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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
NOV 5 2015
DOCKETED BY

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-15-0322

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TUCSON ELECTRIC POWER COMPANY

APPLICATION
TESTIMONY AND EXHIBITS

VOLUME 1 of 4

NOVEMBER 5, 2015

Application

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
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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-____ **APPLICATION**

Tucson Electric Power Company ("TEP" or "Company"), through undersigned counsel, and pursuant to A.R.S. §§ 40-250 and 40-251 and A.A.C. R14-2-103, hereby submits its Application for new rates to be effective no later than January 1, 2017. As proposed, the new rates are intended to result in an increase in non-fuel retail revenues of approximately $109.5 million, or approximately 12% over adjusted test year retail revenues. TEP's requested retail revenues represent an increase of approximately 7% over annualized revenue based on rates currently in effect, which includes a higher fuel cost component.

TEP is also seeking approval of: (i) critical modifications to its rate design and net metering tariff; (ii) modifications to its Purchased Power and Fuel Adjustment Clause mechanism ("PPFAC"), its Environmental Compliance Adjustor ("ECA") and Lost Fixed Cost Recovery mechanism ("LFCR"); (iii) updated depreciation rates; (iv) modifications to its Tariffs and Rules and Regulations; and (v) other related matters.

The significant updates to TEP's rate design and the proposed revenue requirement will result in the current average monthly bill for a typical TEP residential customer based on 1,150 kWh consumption in the summer and 785 kWh consumption in the winter to increase from $105.57 to $117.48 (an $11.91 increase).

The Company's request is fully supported by the testimony, exhibits, and schedules submitted concurrently with this Application.

I. OVERVIEW.

TEP's current rates were established in Decision No. 73912 (June 27, 2013), based on a test year ending December 31, 2011, with rates effective on July 1, 2013. As outlined below and as set forth in the supporting testimony, the Company is filing this rate case for several reasons. Over the three and a half years since the last test year, TEP has invested approximately $1.3 billion to maintain and improve service to its customers, to diversify its generation resource portfolio and to meet new environmental requirements. Changing customer usage patterns, declining use per customer and lower overall sales also have resulted in under-recovery of fixed cost revenues. Further, the current rate design and net metering policies, coupled with increased deployment of distributed generation and energy efficiency, have exacerbated inequities among customers in paying for the fixed costs of the grid.

Accordingly, TEP is filing this rate case to: (i) update and improve its rate design and tariffs to provide for more equitable allocation of its fixed costs to its customers; (ii) enable TEP to continue to provide safe and reliable service; (iii) provide the Company with an opportunity to recover its full cost of service, including an appropriate return on invested capital; (iv) maintain or improve its credit rating; and (v) obtain necessary approvals for the relief sought in its Application, all of which will benefit TEP and its customers.

A. Need for Increased Revenue.

Since its previous test year, TEP has invested approximately $1.3 billion to diversify its resource portfolio; maintain its existing generation fleet; upgrade, expand and reinforce its transmission and distribution plant systems; enhance customer service and leverage the use of technology throughout the Company. All of these investments contribute to the Company's ability to maintain and improve safe, reliable and economic electric service. For example, in December 2014, TEP acquired a 75% interest in Gila River Power Plant Unit 3 ("Gila River"), a 550 MW combined cycle gas-fired generation facility for approximately $164 million. Since the last test

year, TEP has also invested approximately $100 million in solar generating facilities. These investments reflect the significant steps the Company is taking to reduce its reliance on coal-fired generation and to build a cleaner, more diverse energy portfolio.

In addition to these capital expenditures, TEP has incurred increases in operating costs over the past three and a half years that were required to provide safe and reliable service to customers.

B. Need for Updated Rate Design.

TEP's test year retail sales are nearly 3% below the December 31, 2011 test year used in the Company's last rate case. Residential usage per customer fell nearly 7.5% between 2011 and the test year. The declining usage per customer and overall sales levels are due to several factors, including: (i) the effects of increased conservation, energy efficiency ("EE") and distributed generation ("DG"), and (ii) the slow pace of economic growth in the Tucson metropolitan area.

The effect of lower energy sales means that the Company must recover its increased fixed costs over fewer kilowatt-hours ("kWh") sales. Because the majority of the Company's fixed costs are currently recovered volumetrically on a per-kWh basis, lower electricity sales contributes to a significant under-recovery of costs over time, particularly as the Company's cost of service increases. The ability to recover fixed costs through volumetric rates is compounded by an inclining block rate structure – where more of the fixed costs are collected at higher usage levels. Although this historic rate design may have been appropriate in times of increasing customer usage and sales growth, as customer usage has declined, this approach has contributed to under-recovery of TEP's authorized revenue requirement. The current rate design also does not fit our customers' evolving use of the electric system; rather it is creating greater inequities in recovering fixed costs from TEP's customers, increasing the level of cross-subsidies between customers, and discouraging the use and deployment of new technologies.

Moreover, TEP has many residential and small general service customers with relatively low volumetric usage over the course of a year. However, there are times when these customers, such as seasonal residents and customers with rooftop PV systems, place significant energy

demands on TEP's system that the Company must be prepared to meet. As a result, customers with low annual usage, but average peak demand, are not paying an equitable share of the fixed costs to operate and maintain the TEP grid to which they are connected. Because of the volumetric rate design and the current net metering rules, a significant amount of fixed cost recovery must ultimately be shifted to other customers.

In addition to the fixed cost recoveries being shifted disproportionately to the customers who use higher volumes of electricity on a more regular basis, the Company is also suffering lost revenues because its LFCR is not designed to capture all of the lost fixed cost revenues associated with meeting the Commission's Renewable Energy Standard and Energy Efficiency Rules.

Therefore, the Company is proposing changes to its rate design to help ensure that all customers pay a more equitable share of the fixed, ongoing costs of providing safe and reliable service. TEP also is proposing to modify its net metering tariff to reduce the subsidies provided to net metered customers, which will also reduce future cost shifting. These proposed tariffs and rates will provide the Company with a better opportunity to recover its fixed costs and earn a reasonable return on its investment, as well as provide a more equitable allocation of costs among customers.

II. KEY ELEMENTS OF THE RATE CASE.

A. Revenue Requirement.

The Company is requesting a $109.5 million increase to test year adjusted non-fuel revenues. TEP's requested retail revenues represent an increase of approximately 7% over annualized revenue based on rates currently in effect, which includes a higher fuel cost component. As proposed, the average monthly bill for a typical TEP residential customer would increase from $105.57 to $117.48.

TEP's revenue requirement is based on a Fair Value Rate Base ("FVRB") of $2.91 billion, calculated using a traditional 50/50 weighting of Original Cost Rate Base ("OCRB") of $2.10 billion and a Replacement Cost New Less Depreciation ("RCND") rate base of $3.72 billion. The FVRB has increased by $645 million since TEP's last test year.

TEP proposes to use its actual capital structure, adjusted for recent long-term debt retirements, to determine the weighted average cost of capital ("WACC"). That capital structure consists of 50.03% common equity and 49.97% long-term debt.

TEP's cost of long-term debt is 4.32% and required cost of common equity is 10.35%. The Company's WACC, based on these cost rates and the test year capital structure, is 7.34%.

TEP is further proposing a fair value rate of return ("FVROR") of 5.69%. This FVROR is based on the methodology adopted by the Commission in several recent rate cases. The FVROR also reflects a lower return on the fair value increment of rate base than what TEP believes it could justify.

B. Rate Design.

TEP is proposing to continue its efforts to update and modernize its rate design. Through its proposals, the Company is seeking to better align rate design with cost causation and to reduce inter- and intra-class inequities. The proposed rate structure is intended to meet our customers' evolving use of the electric system, reduce the level of cross-subsidies among customers, encourage the use and deployment of new technologies, and improve the Company's ability to recover its fixed costs. The rate design will provide for a more equitable allocation of the cost of the TEP infrastructure that is the backbone of providing safe and reliable service to all of its customers.

The Company's rate design proposals include: (i) increased basic service charges for both residential and small commercial customers to assist in more equitable fixed cost recovery; (ii) a reduced number of volumetric rate tiers for residential customers; (iii) an optional three-part rate structure for residential and small commercial customers that includes a monthly service charge, a demand charge and a volumetric energy charge; and (iv) a mandatory three-part rate structure for partial requirements customers, including new users of solar arrays and other distributed generation equipment. In addition to these rate design proposals, TEP also is proposing modified large commercial rates and new interruptible rates.

C. New Tariffs.

In order to incent business development and retention in its service area, TEP is proposing an Economic Development Rate. This rate will provide discounted electricity rates to new or existing businesses that meet certain qualifications, such as job creation or minimum load requirements. Given the slow economic recovery in the Tucson area, this proposal provides another avenue to attract or expand business.

TEP also is proposing a Prepaid Service tariff that will provide another option for customers to manage their energy costs.

Further, in compliance with Decision No. 73912, the Company is proposing a high voltage service tariff that would be available to customers taking service at 138kV or higher.

Finally, in compliance with Decision No. 74689 (August 12, 2014), TEP is submitting a pilot program for a "buy through" tariff that, if approved, would be available to Large Power Service customers.

D. Net Metering Tariff.

The Company is proposing to modify its net metering rider.[1] The new net metering rider will modify how new net metered customers receive credit for excess energy that is generated by their DG system and delivered to TEP. The new rider would apply to net metered customers that submit applications for interconnection to TEP's grid facilities after June 1, 2015.[2]

Under the new rider:

- New net metered customers would pay the approved and applicable retail rate for all energy delivered by TEP. The applicable retail rates will be based on the proposed three-part rate design proposed by the Company; and
- New net metered customers would be compensated for any excess energy their DG system produces and delivers to TEP with bill credits calculated using the Renewable

[1] The modifications are the same as set forth in its application in Docket No. E-1933A-15-0100 (that application was withdrawn on June 16, 2015 and the withdrawal was approved in Decision No. 75224 (August 26, 2015)).

[2] TEP customers have been and will continue to be notified of proposed modifications to the net metering tariff through a disclaimer in its interconnection materials.

Credit Rate (which is a rate that reflects the current cost of utility-scale solar energy tied to the distribution system). Besides mitigating the cost shift, this approach also is intended to result in TEP and its customers not overpaying for renewable energy. New net metered customers also will be allowed to carry over unused bill credits to future months if they exceed the amount of their current TEP bill.

E. Adjustors.

TEP is proposing modifications to its PPFAC, its ECA and its LFCR. With respect to the PPFAC, TEP is requesting a number of modifications that will smooth out the PPFAC rate changes and more closely align the PPFAC with individual customers' base fuel rate. The changes include modifying the PPFAC rate to adjust monthly based on a historic 12-month rolling average (as compared to changing the PPFAC rate once a year). In addition, the Company is proposing that the PPFAC rate be calculated as a percentage of a customer's base fuel rate, rather than as a single per kilowatt hour (kWh) energy rate that is applied to all customers. This approach will more fairly align the changes in fuel costs with each rate class' base fuel costs.

With respect to its ECA, TEP proposes to modify the ECA by: (i) increasing the cap on annual recovery through the ECA to help smooth the rate impacts of compliance with new environmental regulations and (ii) converting the cap to a percentage based cap, which will allow for more equitable recovery from all classes.

With respect to the LFCR, TEP proposes to modify the LFCR to include recovery of fixed generation costs and 100% of non-generation demand charges (instead of the current 50%), as well as increasing the annual recovery cap from 1% to 2% of total revenues. The proposed changes will better address the impacts of the continuing expansion of distributed generation and mandated energy efficiency programs and mitigate the erosion of revenues experienced under TEP's currents rates.

F. Springerville Generating Station.

Since TEP's last rate case, there have been significant changes with respect to its interest in the Springerville Generating Station ("SGS") and TEP's rates should reflect these changes. In

December 2014 and January 2015, TEP purchased leased interests in SGS Unit 1 totaling 35.4% for an aggregate purchase price of $65 million; these purchases brought TEP's total ownership interest in the unit to 49.5%. Prior to January 1, 2015, TEP leased 100% of SGS Unit 1 and owned an equity interest in one of the leases covering a 14% share of the unit. The Company's rate application removes the lease costs from TEP's revenue requirement and includes adjustments to rate base and operating expenses to reflect the Company's 49.5% ownership interest in SGS Unit 1. In April 2015, TEP also purchased the SGS coal handling facilities at the end of the lease for those facilities. The purchase price paid was $120 million. Accordingly, the Company's rate application removes the lease costs from TEP's revenue requirement and includes adjustments to rate base and operating expenses to reflect the Company's ownership interest in the coal handling facilities. TEP is also seeking other approvals related to changes at the SGS, including an extended recovery period for leasehold improvements made to SGS common facilities, as well as recovery of operating costs through TEP's PPFAC for energy dispatched from the 50.5% co-owner share of SGS Unit 1, to the extent that capacity is available to meet retail customer needs.

G. Depreciation Rates.

TEP is proposing new depreciation rates based on an updated depreciation study. The updated depreciation rates would modify the depreciation rates approved by the Commission in Decision No. 73912.

H. Rules and Regulations.

The Company is proposing modifications to its Rules and Regulations and to its Tariffs. These modifications are intended to modernize TEP's Rules and Regulations and to clarify areas in the Rules and Regulations that have caused undue confusion.

III. APPLICATION.

In support of this Application, TEP respectfully states as follows:

A. The Company is a corporation duly organized, existing and in good standing under the laws of the State of Arizona. Its principal place of business is 88 East Broadway Boulevard, Tucson, Arizona 85701

B. The Company is a public service corporation principally engaged in the generation, transmission and distribution of electricity for sale in Arizona pursuant to Certificates of Convenience and Necessity issued by the Commission.

C. All communications and correspondence concerning this Application, as well as communications and pleadings with respect thereto filed by other parties, should be served upon the following:

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D. The Commission has jurisdiction to conduct public hearings to determine the fair value of the property of a public service corporation, to fix a just and reasonable rate of return thereon, and thereafter, to approve rate schedules designed to develop such return. Further, the Commission has jurisdiction to establish the practices and procedures to govern the conduct of

such hearing, including, but not limited to, such matters as notice, intervention, filing, service, exhibits, discovery, and other prehearing and hearing matters.

E. Accompanying this Application are the standard filing requirements and rate design schedules described in A.A.C. R14-2-103. The Company also provides pre-filed direct testimonies and related exhibits from the following witnesses for TEP supporting the requests made within the Application and schedules:

David Hutchens:	Overview of TEP's rate application and primary proposals, including the need for the modified rate design.
Susan Gray:	Overview of TEP's operations.
Michael Sheehan:	Overview of TEP's generation portfolio and planning; acquisition of Gila River; certain modifications to PPFAC.
Carmine Tilghman:	Scope and impact of the deployment of distributed generation in the TEP service area; utility scale solar facilities.
Kentton Grant:	Overview of TEP's financial condition; capital structure; cost of debt; WACC; cost of credit support for fuel and purchased power procurement; cost of the SGS common facilities lease, end-of-lease purchases of SGS Unit 1 and the SGS coal handling facilities; and the status of the co-owner share of SGS Unit 1.
Ann Bulkley:	Cost of equity; fair value rate base; and fair value rate of return.
Dr. Ron White:	Depreciation methodology and rates.
Frank Marino:	Regulatory treatment of certain coal assets; income tax and property tax; revenue requirement, including rate base, income and expense adjustments.
Dallas Dukes:	Revenue requirement, including income and expense adjustments; rate base and income statement pro forma adjustments; post-test

year plant adjustments; Reconstructed Cost New Less Depreciation (RCND); depreciation expense; proposed rate design.

Craig Jones: Cost of service study; proposed rate design; revisions to the base cost of fuel and purchase power; modifications to the cost recovery mechanisms; and revisions to tariffs.

Denise Smith: Revisions to TEP's Rules and Regulations; customer satisfaction initiatives and customer assistance programs; compliance waivers.

