery of actual costs is recorded in the PPFAC bank balance. If the PPFAC bank balance becomes over collected by more than $30 million, TEP must file for a PPFAC rate adjustment within 45 days, or contact Staff to discuss why a PPFAC rate adjustment is not necessary at that time. If the PPFAC bank balance is under collected by more than $30 million, the Company has the right to file an application with the Commission requesting a surcharge adjustment.

Preference Power - Power allocated to TEP wholesale customers by federal power agencies such as the Western Area Power Administration.

Refined Coal Revenues – Revenues net of expenses, such as site license, refining premiums, and service fees, from the coal refining process as defined under Section 45 of the Internal Revenue Service Tax Code, and used in the production of steam generation for TEP's retail customers.

Retail Native Load Energy Sales – The portion of load from Total Native Load Energy Sales that serves TEP's retail customers located within the TEP control area.

Short Term Sales – Wholesale sales with durations of less than one year made to non-Native Load customers for the purpose of optimizing the TEP system, using TEP owned or contracted generation and purchased power.

Short Term Sales Revenue - The revenue recorded from wholesale sales with durations of less than one year made to non-Native Load customers, for the purpose of optimizing the TEP system, using TEP-owned or contracted generation and purchased power.

SO_2 Allowance Sales – The revenues related to the sale of SO_2 emission allowances, including gain on SO_2 allowance sales and auction proceeds net of Brokerage Fees paid.

Sulfur Credits – Credits received by TEP related to coal sulfur content that offset the cost of chemicals used to remove sulfur compounds formed during coal combustion.

Total Native Load Energy Sales – Retail Native Load Energy Sales and Long Term Energy Sales for which TEP has a generation service obligation.

Total Average Retail Fuel and Purchased Power Rate – The average base cost of fuel and purchased power ($0.0XXX per kWh) plus the appropriate PPFAC rate.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of TEP's electricity over transmission facilities owned by others.

Wholesale Trading Activity – Revenue recorded from realized wholesale trading profits.

3. PPFAC COMPONENTS

The PPFAC percentage rate (applied as a percentage of base fuel and purchased power rates) is calculated based upon a historical rolling average of fuel and purchased power costs during the Applicable 12-Month period. All revenues from Short-Term Off-System Sales and sales of renewable energy credits that do not flow through the Renewable Energy Standard Tariff will be credited against fuel and purchased power costs.

The PPFAC rate shall be reset monthly, beginning the second month new rates are in effect. For example, if new rates are effective January 1, 2017, the PPFAC rate will be 0% of the Average Base Rate in the month of January 2017 and a new PPFAC rate will be effective in February 2017 based on the Applicable 12-Month period ending December 31, 2016.

The new PPFAC rate will be effective with the first billing cycle of each month and will not be prorated. The change in the PPFAC rate is banded, so the new PPFAC rate for a month cannot increase or decrease the Total Average Retail Fuel and Purchased Power Rate by more than 1.0%. Any over or under recovery of actual costs is recorded in the PPFAC bank balance. The PPFAC rate shall be applied to the customer's bill as a monthly percentage adjustment that is the same for all customer classes.

Credits to the PPFAC

The following will be credited to the PPFAC:

1. All revenues from Short Term Sales;
2. Ten percent of the net positive margins realized by TEP during the PPFAC year on its Wholesale Trading Activities;
3. One hundred (100%) percent of the margins realized by TEP on SO_2 Allowance Sales (net of brokerage fees);
4. All Sulfur Credits received by TEP
5. The sale of renewable energy credits that do not flow through the Renewable Energy Standard Tariff;
6. Tax refunds related to costs that are recoverable through the PPFAC, net of outside professional expenses incurred in seeking refunds; and
7. Refined Coal Revenues.

4. BASE FUEL AND PURCHASED POWER RATE ANNUAL ADJUSTMENT

Each year, beginning with the monthly filing for January, 201X, TEP shall calculate the prior year's Base Cost of Fuel and Purchased Power Factor ("Base FPP Rate Factor") and the Base Fuel and Purchased Power Rate Adjuster ("Base FPP Rate Adjuster". The Base FPP Rate Factor shall be calculated by dividing the prior year's actual Retail Base Fuel and Purchased Power Rate collections by the Base Cost of Fuel and Purchased Power established according to Decision No. XXXXX. The FPP Base Rate Adjuster shall be calculated as [1 / Base FPP Rate Factor].

The Effective Base Fuel and Purchased Power Rate ("Effective Base FPP Rate") will be calculated by multiplying the Base Cost of Fuel and Purchased Power established in Decision No. XXXXX by the Base FPP Rate Adjustor. The Effective Base FPP Rate will be calculated annually and used to calculate the subsequent twelve months' PPFAC rate. For example, the monthly PPFAC filing January 2017 shall use the Effective Base FPP Rate calculated as the Base Cost of Fuel and Purchased Power in Decision No. XXXXX multiplied by the FPP Base Rate Adjustor calculated using actual retail Base Fuel and Purchase Power Revenues collected in from January 2016 through December 2016. Each January, actual retail fuel and purchased power revenues recovered through base rates during the prior 12 months will be used to calculate a new Base FPP Rate Factor, Base FPP Rate Adjustor and Effective Base FPP Rate. The example in Table 1 below illustrates the calculation.

Table 1 - Effective FPP Base Rate Calculation

		¢/kwh
Line 1	Actual Base FPP Rate January 2017 – December 2017	.036
Line 2	Average Base FPP Rate per Decision No. XXXXX	.040
Line 3	Base FPP Rate Factor (L1/L2)	.900
Line 4	Base FPP Rate Adjuster (1/L3)	1.111
Line 5	2018 Effective FPP Base Rate (L2 x L4)	.0444

The use of the Effective Base FPP Rate does not change the Base Fuel and Purchased Power Rate approved in Decision No. XXXXX, but serves to calibrate the Base Cost of Fuel and Purchased Power with actual collections from customers. The Base FPP Rate Factor illustrates the expected collections based on historical actual collections. Table 2 below illustrates the effect.

Table 2

2017 Load GWh	Average Base FPP Rate per Decision No. XXXXX ¢/kwh	Expected Collections $000s	Actual Collections $000s	Collected Base Rate ¢/kwh
9,900	.040	$320,000	$288,000	.036

2018 Load GWh	2018 Effective Base FPP Rate ¢/kwh	Expected Collections $000s	Actual Collections $000s	Collected Base Rate ¢/kwh
9,900	.0444	$320,000*	$320,000	.040

*Note: Actual Collections equal Expected Collections, and the original approved Base FPP Rate per Decision No. XXXX, by calculating [Effective Base FPP Rate x Base FPP Rate Factor x Base FPP Rate Adjustor]. The Base FPP Rate Factor is shown in Table 1 above.

5. ACCUMULATED PPFAC BANK BALANCE

TEP shall maintain and report monthly the accumulated PPFAC bank balance. The PPFAC bank balance shall reflect any over or under recovery of actual purchased power and fuel costs compared with the actual amounts recovered through the Base Fuel and Purchased Power and PPFAC rates.

6. VERIFICATION AND AUDIT

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent.

7. SCHEDULES

Samples of the following schedules are attached to this Plan of Administration:

Schedule 1 Total Average Retail Fuel & Purchased Power Rate Calculation
Schedule 2 Purchased Power and Fuel Rate Calculation
Schedule 3 Total Average Retail Fuel Account
Schedule 4 Base Fuel and Purchased Power Rate Factor Calculation

8. COMPLIANCE REPORTS

TEP shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A TEP Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief and that there have been no changes to the Allowable Costs recovered through the PPFAC without Commission approval. These monthly reports shall be due within 45 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PPFAC Rate Calculation (Schedule 1); Forward Component and True-Up Component Calculations (Schedules 2 and 4); Annual Forward Component and, True-Up Component Tracking Account Balances (Schedules 3 and 5). Additional information will provide other relative inputs and outputs such as:

    a. Total fuel and purchased power costs.
    b. Customer sales in both MWh and thousands of dollars by customer class.
    c. Number of customers by customer class.
    d. A detailed listing of all items excluded from the PPFAC calculations.
    e. A detailed listing of any adjustments to the adjustor reports.
    f. Total short term sales revenues.
    g. System losses in MWh.
    h. Monthly maximum retail demand in MW.
    i. SO_2 allowance sales.

2. Identification of a contact person and phone number from TEP for questions.

TEP shall also provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 45 days of the end of the reporting period. All of these additional reports must be provided confidentially.

A. Information for each generating unit will include the following items:
    1. Net generation, in MWh per month, and 12 months cumulatively.
    2. Average heat rate, both monthly and 12-month average.
    3. Equivalent forced-outage rate, both monthly and 12-month average.
    4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
    5. Total fuel costs per month.
    6. The fuel cost per kWh per month.

B. Information on power purchases will include the following items per seller (information on economy interchange purchases may be aggregated):
    1. The quantity purchased in MWh.
    2. The demand purchased in MW to the extent specified in the contract.
    3. The total cost for demand to the extent specified in the contract.

4. The total cost of energy.

C. Fuel purchase information shall include the following items:
   1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
   2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

D. TEP will also provide:
   1. Monthly projections for the next 12-month period showing estimated (over)/under collected amounts.
   2. A summary of unplanned outage costs by resource type.
   3. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.
   4. The data necessary to arrive at the Total Fuel and Purchase Power cost reflected in the non-confidential filing (Section 8.1.a).

In addition, TEP will prepare certain schedules and documents that will provide the necessary transparency of TEP's fuel and purchased power procurement activities such that the prudence of these activities can be determined and compliance with company procurement protocols can be confirmed.

Workpapers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate protective agreement. TEP will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC at any time. Any costs flowed through the PPFAC are subject to refund, if those costs are found to be imprudently incurred.

9. ALLOWABLE COSTS AND CREDITS

A. Accounts

The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

B. Other Allowable Costs/Credits

- Brokerage Fees recorded in FERC Account 557
- Lime costs recorded in FERC Account 502
- Sulfur credits recorded in FERC Account 502
- Chemical costs used to remove mercury and associated compounds resulting from the combustion of coal recorded in FERC Account 502
- Tax refunds related to costs that are recoverable through the PPFAC, net of outside professional expenses incurred in seeking refunds
- Refined Coal Revenues recorded in FERC Account 501

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

Other costs or credits are allowed with approval from the Commission in an Order.