F. TEP respectfully requests that this Commission set a date for a hearing on this Application in Tucson, Arizona, such that new rates for the Company will become effective no later than January 1, 2017. At the hearing conducted pursuant to this rate request, TEP will establish, among other things, that:

(1) its current rates and charges do not permit the Company to earn a fair return on the fair value of its assets devoted to public service, and that as a result, its current rates and charges are not just and reasonable;

(2) the requested revenue increase is the minimum amount necessary to allow the Company an opportunity to earn a fair return on the fair value of its assets devoted to public service, for preservation of the Company's financial integrity and for the attraction of new capital on reasonable terms, and is in the public interest;

(3) the Company's revenue request is reasonable and necessary for the Company to continue to provide adequate and reliable electric service to its customers as required by law, and is in the public interest;

(4) including post-test year plant that will be in service by December 31, 2015 in rate base is in the public interest;

(5) modifying the Company's PPFAC to allow for recovery of additional costs and to more equitably allocate PPFAC rates is in the public interest;

(6) the proposed modifications to the LFCR will improve and more equitably allocate recovery of lost fixed cost revenues resulting from DG, net metering and EE programs is in the public interest;

(7) the proposed modifications to the ECA to allow it to continue to address the need to timely recover significant investment in pollution control and other facilities to respond to government mandates for environment standards, and is in the public interest;

(8) the proposed rate design will better align the fixed and variable costs of service with the rates paid by the customers causing those costs and is in the public interest

(9) the proposed Net Metering Tariff and related waiver of the Commission's Net Metering Rules provides for a more equitable allocation of fixed costs among customers, and is in the public interest;

(10) the proposed revisions to the Company's Tariff, Rules and Regulations and certain compliance requirements are in the public interest; and

(11) the proposed treatment of the SGS, H. Wilson Sundt Generating Station ("Sundt"), and San Juan Generating Station ("San Juan") is in the public interest.

G. In addition to setting a hearing date, TEP asks that the Commission issue a procedural order setting forth the prescribed public notice for the Application, establishing procedures for intervention, and providing for appropriate discovery. TEP further requests that the Company be authorized to serve all discovery requests, answers and objections electronically. Finally, TEP requests that a procedural schedule be established so that a final order in this case can be rendered and new rates can be effective by January 1, 2017.

WHEREFORE, TEP respectfully requests that the Commission issue an order:

(1) establishing a date for hearing evidence concerning the Application, prescribing the time and form of public notice to TEP customers, establishing procedures for intervention and discovery as described above;

(2) finding and concluding that the Company's rate application is just and reasonable and granting new rates that result in an increase in retail revenues of approximately $109.5 million to allow it to recover its expenses and a reasonable opportunity to earn its authorized rate of return on its investment;

(3) approving the tariffs (including any related waivers) and statement of charges included with the Company's Application with an effective date no later than January 1, 2017;

(4) approving the Company's proposed revisions to its Purchased Power and Fuel Adjustment Clause;

(5) approving the Company's proposed revisions to its Lost Fixed Cost Recovery Mechanism;

(6) approving the Company's proposed revisions to its Environmental Compliance Adjustor;

(7) approving the Company's proposed Net Metering Tariff and granting a related waiver of A.A.C R14-2-2301 et seq.;

(8) approving the Company's proposed depreciation rates as set forth in Dr. White's testimony;

(9) approving the Company's proposed rate and regulatory treatment of SGS, Sundt, and San Juan generation assets;

(10) approving the Company's revised Rules and Regulations and modified compliance requirements; and

(11) granting the Company such additional relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 5th day of November 2015.

TUCSON ELECTRIC POWER COMPANY

By _____

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By Jaclyn Howard

Direct Testimony of

David G. Hutchens

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
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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

David G. Hutchens

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. My name is David G. Hutchens. 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 President and Chief Executive Officer of TEP as well as for UNS Energy Corporation ("UNS Energy"), UniSource Energy Services ("UES"), UNS Electric, Inc. ("UNS Electric"), and UNS Gas, Inc. ("UNS Gas").

Q. Please describe your background and work experience.

A. I received a Bachelor of Science degree in Aerospace Engineering from the University of Arizona in 1988 and a Master of Business Administration degree from the University of Arizona's Eller Graduate School of Management in 1999.

I was commissioned into the United States Navy in 1988 and served as a Nuclear-Trained Submarine Line Officer until 1993.

I was hired by TEP in 1995 as an Analyst in Product Planning and Development. In 1996, I moved into TEP's Wholesale Marketing Department as an Energy Marketer/Trader. I was promoted to Supervisor of the area in 1999, Manager in 2001, and General Manager in 2003. I was promoted to Vice President of Wholesale Energy and of UNS Gas, Inc. ("UNS Gas") in 2007 and to Vice President of Energy Efficiency and Resource Planning in 2009. In 2011, I was promoted to Executive Vice President of UNS Energy and TEP; in December 2011, I was promoted to President of UNS Energy

and TEP. In 2014, I was promoted to my current position of President and Chief Executive Officer of UNS Energy, TEP and UES.

Q. What is the purpose of your Direct Testimony?

A. My testimony covers the following topics:

- A summary of the challenges facing our business.
- A summary of TEP's rate request.
- TEP's resource diversification strategy including: the importance of the Company's acquisition of 75% of Gila River Power Plant Unit 3 ("Gila River") and reasons why the facility should be placed in rate base; and an overview of the Environmental Protection Agency's Clean Power Plan.
- Springerville Generating Station Unit 1 ("SGS Unit 1") lease expiration and TEP's purchase of a partial ownership interest.
- Rate changes designed to (i) more closely reflect the cost of all services customers receive from the electric system, (ii) mitigate the cost shift between and within classes of customers, (iii) provide the Company with recovery of its fixed infrastructure costs, and (iv) provide the Company with an opportunity to earn its authorized rate of return.
- A new rate aimed at promoting economic development in TEP's service territory.
- An overview of the Company's capital expenditures since its last rate case.
- The acquisition of UNS Energy by Fortis Inc. ("Fortis").

II. INDUSTRY CHALLENGES.

Q. How is TEP responding to the evolving energy needs of its customers?

A. In its second century of service, TEP is upholding its traditional commitments of providing safe, reliable and affordable service in innovative, cost-effective and increasingly non-traditional ways. TEP is developing creative new energy options, engaging more directly with customers and building a smarter, more responsive transmission and distribution system to accommodate emerging energy resources. The Company's success in these endeavors has earned national acclaim and an enthusiastic reception from customers who appreciate our forward-looking approach. But these efforts cannot be sustained without significant updates to rates that remain tied to an outdated 20th-century conception of electric utility service.

Q. What changes are necessary in order for TEP to successfully, fairly and cost-effectively serve the energy needs of all its customers?

A. We must modify traditional rate design principles to address our changing industry. TEP's rates must send accurate price signals that reflect the cost of serving our customers, including those who generate some of their own power with renewable distributed generation ("DG") systems. The Company's rates must be fair for everyone, in part through the accurate, equitable allocation of costs to all appropriate customers. Additionally, TEP's rates must be affordable, obliging the Company to choose the most cost-effective strategies for fulfilling its obligations, achieving its goals and providing the right solutions for our customers.

TEP's rates also must reflect a diverse portfolio of energy resources needed to serve its customers. The Company has made significant progress toward this goal in recent years by reducing its reliance on coal, investing in an efficient natural gas-fired resource, expanding its use of renewable energy, promoting cost-effective energy efficiency ("EE")

and laying the groundwork for new energy storage facilities. Going forward, TEP must direct even more resources to ensuring that customers have access to affordable energy resources that comply with increasingly strict limits on carbon dioxide ("CO_2") and other power plant emissions. This progress will not be possible without updated rates that reflect the Company's true costs, eliminate subsidies and allow resources to be directed toward the most cost-effective energy investments.

Finally, TEP's rates must reflect its efforts to update and reinforce the facilities that support safe, reliable service. Even as emerging technologies provide new options for customers, we remain fully reliant on the immediate availability of our generation, transmission and distribution systems that serve all our customers. TEP's infrastructure improvements have allowed the Company to preserve the reliability of its service while expanding its access to reliable, affordable energy resources, promoting long-term rate stability. While these investments represent traditional utility costs, they also will form the foundation for new products and services that will be developed to fully address the evolving energy needs of TEP's current and future customers.

Customers will benefit from updated rates that allocate costs more fairly, provide accurate price signals and allow TEP to extend its historic commitment to reliability, service and value to a new generation of customers. The public interest is not well served by clinging to outdated subsidies, inaccurate price signals and increasingly inequitable cost allocations. TEP needs the freedom to follow its customers into the 21st century with revised rates that reflect current costs and usage patterns. By approving such rates, the Commission can ensure that all customers continue to enjoy equitable, affordable access to safe, reliable electric service from a company committed to addressing their evolving energy needs over the next century. In this way, updating TEP's rates represents a sound investment in a sustainable energy future for Southern Arizona.

III. RATE REQUEST OVERVIEW.

Q. Why are new rates necessary?

A. In this proceeding, TEP seeks approval for 21st century rates that: reflect infrastructure investments made by the Company since the last test year; accommodate changing customer usage patterns; recover costs more equitably; promote economic development; and help the Company maintain safe, reliable and affordable electric service for the benefit of all customers.

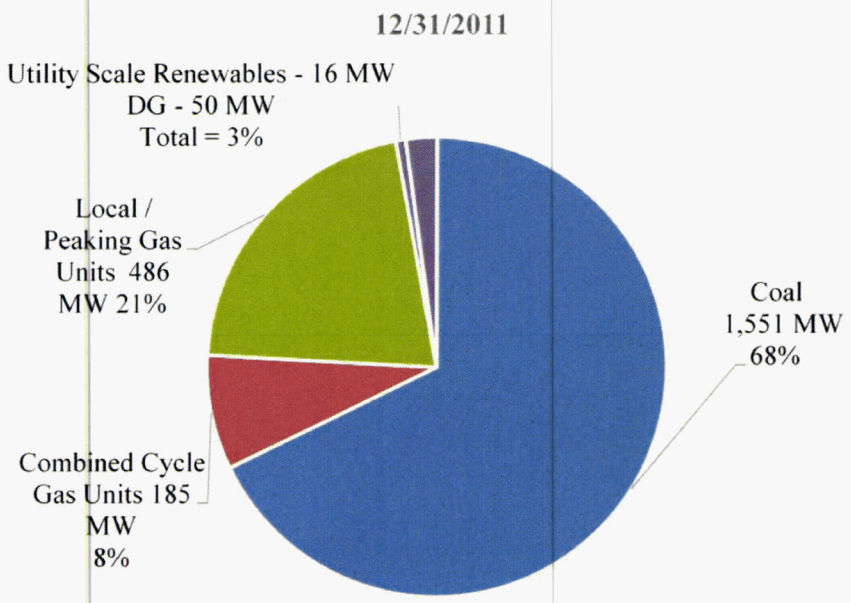
Q. Can you please elaborate?

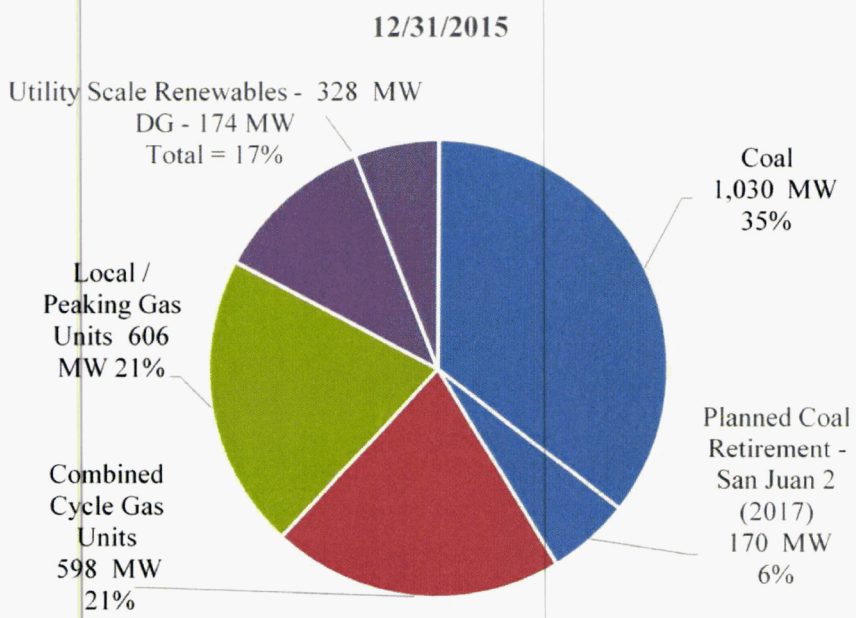
A. Arizona is at the focal point of forces shaping the future of the electric power industry, including the imposition of broad new environmental regulations and the proliferation of rooftop solar. TEP is pursuing cost-effective strategies to preserve safe, reliable and affordable electric service amid such changes, and the rates proposed in this rate application ("Application") are necessary to support and advance those efforts.

Generation Resource Diversification.

TEP has been working for many years to diversify its generation portfolio, including reducing its reliance on coal-fired generation, expanding its use of renewable energy resources and promoting cost-effective EE. The following charts reflect TEP's diversification efforts since the test year used in its last rate case.

TEP Resource Capacity





Renewable Energy

In 2015, the Company's growing renewable energy portfolio (including DG) is expected to expand to over 500 megawatts ("MW"). The Company has exceeded the annual goals of Arizona's Renewable Energy Standard ("RES") while earning widespread acclaim for its renewable energy successes, including recognition as the Solar Electric Power Association's investor-owned utility of the year in 2012 and a finalist for the same award in 2014. We expect to supply at least 30 percent of TEP's energy from renewable resources by 2030 – doubling the level the Company must achieve by 2025 under Arizona's RES. TEP's renewable energy strategy will focus on opportunities to add cost-effective utility-scale projects that further diversify our portfolio through resource type, technology and geographic location.

Energy Efficiency and Distributed Generation

The impact of EE and DG on the Company's retail electric sales has been significant. Since 2012, cumulative sales reductions attributable to energy efficiency and distributed generation reached nearly 1,000,000 MWh, which equates to about 11% of TEP's test year sales. DG and EE are components of TEP's resource portfolio, and the rates must reflect their true cost.

Reductions in Coal-Fired Generation

TEP also has executed strategic updates to its fossil fuel generation portfolio. As I describe later in my testimony, the Company is reducing its long-term reliance on coal as TEP's primary fuel source by (i) ending the use of coal as fuel for Unit 4 of the H. Wilson Sundt Generating Station ("Sundt Unit 4"); (ii) reducing TEP's share of SGS Unit 1 capacity; and (iii) planning for the retirement of Unit 2 at the San Juan Generating Station ("San Juan Unit 2"). In December 2014, TEP purchased a 75% interest in Gila River to replace these coal capacity reductions. Gila River is one of TEP's newest, most efficient

combined cycle natural gas generating facilities, to offset reductions in the Company's coal-fired generating capacity.[1]

These decisions will preserve TEP's access to reliable, cost-effective base-load resources in the face of coal plant retirements and other impacts that may result from Environmental Protection Agency ("EPA") enforcement of new rules regulating CO_2 emissions from power plants ("the Clean Power Plan") and other new emission limits.

Cost Recovery and Rate Design.

In this Application, TEP seeks to recover its rate base investments and modernize its rate structure to reflect the new imperatives of our evolving energy marketplace. Arizona utilities can no longer rely on increased energy usage to cover the cost of infrastructure investments. Instead, TEP and other providers now face declining usage due to economic forces, EE, technology improvements and other factors. Additionally, growing numbers of TEP customers are generating a portion of their own power from solar DG systems, motivated in large part by generous rate and net metering subsidies that have not been updated to reflect lower DG costs, more cost-effective renewable energy development options and various other market realities.

It has become abundantly clear that resources directed to subsidize rooftop systems could be better spent developing more cost-effective large-scale systems. Several credible sources, including the Massachusetts Institute of Technology ("MIT"), the Natural Resources Defense Council ("NRDC") and the Brattle Group, have published reports supporting such a conclusion. According to a study published in 2015 by MIT, rooftop

[1] In December 2014 and January 2015, TEP purchased certain leased interests in SGS Unit 1. Prior to December 2014, TEP owned approximately 14% of the plant and leased the remaining 86%. TEP currently owns 49.5% of SGS Unit 1.

residential solar is about 70% more expensive than utility-scale solar.[2] TEP is committed to the cost-effective expansion of its renewable energy portfolio. But some of the resources that might fund such efforts are instead being directed to rooftop systems through subsidies embedded in the Company's current rates and net metering plan. Accordingly, the Company has proposed updated rates and net metering benefits for new solar power users. By providing TEP with full recovery of its cost of service and an opportunity to earn an appropriate rate of return, the Company will be positioned to increase its investments in affordable large-scale renewable energy resources. This significant expansion of TEP's utility-scale renewable energy resources is just one of many benefits that would result from approval of the rates and rate design changes set forth in this Application.

Q. Do you have any further comments on the importance of the rate design changes proposed in this Application?

A. Yes. The current rate design structure that has been in place for decades is predicated on all utility customers paying their share of costs necessary to serve them and to provide the utility a reasonable opportunity to earn a fair return on its investment. Along with the RES, the Commission adopted the Net Metering Rules in order to promote the initial deployment of customer-sited DG. Given drastically declining DG installation costs, the number of DG systems installed in TEP's service area is rapidly increasing. However, rate design and net metering have not been changed to account for this, resulting in an inability for utilities to recover their authorized revenue requirement, as well as creating an inequitable cost shift amongst ratepayers. Using the existing rate design model in light of DG and net metering is like trying to "put a square peg in a round hole." Without implementation of the proposed changes to the Company's rate design and net metering tariff, these problems will only continue to worsen. If the utility is required to stand ready,

[2] "The Future of Solar," MIT, 2015. http://mitei.mit.edu/news/mitei-releases-report-future-solar-energy

willing and able to serve all customers in its service territory, it is duly entitled to charge just and reasonable rates that provides the utility a reasonable opportunity to earn its revenue requirement as contemplated by the regulatory compact.

Q. Please describe the Company's revenue request.

A. TEP is requesting a non-fuel retail revenue increase of approximately $109.5 million, or 12% over adjusted test-year revenues. TEP's requested retail revenues represent an increase of approximately 7% over annualized revenue based on rates currently in effect, which includes a higher fuel cost component.[3]

Q. Please describe the bill impact for the average residential customer.

A. If the Company's revenue requirement and rate design proposals are approved, residential customers under the Company's standard rate would experience a monthly bill increase of approximately $11.91.

Q. Please describe the key elements driving the Company's request.

A. TEP's request is driven in part by investments in safe, reliable service that have contributed to a $600 million increase in the Company's original cost rate base ("OCRB") since the last test year, as well as retail sales reductions. Key investments and other factors are described below.

- **Retail Sales Reductions**. TEP's test year retail sales are nearly 3% *below* the level from the December 31, 2011 test year used in the Company's last rate case, despite a 2.3% increase in the number of customers over the same period of time. Residential usage per customer fell approximately 7.5% between 2011 and the test

[3] See the Direct Testimony of Dallas Dukes.

year ended June 30, 2015. The decline in sales is due to several factors, including the effects of increased EE and DG and the slow pace of economic recovery. Due to lower overall sales, the Company must recover its fixed costs over fewer kilowatt hours ("kWh"). TEP's 2016 retail sales will be negatively impacted by the announced curtailment of operations by the Company's largest mining customer.[4]

- **Gila River.** The $164 million purchase[5] of 413-megawatts ("MW") of capacity from Gila River provides TEP with a highly efficient, combined cycle natural gas plant to offset reductions in coal-fired generating capacity.

- **SGS Unit 1.** In December 2014 and January 2015, TEP purchased leased interests in SGS Unit 1 totaling 35.4% for an aggregate purchase price of $66 million. These purchases brought TEP's total ownership interest in the unit to 49.5%. Prior to January 1, 2015, TEP leased 100% of SGS Unit 1, received 100% of its 387 MW capacity and owned an equity interest in one of the leases covering a 14% share of the unit. The Company's rate application removes the lease costs from TEP's revenue requirement and includes adjustments to rate base and operating expenses to reflect the Company's 49.5% ownership interest in SGS Unit 1. The expiration of the lease and subsequent ownership of just part of the unit served to reduce TEP's reliance on coal-fired generation.

Q. Why has the Company proposed rate design changes?

A. The primary objectives of the proposed rate design changes are summarized below.

- **To align rate structures with our customers' evolving energy use.** The Company must update its rate structures to more closely match the price our

[4] See the Direct Testimony of Craig Jones.

[5] TEP owns 75% of Gila River, or 413 MW of capacity. UNS Electric owns 25% of Gila River, or 137 MW of capacity.

customers pay to the cost of the service they receive. For example, our rates do not appropriately charge solar DG customers for their use of the Company's electric system to (i) sell excess energy when their solar arrays' output exceeds their demand and (ii) receive energy when their solar arrays' output falls short of their demand.

- **To reduce the level of cross-subsidies between customers**. TEP seeks to consistently apply rates across all of our customer classes based on the cost of providing service to each customer group.

- **To allow the Company to recover its costs and provide it an opportunity to earn a reasonable rate of return.** Current rates for TEP's residential customers collect over 80% of the Company's fixed costs through volumetric charges based on electric consumption.[6] TEP is proposing rate design changes that will provide more equitable cost recovery in an environment where overall electricity sales are declining yet the Company's cost of service requirements have increased.

Q. Does the Company's application include any proposals to promote economic development in TEP's service territory?

A. Yes. The Company is proposing a new Economic Development Rate ("EDR") intended to attract new businesses and support local economies. EDRs, as developed across the nation, provide discounted electricity rates to new or existing businesses that meet certain qualifications (such as job creation or minimum load requirements).[7] Utilities offer EDRs to (i) attract new business to their service territory and (ii) encourage existing customers to expand their operations within the utility's service territory.

[6] See the Direct Testimony of Craig Jones.
[7] See the Direct Testimony of Dallas J. Dukes.

Q. Why should utilities support economic development?

A. Economic growth provides a wide range of public benefits, including stabilizing or even reducing electric rates. Manageable customer and sales growth allows utilities to operate their systems more efficiently while spreading the fixed costs among a greater number of customers, thus mitigating the magnitude and frequency of rate case filings. Additionally, because many utilities either have or are beginning to implement EDRs, not having one would put TEP at a competitive disadvantage. The Company believes it can play a bigger role in attracting and promoting the growth of businesses in its service territories if the Commission approves an EDR.

IV. GENERATION RESOURCE DIVERSIFICATION STRATEGY.

Q. Please describe TEP's resource diversification strategy.

A. TEP's generation resource strategy, as described in its 2014 Integrated Resource Plan and acknowledged by the Commission, strikes a balance among minimizing costs to customers, mitigating environmental impacts, and effectively using TEP's existing infrastructure while supporting Arizona's local economies.[8] TEP is executing a portfolio diversification strategy that will reduce the risks associated with investments in coal-fired generation and increase reliance on zero-carbon resources such as utility-scale renewable energy and energy efficiency. While TEP's strategy is consistent in many respects with the EPA's Clean Power Plan, the Company recognizes that its resource plans could be altered depending on Arizona's State Implementation Plan ("SIP") under the Clean Power Plan. TEP has already executed some key components of its resource diversification strategy, as described below.

[8] TEP's 2014 Integrated Resource Plan was filed on April 1, 2014 (Docket No. E-00000A-13-0070).

Coal Capacity Reductions

Q. Please describe the planned reductions in TEP's coal capacity mentioned above.

A. The Company's resource diversification strategy includes the following reductions in coal-fired capacity.

- **Sundt Unit 4.** Prior to August 2015, TEP switched between coal and natural gas as the primary fuel source for Sundt Unit 4 depending on commodity prices and other factors. In August 2015, the Company exhausted its remaining inventory of coal and stopped burning coal at Sundt Unit 4. This allowed TEP to take advantage of favorable natural gas prices relative to coal (which leads to lower energy costs for our customers), as well as to accelerate the Company's generation diversification plans. The capacity of Sundt Unit 4 when fueled by natural gas is 120 MW; the unit's coal-fired capacity is 156 MW.

- **San Juan.** TEP currently owns 50% of San Juan Units 1 and 2 for a total of 340 MW of coal-fired generating capacity. The entire site consists of four units which are owned in varying interests by nine separate utilities ("Participants"). The operator of San Juan is Public Service Company of New Mexico ("PNM"). In October 2014, the EPA approved a plan that will bring San Juan in compliance with the Regional Haze Rule. The plan calls for the closure of San Juan Units 2 and 3 by December 2017 and the installation of emission control equipment on Units 1 and 4 in January 2016. Prior to the shutdown of any units, PNM must obtain approval from the New Mexico Public Regulation Commission. As this compliance plan was being developed, some San Juan Participants sought to exit their ownership in the plant. As a result, the Participants have negotiated a restructuring of the ownership in San Juan that addresses their obligations for plant decommissioning, mine reclamation, environmental matters and certain ongoing

operating costs, among other items. TEP has the opportunity to exit its remaining interest in San Juan Unit 1 when the coal contract expires in 2022.

- **SGS Unit 1.** Prior to January 2015, TEP leased 100% of SGS Unit 1. Following expiration of the leases, TEP purchased certain leased interests in SGS Unit 1, bringing TEP's total ownership in the unit to 49.5%. The remaining 50.5% of SGS Unit 1 is owned by the former lessors of the plant. This decision by TEP reduced the Company's reliance on coal-fired power by approximately 200 MW. However, the co-owners of SGS Unit 1 have defaulted on their payment obligations to TEP for their share of operating and capital expenditures on the unit and are currently engaged in litigation with the Company. Although the Company is presently selectively dispatching the co-owner's share of SGS Unit 1 and selling the power in the wholesale market, the future status of this capacity is currently unknown.

Gila River

Q. Please describe Gila River.

A. Gila River Unit 3 is a 550 MW natural gas combined cycle power plant located near Gila Bend, Arizona. Unit 3 was built in 2003 and is one of Arizona's newest, most efficient generating facilities. In December 2014, TEP purchased a 75% interest in Gila River (413 MW) for $164 million. The remaining interest in the unit was purchased by TEP's sister company, UNS Electric.[9]

Q. Why did TEP purchase an interest in Gila River and what are the benefits to customers and the Company?

[9] See Direct Testimony of Michael Sheehan for more information regarding Gila River.

A. The acquisition of Gila River was a unique opportunity to partner with UNS Electric to purchase one of the newest and most efficient power plants in Arizona. The purchase provided TEP with the opportunity to acquire an optimal amount of generating capacity at a very favorable price while diversifying its resource portfolio.

The $398 cost per kW to acquire Gila River was significantly lower than the estimated cost of $1,367 per kW to build a new unit, allowing the Company to avoid a higher rate impact for customers.

Several factors support the Company's purchase of Gila River, including: i) Gila River is an economic, highly efficient source of base-load power for customers; (ii) the purchase was significantly less expensive than other options analyzed by the Company; (iii) ownership of Gila River provides the Company with replacement capacity for reductions in coal-fired generating capacity; and (iv) Gila River enhances system reliability by providing fast-ramp generation to support the increasing levels of variable renewable and distributed generation on TEP's system.[10]

Clean Power Plan

Q. Briefly describe the Clean Power Plan.

A. On August 3, 2015, the EPA issued the final Clean Power Plan. The Clean Power Plan includes: 1) a rule limiting CO_2 emissions from existing fossil fuel fired power plants (the 111(d) rule), 2) a rule limiting CO_2 emissions from new fossil fuel fire power plants (the 111(b) rule), and 3) a model Federal Plan that may be applied to TEP's facilities on the Navajo Nation and to each state that does not submit a plan approved by the EPA.

[10] See the Direct Testimony of Michael Sheehan for further information on Gila River.

Q. Please describe the compliance process and timing.

A. States are required to submit either a final State Plan or an initial plan with a request for an extension by September 6, 2016. The Clean Power Plan allows for a two-year extension, to September 6, 2018, for submittal of a final State Plan.

Q. How does this rate application relate to the Clean Power Plan?

A. TEP's rate proposal includes adjustments for the early retirement of San Juan Unit 2 and the coal handling facilities at Sundt Unit 4 – both of which are key components of TEP's resource diversification plan. The rates requested in this application will support TEP's resource diversification strategy, including making ongoing investments in utility-scale solar. As I stated earlier in my testimony, the Company's long-term resource plan will result in meaningful steps toward meeting the emissions reduction targets required by the Clean Power Plan.

V. SPRINGERVILLE GENERATING STATION UNIT 1.

Q. Please provide a brief background of SGS Unit 1.

A. SGS Unit 1 is a 387 MW coal-fired generator that was built in 1985. Prior to January 2015, TEP received 100% of the unit's output under seven separate lease agreements.[11]

The SGS Unit 1 leases contained purchase options giving TEP the right to buy all or part of the unit upon the expiration of leases. In December 2014 and January 2015, TEP purchased leased interests in SGS Unit 1 totaling 35.4% for an aggregate purchase price of $65 million; these purchases brought TEP's total ownership interest in the unit to 49.5%.

[11] TEP purchased an equity interest in one of the leases covering a 14% share of SGS Unit 1 in 2006.

TEP operates all four SGS units. In addition to its interests in unit 1, TEP owns 100% of Unit 2. SGS Unit 3 is leased by Tri-State Generation and Transmission Association, while SGS Unit 4 is owned by Salt River Project.

Q. What is the Company's proposed rate treatment for the portion of SGS Unit 1 that was previously leased and now owned by TEP?

A. The Company's rate application removes the lease costs from TEP's revenue requirement and includes adjustments to rate base and operating expenses to reflect the Company's 49.5% ownership interest in SGS Unit 1.

Q. What is the status of the 50.5% share of SGS Unit 1 that is not owned by TEP?

A. Since the end of the SGS Unit 1 lease in January 2015, the third-party owners of the 50.5% share of SGS Unit 1 have failed to pay TEP for their share of the operating and capital costs of the unit. TEP has since started selectively dispatching the co-owner share of SGS Unit 1 in order to generate wholesale margins Should this generating capacity remain available for dispatch by TEP, the Company proposes that it begin dispatching this share of SGS Unit 1 to meet retail customer needs and to begin recovering the related operating costs through the PPFAC.[12]

VI. PROPOSED RATE DESIGN CHANGES AND NEW RATE OFFERINGS.

Q. Please explain TEP's three-part rate design proposal.

A. The three-part rate design would be mandatory for all new users of DG systems and other partial requirements customers and would be available as an option for non-DG customers. The proposed three-part rate design would include (i) a basic service charge

[12] See the Direct Testimony of Kentton C. Grant.

to recover some fixed service costs, such as the meter, service lines, customer service and billing functions, and minimum distribution system costs; (ii) a demand charge to send appropriate cost-of-service price signals and allow for recovery of fixed transmission and generation costs necessary to satisfy a customer's maximum electric demand over a specific period of time; and (iii) an energy charge to recover fuel and purchased power expenses associated with customers' energy usage. The Company believes that a three-part rate design sends more appropriate cost-based price signals, allows customers to reduce their bills by managing their energy consumption through EE or DG, and better aligns rates with the way customers use the Company's electric system.

Q. Would TEP support mandatory three-part rates for all residential customers in this proceeding?

A. Yes. However, each component of the three-part rate would need to be designed such that *all* customers receive accurate, cost-based price signals, while also providing the Company with (i) recovery of its full cost of service and (ii) an opportunity to earn a reasonable rate of return.

Equally important as getting the rate design right is promoting customer awareness. If mandatory three-part rates are applied to all residential customers, we, along with Commission Staff and other stakeholder groups, would need to conduct outreach to educate our customers about three-part rates. Any customer awareness efforts should include a phase-in or transitional period in order to provide for a smoother implementation of demand-based rates. A phase-in period should also include the ability to make revenue-neutral rate design changes to avoid unintended consequences.

Q. Briefly describe the Company's rationale for its rate design proposals.

A. The Company is proposing rate design changes that will (i) align rate structures with our customers' evolving use of power and the electric system, (ii) send appropriate price signals that more accurately reflect the cost of the service customers are receiving from the electric system, and (iii) allow the Company to recover the full cost of providing safe and reliable electric service.

- **Fair allocation of costs**. The rapid expansion of solar DG has changed the way that many customers use and access the Company's distribution and generation system. TEP must continue to invest in the necessary infrastructure to deliver safe, reliable service to every customer 24 hours a day, 7 days a week, regardless of whether some customers can meet a portion of their own energy needs with a solar array. The Company's current rate design sends inaccurate price signals and unfairly shifts costs from DG users to other customers. In Decision No. 74202 (December 3, 2013) involving Arizona Public Service Company ("APS"), the Commission found that the expansion of DG systems in APS's service territory "results in a cost shift from APS's DG Customers to APS's non DG residential customers absent significant changes to APS's rate design."[13] Addressing this cost shift expeditiously would serve the public interest by allocating the cost of the electric system more equitably among all customers who use it.