Exhibit MES-2

Tucson Electric Power Company
Purchased Power and Fuel Adjustment Clause
January-17

Schedule 1	Total Average Retail Fuel and Purchased Power Rate Calculation Effective January 1, 2017 And Projected February 1, 2017
Schedule 2	PPFAC Rate Calculation Effective January 1, 2017 And Projected February 1, 2017
Schedule 3	Applicable 12 month Total Average Fuel Account - (Rate Effective January 1, 2017 And Projected February 1, 2017)
Schedule 4	Base Fuel and Purchased Power Rate Factor Calculation

Tucson Electric Power Company

Ray Robey (520) 745-3360
Manager, Fuels and Hedging

Tucson Electric Power Company
Schedule 1
Total Average Retail Fuel & Purchased Power Rate Calculation Effective January 1, 2017

Line No.	Total Average Retail Fuel and Purchased Power Rate Calculation	Current 1-Jan-17 [1]	Proposed 1-Feb-17
1	PPFAC % Rate (Sch. 2, L11) [1,4,5]	0%	0%
2	Surcharge/Credit % Rate [2, 4,5]	0%	0%
3	Total PPFAC % Rate [4,5] (L1+L2)	0%	0%
4	Average Base Rate[3]	$ -	$ -

Notes:

1 See XXXXX PPFAC Filing and ACC Decision No. XXXXX.

2 A Surcharge/Credit is a figure which may be added/subtracted from the PPFAC Rate should the the Accumulated Bank Balance become less than negative $30 million

3 Average Base Rate as determined in ACC Decision No. XXXXX through 12/31/2017 then uses Schedule 4, line 5 amount thereafter.

4 Negative value is PPFAC credit; positive value is PPFAC surcharge.

5 Calculation is percentage of Average Base Rate

A

Tucson Electric Power Company
Schedule 2
Purchased Power and Fuel Rate Calculation Effective January 1, 2017
($ in thousands)

Line No.	PPFAC Rate - Calculation	Current 1-January-17[1]	Proposed 1-Feb-17
1	Applicable 12 Months Fuel and Purchased Power Costs [1]	$ -	$ -
2	Applicable 12 Months Short Term Sales Revenue Credit [2]	$ -	$ -
3	Applicable 12 Months Net Fuel and Purchased Power Cost (L1 + L2)	$ -	$ -
4	Applicable 12 Months Total Native Load Energy Sales (MWhs)		
5	Calculated Total Average Retail Costs $/kWh (L3/L4)	$ -	$ -
6	Maximum total average retail cost rate3 ($/kWh for calculation)	$ -	$ -
7	Minimum total average retail cost rate[3] ($/kWh for calculation)	$ -	$ -
8	Calculated total average cost[3] ($/kWh for calculation)	$ -	$ -
9	Average Base Rate[3] (Sch 1, L4, $/kWh)	$ -	$ -
10	Eligible PPFAC collection calculation $/kWh (L8-L9) [3, 4]	$ -	$ -
11	PPFAC Rate to be billed as % of Base Rate (L10/L9) [3, 4]	0%	0%

Notes:

1 See XXXXX PPFAC Filing and ACC Decision No. XXXXX.
2 Short Term Sales revenues are credited at 100% as approved by the Commission in Decision No. XXXXX.
3 The amounts in "Proposed" column, Lines 6 and 7, will be limited to a +/- 1% change from the amount in the "Current" column, Line 8.
4 Negative value is PPFAC credit; positive value is PPFAC surcharge.

Schedule presentation will appear to roundup dollars and energy; however calculations are performed on an actual dollar and megawatt-hour basis with resultant rates/kWh rounded up to $0.000000/kWh

B

Tucson Electric Power Company
Schedule 3
Total Average Retail Fuel Account
($ in thousands; PPFAC and Base Rate in $/kWh)
(Negative value is over-collected, Positive value is under-collected)

Line			May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17
1	Prior Month Balance	(L15)											
1A	Beginning Balance Adjustment (if any)	(L15)											
1B	Adjusted Beginning Balance (if any)	(L15)											
Energy Sales													
2	Retail Native Load Energy Sales (MWh)												
2.5	Retail Native Load Energy Sales Less Community Solar Sales (MWh)												
3	Retail Native Load Energy Sales including losses (MWh) [1]												
4	Long Term Energy Sales (MWh)												
5	Long Term Energy Sales including losses (MWh) [2]												
6	Total Native Load Energy Sales (MWh)	(L2 + L4)											
7	Total Native Load Energy Sales including losses (MWh)	(L3 + L5)											
Fuel and Purchased Power Costs													
8	Fuel and Purchased Power Costs[3]												
9	Short Term Sales Revenue Credit[4]												
10	Wholesale Trading Activities Credit[5]												
11	SO_2 Allowance Sales Credit[6]												
12	Net Fuel and Purchased Power Costs	(Sum L8:L11)											
Total Retail Fuel and Purchased Power Recovery													
13	PPFAC Retail Power Supply Costs	(L3 /L7*L10)											
14	Applicable 12 Months Average Fuel Cost[7]												
(Over) / Under Collections and Accrued Interest													
15	(Over)/Under Collections	(L11 -L12)											
16	Interest[8]	L1*(L19 /12)											
17	**Bank Balance**	(L1 + L13 + L14)											
18	**Bank Balance Including True-Up**												
19	12-month Average Base Cost of Fuel & Purchased Power - $ per kWh												
20	Interest Rate (as of 1/1/2017) [7]												

1 Retail energy losses are the difference between billed retail energy sales and TEP's control area metered quantity.

2 Long Term Energy Sales losses calculated using applicable EHV loss percentage as defined in appropriate OATT.

3 Includes total native load and short term fuel and purchased power excluding mark-to-market accounting adjustments.

4 Includes Short Term Sales Revenue at 100% per ACC Decision No. XXXXX, excluding mark-to-market accounting adjustments.

5 10% of Wholesale Trading Activities net positive margins realized by TEP during the PPFAC year are credited annually against Fuel and Purchased Power Costs.

6 100% of SO_2 Allowance Sales credited against Fuel and Purchased Power Costs per Settlement Agreement in Docket No. E-01933A-12-0291.

7 Applicable 12 Months Avg Fuel Cost is rate which is eligible to be applied each month creating a change equal to or less than a 1% change in Total Retail Rate

8 Interest Rate (as of 1/1/2017) Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15 on the first business day of the calendar year

Schedule presentation will appear to roundup dollars and energy; however calculations are performed on an actual dollar and megawatt-hour basis with resultant rates/kWh rounded up to $0.000000/kWh

Line		Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
1	Prior Month Balance									
1A	Beginning Balance Adjustment (if any)									
1B	Adjusted Beginning Balance (if any)									
Energy Sales										
2	Retail Native Load Energy Sales (MWh)									
2.5	Retail Native Load Energy Sales Less Community Solar Sales (MWh)									
3	Retail Native Load Energy Sales including losses (MWh) [1]									
4	Long Term Energy Sales (MWh)									
5	Long Term Energy Sales including losses (MWh) [2]									
6	Total Native Load Energy Sales (MWh)									
7	Total Native Load Energy Sales including losses (MWh)									
Fuel and Purchased Power Costs										
8	Fuel and Purchased Power Costs[3]									
9	Short Term Sales Revenue Credit[4]									
10	Wholesale Trading Activities Credit[5]									
11	SO_2 Allowance Sales Credit[6]									
12	Net Fuel and Purchased Power Costs									
Total Retail Fuel and Purchased Power Recovery										
13	PPFAC Retail Power Supply Costs									
14	Applicable 12 Months Average Fuel Cost[7]									
(Over) / Under Collections and Accrued Interest										
15	(Over)/Under Collections									
16	Interest[8]									
17	**Bank Balance**									
18	**Bank Balance Including True-Up**									
19	12-month Average Base Cost of Fuel & Purchased Power - $ per kWh									
20	Interest Rate (as of 1/1/2017) [7]									

1 Retail energy losses are the difference between billed retail energy sales and TEP's control area metered quantity

2 Long Term Energy Sales losses calculated using applicable EHV loss percentage as defined in appropriate OATT

3 Includes total native load and short term fuel and purchased power excluding mark-to-market accounting adjustments

4 Includes Short Term Sales Revenue at 100% per ACC Decision No. XXXXX, excluding mark-to-market accounting adjustments

5 10% of Wholesale Trading Activities net positive margins realized by TEP during the PPFAC year are credited annually against Fuel and Purchased Power Costs

6 100% of SO_2 Allowance Sales credited against Fuel and Purchased Power Costs per Settlement Agreement in Docket No. E-01933A-12-0291

7 Applicable 12 Months Avg Fuel Cost is rate which is eligible to be applied eac

8 Interest Rate (as of 1/1/2017) Based on one-year Nominal Treasury Constant M

Schedule presentation will appear to roundup dollars and energy, however calculations are performed on an actual dollar and megawatt-hour basis with resultant rates/kWh rounded up to $0.000000/kWh

Tucson Electric Power Company
Schedule 4
Base Fuel and Purchased Power Rate Factor Calculation

Line No.	PPFAC Rate - Calculation	(cents per kWh)
1	Actual Base FPP Rate January 2017 – December 2017 (Actual collections divided by GWh load)	
2	Average Base FPP Rate approved in Decision No. XXXXX	
3	Base FPP Rate Factor (L1/L2)	
4	Base FPP Rate Adjustor (L1/L3)	
5	2018 Effective FPP Base Rate (L2 x L4)[1]	

Notes:

1 See XXXXX PPFAC Filing and ACC Decision No. XXXXX.

Schedule presentation will appear to roundup dollars and energy; however calculations are performed on an actual dollar and megawatt-hour basis with resultant rates/kWh rounded up to $0.000000/kWh

D

CONFIDENTIAL

Exhibit MES-3

THIS EXHIBIT CONTAINS CONFIDENTIAL AND/OR COMPETITIVELY SENSITIVE INFORMATION

CONFIDENTIAL

Exhibit MES-4

THIS EXHIBIT CONTAINS CONFIDENTIAL AND/OR COMPETITIVELY SENSITIVE INFORMATION

Exhibit MES-5

Tucson Electric Power Company
Purchased Power and Fuel Adjustment Clause
Plan of Administration

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1. GENERAL DESCRIPTION

This document describes the plan for administering the Purchased Power and Fuel Adjustment Clause ("PPFAC") the Arizona Corporation Commission ("Commission") approved for Tucson Electric Power Company ("TEP") in Decision No. 70628 (December 1, 2008) and amended by the Commission in Decision NoNos. 73912 (June 11, 2013). .and Decision No. XXXXX.

The PPFAC described in this Plan of Administration ("POA") uses a forward-looking estimatehistorical twelve (12) month rolling average of actual fuel and purchased power costs to set athe rate that is then reconciled to actual costs experienced. This POA describes the application of the PPFAC.

2. DEFINITIONS

Applicable Interest - Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Applicable Twelve (12) Months – The historical 12-month period that ends two months prior to the monthly PPFAC rate change. For example, a January PPFAC rate is based on the 12 months ending November 30.