- **Fixed cost recovery**. As I previously mentioned, TEP's test year retail sales are nearly 3% *below* those from the test year used in the Company's last rate case. The decline in sales is due to several factors, including the Commission's EE and DG requirements, as well as the slow pace of economic recovery. TEP's current rates

[13] See Decision No.74202, Finding of Fact 49.

rely heavily on volumetric sales to recover service costs that are largely fixed – that is, they do not vary with individual usage. TEP's proposed residential basic service charge of $20 per month would recover about 21% of the average fixed costs identified in TEP's in this case to serve a customer.[14] This model is outdated and no longer appropriate at a time when usage per customer is declining amid increasingly successful EE programs and growing DG usage. Absent any change in rate design, the Company cannot recover its costs or earn a reasonable return on its investments.

Q. How is the Company proposing to improve fixed cost recovery?

A. The Company is proposing the following rate design changes.

- **Basic Service Charge.** Based on the results of its cost of service study, the Company has proposed a residential basic service charge of $20 per month. TEP estimates that, on average, it must collect approximately $94 per month from residential customers to recover all of the fixed costs associated with serving them based on the current test year data.[15] The Company's proposal to increase the basic service charge is an important step toward aligning prices with service costs. Reducing the reliance on volumetric charges to recover fixed costs also represents an appropriate and necessary response to sales reductions resulting from expanding EE and DG.

- **Demand Charge.** The Company's proposal includes a mandatory three-part rate design for new residential DG users and new small commercial DG users. This rate design also would be an option for other residential and small commercial

[14] See the Direct Testimony of Craig Jones.
[15] See the Direct Testimony of Craig Jones.

customers. The three parts include a basic service charge, a demand charge and an energy charge.[16] If designed properly, a demand charge can provide customers with a price signal that accurately reflects the cost of the system that must be available to serve their individual peak load while affording the Company with better recovery of its fixed system costs.

- **Rate Tiers**. The Company's current rates include higher kWh charges at higher levels of consumption, a feature typically described as an inclining block structure. This type of rate design was first implemented when economic growth and higher residential consumption levels drove annual increases in electric sales, providing electric utilities with better recovery of its fixed system costs. However, the "new normal" of flat or declining sales – resulting primarily from the use of EE and DG – limits the Company's ability to recover its costs through rates that feature an inclining block structure. This problem is exacerbated by DG customers whose energy usage rarely reaches the upper rate tiers, thus shifting the burden of paying for fixed system costs to other customers. TEP is proposing to eliminate certain upper tiers to reduce this cost shift and enhance the Company's ability to recover its fixed costs.

Q. Why is it important to align rate design with customers' use of the system?

A. All customers should pay their share of the Company's service costs. For example, solar DG users depend on TEP's system throughout the day to supplement and stabilize their solar arrays' intermittent output. While they take less power from TEP when sunlight is powering their solar panels, they rely heavily on the utility system during the late afternoon

[16] See the Direct Testimony of Dallas J. Dukes.

and early evening, when solar output wanes and use of the Company's system typically reaches its summer peak. Similarly, DG customers rely completely on the utility system during the Company's winter peaking periods, which occur in the periods before sunrise and after sunset. DG customers also rely on the Company to manage excess energy from their systems.

The level of service TEP provides to solar DG customers is even greater than other customers receive because the Company must manage the intermittent push and pull of electricity from their solar arrays. Yet under the Company's current rates, which feature a tiered rate design that relies heavily on volumetric sales to recover fixed costs, solar DG users are not paying for their share of the electric system. Instead, their costs are shifted to other customers.

Continuing to apply outdated rate design principles with the current net metering tariff sends inaccurate price signals to DG customers and discourages the development of cost-effective grid technologies. The rate design proposals in this Application, as well as the revised net metering tariff, would (i) provide the right economic incentives for the development of cost-effective energy technologies, such as storage; and (ii) continue to encourage the implementation of cost-effective energy efficiency.

TEP must build and maintain its system to meet the peak demand of *every* customer, regardless of the technologies or supplemental energy sources they may use. Therefore, every customer should pay an equitable price for their use of that system.

Q. Would the higher basic service charge and three-part rate design in your proposal allow the recovery of *all* of the Company's fixed costs or eliminate the DG cost shift?

A. No. In the interests of gradualism, we have not asked to increase the basic service charge to a level that would recover all of the Company's fixed service costs, or even those fixed

costs associated with local distribution services. As a result, our proposed rates would continue to recover some fixed costs through volumetric charges, preserving the conditions that shift some costs from DG system users to other customers. This cost shift would be exacerbated if the Commission requires continued use of current net metering rules that allow DG system users to trade excess solar energy for free, on-demand utility service.

VII. NET METERING TARIFF.

Q. Is the Company proposing any other changes to further mitigate the DG cost shift?

A. Yes. The Company is requesting approval of (i) a new Net Metering tariff for new DG system users that provides monthly bill credits for any excess energy produced from an eligible DG facility and (ii) a partial waiver of the Commission's Net Metering Rules.[17] These changes would apply to customers who installed DG facilities on or after June 1, 2015.

Q. Please describe the Company's proposed Net Metering Tariff.

A. The new Net Metering tariff will modify how new DG customers receive credit for excess energy that is generated by their DG system and delivered to TEP. Under the new tariff:

- New DG customers would pay the requested three-part rate for all energy delivered by TEP.
- New DG customers would be compensated for any excess energy their DG system produces and delivers to the Company with bill credits calculated using the Renewable Credit Rate.

[17] The Company filed an application on March 25, 2015 containing similar requests (Docket No. E-01933A-15-0100). However, on June 19, 2015, TEP filed a motion to withdraw its net metering application. On August 26, 2015 the Commission issued an order granting the Company's motion to withdraw (Decision No. 75224).

- New DG customers could carry over unused bill credits to future months if they exceed the amount of their current TEP bill.

Q. What is the Renewable Credit Rate?

A. The proposed Renewable Credit Rate of 5.84 cents per kWh, which would be reset annually, is the rate equivalent to the most recent utility scale renewable energy purchased power agreement connected to the distribution system of TEP.[18]

Q. Would customers be grandfathered under the current net metering tariff?

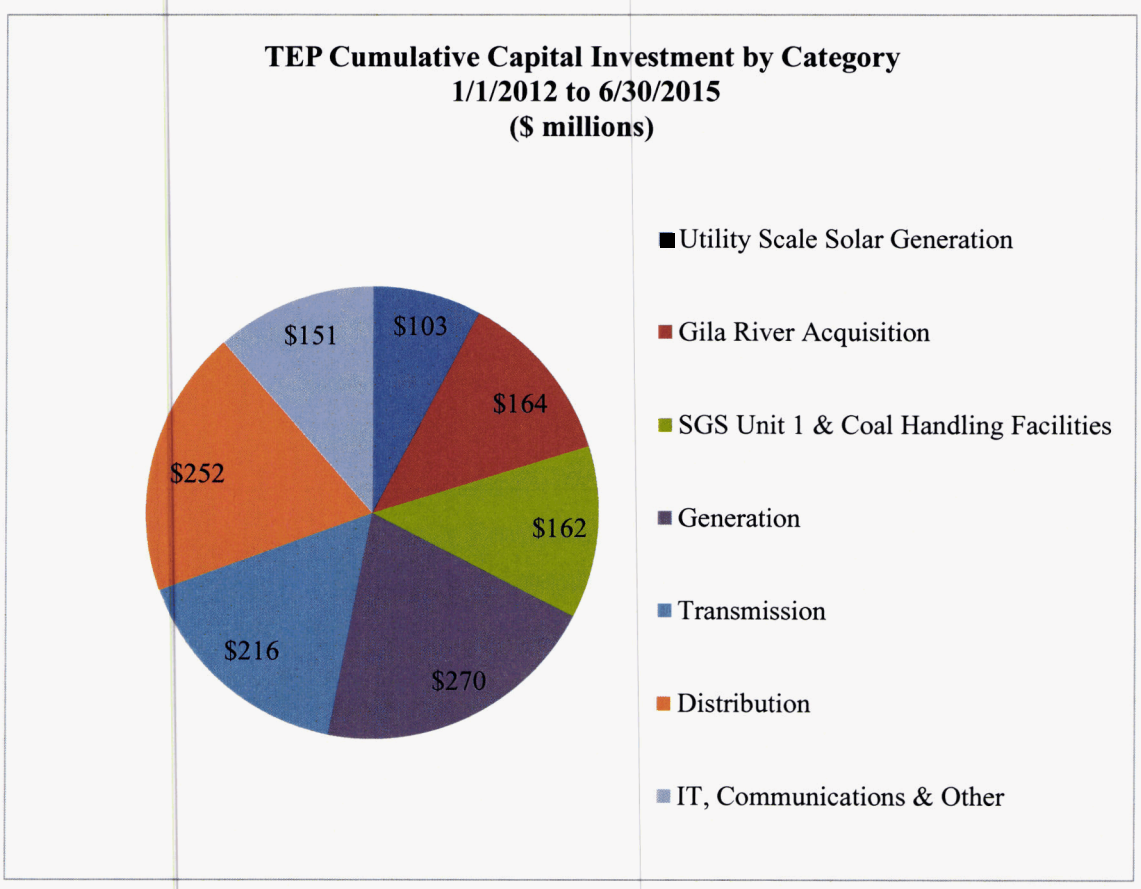
A. Yes. If the Company's proposal is approved, the following customers will be grandfathered under the current net metering tariff: (i) DG customers that were on TEP's existing net metering tariff prior to June 1, 2015; and (ii) DG customers who submitted approved applications as of June 1, 2015.

VIII. HISTORICAL CAPITAL INVESTMENTS.

Q. Please describe the Company's capital investments since 2011, the test year used in the Company's last rate case.

A. From the period of January 1, 2012 to June 30, 2015, TEP invested approximately $1.3 billion in order to continue providing its customers with safe and reliable service. The Company's capital investments are summarized in the chart below.

[18] See the Direct Testimony of Carmine Tilghman.



As shown in the chart above, TEP's capital investments include

- $103 million of investments in utility-scale solar generation. Since 2011, TEP has added approximately 37 MW of utility-owned, community-scale solar generation, expanding the Company's owned solar generating capacity by more than three-fold.
- $164 million for the acquisition of Gila River, as previously described in my testimony.[19]
- $162 million for the acquisition of certain leased interests in SGS Unit 1 and the coal handing facilities at the Springerville Generating Station.[20]

[19] Also see the Direct Testimony of Mike Sheehan.
[20] See the Direct Testimony of Kentton C. Grant.

- $270 million of improvements made to TEP's current generation fleet. This amount includes approximately $34 million for the environmental upgrade at San Juan Unit 1 I referenced previously.
- $151 million of investments primarily comprised of technology and communications upgrades.
- $468 million of transmission and distribution system investments. The Company's high voltage transmission investments of $216 million have enhanced TEP's system reliability and energy import capability. TEP's $252 million of distribution investments include system reinforcement, growth for new business, public improvement projects, substation construction and maintenance, and the replacement of aging infrastructure.[21]

IX. ACQUISITION OF UNS ENERGY BY FORTIS.

Q. When did Fortis complete its acquisition of UNS Energy?

A. On August 15, 2014, Fortis completed the acquisition of UNS Energy and its subsidiaries, including TEP, UNS Electric and UNS Gas. The Commission had approved the transaction in Decision No. 74689 (August 12, 2014).

Q. Please comment on the relationship between Fortis and UNS Energy since the acquisition was completed.

A. The relationship is excellent. The Fortis business model of acquiring utilities and leaving control in the hands of the utilities has provided for a very smooth transition.

[21] See the Direct Testimony of Susan Gray for more information on the Company's investments in TEP's transmission and distribution system.

Q. Briefly describe the benefits that have resulted from the acquisition.

A. Both the Company and our customers have realized several benefits since the closing of the acquisition. I summarize a few of those benefits below.

- **Bill Credits.** Our customers at TEP, UNS Electric and UNS Gas are receiving bill credits for a five year period that total $30 million. Customers receive the bill credits each year from October 1 to March 1.

- **Financial Support and Credit Ratings.** Since the closing of the acquisition, Fortis has made equity contributions through UNS Energy to TEP that have (i) provided funding for the acquisitions of Gila River and certain interests in SGS Unit 1, (ii) enabled TEP to reduce its debt obligations and (iii) increased TEP's equity ratio to approximately 50%. The acquisition by Fortis and ongoing improvements in TEP's financial condition contributed to an increase in TEP's credit rating to A3. As a result of TEP's ongoing financial discipline and the financial support provided by Fortis, the average cost of debt used in the Company's revenue requirement of 4.32% is nearly one full percentage point *lower* than the cost of debt approved in our last rate case which helps to reduce the amount of future borrowing costs that need to be recovered from customers.[22]

- **Synergies.** As a result of the merger, TEP has been able to negotiate better insurance rates and reduce its external audit fees. The annual cost savings are estimated to be approximately $1.8 million.

[22] The Commission approved the acquisition of UNS Energy by Fortis in Decision No. 74689 (August 12, 2014). During the acquisition proceedings, UNS Energy indicated that the Fortis acquisition would deliver numerous benefits, including the potential for an improvement in the credit ratings of TEP, UNS Gas, and UNS Electric. Following the acquisition, Moody's Investor Services upgraded the unsecured bond ratings of each of those companies to A3.

- **Credit Ratings.** UNS Energy's merger with Fortis was viewed very positively by the rating agencies. The merger was cited as one of the primary factors in the ratings upgrades that occurred during 2014 and 2015 for TEP, UNS Gas and UNS Electric. The credit rating improvements reduces the borrowing costs of each company.

Q. In connection with the merger, Commission Decision No. 74689 approved a settlement agreement with 66 conditions. Are some of the conditions related to rate cases filed by the regulated utility subsidiaries of UNS Energy?

A. Yes, there are several conditions that are addressed in this rate case. Frank Marino and Susan Gray address the pertinent conditions in their direct testimony.

X. CONCLUSION.

Q. Is the Company requesting that the Commission take action on its rate application by a certain date?

A. Yes. TEP respectfully requests that the Commission issue a final order in this case on or before December 31, 2016.

Q. Does this conclude your testimony?

A. Yes.

Direct Testimony of

Susan M Gray

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

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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:

<u>EHV System</u>

- 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.

Direct Testimony of

Michael E. Sheehan

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

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Exhibit MES-2	TEP Revised PPFAC Schedules 1-4
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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?