Base Cost of Fuel and Purchased Power - AnFor each rate class it is an amount generally expressed as a rate per kilowatt-hour ("kWh;"), which reflects the fuel and purchased power, and purchased transmission cost embedded in the base rates by class as approved by the Commission in TEP's most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. 73912 set the base cost $0.032335 per kWh are effective on July 1, 2013. for each rate class.

Brokerage Fees – The costs attributable to the use of brokers recorded in Federal Energy Regulatory Commission ("FERC") Account 557.

Forward Component – An amount expressed as a rate per kWh charge that is updated annually on April 1 of each year and effective with the first billing cycle in April. The Forward Component for the PPFAC Year will adjust for the difference between the forecasted fuel and purchased power costs expressed as a rate per kWh less the Base Cost of Fuel and Purchase Power generally expressed as a rate per kWh embedded in TEP's base rates. The result of this calculation will equal the Forward Component, expressed as a rate per kWh.

Forward Component Tracking Account – An account that records on a monthly basis TEP's over/under recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PPFAC Year is, subject to periodic audit, reflected in the next True-Up Component calculation. TEP files the balances and supporting details underlying this Account with the Commission on a monthly basis via a monthly reporting requirement.

Coal Additives or Adsorbents (FERC Account 502) – Chemicals such as calcium bromide, activated carbon, or amended silicates used in the removal of mercury for compliance under the MATS Rule.

Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by TEP to serve both Total Native Load Energy Sales and Short Term Sales. ~~Wheeling~~Transmission wheeling costs are also included.

Lime Costs (FERC Account 502) – The costs recorded for lime used to remove sulfur compounds formed during coal combustion.

Long Term Energy Sales - The portion of load from Total Native Load Energy Sales wholesale customers (currently ~~Salt River Project~~Navajo Tribal Utility Authority, Tohono O'odham Utility Authority and ~~Navajo Tribal Utility Authority~~TRICO) that is served by TEP, excluding the load served with Preference Power. ~~Wholesale~~New wholesale sales with a duration of one year or greater are also included.

MATS Rule - On December 21, 2011, EPA issued the final Mercury and Air Toxics Standards ("MATS Rule") establishing limits on emissions of mercury, acid gasses and non-mercury metals from coal-fired power plants. TEP's coal fired facilities will be subject to the MATS Rule starting April 1, 2016. TEP plans to comply with the MATS Rule with a combination of existing equipment, coal additives or adsorbents.

PPFAC - The Purchased Power and Fuel Adjustment Clause approved by the Commission in Decision No. 70628, and amended ~~by the Commission~~ in Decision ~~No~~Nos. 73912~~, is a combination of two rate components that track~~ and XXXXX. The PPFAC rate tracks the changes in the cost of obtaining power supplies based upon ~~forward-looking estimates~~a historical 12-month rolling average of fuel ~~and~~, purchased power, and purchased transmission costs ~~that are eventually reconciled to~~. The PPFAC rate is adjusted monthly. The change in the PPFAC rate is banded, so the new monthly PPFAC rate cannot increase or decrease the Total Average Retail Fuel and Purchased Power Rate by more than 1% from the preceding month's rate, net of Wholesale Sales revenues, unless authorized by the Commission. Any over or under recovery of actual costs ~~experienced. This PPFAC also provides~~is recorded in the PPFAC bank balance. If the PPFAC bank balance becomes over collected by more than $30 million, TEP must file for a ~~reconciliation between actual and estimated costs of the last three months of estimated costs used in True-Up Component calculations.~~

~~PPFAC Year - A consecutive 12-month period beginning each April 1 and lasting through March 31 the following year~~PPFAC rate adjustment within 45 days, or contact Staff to discuss why a PPFAC rate adjustment is not necessary at that time. If the PPFAC bank balance is under collected by more than $30 million, the Company has the right to file an application with the Commission requesting a surcharge adjustment.

Preference Power - Power allocated to TEP wholesale customers by federal power agencies such as the Western Area Power Administration.

Refined Coal Revenues – Revenues net of expenses, such as site license, refining premiums, and service fees, from the coal refining process as defined under Section 45 of the Internal Revenue Service Tax Code, and used in the production of steam generation for TEP's retail customers.

Retail Native Load Energy Sales – The portion of load from Total Native Load Energy Sales that serves TEP's retail customers located within the TEP control area.

Short Term Sales – Wholesale sales with durations of less than one year made to non-Native Load customers for the purpose of optimizing the TEP system, using TEP owned or contracted generation and purchased power.

Short Term Sales Revenue - The revenue recorded from wholesale sales with durations of less than one year made to non-Native Load customers, for the purpose of optimizing the TEP system, using TEP-owned or contracted generation and purchased power.

SO_2 Allowance Sales – The revenues related to the sale of SO_2 emission allowances, including gain on SO_2 allowance sales and auction proceeds net of Brokerage Fees paid.

Sulfur Credits – Credits received by TEP related to coal sulfur content that offset the cost of chemicals used to remove sulfur compounds formed during coal combustion.

Total Native Load Energy Sales – Retail Native Load Energy Sales and Long Term Energy Sales for which TEP has a generation service obligation.

~~True-Up Component - An amount expressed as a rate per kWh charge that is updated annually on April 1 of each year and effective with the first billing cycle in April. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PPFAC Year tracking account balances to be refunded/collected from customers in the coming year's PPFAC rate.~~

~~True-Up Component Tracking Account - An account that records on a monthly basis the account balance to be collected or refunded via the True-Up Component rate as compared to the actual True-Up Component revenues, plus Applicable Interest; the balance of which at the close of the preceding PPFAC Year is, subject to periodic audit, then reflected in the next True-Up Component calculation. TEP files the balances and supporting details underlying this Account with the Commission on a monthly basis.~~

Total Average Retail Fuel and Purchased Power Rate – The average base cost of fuel and purchased power ($0.0XXX per kWh) plus the appropriate PPFAC rate.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of TEP's electricity over transmission facilities owned by others.

Wholesale Trading Activity – Revenue recorded from realized wholesale trading profits.

3. PPFAC COMPONENTS

The PPFAC ~~Rate will consist of two components designed to provide for the recovery of actual, prudently incurred~~ percentage rate (applied as a percentage of base fuel and purchased power ~~costs. Those components are:~~

~~1. The Forward Component, which recovers or refunds differences between expected PPFAC Year (each April 1 through March 31 period shall constitute a PPFAC Year)~~rates) is calculated based upon a historical rolling average of fuel and purchased power costs during the Applicable 12-Month period. All revenues from Short-Term Off-System Sales and sales of renewable energy credits that do not flow through the Renewable Energy Standard Tariff will be credited against fuel and purchased power costs ~~and those embedded in base rates.~~.

~~2. The True-Up Component, which tracks the differences between the PPFAC Year's actual fuel and purchased power costs and those costs recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PPFAC Year.~~

~~The PPFAC Year begins on April 1 and ends the following March 31.~~

~~On or before October 31 of each year, TEP will submit a PPFAC Rate filing, which shall include an estimate of the components for the following April's PPFAC rate. This filing shall be accompanied by supporting information as Staff determines to be required. TEP will update this filing on or before February 1 in order to replace estimated balances with actual balances, as explained below.~~

~~A. Forward Component Description~~

~~The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PPFAC Year that begins on April 1 and ends the following March 31. TEP will submit, on or before October 31 of each year, a forecast for the upcoming PPFAC year (April 1 through March 31) of its fuel and purchase power costs. It will also submit a forecast of kWh sales for the same PPFAC year, and divide the forecasted costs by the forecasted sales to produce the cents per kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.~~ The PPFAC rate shall be reset monthly, beginning the second month new rates are in effect. For example, if new rates are effective January 1, 2017, the PPFAC rate will be 0% of the Average Base Rate in the month of January 2017 and a new PPFAC rate will be effective in February 2017 based on the Applicable 12-Month period ending December 31, 2016.

The new PPFAC rate will be effective with the first billing cycle of each month and will not be prorated. The change in the PPFAC rate is banded, so the new PPFAC rate for a month cannot increase or decrease the Total Average Retail Fuel and Purchased Power Rate by more than 1.0%. Any over or under recovery of actual costs is recorded in the PPFAC bank balance. The PPFAC rate shall be applied to the customer's bill as a monthly percentage adjustment that is the same for all customer classes.

Credits to the PPFAC

The following will be credited to the PPFAC:

1. All revenues from Short Term Sales;
2. Ten percent of the net positive margins realized by TEP during the PPFAC year on its Wholesale Trading Activities;
3. One hundred (100%) percent of the margins realized by TEP on SO_2 Allowance Sales (net of brokerage fees);
4. All Sulfur Credits received by TEP~~; and~~
5. The sale of renewable energy credits that do not flow through the Renewable Energy Standard Tariff~~.~~;
6. Tax refunds related to costs that are recoverable through the PPFAC, net of outside professional expenses incurred in seeking refunds; and
7. Refined Coal Revenues.

4. BASE FUEL AND PURCHASED POWER RATE ANNUAL ADJUSTMENT

Each year, beginning with the monthly filing for January, 201X, TEP shall calculate the prior year's Base Cost of Fuel and Purchased Power Factor ("Base FPP Rate Factor") and the Base Fuel and Purchased Power Rate Adjuster ("Base FPP Rate Adjuster". The Base FPP Rate Factor shall be calculated by dividing the prior year's actual Retail Base Fuel and Purchased Power Rate collections by the Base Cost of Fuel and Purchased Power established according to Decision No. XXXXX. The FPP Base Rate Adjuster shall be calculated as [1 / Base FPP Rate Factor].

The Effective Base Fuel and Purchased Power Rate ("Effective Base FPP Rate") will be calculated by multiplying the Base Cost of Fuel and Purchased Power established in Decision No. XXXXX by the Base FPP Rate Adjustor. The Effective Base FPP Rate will be calculated annually and used to calculate the subsequent twelve months' PPFAC rate. For example, the monthly PPFAC filing January 2017 shall use the Effective Base FPP Rate calculated as the Base Cost of Fuel and Purchased Power in Decision No. XXXXX multiplied by the FPP Base Rate Adjustor calculated using actual retail Base Fuel and Purchase Power Revenues collected in from January 2016 through December 2016. Each January, actual retail fuel and purchased power revenues recovered through base rates during the prior 12 months will be used to calculate a new Base FPP Rate Factor, Base FPP Rate Adjustor and Effective Base FPP Rate. The example in Table 1 below illustrates the calculation.

Table 1 - Effective FPP Base Rate Calculation

		[redacted]
Line 1	Actual Base FPP Rate January 2017 – December 2017	.036
Line 2	Average Base FPP Rate per Decision No. XXXXX	.040
Line 3	Base FPP Rate Factor (L1/L2)	.900
Line 4	Base FPP Rate Adjuster (1/L3)	1.111

Line 5	2018 Effective FPP Base Rate (L2 x L4)	.0444

The use of the Effective Base FPP Rate does not change the Base Fuel and Purchased Power Rate approved in Decision No. XXXXX, but serves to calibrate the Base Cost of Fuel and Purchased Power with actual collections from customers. The Base FPP Rate Factor illustrates the expected collections based on historical actual collections. Table 2 below illustrates the effect.

Table 2

9,900	.040	$320,000	$288,000	.036

9,900	.0444	$320,000*	$320,000	.040

*Note: Actual Collections equal Expected Collections, and the original approved Base FPP Rate per Decision No. XXXX, by calculating [Effective Base FPP Rate x Base FPP Rate Factor x Base FPP Rate Adjustor]. The Base FPP Rate Factor is shown in Table 1 above.

5. ACCUMULATED PPFAC BANK BALANCE

TEP shall maintain and report monthly the ~~balances in a Forward Component Tracking Account, which will record TEP's~~ accumulated PPFAC bank balance. The PPFAC bank balance shall reflect any over~~/~~ or under-recovery of ~~its~~ actual ~~costs of fuel and~~ purchased power ~~as~~ and fuel costs compared ~~to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue. This Account will operate on a PPFAC Year basis (i.e. April 1 to the following March 31), and its balances will be used to administer this PPFAC's True-Up Component, which is described immediately below.~~

~~B. True-Up Component Description~~

~~The True-Up Component in any current PPFAC Year is intended to refund or recover the balance accumulated in the Forward Component Tracking Account (described above) during the previous PPFAC year. Also, any remaining balance from the True-Up Component Tracking Account as of March 31 would roll over into the True-Up Component for the coming PPFAC year starting April 1. The sum of projected Forward Component Tracking Account and True-Up Component Tracking Account balances on March 31 is divided by the forecasted PPFAC year kWh sales to determine the True-Up Component for the coming PPFAC year.~~

~~TEP shall maintain and report monthly the balances in a True-Up Component Tracking Account, which will reflect monthly collections or refunds under the True-Up Component and the~~ with the actual amounts ~~approved for use in calculating the True-Up Component.~~
recovered through the Base Fuel and Purchased Power and

~~Each annual TEP filing on October 31 will include an accumulation of Forward Component Tracking Account balances and True-Up Component Tracking Account balances for the preceding April through September and an estimate of the balances for October through March (the remaining six months of the current PPFAC Year). The TEP filing shall use these balances to calculate a preliminary True-Up Component for the coming PPFAC Year. On or before February 1, TEP will update the October filing. This update shall replace estimated monthly balances with those actual monthly balances that have become available since the October 31 filing.~~rates.

~~The October 31 filing's use of estimated balances for October through March (with supporting workpapers) is required to allow the PPFAC review process to begin in a way that will support its completion and a Commission decision before April 1. The February 1 updating will allow for the use of the most current balance information available before the PPFAC rate would go into effect. In addition to the February 1 update filing, TEP monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and True-Up Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected True-Up Component unit rate required for the next PPFAC Year.~~

~~The True-Up Component Tracking Account will measure the changes each month in the True-Up Component balance used to establish the current True-Up Component as a result of collections under the True-Up Component in effect. It will subtract each month's True-Up Component collections from the True-Up Component balance. The True-Up Component Account will also include Applicable Interest on any balances. TEP shall file the amounts and supporting calculations and workpapers for this account each month.~~

~~*4. CALCULATION OF THE PPFAC RATE*~~

~~The PPFAC rate is the sum of the two components: the Forward Component and the True-Up Component. The PPFAC rate shall be applied to customer bills. Upon Commission approval, the proposed PPFAC rate (as amended by the updated February 1 filing) shall go into effect on April 1. The PPFAC rate shall be applicable to TEP's retail electric rate schedules (except those specifically exempted) and is adjusted annually. The PPFAC Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.~~

~~The PPFAC rate shall be reset on April 1 of each year, and shall be effective with the first April billing cycle only after approved by the Commission. It is not prorated~~

~~*5. FILING AND PROCEDURAL DEADLINES*~~

~~A. October 31 Filing~~

~~TEP shall file the PPFAC rate with all Component calculations for the PPFAC year beginning on the next April 1, including all supporting data, with the Commission on or before October 31 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power~~

~~costs for the coming PPFAC year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the True-Up Component calculation for the year beginning on the next April 1, with all supporting data. That calculation will use the same forecast of sales used for the Forward Component calculation.~~

~~**B. February 1 Filing**~~

~~TEP will update the October 31 filing by February 1. This update will replace estimated Forward Component Tracking Account balances, and the True-Up Component Tracking Account balances, with actual balances and with more current estimates for those months (January, February and March) for which actual data are not available. The new PPFAC rate will go into effect on April 1 upon Commission approval.~~

~~**C. Additional Filings**~~

~~TEP will also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PPFAC.~~

~~**D. Review Process**~~

~~The Commission Staff and interested parties will have an opportunity to review the October 31 and February 1 forecast, balances, and supporting data on which the calculations of the two PPFAC components have been based. Any objections to the October 31 calculations must be filed within 45 days of the TEP filing. Any objections to the February 1 calculations must be filed within 15 days of the TEP filing.~~

6. VERIFICATION AND AUDIT

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. ~~Such adjustments, with appropriate interest, shall be recovered or refunded in the True-Up Component for the following year (i.e. starting the next April 1).~~

~~TEP agrees to pay the cost of biennial audits of its PPFAC by an outside auditor retained by the Commission.~~

7. SCHEDULES

Samples of the following schedules are attached to this Plan of Administration:

Schedule 1 ~~PPFAC~~Total Average Retail Fuel & Purchased Power Rate Calculation
Schedule 2 ~~PPFAC Forward Component~~Purchased Power and Fuel Rate Calculation
Schedule 3 ~~PPFAC Forward Component Tracking~~Total Average Retail Fuel Account
Schedule 4 ~~PPFAC True-Up Component~~Base Fuel and Purchased Power Rate Factor Calculation
~~Schedule 5 PPFAC True-Up Component Tracking Account~~

8. COMPLIANCE REPORTS

TEP shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A TEP Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief and that there have been no changes to the Allowable Costs recovered through the PPFAC without Commission approval. These monthly reports shall be due within 45 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PPFAC Rate Calculation (Schedule 1); Forward Component and True-Up Component Calculations (Schedules 2 and 4); Annual Forward Component and, True-Up Component Tracking Account Balances (Schedules 3 and 5). Additional information will provide other relative inputs and outputs such as:

    a. Total fuel and purchased power ~~and fuel~~ costs.
    b. Customer sales in both MWh and thousands of dollars by customer class.
    c. Number of customers by customer class.
    d. A detailed listing of all items excluded from the PPFAC calculations.
    e. A detailed listing of any adjustments to the adjustor reports.
    f. Total short term sales revenues.
    g. System losses in MWh.
    h. Monthly maximum retail demand in MW.
    i. SO_2 allowance sales.

2. Identification of a contact person and phone number from TEP for questions.

TEP shall also provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 45 days of the end of the reporting period. All of these additional reports must be provided confidentially.

A. Information for each generating unit will include the following items:
    1. Net generation, in MWh per month, and 12 months cumulatively.
    2. Average heat rate, both monthly and 12-month average.
    3. Equivalent forced-outage rate, both monthly and 12-month average.
    4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.

5. Total fuel costs per month.
6. The fuel cost per kWh per month.

B. Information on power purchases will include the following items per seller (information on economy interchange purchases may be aggregated):
   1. The quantity purchased in MWh.
   2. The demand purchased in MW to the extent specified in the contract.
   3. The total cost for demand to the extent specified in the contract.
   4. The total cost of energy.

C. Fuel purchase information shall include the following items:
   1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
   2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

D. TEP will also provide:
   1. Monthly projections for the next 12-month period showing estimated ~~(Over)/undercollected~~over)/under collected amounts.
   2. A summary of unplanned outage costs by resource type.
   3. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.
   4. The data necessary to arrive at the Total Fuel and Purchase Power cost reflected in the non-confidential filing (Section 8.1.a).

In addition, TEP will prepare certain schedules and documents that will provide the necessary transparency of TEP's fuel and purchased power procurement activities such that the prudence of these activities can be determined and compliance with company procurement protocols can be confirmed.

Workpapers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate protective agreement. TEP will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC at any time. Any costs flowed through the PPFAC are subject to refund, if those costs are found to be imprudently incurred.

9. ALLOWABLE COSTS AND CREDITS

A. Accounts

The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

B. Other Allowable Costs/Credits

- Brokerage Fees recorded in FERC Account 557
- Lime costs recorded in FERC Account 502
- Sulfur credits recorded in FERC Account 502
- Chemical costs used to remove mercury and associated compounds resulting from the combustion of coal recorded in FERC Account 502
- Tax refunds related to costs that are recoverable through the PPFAC, net of outside professional expenses incurred in seeking refunds
- Refined Coal Revenues recorded in FERC Account 501

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

~~No other~~Other costs or credits are allowed ~~without~~with approval from the Commission in an Order.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS 2016 RENEWABLE ENERGY STANDARD IMPLEMENTATION PLAN.	DOCKET NO. E-1933A-15-0239
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY 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 TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-15-0322

REBUTTAL TESTIMONY OF

MICHAEL E. SHEEHAN

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

EXHIBIT
TEP-25
ADMITTED

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Exhibit MES-R-1: Jurisdictional Allocation Demand Factor

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Exhibit MES-R-3: Resource Planning Timeline

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Michael E. Sheehan. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP" or the "Company").

Q. Which Commission Staff and/or Intervenor Testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses the testimony filed on behalf of the Commission Staff ("Staff"), Arizonans for Electric Choice and Competition ("AECC") and the Residential Utility Consumers Office ("RUCO") in the following subject areas:

- Update on TEP's Base Cost Fuel and Purchase Power
  - Staff Witness Michael J. McGarry, Sr.
- The Long-Term Value of Springerville Unit 1
  - Staff Witnesses Michael J. McGarry, Sr. and Donna H. Mullinax
- Revised Jurisdictional Allocation Proforma
  - RUCO Witness Frank W. Radigan
  - AECC Witness Kevin C. Higgins
- Useful Life Justification for San Juan Generation Station
  - RUCO Witness Frank W. Radigan

- Sierra Club Witness Patrick W. Luckow

- Useful Life Recommendations for TEP's Local Area Gas Generation Fleet
  - Staff Witness Roxie McCullar
- San Juan Retrofit versus Retirement Analysis
  - Sierra Club Witness Patrick W. Luckow

II. TEP's REVISED BASE COST OF FUEL AND PURCHASE POWER.

Q. Does the Company have an updated estimate on the average cost of fuel and purchase power for the timeframe that the proposed TEP rates are likely to go into effect?