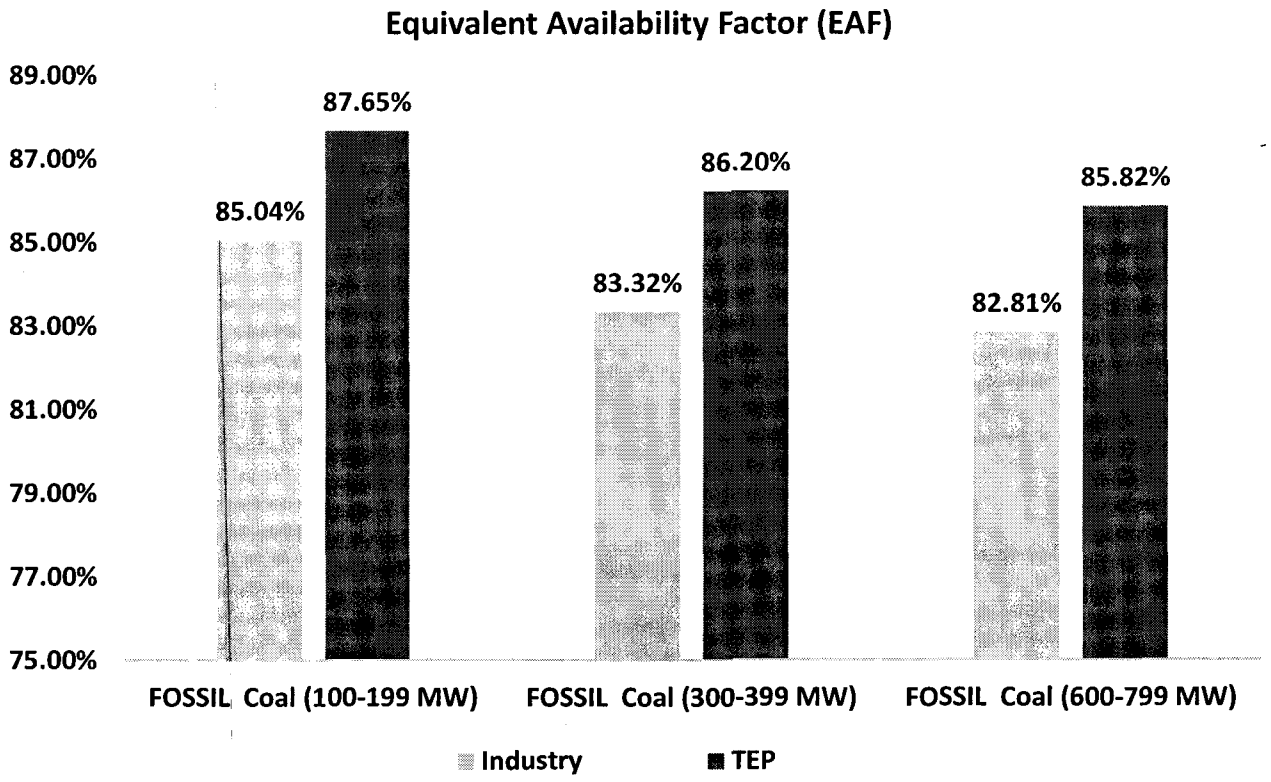
A. TEP measures the reliability of its coal-fired plants against North American Electric Reliability Corporation's ("NERC") Generating Availability Data System ("GADS") definition of Equivalent Availability Factor ("EAF"). EAF represents the percentage of

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

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[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/

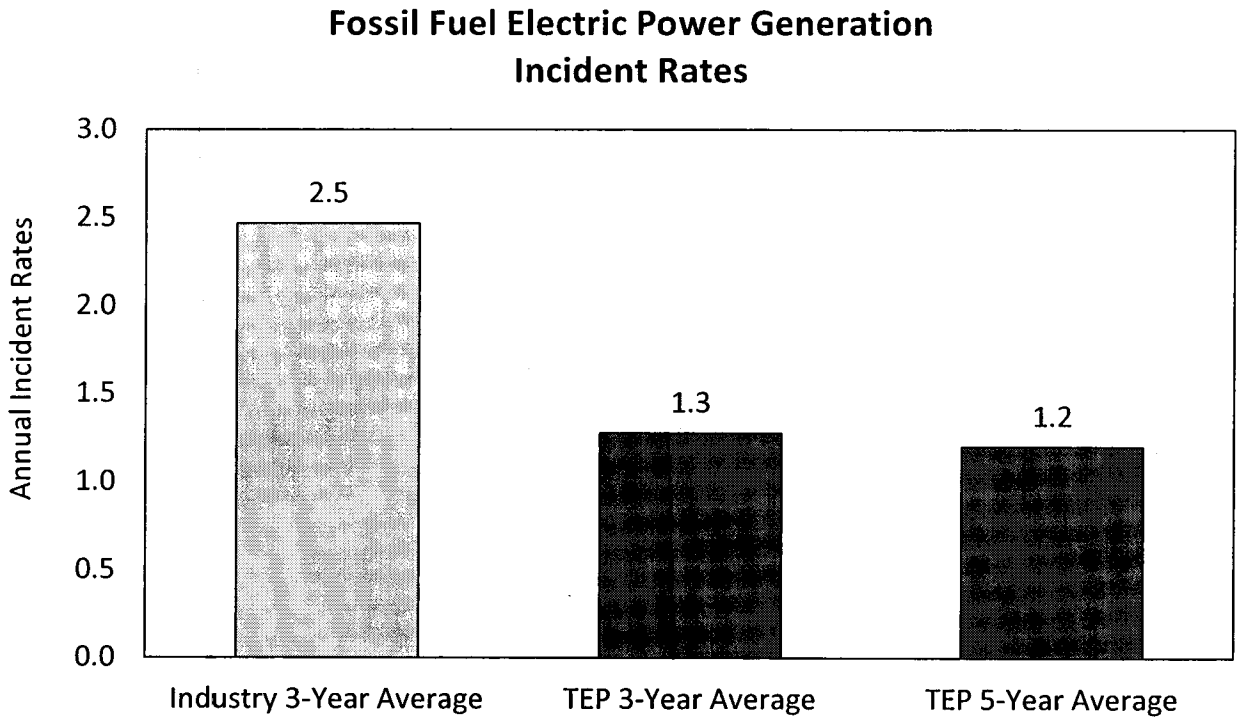
Q. How does TEP evaluate the effectiveness of safety programs at its generation plants?

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.

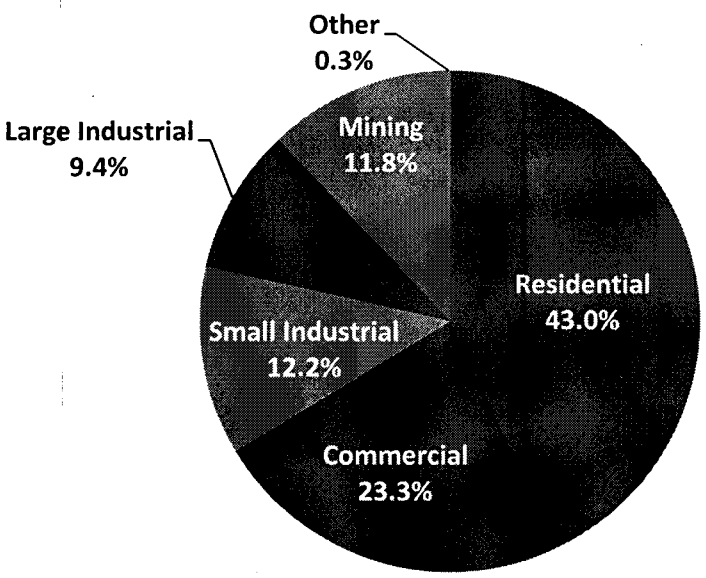
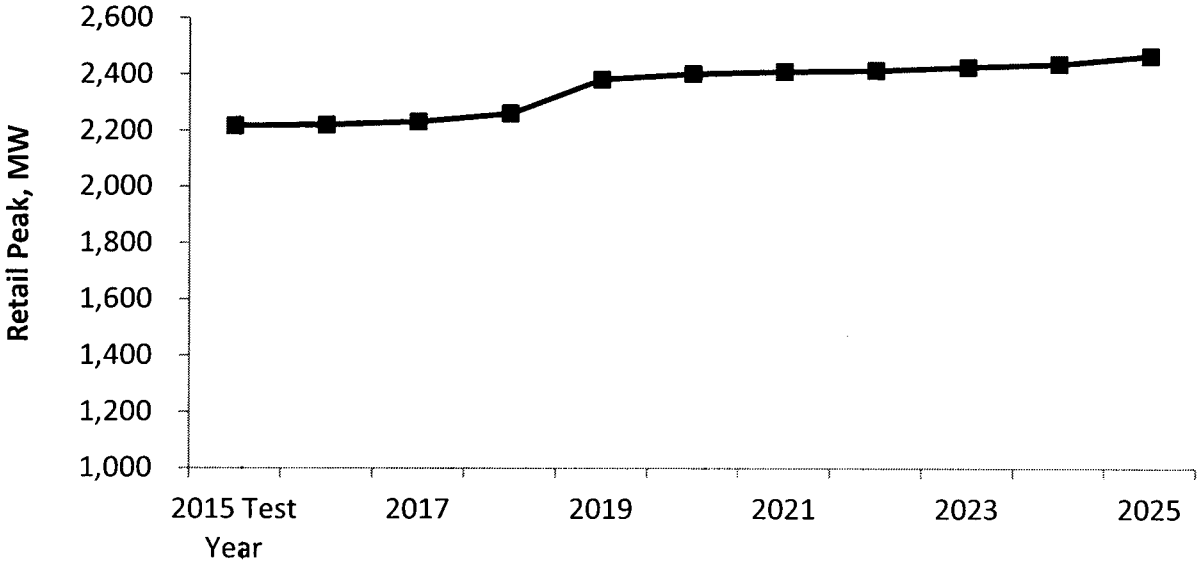


Chart 1 – 2015 Test Year Retail Sales by Customer Class

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?

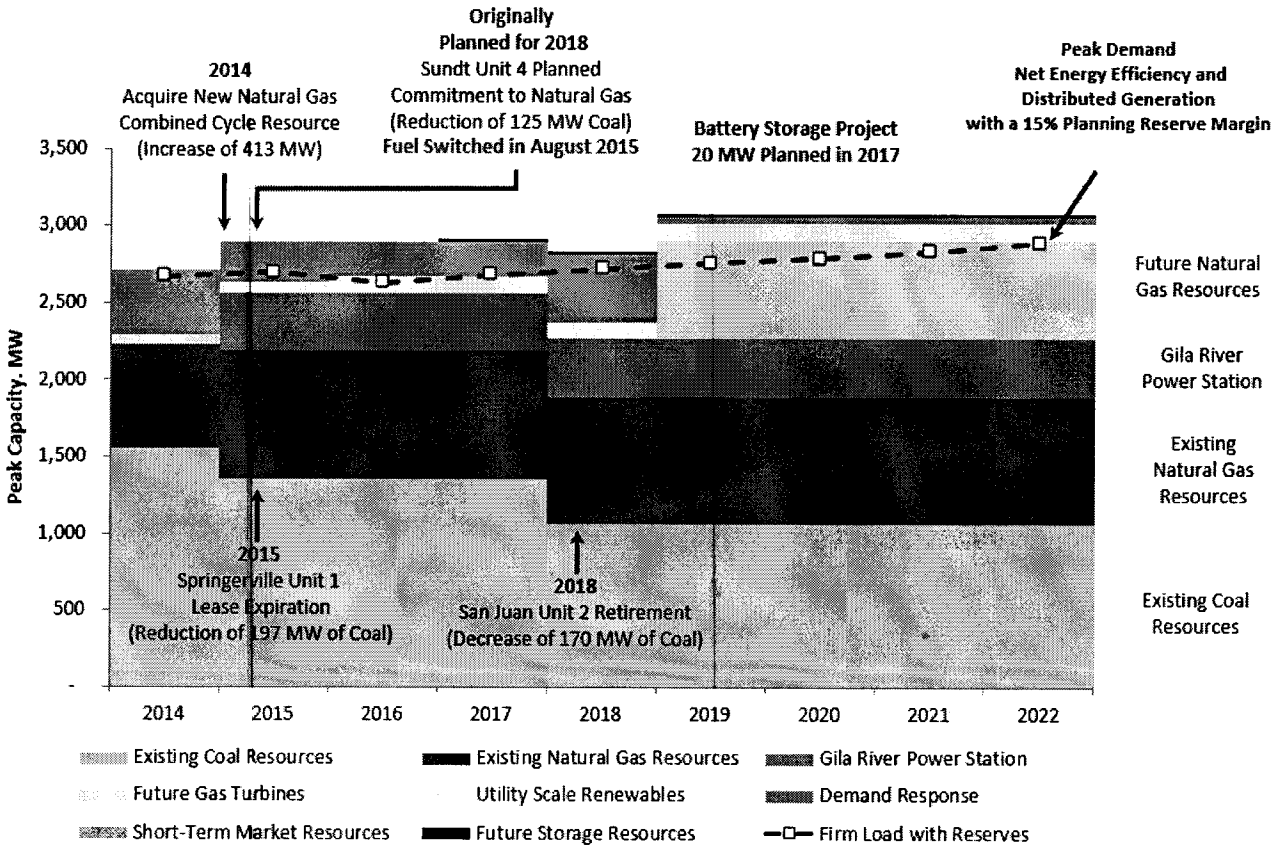
A. Chart 3 below shows a modified version of the loads and resource chart from the 2014 IRP.[38] These modifications reflect actual changes in resources that have occurred after the 2014 IRP filing in April 2014. In December 2014, TEP acquired 413 MW in natural gas combined cycle capacity from Gila River 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.

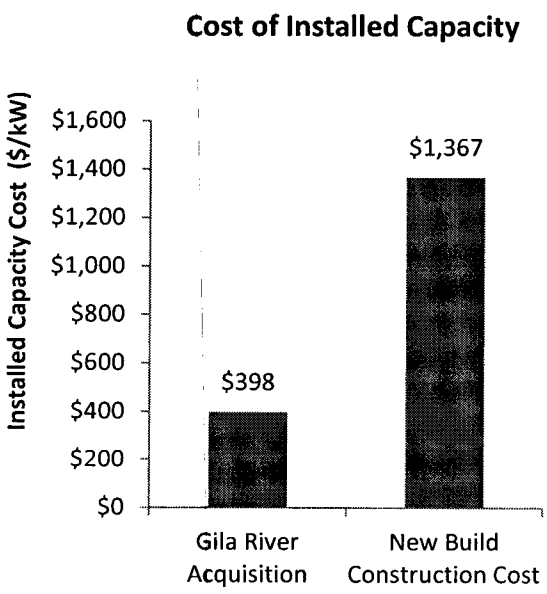
newly constructed combined cycle plant. As shown in the tables below the Gila River Unit 3 purchase price of $398/kW is approximately one-third the cost of new construction at $1,367/kW.

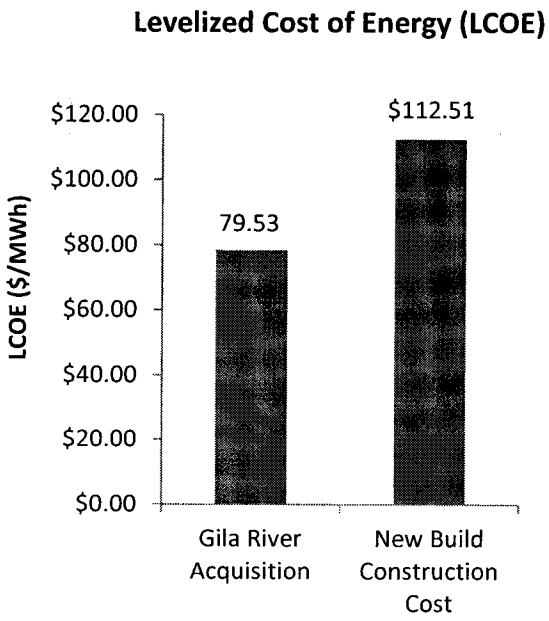
Exhibit 1 - Gila River Unit 3 vs. New Construction Cost Comparison

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

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[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.

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[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.

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[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

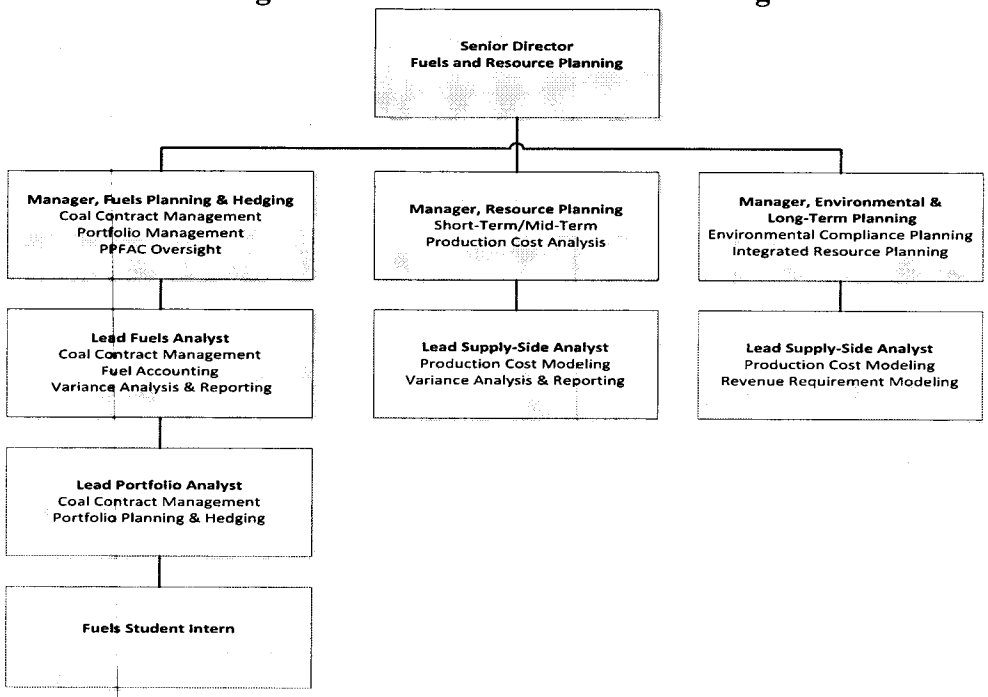
[74] In January 2015, TEP reduced its participation on Springerville Unit 1 from 387 MW to 192 MW and in August 2015, TEP permanently eliminated coal as a fuel source on Sundt Unit 4 (110 MW). Prior to these coal reduction commitments TEP acquired 413 MW of Gila River, Unit 3 (a natural gas combined 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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The PPFAC described in this Plan of Administration ("POA") uses a ~~forward-looking estimate~~historical twelve (12) month rolling average of actual fuel and purchased power costs to set ~~a~~the rate ~~that is then reconciled to actual costs experienced~~. This POA describes the application of the PPFAC.