A. Yes. As part of this rebuttal, TEP's Resource Planning group updated its long term production cost model AuroraXMP.[1] AuroraXMP is currently used for determining the forward projection for TEP's cost of fuel and purchase power. Based on the forecast of forward natural gas and wholesale power prices as of June 2016 prepared by the energy consulting firm Wood MacKenzie,[2] TEP now forecasts the average base rate of fuel and purchase power to be approximately 3.2559¢/kWh as compared to 3.3692¢ in the November 5, 2015 Application. The cost estimate in Table 1 below is based on a forecast of PPFAC eligible costs from January 1, 2017 through December 31, 2017.

[1] AuroraXMP, Power Generation Forecasting Software by EPIS, http://epis.com/.
[2] Wood MacKenzie, North America Gas Markets Short-Term Outlook (June 2016).

Table 1 – Revised 2017 Base Cost of Fuel and Purchase Power

	January 2017 - December 2017
Base Cost of Fuel and Purchase Power ($000)	$281,730
TEP Electric Retail Sales, GWh	8,653
Average Annual Cost, ¢/kWh	3.2559

Forward Market Prices	January 2017 - December 2017
Palo Verde (7x24) Market, $/MWh	$35.65
Permian Natural Gas, $/mmBtu	$ 3.58

Q. Did the Company make any PPFAC proforma adjustments to the base cost of fuel estimate?

A. Yes. In order to capture the PPFAC rate impacts from the curtailment of TEP's largest customer, the Company reduced its retail load forecast for 2017 based on this customer's actual production curtailment from 80 MW to 65 MW. As a result of this reduction in mining demand, the Company's revised 2017 retail forecast decreased approximately 327 GWh or 3.7% in total retail sales from the prior forecast of 8,980 GWh to 8,653 GWh.

Q. Does the base cost of fuel and purchase power estimate still assume recovery of the non-fuel related costs associated with the 50.5% co-ownership share of Springerville Generating Station ("SGS") Unit 1?

A. No. As described by Company witness Kentton C. Grant in his Rebuttal Testimony in response to concerns raised by Staff Witnesses Michael J. McGarry, Sr.[3] and Donna H. Mullinax,[4] as well as AECC witness Kevin C. Higgins,[5] the Company is now proposing

[3] Direct Revenue Testimony of Michael J. McGarry, Sr, page 12, lines 7 - 22 and page 13, lines 1 - 14.
[4] Direct Testimony of Donna H. Mullinax, page 36, lines 10 - 22.
[5] Direct Revenue Testimony of Kevin C. Higgins, page 14, lines 4 - 7.

to recover the $16.2 million of O&M, property taxes and fuel handling costs through non-fuel base rates. As a result of this change, the revised 2017 average base cost of fuel and purchase power shown in Table 1 above excludes all non-fuel related costs associated with the 50.5% co-ownership share of SGS Unit 1.

Q. Did the Company make any other proforma adjustments to the base cost of fuel estimate?

A. Yes. Consistent with the Company's initial rate filing, the estimate in Table 1 above includes a proforma adjustment that credits the margins associated with a firm wholesale sale agreement between TEP and Shell Energy North America[6] ("Shell Energy").[7] This proforma adjustment reflects the forecasted wholesale sale margins from this contract for 2017[8] and reduces the 2017 base cost of fuel and purchase power by approximately $2.8 million. Although this is a long-term wholesale contract, TEP is proposing this adjustment since less than one year will be remaining on the contract when new retail rates are proposed to be implemented.

III. TEP's COST RECOVERY JUSTIFICATION ON THE 50.5% CO-OWNERSHIP SHARE OF SGS UNIT 1.

Q. Has the Company prepared any economic analysis in support of its decision to acquire the 50.5% co-ownership share of SGS Unit 1?

A. Yes. As described by Company witness Kentton C. Grant in his Rebuttal Testimony in response to concerns raised by Staff Witness Donna H. Mullinax,[9] as well as AECC

[6] Direct Revenue Testimony of Kevin C. Higgins, page 34, lines 18 - 21 and page 35, lines 1 - 2.
[7] On December 12, 2014, the Company entered into a day-ahead index call option with Shell Energy North America. The term of this wholesale call option expires December 31, 2017.
[8] Wholesale sale margins equal revenues less the allocated cost of fuel and purchase power to serve this contract.
[9] Direct Testimony of Donna H. Mullinax, page 37, lines 4 - 10.

witness Kevin C. Higgins,[10] a thorough economic analysis was been prepared. In September 2015, the Company hired PACE Global[11] to conduct a long-term assessment of TEP's generation portfolio to evaluate whether the acquisition of the remaining 50.5% of the co-ownership share of SGS Unit 1 would be in the best interest of TEP's retail customers. [12]

Q. Can you provide an overview of the study conducted by PACE Global?

A. Yes. PACE Global conducted a comprehensive risk-based analysis that evaluated seven different resource expansion plans. Three of the expansion plans assumed that the 50.5% co-ownership share of Springerville Unit 1 was acquired in 2017 and remained in the TEP generation portfolio under varying service lives assumptions that reflected possible retirement dates of 2025, 2030 and 2045. The other three expansion plans assumed that Springerville Unit 1 was retired by 2020 and the capacity was replaced with a mix of natural gas and renewable resources. The natural gas resource alternatives consisted of existing merchant combined cycle plants ("NGCC"), new build NGCCs and new combustion turbines, while the renewable resources consisted of solar and wind projects sited within Arizona or New Mexico. Finally, the last expansion plan reflects the generation portfolio assumptions from the 2014 Integrated Resource Plan ("IRP") and serves as a comparison against all of the expansion plans within the PACE Global study.

Q. What customer objectives or metrics did PACE Global utilize in its analysis?

A. PACE Global focused its analysis on three key objectives: least cost, rate stability, and

[10] Direct Revenue Testimony of Kevin C. Higgins, page 14, lines 8 - 16.

[11] Pace Global, A Siemens Business, is a leading provider of strategic energy consulting services. Pace Global has provided consulting services to support the execution of business strategies, complex energy transactions, asset development, and operations focusing on select markets in the Americas. More information can be found at http://www.paceglobal.com/.

[12] The assessment assumes the acquisition of the non-owned capacity of SGS1 (195 MW) and operating the entire plant for longer periods of time than the defined alternatives, which retire 100% of the unit in 2020. Per the terms of the Settlement Agreement between Alterna Springerville LLC and LDVF1 TEP LLC, TEP assumes the cost of the non-owned portion of Springerville Unit 1 at $436/kW.

environmental compliance. PACE Global designed the portfolio analysis to evaluate the objectives based on the metrics referenced in Table 2 below:

Table 2 – PACE Global's Rate Payer Objectives and Metrics

Objective	Metric
Minimize Total Portfolio Cost	Net present value of the total revenue requirements of both fuel and non-fuel related costs ("NPVRR")
Manage Risks for Ratepayers and Achieve Stable Long-Term Power Costs	95th percentile of NPVRR
Achieve Environmental Compliance for CO_2 Emissions under the Clean Power Plan (CPP)	CO_2 emissions or emission rate credits from affected TEP-owned resources in comparison to CPP goals for Arizona

Q. Can you summarize some of the key conclusions from the PACE Global analysis and why the acquisition of the 50.5% co-ownership share of SGS Unit 1 is in the best interest of TEP's retail customers?

A. Yes. Below are some of the key conclusions from PACE Global's analysis regarding the acquisition of the 50.5% co-ownership share of SGS Unit 1. First, expansion plans that acquired the 50.5% co-ownership share of SGS Unit 1 reflected net present value revenue requirement outcomes that were lower by $326 million to $385 million relative to the expansion plans that retire SGS Unit 1 and replace the capacity with a combination of natural gas and renewable resources. Second, the option to preserve Springerville's coal capacity in the near-term and replace TEP's higher cost coal generation resources (e.g.,

San Juan) with a mix of natural gas and renewable resources in the longer term has value to TEP's rate payers. In terms of value, portfolios that retain SGS Unit 1 capacity longer perform better over the near term than those that retire it early and replace it with more natural gas capacity. Third, generation portfolios that retain the 50.5% co-ownership share of SGS Unit 1 maintained higher rate stability for TEP's retail customers due to reduced exposure to natural gas commodity risk and reduced commitments to other large capital investments in the near term. Finally, the acquisition of the 50.5% co-ownership share of SGS Unit 1 still allows TEP to meet compliance under the Final Rule of EPA's Clean Power Plan ("CPP"). [13]

Q. What impact would the acquisition have on the Company's long-term resource diversification strategy?

A. As shown in TEP's 2016 Preliminary IRP, the Company will have the option to divest all of its San Juan coal fired generation over the next several years. Additionally, the Company's will have the option to cease its participation in all of its jointly-owned coal units by 2031.[14] Consequently, TEP will still be able to substantially reduce its reliance on coal-fired resources even with the acquisition of the co-owner share of SGS Unit 1.

Q. How do SGS Units 1 and 2 compare to the other coal-fired resources owned by TEP?

A. The Springerville Generating Station is significantly more valuable for a number of reasons. First, SGS Units 1 and 2 are the Company's newest coal units,[15] they have rail

[13] On August 3, 2015 the Environmental Protection Agency ("EPA") issued its Final Rule - Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; 40 CFR Part 60. http://www.gpo.gov/fdsys/pkg/FR-2015-10-23/pdf/2015-22842.pdf

[14] TEP's 2016 Preliminary IRP shows TEP's viable exit date options for the San Juan Generation Station, Navajo Generating Station and the Four Corners Power Plant, page 12.

[15] The Springerville Generating Station is comprised of four units. Unit 1 went into service in 1985 and Unit 2 went into service in 1990 and is owned by TEP. Unit 3 went into service in 2006 and is owned by Tri-State Generation and Transmission. Unit 4 went into service in 2009 and is owned by the Salt River Project.

access to competitive coal supplies and the day to day operations of the facilities are managed by the Company's highly trained personnel.[16] Second, not only are SGS Units 1 and 2 TEP's lowest cost coal-fired resources on a dollar per kilowatt hour basis, but they are the Company's most reliable coal-fired resources.[17] Third, the Springerville Generating Station is located in a strategic spot on TEP's transmission system and supports a significant portion of the Company's ancillary service requirements. Finally, the Company believes that the continued operation of SGS provides TEP with a low cost, low risk coal resource that enables the Company to maintain a reasonable level of fuel diversification within its generation portfolio.[18]

IV. JURISDICTIONAL ALLOCATION DEMAND FACTOR.

Q. Is the Company now proposing to update its jurisdictional demand allocation calculation due to some of the concerns raised by RUCO[19] and AECC[20]?

A. Yes. The Company is now proposing pro forma adjustments that include a new long-term wholesale contract that was entered into with Navopache Electric Cooperative ("NEC") in September 2015, and reflect the recent curtailment of operations by TEP's largest retail mining customer. Consistent with the Company's initial rate filing, TEP has also excluded from the jurisdictional demand allocation two expiring long-term wholesale contracts with Salt River Project ("SRP") and Shell Energy.

[16] TEP currently employs over 440 employees at SGS and is the largest employer in Springerville, Arizona.
[17] In comparison to TEP's other coal-fired facilities, Springerville Units 1 & 2 have achieved the highest Equivalent Availability Factor in TEP's coal fleet based on the five year period from 2011 to 2015.
[18] TEP's 2016 Preliminary IRP shows the Company's energy portfolio in 2032 is comprised of 30% coal, 34% natural gas, 30% renewables and 6% purchase power. The retirement of SGS Units 1 and 2 would result in a disproportionate amount of energy sourced from natural gas, page 14.
[19] Direct Revenue Testimony of Frank W. Radigan, page 15, line 16 through page 17, line 2.
[20] Direct Revenue Testimony of Kevin C. Higgins, page 34, line 6 through page 36, line 10.

Q. Can you explain why the Company is proposing to exclude the SRP and Shell Energy contracts from this calculation?

A. TEP proposes to exclude the SRP contract because it expired on May 31, 2016. In addition, TEP proposes to exclude the Shell Energy contract because it will only be in effect for one year after rates are set in this rate case proceeding.

Q. Why does the Company feel that it is reasonable to exclude the Shell Energy Contract from the jurisdictional demand allocation in this rate case?

A. The exclusion of the Shell Energy contract from the jurisdictional demand allocation is reasonable for a number of reasons. The Shell Energy contact was put in place after the Company acquired 412 MW of capacity with the purchase of Gila River Unit 3.[21] The Shell Energy contract was intended to serve as a bridge to the anticipated retirement date of San Juan Unit 2 (December 31, 2017), and was expected to provide at least some recovery of non-fuel Gila River costs during this period.[22] Further, all the non-fuel costs associated with TEP's share of Gila River Unit 3 have been borne by TEP's shareholders since the purchase was closed in December 2014. During this same period Gila River Unit 3 has provided significant costs savings for TEP's retail customers through reductions in the PPFAC.[23] Finally, TEP is proposing to credit all of the wholesale revenues of approximately $8.4 million associated with the Shell Energy contract back to retail customers through the PPFAC during 2017. This adjustment is reflected in my updated cost of fuel and purchase power calculation shown above. In my view, this approach to the jurisdictional demand calculation provides for a more equitable allocation of the revenue requirements between the retail and the wholesale jurisdictions over the term that new retail rates will be in effect.

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[21] Direct Revenue Testimony of Frank W. Radigan, page 15, line 20.

[22] This timing reflects the same duration as the Shell Energy contract.

[23] Based on TEP's actual dispatch of Gila River Unit 3 since its acquisition in December 2014, TEP retail customers have avoided approximately $25.4 million in fuel and purchase power costs. See **Exhibit MES-R-2** attached to my Rebuttal Testimony.

Q. What wholesale demand allocator does the Company now propose?

A. Based on the pro forma adjustments described above, the Company is proposing to increase the wholesale demand allocation factor from 4.34% to 6.00%. **Exhibit MES-R-2** attached to my Rebuttal Testimony shows how this demand allocation was derived.

V. USEFUL LIFE JUSTIFICATION FOR SAN JUAN UNIT 1.

Q. Did any witnesses disagree with the Company's recommendation to use a remaining useful life of 2027 for San Juan Unit 1?

A. Yes. RUCO witness Frank W. Radigan recommends leaving the assumed San Juan Unit 1 retirement date at the previously established date of 2036.[24] In contrast, Sierra Club witness Patrick W. Luckow recommends an accelerated retirement date of 2022.[25]

Q. What is the basis for Mr. Radigan's recommendation?

A. Mr. Radigan states that there is insufficient evidence to support reducing the service life of San Juan Unit 1. Further, he argues that there is a case to be made that with the retirements of San Juan Units 2 and 3, the coal supply available for San Juan Units 1 and 4 could extend the life of the units beyond the Company's proposed retirement date of 2027.

Q. Do you agree with Mr. Radigan's position?

A. No. To say there is insufficient evidence to support a service life reduction is not in line with the reality facing many coal-fired generating plants today.[26] Historically, even older coal-fired generation resources maintained a competitive cost advantage over other

[24] Direct Revenue Testimony of Frank W. Radigan, page 18, line 10 - 11.
[25] Direct Testimony of Patrick W. Luckow, page 6, lines 2 - 7.
[26] As shown in the Company's 2016 IRP, TEP is on track to reduce 20% of its coal capacity by 2018.

generation resources due to the availability of low cost coal and less stringent environmental regulation. Today, higher environmental compliance costs, more stringent mining regulations, less favorable mine economics and increased plant maintenance costs and cheap natural gas have eliminated these cost advantages for a number of older coal-fired facilities throughout the country. In today's environment, for utilities like TEP with generation portfolios that have a disproportionate share of coal-fired generation, it is not unreasonable to expect strategically accelerated retirements for the "highest cost" coal-fired resources.[27]

Q. Is there other evidence in the public record that suggests that the economics of San Juan post 2022 are in question?

A. Yes. As part of the New Mexico Public Regulation Commission's ("NMPRC") Supplemental Stipulation for Public Service of New Mexico's ("PNM") request in its 2013 Certificate of Public Convenience and Necessity proceeding there were a number of questions related to the long-term economics of San Juan post 2022.[28] As a result of this uncertainty, the NMPRC ordered PNM to meet certain requirements related to its decisions on San Juan post 2022.

> After July 1, 2018, but no later than December 31, 2018, PNM shall make a filing with the Commission, and serve all parties to this case, to determine the extent to which SJGS should continue serving PNM's retail customers' needs after June 30, 2022. The filing shall be made before PNM has made a binding commitment to a post-2022 coal supply agreement, but after PNM has received firm pricing and other terms for the supply of coal at SJGS, unless PNM proposes not to pursue a coal

[27] "TEP is committed to follow through on its long-term portfolio diversification strategy to take advantage of other near-term opportunities to reduce its coal exposure at its higher cost TEP coal facilities." TEP's 2016 Preliminary IRP, page 12.

[28] Supplemental Stipulation filed on August 13, 2015. NMPRC Case No. 13-00390-UT.

supply post-2022. Under the assumption that SJGS does not continue to operate past 2022, PNM will issue an RFP as soon as practicable after the filing of the 2017 IRP that will request proposals for resources identified in the IRP as the most cost effective portfolio.

Q. You mentioned that unfavorable coal mine economics have eliminated cost advantages for a number of coal-fired facilities throughout the country. Can you explain?

A. Yes. As current long-term coal supply agreements expire, it is important to understand how the mine economics change going forward. If a mine operator must invest significant amounts of capital into development work in order to perform on a future coal supply agreement, the mine operator will require a long-term commitment from the plant owner in order to recover that investment. If the mine operator cannot obtain a long-term commitment, the miner would need to attempt to recover its investment over a shorter period, likely resulting in coal pricing that is not competitive relative to today's projected long-term natural gas prices.

Q. How do the mine economics play into San Juan's outlook on its coal supply going forward beyond June 2022?

A. To understand the mine economics at San Juan, it is important to consider the original San Juan Coal Company ("SJCC") mining plan that was developed in conjunction with the long-term coal supply agreement ("CSA") that was executed in 1980. Under that agreement SJCC was obligated to supply coal to all four units at San Juan through December 31, 2017. In addition, the San Juan Project Participant Agreement ("SJPPA") had a term through June 30, 2022. Based on those original agreements, it was expected that by the end of December 2017, the plant participants would need to determine if the mining operation would only continue through June 2022 or for some longer period of

time. Based on recent mining plan cost studies, mining plans that discontinued operations at the end of June 2022 would enable the plant participants to avoid significant investments at the mine prior to the June 2022 plant retirement. In the case where the plant participants wanted to extend the life of the mine beyond June 2022, the mine plan cost studies indicate that significant investments in mine development work would need to start as early as 2019 in order to avoid supply disruptions post June 2022.

Q. Mr. Radigan assumes that the early retirement of San Juan Units 2 and 3 at the end of 2017 could make coal available to extend the service life of San Juan Unit 1 beyond 2027. Is that a viable scenario?

A. No. As I explained above, the issue of determining the plant service life for San Juan Unit 1 is related to mine economics beyond June 2022. While the early retirements of San Juan Units 2 and 3 do provide some additional flexibility to extend the life of the mine, it was this flexibility that enabled the participants to negotiate a cost-effective coal supply extension ("Westmoreland CSA") with Westmoreland Coal Company ("Westmoreland") through June 2022.

Q. Can you explain how the early retirement of San Juan Units 2 and 3 enabled the participants to negotiate a cost-effective coal supply extension through June 2022?

A. Yes. It was not until the San Juan participants committed to retire Units 2 and 3 by the end of 2017 that the feasibility of obtaining a reasonably priced coal supply agreement through June 2022 became a viable option. This reduced demand for coal and the "harvest-mode" contract structure enabled Westmoreland to offer competitively priced coal for the next seven years while providing all the plant participants a commercially viable option to exit the San Juan project in June 2022.

Q. Given that all the San Juan Project Agreements, along with the Westmoreland CSA, have a term that expires on June 30, 2022, does the Company plan to continue to stay in the project post June 2022?

A. While the Company has not committed to exit the San Juan project at the end of June 2022, based on what we know today, the likelihood that TEP remains in the project beyond June 2022 is not high. It is anticipated that significant amounts of capital will need to be invested in development work by the mine operator as early as 2019 in order for the San Juan Generating Station to have adequate coal supplies under a two unit configuration post June 2022. Over the next two years, the plant participants plan to negotiate terms for a new coal supply extension with Westmoreland for operations post June 2022. By the end of 2018, TEP will determine if it intends to exit the project by June 30, 2022[29] or renegotiate new agreements with the remaining participants to extend operations of both the plant and the mine.

Q Are there other factors that would likely cause San Juan Unit 1 to be retired before 2036?