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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 - ~~An~~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~~. 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

		¢/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 ~~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.

Direct Testimony of

Carmine A. Tilghman

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

Carmine A. Tilghman

on Behalf of

Tucson Electric Power Company

November 5, 2015

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Exhibit CAT-2 2015 Monthly DG Application Data

I. INTRODUCTION.

Q. Please state your name and business address.

A. Carmine Tilghman, 88 East Broadway, Tucson, Arizona 85702

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

A. I am the Senior Director of Energy Supply for Tucson Electric Power Company ("TEP" or "the Company") and UNS Electric ("UNS Electric").

Q. Please describe your background and work experience.

A. I served in the United States Navy from 1984–1993 as a Nuclear Reactor Operator in Submarine Service. From 1993-1995, I worked as a Power Plant Operator for the Biosphere II Project in Oracle, Arizona.

I was hired by TEP in 1995 as a Power Plant Operator. In 1996, I moved into TEP's Wholesale Marketing Department where I held several positions in Energy Trading, Marketing, Project Management, and Scheduling before being promoted to Supervisor/Manager in 2003. From 2003-2008, I held supervisory positions in Trading, Scheduling, and Procurement before taking over Utility Scale Renewable Energy Development in 2008.

In 2010, I took over all aspects of renewable energy development for both TEP and UNS Electric. In my current position, I am responsible for the renewable resources and renewable resource programs for the Companies, including compliance with the Arizona Corporation Commission's ("Commission") Renewable Energy Standard and Tariff Rules ("REST Rules") (A.A.C. R14-2-1801 through R14-2-1818)). In 2013, I added oversight of

the Wholesale Marketing department to my duties, and in 2014 was promoted to Senior Director.

I received my Bachelor of Science in Business Management from the University of Phoenix in 2000 and Master of Business Administration from the University of Phoenix in 2002.

Q. What is the purpose of your Direct Testimony?

A. The purpose of my testimony is to discuss: (1) the Company's investment in renewable generation resources since its last rate case; (2) the Company's request to transfer into base rates those investments and related costs of Company-owned renewable generation resources since the last rate case in accordance with prior Commission orders; (3) the impacts of renewable energy, particularly solar and distributed generation ("DG") resources, on the Company's operations; and (4) the Company's proposed changes to its present net-metering tariff including the renewable credit rate.

II. INVESTMENTS AND RENEWABLE GENERATION RESOURCES.

Q. What is the approximate investment the Company has made on utility-owned renewable resources?

A. Each year since 2010, the Company has requested Commission approval in its annual Renewable Energy Standard and Tariff ("REST") implementation plan to invest in utility-owned resources. In total, the Company has invested close to $140 million in utility-owned renewable generation.

Q. How much of the Company's investment in renewable generation was included in the rate base approved in TEP's last rate case?

A. Approximately $65 Million.

Q. How much has the Company invested in utility scale renewable energy since its last rate case?

A. TEP's has invested approximately $100 million in utility-scale solar facilities since the Company's last general rate case. These facilities include: the White Mountain Solar facility, located in Springerville, Arizona; the Fort Huachuca Solar Facility, located in Sierra Vista, Arizona; TEP's headquarters solar facility located in Tucson, Arizona; the Areva Solar thermal facility located at the Sundt Generating Station in Tucson, Arizona; and a portion of the Company's rooftop solar program. Below is more detail on these facilities.

- The White Mountain facility is a multi-technology facility, consisting of 2.8 MW of SunPower's 305 watt T-5 fixed PV solar panels using (1) AE 500 kW inverter and (7) SMA 250 kW inverters, coupled with 7.5 MW of SunPower's C-7 low concentrating PV (LCPV) technology, utilizing (4) PowerOne Ultra 1500 inverters.
- The Fort Huachuca solar facility consists of 17.2 MW of fixed PV technology using 300-305 watt BYD panels and (16) SMA 850 CP-US inverters.
- The TEP headquarters solar facility is approximately 50 kW of the SunPower's 305 watt T-5 fixed PV solar panels.
- The Areva solar thermal facility is a steam augmentation system that utilizes Compact Linear Fresnel Reflector technology to take feedwater from the Sundt #4 natural gas generating facility and create low pressure steam that is returned to the cold reheat section of the unit.

Q. Please describe TEP's utility scale renewable portfolio, including both utility-owned facilities and power purchase agreements.

A. The Company currently owns eleven solar facilities totaling 45 MW-dc with an additional 10 MW-dc either planned or under construction, and another 5 MW-ac thermal solar facility expected to be purchased at the end of 2015 (pending a successful year-long operational test). Additionally, in 2015, the Company started its utility-owned distributed generation program, in which the Company installs, owns, and operates residential DG systems.

The Company is also under contract to purchase the output from systems with a total combined capacity of more than 250 MW, including 80 MW-ac of wind, 4 MW-ac of biogas, and approximately 165 MW-dc of solar from various entities. Below is a summary of the AC values of the Company's renewable portfolio as November 5, 2015.

	Capacity (AC)
TEP Owned	37
Solar Thermal	5
Solar PPA	137
Wind PPA	80
Biogas	4
Under Constr.	25
Total	**288**

Please refer to **Exhibit CAT-1** for more detailed information regarding all of the Company's renewable facilities.

Using a 0.8 DC to AC conversion factor, the Company has ownership of 12.5% of its utility scale renewable energy portfolio.

III. IMPACT OF RENEWABLE ENERGY ON UTILITY OPERATIONS.

Q. How has the rate of residential DG applications and installations changed since up-front incentives were eliminated by the Commission?

A. Up-front incentives for TEP were eliminated in 2014; however, TEP ran out of incentive money in late 2013, yet still received nearly 160 non-incentivized residential applications between October and December 2013, with an average system size of 7.02 kW-dc. In 2014, the Company received an average of 222 residential solar applications per month, with an average system size of 7.28 kW-dc. Below is a month-to-month breakdown of the applications received in 2014.

2014 Rooftop Application Summary		
Month	Number of Applications	Sum of kW DC
January	114	782.54
February	59	389.70
March	120	823.87
April	117	770.02
May	182	1,247.06
June	260	1,880.79
July	202	1,482.09
August	240	1,762.69
September	514	4,016.30
October	375	2,794.43
November	268	1,951.88
December	212	1,476.60
Grand Total	2,663	19,377.97

For the period of January through April 2015, the Company received an average of 254 residential applications per month, with an average system size of 6.94 kW-dc.

Month	Number of Applications	Sum of kW DC
January	228	1,480.04
February	236	1,664.39
March	270	1,885.49
April	283	2,023.88

Please refer to **Exhibit CAT-2** for more detailed monthly information.

When the residential solar market was effectively controlled by the amount of incentives provided through the REST (through late 2013), the annual installed capacity was roughly 7 MW, which met the incremental renewable portfolio standard requirement each year. However, the proliferation of the solar leasing model and the continued decline in solar panel prices, coupled with policies such as net metering, has effectively tripled the market penetration even though all utility incentives have been eliminated (based on average number of applications and capacity received from 2013 to 2014).

For additional comparison, TEP had a total capacity of 30.4 MW of distributed generation on its system at the end of 2011, the Company's last rate case test year. By the end of the current test year, June 30, 2015, the Company had a total installed/reserved capacity of 173.7 MW of total distributed generation.

Q. From a grid operations perspective, what are the biggest challenges to integrating distributed generation, particularly solar?

A. DG has number of well-documented integration issues that can be placed into three categories: (1) intermittent generation; (2) inability to monitor and control systems; and (3) excess generation flowing back onto the grid.

1) **Intermittent Generation.** The intermittency of renewable generation has long been discussed as the major drawback of renewable energy, requiring the continued services of the centralized grid in order to supply the necessary back-up energy and ancillary services to support solar and other intermittent renewable resources. This problem is exacerbated through policies such as net metering, which encourages customers to oversize their solar systems beyond their average load in order to "bank" as many credits as possible for use later. This results in excessive renewable capacity that requires the centralized grid's existing facilities to adjust to generation fluctuations created during solar production.

This is a growing problem for TEP as the Company is required to supply these ancillary services through the Company's existing generation resources without recovering the associated costs. These services include load balancing, frequency support, voltage support, and spinning and non-spinning reserves. Increased intermittent generation creates greater load imbalance and fluctuations in voltage and frequency requiring additional ancillary services. Ultimately, large scale energy storage facilities will be needed on a system-wide basis to manage this issue.

2) **Inability to Monitor and Control Systems.** The inability to monitor and control DG systems is a growing source of concern for utilities. Operationally, distributed generation is not connected to a utilities' energy management system. As such, the utility has no ability to see the output or control the inverter. In essence, the utility is "driving blind" when it comes to distributed generation. In small quantities, distributed generation can be ignored. However, as the aggregated amount of distributed generation becomes larger, it represents a large generation source that the

utility cannot see, has no control over, provides no ancillary services for, and can create significant load to generation imbalances.

3) **Excess Energy.** The excess energy flowing back onto the grid, a result of net metering policies, creates additional issues on the distribution system beyond the cost-shifting issues discussed in the Direct Testimony of Dallas J. Dukes. Historically, the grid was designed to meet the peak needs of the customers on a particular distribution circuit, from the substation to the feeder to the shared transformers. However, under current net metering rules the customer can generate up to 125% of their connected load annually. Most customers attempt to generate between 90% and 100%. In order to accomplish this through solar generation, the system is designed to be approximately double the customer's peak load. When multiple customers on a single transformer or feeder circuit have systems sized as such, the circuits' capacity rating can be exceeded. While the impacts of this issue are being studied in Hawaii, which has the largest distributed generation penetration of any utility, there are other issues more unique to the Company. Specifically, there are three issues of operational concern beyond simply operating at an "over-capacity" rating:

A) Significantly higher energy flows which can result in increased operations and maintenance costs, and equipment wear and tear.

B) Excess energy does not always "flow to the next door neighbor" as is often quoted. During times of high export and low customer load, neighbors of exporting customers often have low usage as well, resulting in the energy flowing back up through the distribution system.

C) While high penetration of DG can help relieve feeder and circuit overload conditions during peaking months, the resulting over-generation and

higher exports during the shoulder months often results in reverse power flow and overload conditions.

IV. NET METERING AND THE RENEWABLE CREDIT RATE.

Q. Please provide a brief description of the Company's proposed changes to the current net metering tariff?

A. The proposed changes to the Net Metering tariff are two-fold: (1) a request for a new net metering tariff that provides monthly bill credits at a Renewable Credit Rate for excess energy produced and pushed onto the grid from a customer's solar system; and (2) a partial waiver of the Net Metering Rules to eliminate the "roll over" of excess generation to offset future usage, as is currently prescribed in A.A.C. R14-2-2306.

Q. Please describe the Renewable Credit Rate.

A. TEP is proposing to eliminate the requirement to provide DG customers with a full retail credit for all excess energy pushed back onto the grid and "banking" it for future use.[1] While the customer can still offset their energy usage on a real time basis at the full retail rate, any excess production from their system would be purchased by the Company at the Renewable Credit Rate. The Renewable Credit Rate – currently proposed to be 5.84 cents per kWh – is equivalent to the most recent utility scale renewable energy purchased power agreement connected to TEP's distribution system. Although the Company has received lower priced offers from reputable and qualified development companies, the 5.84 cents per kWh is the price for a project currently under construction and scheduled to be completed in 2015. As such, the Company believes this represents the most accurate cost-based proxy.

[1] Please refer to the testimony of Dallas Dukes and Craig Jones for more detailed explanation of the Renewable Credit Rate and rate design.

As the ratepayers ultimately pay the difference between conventional energy prices and renewable energy prices, the Company believes it is appropriate that Net Metering customers receive the same financial compensation for their distributed energy that is available from other, larger, more cost-effective resources.

Q. Will the Renewable Credit Rate Change?

A. Yes. The Company would file an annual Renewable Credit Rate similar to the Company's existing annual Market Cost of Comparable Conventional Generation (MCCCG) filing. This filing would be made with the annual REST filing based on the most recent comparable utility scale purchased power agreement for renewable energy that is connected to TEP's distribution system.

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 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. Would customers be grandfathered under the current net metering tariff?

A. Yes. If the Company's proposal is approved, the following customers will be grandfathered under the current Net Metering tariff: (1) DG customers that were on TEP's existing Net Metering tariff prior to June 1, 2015; and (2) DG customers who submitted approved applications as of June 1, 2015. Additionally, the proposed rider would be specific to the customer's premise, and would be transferrable to new property owners should the existing DG owner sell the property.

Q. Customers with DG systems undertake a significant capital investment to reduce their electric bills. How would this proposal impact their potential savings?

A. Under this proposal, DG customers would still see significant savings on their electric bills as described in Dallas Dukes' Direct Testimony.

Q. Does this conclude your testimony?

A. Yes

Exhibit CAT-1

EXHIBIT CAT-1

TEP
Tucson Electric Power
Building a Bright Tomorrow

Revised 10-06-15 ES

Utility Scale Renewable Portfolio

TEP

Project Name	Project Owner	AKA	Technology	DC MW Capacity	AC MW Capacity	Annual Energy, GWh	COD	Site Location	County	Term	Comments
[illegible]	Centaurus Renewable Energy	Avalon Phase II	[illegible]	23.53	17.22	37.71		Sahuarita	Pima County	20	Esimated COD 12/15/2015
[illegible] Solar 5 MW	TEP		TBD	5.00	4.00	8.76		Tucson, Az	Pima County	Own	Estimated COD 12/13/2016
Fort Huachuca Phase II	TEP	Fort Huachuca Phase II	Fixed PV	5.00	4.00	8.76		Fort Huachuca, Sierra Vista, AZ	Cochise County	Own	Esimated COD 6/15/2016
Aminox UASTP Solar Power Generation Station	FRB Solar LLC	Amonix	CPV	2.00	1.20	2.63	3/31/2011	UA Tech Park	Pima County	20	
Avalon Solar	Coronal Management, LLC	Avalon Phase I	Fixed PV	35.00	28.34	62.06	12/23/2014	Sahuarita	Pima County	20	
Avra Valley	NRG Solar Avra Valley LLC	NRG Avra Valley	Fixed PV	34.41	25.00	54.75	12/14/2012	Marana, Az	Pima County	20	
Cogenera	WGL Energy	Cogenra	CPV	1.38	1.10	2.42	7/1/2014	UA Tech Park	Pima County	20	
DeMoss Petrie	Tep	TEP	Fixed	0.22	0.18	0.39	6/6/2001	DeMoss Petrie Sub Station	Pima County	Own	
E.On Tech Park	Tech Park Solar, LLC	E.On UASTP	Single-Axis PV	6.60	4.80	10.51	12/28/2012	UA Tech Park	Pima County	20	
Fort Huachuca Phase I	TEP	Fort Huachuca Phase I	Fixed PV	17.20	13.60	29.78	12/9/2014	Fort Huachuca, Sierra Vista, AZ	Cochise County	Own	
Gato Montes Solar	Gato Montes Solar, LLC	AstroSol/Astronergy	Fixed PV	6.00	4.92	10.77	12/19/2012	Tech Park	Pima County	20	
Macho Springs	Capital Power	Macho Springs	Wind	[redacted]	50.40	110.38	11/15/2011	Deming, NM	Luna County	20	
Picture Rocks	Picture Rocks Solar, LLC	FRV Marana	Fixed PV	25.00	20.00	43.80	12/5/2012	Marana, Az	Pima County	20	
Red Horse Solar	Red Horse Wind 2, LLC	Red Horse Solar	Solar	51.25	41.00	89.8	08/31/2015	Wilcox, Az	Cochise County	20	
Red Horse Wind	Red Horse Wind 2, LLC	Red Horse Wind	Wind	[redacted]	30.00	65.70	08/31/2015	Wilcox, Az	Cochise County	20	
Solon Prairie Fire	TEP	DM Air Corridor project	Fixed PV	5.00	4.00	8.76	12/28/2012	Old Vail & Valencia	Pima County	Own	
Springerville .81 expansion	TEP	Springerville	Fixed PV	0.81	0.65	1.42	12/30/2010	Springerville, Az	Apache County	Own	
Springerville 1.0 expansion	TEP	Springerville	Fixed PV	1.00	0.80	1.75	12/30/2010	Springerville, Az	Apache County	Own	
Springerville 4.6	TEP	Springerville	Fixed PV	4.60	3.68	8.06	6/6/2004	Springerville, Az	Apache County	Own	
Sundt - Los Reales	TEP	Sundt - Los Reales	Biogas	[redacted]	4.00	8.76	1/20/1998	Los Reales Landfill	Pima County	Through 2017	These resources provide augmentation only and do not increase the generating capacity rating of the unit.
Sundt Augmentation	TEP	Areva Solar Thermal	Thermal	[redacted]	5.00	10.95	12/30/2014	Sundt #4	Pima County	Own	These resources provide augmentation only and do not increase the generating capacity rating of the unit.
SunPower HQ	TEP	Rooftop	Fixed PV	0.05	0.04	0.088	6/7/2012	HQ	Pima County	Own	DG on company owned buildings
SunPower OH	TEP	Rooftop	Fixed PV	0.50	0.40	0.88	6/6/2012	OH	Pima County	Own	DG on company owned buildings
UASTP I	TEP	UASTP 1.6 Solon	Single-Axis PV	1.60	1.28	2.80	12/31/2010	UA Tech Park	Pima County	Own	
UASTP II	TEP	Solon 5 UASTP TEP Owned	Fixed PV	5.00	4.00	8.76	12/29/2011	UA Tech Park	Pima County	Own	
Valencia Solar	Valencia Solar, LLC	E. On Valencia	Single-Axis PV	13.20	10.00	21.90	6/28/2013	Valencia & I-10	Pima County	20	
White Mountain Solar	TEP	Springerville 10 - SunPower	Fixed / LCPV	10.00	8.25	18.07	12/12/2014	Springerville	Apache County	Own	
Projects not yet under construction/in development			Totals	DC MW Capacity 252.35	AC MW Capacity 287.86	Annual Energy, GWh 630.41					