A. Yes. In addition to the future coal supply price uncertainty, San Juan Units 1 and 2 are TEP's highest cost coal-fired generating facilities on a dollar per megawatt-hour basis. This high cost profile along with the uncertainty related to future coal pricing, environmental compliance risk and low cost natural gas makes San Juan Unit 1 the next coal unit to be targeted for retirement within the TEP generation portfolio.[30]

Q Given that it is not a high probability outcome that TEP continues to stay in San Juan Unit 1 post 2022, what is your rationale for the 2027 retirement date?

A. While continued operations of San Juan Unit 1 for TEP post 2022 are not a high

[29] TEP may consider options that include changes in plant ownership shares, unit shutdowns or sale of generation assets to third parties. TEP's 2016 Preliminary IRP, page 12.
[30] Ibid

probability outcome, there may be a viable scenario where TEP's participation in the San Juan project goes beyond June 2022. As I mentioned above, as the plant participants work with Westmoreland to develop a mine extension plan post June 2022, there may be a scenario where the mine can competitively operate under a one unit configuration for a short period of time. It is this scenario that TEP uses as the basis for the 2027 retirement date for San Juan Unit 1. As the Company makes plans to diversify away from coal, it is appropriate from a rate making standpoint to make adjustments to the plant service lives as the likelihood of these accelerated plant retirements become more certain.

Q Does the Company agree with Patrick W. Luckow's recommended retirement date of 2022?

A. No. Rather than request to change the service life of San Juan Unit 1 to June 2022, the Company is taking an incremental approach in this rate case to change the service life from 2036 to 2027. Until TEP makes its final decision in 2018 regarding San Juan, the Company feels the 2027 retirement date provides a balanced approach that limits the near-term rate impacts on customers. It is contemplated that in TEP's next rate case, the Company will have a definitive retirement date set on San Juan Unit 1 and will propose a plant depreciation strategy[31] that is in the best interest of TEP's current and future customers.

[31] Given that the outcome around San Juan Unit 1 could result in a full unit retirement, a short-term extension or a sale of TEP's ownership share to a third-party, in the Company's next rate case, TEP would propose a recovery strategy that would limit the rate impact on its customers.

VI. USEFUL LIFE RECOMMENDATIONS FOR TEP'S LOCAL AREA NATURAL GAS RESOURCES.

Q. Have any witnesses recommended using different service lives for some of the units in the Company's local area natural gas fleet.

A. Yes. Rather than using the Company's proposed ten year life extension recommendations, Staff witness Roxie McCullar is recommending using a final retirement year of 2032 for Sundt Steam Units 1 and 2; North Loop CT Units 1, 2, and 3; and Sundt CT Units 1 and 2.[32] Table 3 below provide an overview of these resources.

Table 3 – TEP's Local Area Natural Gas Units

Generating Units	Unit Capacity (MW)	Retirement Date in Current Depreciation Rates	Company Proposed Retirement Year	Staff's Proposed Retirement Year
H.W Sundt 1	80	2018	2028	2032
H.W Sundt 2	80	2020	2030	2032
H.W Sundt 3	105	2022	2032	2032
H.W Sundt CT 1	25	2017	2027	2032
H.W Sundt CT 2	25	2017	2027	2032
North Loop CT 1	24	2017	2027	2032
North Loop CT 2	24	2017	2027	2032
North Loop CT 3	24	2017	2027	2032

[32] Direct Revenue Testimony of Roxie McCullar, page 8, line 8.

Q. What is the basis for Staff's recommendation?

A. Staff witness Roxie McCullar's testimony indicates that the 2032 retirement date is based on data taken from an exhibit contained in TEP's 2016 Preliminary IRP.[33] These values were taken from a section of the report based on the Company's preliminary loads and resource assessment.

Q. Does this preliminary IRP assessment represent the Company's expectations regarding the useful life of its local generating units listed in Table 3 above?

A. No. The 2016 IRP is a preliminary report. The Company plans to file a final report in April 2017 based on full assessment of its resource portfolio. As part of this final report the Company is evaluating the long-term viability of TEP's local area natural gas fleet. Based on work completed to date,[34] the Company is projecting a need for quick-start, fast ramping natural gas peaking units between 2022 and 2025 for the purpose of managing the operational challenges related to the integration of higher levels of renewable resources.[35] The 2017 Final IRP report will reflect TEP's anticipated retirement dates for these local area natural gas resources.

Q. Does TEP still propose using its recommended service life extension of ten years?

A. Yes. While it is possible that some of these local area resources could potentially still be in service in 2032, given our future resource needs and our transition away from coal to more efficient natural gas resources and renewables, it is more likely that at least 50% of these older less efficient local area natural gas resources will be retired and replaced with newer technologies by 2025.

[33] Table 5, Page 35 from TEP's 2016 Preliminary IRP Report.

[34] TEP is currently evaluating the possible retirement of some of its current local area resources with the replacement of new natural gas reciprocating engines ("RICE"). Information on RICE is presented on page 47 of the 2016 Preliminary IRP and an update on TEP's IRP plan was also presented at the 2016 IRP Workshop that was held at the Arizona Corporation Commission on June 18, 2016.

[35] https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf .

VII. SAN JUAN GENERATING STATION RETROFIT VERSUS RETIREMENT ANALYSIS.

Q. Did any witnesses raise any concerns regarding the Company's retrofit decisions on San Juan Unit 1?

A. Yes, Sierra Club Witness Patrick W. Luckow believes that TEP relied primarily on PNM's cost-benefit analysis rather than conduct its own detailed review in its retrofit decisions on San Juan Unit 1.[36]

Q. Is it true that the TEP relied on PNM's analysis related to the Company's retrofit decisions at San Juan?

A. No. The Company never relied on PNM's analysis related to the retrofit decisions on San Juan Unit 1. In fact, Mr. Luckow's testimony related to the PNM analysis has no relevance in this case, because the analysis he refers to is based on PNM's generation fleet and is completely unrelated to the resource decisions for TEP.

Q. Did the Company perform its own analysis related to the retrofit decisions on San Juan Unit 1?

A. Yes. Between July 2012 and the May of 2013, the Company analyzed in depth a series of options around the operations at the San Juan Generating Station ("SJGS"). These options included: 1.) the installation of selective catalytic reduction ("SCR") technology on all four SJGS units, 2.) the closure of all four units at SJGS by December 2017, or 3.) the retirement of two SJGS units and the installation of selective non-catalytic reduction ("SNCR") technology on the remaining two units.[37] Based on the Company's internal

[36] Direct Testimony of Patrick W. Luckow, page 15, lines 10 - 12.

[37] While the three scenarios described above describe the outcomes related to the entire station, TEP's internal analysis only considers the cost and benefits associated with its ownership share of Units 1 and 2.

analysis, it was determined that retiring Unit 2 and installing SNCR controls on Unit 1 ("SNCR Option") was $54 million to $63 million lower on a net-present-value basis versus a complete shutdown on both Units 1 & 2.

Q. In addition to being the least cost alternative at the time, what other factors went into the Company's position to proceed with the SNCR Option at SJGS?

A. The SNCR Option decision was made as part of TEP's overall portfolio strategy at the time. From a generation portfolio standpoint, a full shutdown of Units 1 and 2 at San Juan by 2017 was seen as a risky alternative given the uncertainty related to the potential early retirements at Four Corners Power Plant ("FCPP"), the Navajo Generating Station ("NGS"), and Unit 4 at the Sundt Generating Station as well as the potential loss of generation at the Springerville Generating Station ("SGS"). With approximately 950 MW of TEP's generation portfolio (43% of the Company's total resource capacity) at risk of near-term retirement, the Company made its decision in June 2013 to support the SNCR Option.[38]

Q. Does Mr. Luckow's suggestions that the Company should have re-evaluated its retrofit decisions on San Juan Unit 1 post 2013 have any merit?

A. No. Given the significant lead time necessary to engineer, procure equipment and construct the project, the company was required to commit to the retrofit decision on San Juan Unit 1 in October 2013. TEP's Engineering and Operating Committee vote in October 2013 to approve the SNCR Option contractually committed the Company to the retrofit project with spending on capital expenditures starting in late 2013. Any costs related to the SNCR Option in any subsequent resource planning decisions would have been considered a sunk cost.

[38] **Exhibit MES-R-3** attached to my Rebuttal Testimony summarizes this early retirement risk in further detail.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit MES – R – 1

TUCSON ELECTRIC POWER COMPANY
ACC/FERC JURISDICTION - DEMAND ALLOCATION FACTOR

As Filed

DEMAND ALLOCATON - 2015

Line No.	Date	Retail System Peak	SRP	NTUA	TOUA	Shell	Trico	Sub-Total FERC	Removes SRP & Shell	Total	Line No.	
		(a)	(b)	(c)	(d)	('e)	(f)	(g)	(h)	(i)		
1	June, 2015	2,206	100	41	5	100	50	296	96	2,302	1	
2	July, 2015	2,066	100	48	5	100	50	303	103	2,169	2	
3	August, 2015	2,214	100	40	5	100	50	295	95	2,309	3	
4	September, 2015	1,995	100	35	5	100	50	290	90	2,085	4	
5	Total	8,481						1,185	385	8,866	5	
6	Average (Line 5/ 4)	**2,120.25**							**96.2**	**2,216.5**	6	
7	Demand Allocation Factor (Line 6 - (a)/(i) and (h)/(i)	95.66%							4.34%		7	**100.00%**

Revised

DEMAND ALLOCATON - 2017

Line No.	Date	Retail System Peak	NEC	NTUA	TOUA	Shell	Trico	Sub-Total FERC	Removes Shell	Total	Line No.
		(a)	(b)	(c)	(d)	('e)	(f)	(g)	(h)	(i)	
1	June, 2017	2,131	41	48	4	100	50	243	143	2,274	1
2	July, 2017	2,309	44	53	4	100	50	251	151	2,460	2
3	August, 2017	2,258	33	52	4	100	50	239	139	2,397	3
4	September, 2017	2,060	34	39	3	100	50	226	126	2,186	4
5	Total	8,758						959	559	9,317	5
6	Average (Line 5/ 4)	**2,189.57**							**139.7**	**2,329.3**	6
7	Demand Allocation Factor	94.00%							6.00%		7