Exhibit CAT-2

Exhibit CAT-2

2015

STATUS	APPROVED

Month	Number of Applicatic	Sum of kW DC
1	228	1,480.04
2	236	1,664.39
3	270	1,885.49
4	283	2,023.88
5	895	6,466.84
6	795	5,933.40
7	94	623.25
8	156	1,087.32
9	207	1,414.07
10	235	1,685.81
Grand Total	3,399	24,264.49

Direct Testimony of

Kentton C. Grant

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

Kentton C. Grant

on Behalf of

Tucson Electric Power Company

November 5, 2015

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Exhibit KCG-1: TEP Capital Expenditures

Exhibit KCG-2: TEP Capital Structure

Exhibit KCG-3: SGS Common Facilities Lease Payments

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Kentton C. Grant. My business address is 88 East Broadway, Tucson, Arizona 85701.

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

A. I hold the position of Vice President and Treasurer. I also serve as Vice President of Finance and Rates for TEP's parent company, UNS Energy Corporation ("UNS Energy").

Q. Please describe your background and work experience.

A. I have been employed by TEP since 1995. From 1995 to 2007 I served in a variety of financial roles including Senior Financial Analyst, Director of Capital Resources and Manager of Financial Planning. In 2007, I was elected Vice President of Finance and Rates. In 2010, I was elected Treasurer of TEP. In these roles I have gained extensive experience in financial forecasting, financial analysis, the structuring of financing transactions and other related activities.

Before my employment at TEP, I was employed as a staff member at the Public Utility Commission of Texas from 1984 to 1995. During this period I worked in several different capacities, including Director of the Financial Review Division. In that role, I directed staff responsible for performing financial analyses, accounting reviews and management audits of electric and telecommunications utilities. As a staff member, I also provided expert testimony on a variety of financial topics including the cost of capital, financial integrity, rate moderation and the valuation of utility properties.

I received a Master of Business Administration degree with a concentration in finance from the University of Texas at Austin, as well as a Bachelor of Science degree in Civil Engineering from Purdue University. I am also a member of the Chartered Financial Analyst ("CFA") Institute, and in 1995, I was awarded the professional designation of CFA.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to provide an overview of the Company's financial condition and to make recommendations concerning the Company's capital structure, cost of debt, and weighted average cost of capital ("WACC"). I also discuss the methods used by TEP to determine fair value rate base ("FVRB") and the appropriate rate of return ("ROR") on FVRB, otherwise referred to as the fair value rate of return ("FVROR"). Further, I discuss the cost of credit support required for the Company's fuel and purchased power procurement activities, the cost of the Springerville Generating Station ("SGS") common facilities lease, and the rate treatment of TEP's investments in the SGS coal handling facilities and SGS Unit 1.

Q. Please summarize your conclusions and recommendations.

A. I offer the following conclusions and recommendations:

- The Company is in good financial condition. However, the rate relief and changes to rate design requested in this Application are critical to maintaining TEP's long-term financial health;
- Due in large part to equity contributions made by TEP's ultimate parent company, Fortis Inc. ("Fortis"), the Company's capital structure has improved to the point where it is now supportive of a strong investment-grade credit rating. TEP proposes using its actual test year capital structure, adjusted for recent long-term

debt retirements, resulting in a proposed capital structure consisting of 50% common equity and 50% long-term debt;

- The Company's weighted average cost of debt has fallen significantly since TEP's last rate case, due largely to refinancing activity, a favorable interest rate environment, and improved credit ratings at TEP. The Company proposes using its actual cost of long-term debt of 4.32%.
- Based on the proposed capital structure and cost of debt, as well as the cost of common equity of 10.35% determined by TEP witness Ann E. Bulkley, the Company is proposing a WACC of 7.34%;
- With respect to the FVROR, the Company is proposing that it be calculated using a ROR of only 1.42% on the fair value increment of rate base (the difference between original cost rate base and fair value rate base). As discussed in the Direct Testimony of TEP witness Ann Bulkley, this results in a FVROR of 5.69%;
- The cost of credit support for the Company's fuel and purchased power procurement has decreased significantly compared to prior years, due largely to the improvement in TEP's credit ratings. The Company is proposing a test year cost of credit support of only $3,750;
- TEP still leases a 50% undivided interest in SGS common facilities under three separate lease agreements that are scheduled to expire in December 2017 and January 2020. Since the scheduled lease payments have not changed materially from TEP's last rate case, the requested annual lease expense of $10.6 million is nearly the same as the amount previously approved by the Commission;
- In light of the relatively short remaining lease term for the SGS common facilities, TEP is proposing to extend the amortization period for leasehold improvements the Company has made to these facilities. The Company is

proposing to use a 10-year amortization period, compared with a remaining life-of-lease recovery period authorized in TEP's last rate case;

- In April 2015, TEP completed the purchase of the previously leased SGS coal handling facilities. Net of amounts allocable to SGS Units 3 & 4, and to a 50.5% interest in SGS Unit 1 owned by third parties, TEP is requesting rate base treatment of a $57.1 million net purchase price;
- In December 2014 and January 2015, TEP completed the purchase of a 35.4% interest in the previously leased SGS Unit 1. When combined with the 14.1% interest purchased by TEP in 2006, the Company now owns a 49.5% share of SGS Unit 1. TEP is requesting rate base treatment of the $65 million purchase price paid in late 2014 and early 2015, as well as $43 million pertaining to the purchase completed in 2006;
- With respect to leasehold improvements TEP made to SGS Unit 1 during the term of the SGS Unit 1 lease, TEP is proposing that those investments continue to be amortized over the ten-year recovery period approved in the Company's last rate case. These capital investments were required in order to keep SGS Unit 1 in good operating condition in accordance with the lease and other governing agreements, and to comply with various state and federal regulations;
- Since the end of the SGS Unit 1 leases in January 2015, the third-party owners of a 50.5% share of SGS Unit 1 have failed to pay TEP for their share of the operating and capital costs of the unit. TEP has since started dispatching the co-owner share of SGS Unit 1 in order to generate wholesale margins. Should this generating capacity remain available for dispatch by TEP, the Company proposes that it begin dispatching this share of SGS Unit 1 to meet retail customer needs and to begin recovering the related operating costs through the Company's Purchased Power and Fuel Adjustment Clause ("PPFAC"); and

- Finally, with respect to the $1 million of plant investments made by TEP and billed to the SGS Unit 1 co-owners through the end of the test year, for which the Company has yet to be reimbursed, TEP is proposing the same rate treatment previously approved by the Commission for the SGS Unit 1 leasehold improvements. Should the Company be reimbursed by the co-owners for these investments, which were required to ensure continued operation of SGS Unit 1, TEP would commit to returning this amount to customers, with interest, in its next rate case.

II. FINANCIAL CONDITION OF TEP.

Q. Please describe the current financial condition of TEP.

A. The Company is currently in good financial condition. Although TEP is not presently earning its authorized return on equity ("ROE") from its retail jurisdictional business, the Company currently enjoys a healthy balance sheet, solid investment-grade credit ratings, and relatively stable cash flows that are expected to fund a large portion of near-term capital spending needs.

Q. What impact did the recent acquisition of UNS Energy by Fortis have on the Company's financial condition?

A. The acquisition had a very positive impact on TEP's financial condition. Shortly after the acquisition was closed in August 2014, Fortis injected $287 million of equity capital into UNS Energy, of which $225 million was invested in TEP. This capital was used by TEP to help fund the purchase of interests in Gila River Unit 3 and SGS Unit 1, as well as for other plant investments. In 2015, Fortis injected an additional $180 million of equity capital into UNS Energy, all of which was invested in TEP and used to repay debt and support the Company's working capital needs. These equity infusions were very timely

from a financial perspective since they were made during a period of heightened capital spending by TEP. As illustrated in **Exhibit KCG-1** attached to my testimony, TEP invested nearly $500 million in plant and equipment in 2014, with nearly the same amount expected for 2015. By making these equity contributions, Fortis enabled TEP to finance its capital expenditures with a balanced mix of debt and equity, and to improve the Company's capital structure to a level supportive of a strong investment-grade credit rating.

Q. How much progress has TEP made since the last test-year in terms of improving its balance sheet and credit ratings?

A. Since TEP's last test-year ending December 31, 2011, the Company has made significant strides in terms of reducing its debt leverage and improving its credit ratings. As indicated in **Exhibit KCG-2** attached to my testimony, TEP added nearly $1 billion of debt and equity capital over the past three and one-half years, while reducing capital lease obligations by approximately $360 million. At the same time, the Company's equity ratio (ratio of equity capital to total capital, including lease obligations) improved from approximately 35% to nearly 50%. This improvement is due to the Fortis equity injections, the retention and reinvestment of earnings at TEP, and the expiration of long-term lease agreements covering SGS Unit 1 and the SGS coal handling facilities.

Over this same time period, TEP's unsecured credit ratings were raised twice by Standard & Poor's Ratings Service ("S&P") and three times by Moody's Investors Service ("Moody's"). In 2011, TEP's unsecured debt was rated just above speculative-grade by both Moody's and S&P. Today, TEP has solid investment-grade credit ratings of A3 from Moody's and BBB+ from S&P. These improved credit ratings are more in line with industry-wide credit ratings, and provide the Company with access to debt capital on more reasonable terms.

Q. What factors did the rating agencies cite in their upgrade of TEP credit ratings?

A. The initial round of upgrades occurred in 2013 following the completion of the Company's last retail rate case. In June 2013, Moody's specifically cited the Commission rate order for TEP as being a credit positive event, and moved up the Company's unsecured credit rating by one notch to Baa2. In August 2013, S&P followed suit and increased TEP's unsecured credit rating by one notch to BBB. Like Moody's, S&P cited the amount of rate relief granted, the addition of the Lost Fixed Cost Recovery ("LFCR") mechanism, and the timeliness of the TEP rate order as positive factors influencing their rating decision.

A second round of credit rating upgrades occurred in 2014. In January 2014, Moody's increased TEP's credit rating by one notch to Baa1 as part of an industry-wide ratings re-assessment. In October 2014, two months after the Fortis acquisition, S&P increased TEP's credit rating by one notch to BBB+. In their ratings assessment S&P cited the stable credit rating outlook of Fortis as a key factor influencing their rating decision.

In February 2015, Moody's announced one additional credit rating upgrade for TEP. In that announcement, which moved the unsecured credit rating of TEP higher by one notch to A3, as well as the ratings of sister companies UNS Gas, Inc. and UNS Electric, Inc., Moody's stated that the ratings upgrades were "...driven by strong financial metrics across all of UNS' utility subsidiaries; a constructive Arizona regulatory environment; and the recent ownership by a financially larger parent in Fortis Inc. (unrated), which we view as credit positive."

Q. What impact do TEP's credit ratings have on the Company and its customers?

A. Credit ratings have a huge impact on the perceived creditworthiness of the Company, and by extension, the cost and availability of credit. As a capital intensive business, TEP

must access the debt capital markets on a regular basis to finance a portion of its capital expenditures and to refinance maturing debt obligations. Since long-term corporate bonds are priced by adding a credit spread to the yield on U.S. Treasury bonds, issuers with higher credit ratings typically enjoy lower credit spreads and lower interest rates on newly issued bonds. As a result, in 2014 and 2015, TEP benefitted from its recent credit rating upgrades when the Company issued a total of $450 million in new long-term corporate debt. In 2014, the Company was able to lock in a fixed rate of 5.00% on $150 million of 30-year bonds, and in 2015, TEP issued $300 million of new 10-year bonds at a fixed rate of 3.05%. The interest rate of 3.05% was the lowest rate realized by TEP in over four decades on an issuance of fixed-rate long-term debt. As proposed in this rate filing, the resulting interest savings will now being passed onto customers through a lower weighted average cost of debt.

The Company also maintains banking lines of credit to meet seasonal working capital needs, to provide interim financing of construction expenditures, to provide credit support for fuel and purchased power procurement, and for general corporate purposes. In October 2015, TEP completed a refinancing of its previous $200 million revolving credit facility with a larger $250 million credit facility that is scheduled to expire in October 2020. The cost of this bank credit is tied directly to the Company's credit ratings. The higher the rating, the lower the cost is to TEP. Currently TEP can borrow under this credit facility at a credit spread of 1.0% over the London Interbank Offered Rate ("LIBOR") for loans of one month or more, and must pay a commitment fee of 0.125% (annual rate) on the unused portion of the facility. Those rates are significantly lower than they would have been absent the recent credit rating upgrades. Similarly, the Company realizes savings from its higher credit ratings under two other credit agreements related to tax-exempt floating rate debt. The resulting savings on those

bonds, as well as the reduced credit facility commitment fees, are also fully reflected in Company's weighted average cost of debt.

Lastly, TEP relies on short-term trade credit from suppliers of various goods, services, fuel, and wholesale power purchased to meet the energy needs of its customers. As a result of the Company's recent credit rating upgrades, the amount of credit extended by suppliers of natural gas and wholesale power has increased significantly, thereby reducing the cost of credit support needed for fuel and wholesale power procurement. Those savings have also been passed onto customers in the Company's rate filing.

Q. Does TEP still face significant financial challenges in the years ahead?

A. Yes. The Company still faces several significant financial challenges. Over the near-term, TEP needs to achieve a timely and constructive outcome in this rate case in order to modernize its rate structure and to recover its full cost of providing service. The Company is also striving to achieve a successful resolution of the ongoing litigation with the third-party owners of a 50.5% interest in SGS Unit 1. Those co-owners have defaulted on payment obligations for their share of operating and capital costs, a situation that has resulted in additional unanticipated costs to the Company. Additionally, the Company's largest retail customer recently announced a 50% curtailment of mining production at the Sierrita copper mine located south of Tucson, and indicated that studies are underway to evaluate the possible closure of the mine. Not only will this affect the Company's margins over the near-term, it is also expected to have a significant impact on economic growth in the Tucson metropolitan area.