Demand Report
AuroraXMP
2017 Base Cost of Fuel Nominal | 7/8/2016 8:06:31 AM

Loads & Resource Summary, MW	1/1/2017	2/1/2017	3/1/2017	4/1/2017	5/1/2017	6/1/2017	7/1/2017	8/1/2017	9/1/2017	10/1/2017	11/1/2017	12/1/2017
Retail Demand (Metered Load)	1,218.0	1,300.0	1,176.0	1,284.0	1,730.0	1,990.0	2,150.0	2,109.0	1,928.0	1,527.0	1,200.0	1,268.0
Total Firm Wholesale	214.4	203.8	179.4	159.7	146.7	142.8	150.6	139.2	126.4	156.6	180.9	211.2
Reserve Requirements	214.9	225.6	203.3	216.6	281.5	319.9	345.1	337.2	308.2	252.5	207.1	221.9
Total Forward Sales	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Retail, Firm & Reserves	1,747.2	1,829.4	1,658.7	1,760.3	2,258.2	2,552.7	2,745.6	2,685.4	2,462.6	2,036.1	1,688.1	1,801.1
Total Thermal Generation	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	2,557.5	4,199.0
Total Firm Purchases	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	83.6	167.3
Total Fuel & Purchase Power	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	2,641.1	4,366.3
City Gate Peak Retail Demand	1,288.6	1,368.7	1,240.8	1,362.9	1,852.9	2,131.3	2,309.5	2,257.9	2,059.6	1,619.6	1,269.0	1,347.3

Sales Demand, MW	1/1/2017	2/1/2017	3/1/2017	4/1/2017	5/1/2017	6/1/2017	7/1/2017	8/1/2017	9/1/2017	10/1/2017	11/1/2017	12/1/2017
Retail Demand	1,218.0	1,300.0	1,176.0	1,284.0	1,730.0	1,990.0	2,150.0	2,109.0	1,928.0	1,527.0	1,200.0	1,268.0
Firm Wholesale												
Salt River Project	-	-	-	-	-	-	-	-	-	-	-	-
Navajo Tribal Utility Authority	82.8	80.0	60.1	53.8	44.5	47.9	52.7	52.0	39.4	51.4	67.3	82.8
Navopache Electric Cooperative	78.0	69.9	67.0	53.2	49.2	41.3	44.1	33.3	33.9	52.8	61.1	75.7
TRICO	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Shell Option Sale												
Tohono O'odham Utility Authority	3.6	3.9	2.3	2.7	2.9	3.6	3.8	3.8	3.1	2.4	2.5	2.7
Total Firm Wholesale	214.4	203.8	179.4	159.7	146.7	142.8	150.6	139.2	126.4	156.6	180.9	211.2
Reserve Requirements	214.9	225.6	203.3	216.6	281.5	319.9	345.1	337.2	308.2	252.5	207.1	221.9
Total Forward Sales	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Retail, Firm & Reserves	1,647.2	1,729.4	1,558.7	1,660.3	2,158.2	2,452.7	2,645.6	2,585.4	2,362.6	1,936.1	1,588.1	1,701.1
Distribution Loss	5.79%	5.29%	5.51%	6.15%	7.11%	7.10%	7.42%	7.06%	6.83%	6.06%	5.75%	6.25%

Exhibit MES – R – 2

Exhibit MES-R-2

Gila River Unit 3 Avoided PPFAC Cost Estimate

Based on Actuals through June 2016, Forecast through December 2016

2015 TEP Gila River - Unit 3	Jan-15	Feb-15	Mar-15	Apr-15	May-15	Jun-15	Jul-15	Aug-15	Sep-15	Oct-15	Nov-15	Dec-15	2015
1 Total Gila River Generation for TEP, MWh	133.1	104.5	27.0	140.3	124.2	145.7	176.8	167.7	161.9	72.1	169.8	219.1	1,642.3
2 Palo Verde ICE, On-Peak , $/MWh (1)	$27.44	$25.30	$28.60	$26.64	$27.58	$37.30	$37.02	$37.64	$33.67	$28.77	$23.05	$21.42	$29.53
3 Palo Verde ICE, Off-Peak, $/MWh (1)	$23.78	$23.15	$26.43	$20.49	$25.17	$25.60	$27.64	$26.91	$24.68	$23.50	$20.29	$19.03	$23.89
4 Market Value of Replacement Energy	$3,494	$2,593	$755	$3,438	$3,330	$4,870	$5,930	$5,605	$4,927	$1,857	$3,715	$4,462	44,977.1
5 Less Gila River Fuel Expenses	-$4,032	-$2,089	-$972	-$3,021	-$3,204	-$3,961	-$4,804	-$4,722	-$4,164	-$1,888	-$2,620	-$3,551	(39,028.5)
6 Avoided Energy Costs (2)	-$538	$504	-$217	$417	$126	$909	$1,126	$882	$763	-$31	$1,095	$911	5,948.6
7 Avoided Capacity Savings (3)	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	7,524.0
8 Total Deferred Savings (Line 4 + 5 + 7)	$89	$1,131	$410	$1,044	$753	$1,536	$1,753	$1,509	$1,390	$596	$1,722	$1,538	13,472.6
Cumulative Deferred Savings	$89	$1,220	$1,630	$2,674	$3,427	$4,962	$6,716	$8,225	$9,616	$10,212	$11,934	$13,473	

Notes:

1 Reflects the price from the Intercontinental Exchange (ICE) weighted based on Gila River dispatch

2 Capacity Purchases are $1.52 per kW/month

2016 TEP Gila River - Unit 3	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	2016
1 Total Gila River Generation for TEP, MWh	217.4	149.7	117.8	184.5	132.7	118.1	101.8	101.1	86.8	73.2	69.3	63.2	1,415.7
2 Palo Verde ICE, On-Peak , $/MWh (1)	$21.46	$18.60	$17.21	$20.67	$21.02	$35.28	$28.32	$29.96	$25.86	$26.33	$25.89	$26.84	$24.79
3 Palo Verde ICE, Off-Peak, $/MWh (1)	$19.50	$18.37	$13.38	$15.19	$17.27	$31.86	$17.44	$19.18	$17.61	$21.59	$21.69	$21.81	$19.57
4 Market Value of Replacement Energy	$4,478	$2,771	$1,849	$3,407	$2,628	$4,069							19,202.1
5 Less Gila River Fuel Expenses	-$3,950	-$2,427	-$1,624	-$3,301	-$3,055	-$3,408							(17,764.4)
6 Avoided Energy Costs (2)	$528	$345	$225	$106	-$427	$662	$399	$319	$544	$390	$592	$687	4,368.3
7 Avoided Capacity Savings (3)	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	$627	7,524.0
8 Total Deferred Savings (Line 4 + 5 + 7)	$1,155	$972	$852	$733	$200	$1,289	$1,026	$946	$1,171	$1,017	$1,219	$1,314	11,892.3
Cumulative Deferred Savings	$14,627	$15,599	$16,451	$17,184	$17,384	$18,672	$19,698	$20,644	$21,815	$22,832	$24,051	$25,365	

Notes:

1 Reflects the price from the Intercontinental Exchange (ICE) weighted based on Gila River dispatch

2 Capacity Purchases are $1.52 per kW/month

Exhibit MES – R – 3
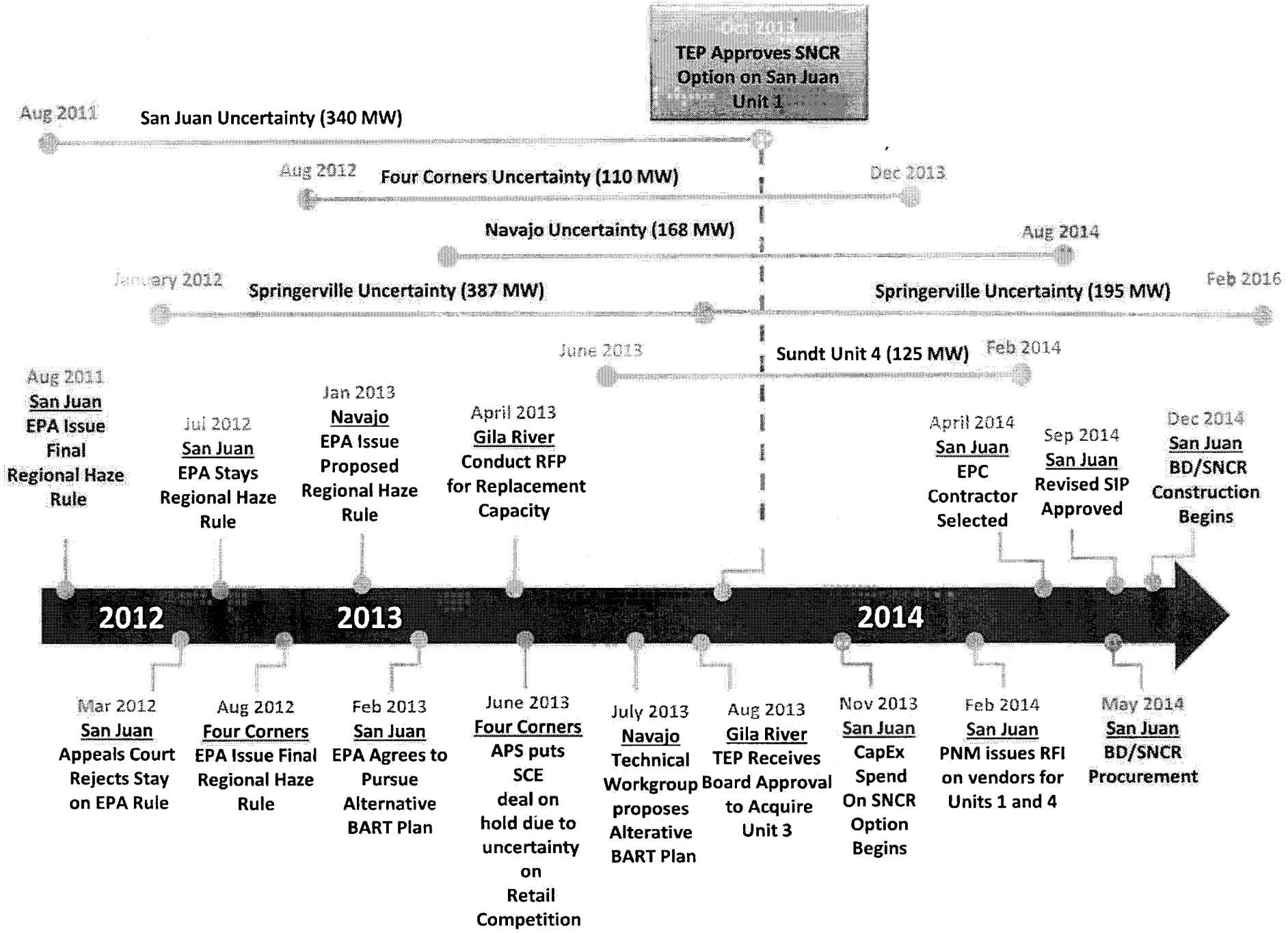
Exhibit MES-R-3