Over the long-term, the Company may have to raise substantial amounts of capital to meet the requirements of the Clean Power Plan ("CPP") recently released by the Environmental Protection Agency. Depending on how the CPP is ultimately

implemented, additional outlays for renewable energy, natural gas-fired generation and related bulk transmission may be required. Substantial new investments in TEP's local distribution system may also be needed to accommodate increasing amounts of distributed generation. In light of these contingent capital needs, it is vitally important that TEP maintain access to the debt capital markets on reasonable terms.

Q. Please comment on the importance of this rate Application to TEP's financial health.

A. The outcome of this rate case is critical to TEP's financial health and credit ratings. Since the Company's last test year ending December 31, 2011, TEP has invested approximately $1.3 billion in new utility plant, and increased its balance of debt and equity capital (excluding leases) by over 50%. Over this same period, the Company's retail sales have decreased, due largely to customer conservation and the proliferation of distributed generation. Meanwhile, the Company's operating costs have increased due to general inflation, higher property taxes and a variety of new federal regulations. As a result, TEP is no longer recovering its full cost of service from customers. In terms of magnitude, the Company has identified a test year non-fuel revenue deficiency of $109.5 million. Such a revenue deficiency is obviously not sustainable over the long-run, and would have significant adverse effects on the Company and its credit ratings if it were allowed to continue for an extended period of time. TEP's rate request is designed to provide the Company with a fair rate of return on invested capital and to continue the progress TEP has made in improving its financial health and credit ratings.

Additionally, as noted above, there has been a significant increase in customer conservation efforts and distributed generation in the Company's service area. The impact of these factors on TEP, and on the industry as a whole, has clearly drawn the attention of the credit rating agencies and the investment community. It is now widely

recognized that the recovery of fixed costs through traditional volumetric rate design is no longer well suited to an industry undergoing such change. Over 9,000 of TEP's customers now own or lease a rooftop solar array, and this number is expected grow substantially in the years ahead. As discussed in the testimony of Company witness Dallas Dukes, it is important that TEP begin recovering a much larger portion of its fixed costs through fixed monthly customer charges and, in the case of partial requirements customers, through monthly demand charges as well.

III. CAPITAL STRUCTURE.

Q. Please describe the capital structure for TEP as of the end of the test-year.

A. Excluding capital lease obligations, which are treated as operating expenses for rate making purposes, the capital structure for TEP as of June 30, 2015, consisted of $1.44 billion of common equity and $1.54 billion principal amount of long-term debt. After adjusting for unamortized debt issuance costs, the debt balance as of June 30, 2015 was $1.52 billion. As reflected in Schedule D-1 in the Company's Application, the Company's test-year capital structure consisted of 48.7% common equity and 51.3% long-term debt:

($ Thousands)	6/30/2015	% of Total
Common Equity	$1,443,610	48.69%
Long-Term Debt	1,521,156	51.31%
Total Capital	$2,964,766	100.00%

Q. Do you recommend any adjustments to the test-year capital structure for rate setting purposes?

A. Yes, I do. A portion of the $180 million equity infusion made by Fortis and UNS Energy in 2015 was set aside for the retirement of two series of long-term bonds with a combined

principal amount of $78.6 million. Due to notice provisions contained in the bond indentures, those bonds could not be redeemed until August 17, 2015, even though redemption notices were sent to bondholders prior to the end of the test year. Since TEP had the necessary cash on hand to retire the bonds as of June 30, 2015, and since the Company was legally obligated to redeem the bonds when the redemption notices were issued, it is appropriate to remove those two series of bonds from TEP's test-year capital structure. Additionally, TEP incurred additional debt issuance costs after the test year for a new five-year revolving credit facility. As reflected in Schedule D-1 of the Company's Application, making these two adjustments results in a proposed capital structure consisting of 50% common equity and 50% long-term debt:

($ Thousands)	6/30/2015	% of Total
Common Equity	$1,443,610	50.03%
Long-Term Debt	1,441,656	49.97%
Total Capital	$2,885,266	100.00%

Q. How does a 50% equity ratio compare with the capital structure employed by other investor-owned electric utilities?

A As discussed in the testimony of Company witness Ann Bulkley, a 50% equity ratio is consistent with the capital structure employed by other investor-owned electric utilities with investment-grade credit ratings. It is also comparable to, and somewhat lower than, the equity ratio approved by the Commission in the most recent rate cases for UNS Electric Inc. (52.6%) and Arizona Public Service Company (53.9%).

Q. In the Commission order approving the merger of Fortis and UNS Energy, was a minimum equity ratio specified for purposes of restricting TEP dividend payments to UNS Energy?

A. Yes. Condition No. 16 in the Settlement Agreement approved by the Commission specifies that TEP cannot pay dividends greater than of 60% of annual earnings for a period of five years, or until such time the Company's equity capitalization reaches 50% of total capital, whichever is earlier. The values for equity capitalization and total capital are to be based on TEP's balance sheet prepared in accordance with Generally Accepted Accounting Principles ("GAAP").

Q. Is the equity ratio specified in the Commission merger order calculated the same way as the equity ratio proposed for ratemaking purposes?

A. No, the two ratios are slightly different. For ratemaking purposes, it is common practice to subtract unamortized debt issuance costs and losses on reacquired debt from the principal amount of debt, whereas the test-year GAAP balance of debt reflects the principal amount of debt adjusted only for a small amount of original issuance discount. Additionally, the Company's capital lease obligations are excluded from TEP's capital structure for ratemaking purposes, whereas these same obligations are included in TEP's total capitalization in accordance with GAAP. As shown in the table below, based on the Company's actual GAAP balance sheet as of June 30, 2015, TEP had an equity ratio of 47.25% for purposes of the dividend limitation test. On a pro forma basis, after removing the two series of bonds retired by TEP in August 2015, this same ratio would have been 48.50%:

($ Thousands)	Actual 6/30/15 Balance	Actual 6/30/15 % of Total	Pro Forma 6/30/15 Balance	Pro Forma 6/30/15 % of Total
Common Equity	$1,443,610	47.25%	$1,443,610	48.50%
Long-Term Debt	1,541,556	50.46%	1,462,956	49.15%
Capital Lease Obligation	69,938	2.29%	69,938	2.35%
Total Capital	$3,055,104	100.00%	$2,976,504	100.00%

As demonstrated above, even with the recent equity investments from Fortis and UNS Energy, TEP still needs to build additional equity capital to reach the 50% minimum equity ratio specified in the Commission order approving the merger of UNS Energy and Fortis. TEP currently expects to meet this threshold over the next several years through the retention and reinvestment of earnings.

IV. COST OF DEBT.

Q. What cost of debt is TEP proposing in this Application?

A. TEP is proposing a weighted average cost of debt of 4.32%. As shown on page 1 of Schedule D-2 in the Company's Application, this reflects TEP's weighted average cost of debt as of the end of the test-year, adjusted for the removal of two bond series that were redeemed in August 2015 and the refinancing of TEP's revolving credit facility in October 2015.

Q. How does this cost of debt compare with the cost approved in TEP's last rate case?

A. It is significantly lower. A 5.18% cost of long-term debt was approved in the Company's last rate order (Decision No. 73912 dated June 27, 2013). That value was based on the weighted average cost as of December 31, 2011. Since that time, TEP has refinanced four series of tax-exempt bonds at significantly lower rates, and has tapped the corporate bond market for an additional $600 million of financing at historically attractive rates.

These savings, which are the result of both a favorable interest rate environment and improved credit ratings at TEP, are now being passed onto customers through a lower cost of debt.

Q. Please explain the adjustment you made to remove two series of debt from the test-year balance of long-term debt.

A. As described earlier, a portion of the $180 million equity investment from Fortis was used to retire two series of long-term bonds with a combined principal amount of $78.6 million. These two series of bonds were issued on behalf of TEP by the Industrial Development Authority of Pima County in 1982 ("1982 Pima Bonds"). Although TEP had sufficient cash proceeds to retire the bonds at the end of the test-year, and had provided irrevocable redemption notices to the trustee and bondholders prior to June 30, 2015, the 1982 Pima Bonds could not be redeemed until August 2015 due to notice provisions contained in the bond indentures. Since the bonds are no longer outstanding, it is appropriate to remove them from the Company's long-term debt structure for purposes of setting new rates.

Q. Why did the Company redeem the 1982 Pima Bonds?

A. There were three reasons. First, due to the requirement that TEP provide supplemental credit support in the form of bank letters of credit, the 1982 Pima Bonds were the most expensive floating-rate debt that TEP had. Second, they were scheduled to mature in 2022, well ahead of the other bonds that TEP could have retired at par value. Third, these two series of bonds were "two-county" tax-exempt bonds that financed facilities for the local furnishing of electricity, including the addition of coal handling facilities at Sundt Unit 4. Since the coal handling facilities will likely be retired within a few years, and since it is becoming increasingly difficult for TEP to comply with certain operating

restrictions required under two-county financing rules, it is possible the Company would have had to retire these bonds well before their scheduled maturity dates.

Q. What other debt financing costs have you included in the proposed cost of debt?

A. The 4.32% cost of debt also incorporates the commitment fees and amortization of issuance costs on TEP's new revolving credit facility. On October 15, 2015, TEP refinanced its existing $200 million revolving credit facility with a new five-year $250 million revolving credit facility. This transaction was completed pursuant to a financing order of the Commission in Decision No. 73658. Commitment fees on the unused balance of credit are payable quarterly and are based on an annual fee rate of 0.125%. Up-front fees paid to participating banks, as well as fees paid to the credit rating agencies, have been included as a cost of issuance and amortized over the five-year term of the facility.

TEP's revolving credit facility provides the Company with access to liquidity for seasonal working capital needs, short-term funding of construction expenditures, and credit support for fuel and purchased power procurement. Since the commitment fees and amortization of issuance costs are recorded as a component of interest expense, and not as an operating expense, they need to be included in the cost of debt for purposes of cost recovery. This recovery method is consistent with Commission treatment in TEP's last two rate orders.

V. WEIGHTED AVERAGE COST OF CAPITAL.

Q. What is the WACC for TEP?

A. Based on the adjusted test year capital structure, a 4.32% cost of long-term debt, and a 10.35% cost of common equity recommended by TEP witness Ann Bulkley, the

Company's WACC is 7.34%. This value is calculated as follows:

	% of Capital Structure	Component Cost	Weighted Average Cost
Common Equity	50.03%	10.35%	5.18%
Long-Term Debt	49.97%	4.32%	2.16%
Total	100.00%		7.34%

Q. How does this compare with the WACC approved in TEP's last rate case?

A. It is nearly the same. The capital structure and costs of debt and equity adopted in TEP's last rate case resulted in a WACC of 7.26%. Even though equity is more expensive than debt, and equity as a percentage of total capital has increased from 43.5% approved in TEP's last rate case to 50.0% currently, the Company's overall cost of capital has not changed materially. The primary reason for this is a lower cost of debt. With the benefit of a stronger balance sheet and improved credit ratings, TEP is now well positioned to issue new debt, when needed, at a significantly lower cost than it otherwise would be.

VI. FAIR VALUE RATE BASE AND FAIR VALUE RATE OF RETURN.

Q. What fair value rate of return ("FVROR") is TEP proposing in its rate application?

A. As discussed in the Direct Testimony of TEP witness Ann Bulkley, the Company proposes a FVROR of 5.69%. Although the Company can justify a higher value for the FVROR, as Ms. Bulkley discusses in her pre-filed direct testimony, the Company requested that Ms. Bulkley apply a ROR equal to only one-half of the real risk-free rate to the fair value increment of rate base (the difference between original cost rate base ("OCRB") and FVRB).

Q. How did TEP calculate FVRB for the purposes of this filing?

A. TEP relied on the approach traditionally adopted by the Commission, using the average of OCRB and reconstructed cost new less depreciation rate base ("RCND"), as those terms are defined in the Commission's rules, as the basis for calculating the Company's FVRB.

As discussed in Ms. Bulkley's testimony, this value for FVRB is also supported by a market-based approach to fair value.

VII. COST OF CREDIT SUPPORT FOR FUEL AND PURCHASED POWER PROCUREMENT.

Q. Does TEP incur credit-related costs to support the procurement of natural gas and wholesale power for retail customers?

A. Yes. In addition to financing temporary under-collections of fuel and purchased power costs under the Company's PPFAC, TEP must also provide credit support to wholesale suppliers from whom these purchases are made. This credit support may either take the form of a letter of credit issued by a creditworthy bank, a deposit of cash collateral in an escrow account, or under some circumstances a pre-payment of amounts owed to the supplier. Credit support is often required to provide assurance to a wholesale counter-party that TEP will perform its obligation to purchase natural gas or wholesale power as specified by contract.

Q. Under what situations may wholesale credit support be required?

A. It is customary for participants in the wholesale gas and power markets to set a credit limit for each counter-party with whom it conducts business. Larger credit lines are typically extended to large and highly-rated market participants, while credit lines are typically

much lower for small and mid-sized companies or those having weaker credit ratings. When the credit exposure to a counter-party exceeds the specified credit limit, a request for credit support is made. From the standpoint of a seller of natural gas or wholesale power, credit exposure to a contracted buyer is typically defined as the sum of: (i) the receivable balance due from the buyer and (ii) the mark-to-market value (positive or negative) of future sales specified under the contract.

In the case of TEP, requests for credit support are received from sellers of natural gas and wholesale power whenever their credit exposure to the Company exceeds the credit limit they have assigned to TEP. Although credit limits may be negotiated when a new business relationship is being established or when a change in credit ratings occurs, the decision to extend credit is solely at the discretion of the seller.

Q. Is wholesale credit support needed to facilitate TEP's energy hedging program?

A. Yes. TEP's energy hedging program involves the purchase of natural gas and wholesale power in the forward energy markets in order to stabilize the cost of energy provided to TEP's customers. As discussed above, changes in the market value of forward energy contracts can create a need for wholesale credit support.

Q. What level of credit support has TEP been required to provide?

A. Historically, the Company has had to provide considerable credit support due to previously lower credit ratings and less stable market conditions for natural gas and wholesale power. In 2009, during a period of rapidly declining natural gas and wholesale power prices, the Company had to provide as much as $12 million in credit support. In the Company's last rate case, the average level of credit support during the test-year had fallen to $1 million. At the end of the current test-year ending June 30, 2015, TEP had only one letter of credit outstanding in the amount of $300,000 to support natural gas and

wholesale power procurement. This lower level of required credit support is due in large part to the improvement in TEP's credit rating.

Q. How were credit support costs addressed in TEP's last rate order?

A. In Decision No. 73912 (June 27, 2013) they were included in the Company's non-fuel revenue requirement as an adjustment to operating expense.

Q. What is your recommendation concerning the recovery of wholesale credit support costs by TEP?

A. Since these costs are highly variable and directly related to TEP's fuel and purchased power procurement, I have previously recommended that they be recovered through the Company's PPFAC. However, in light of past Commission treatment of these costs, I am recommending that they be included in rates as an adjustment to test-year operating expense. Since the annual cost of a letter of credit is currently 1.25% for TEP, and a single $300,000 letter of credit was outstanding as the end of the test year, the proposed cost of credit support is only $3,750.

VIII. <u>SGS COMMON FACILITIES LEASE.</u>

Q. Please describe the Company's long-term lease of the SGS Common Facilities.

A. TEP leases a 50% undivided interest in the SGS common facilities under three separate lease agreements that expire in 2017 and 2021. The common facilities under lease include roads, water wells, warehouse buildings, the main control room for SGS Units 1 & 2, and other facilities including various piping systems, lined reservoirs, and water treatment systems. The three lease agreements are nearly identical to one another, except that each lease covers a different ownership share and has different scheduled rent payments. In my testimony, I will refer to these three lease agreements collectively as

the Common Facilities Lease. The other 50% undivided interest in common facilities is jointly owned by TEP and the co-owners of SGS Unit 1.

Under the terms of the Common Facilities Lease, rent is paid semi-annually by TEP to a trustee. The trustee applies the rent to pay principal and interest on lease debt that was issued in connection with the original sale and leaseback transaction, and then distributes any remaining rent proceeds to the owner participants who have an equity interest in the lease agreement. Since the lease debt issued in connection with this lease is variable rate, the lease payments vary based on changes in the underlying variable interest rate.

Q. How is the Common Facilities Lease accounted for?

A. For financial reporting purposes it is accounted for as a capital lease obligation. For rate-making purposes it is accounted for as an operating lease and included in TEP's revenue requirement as an operating expense. The amount of common facilities rent expense included in the Company's last rate case was based on the average lease payment over the primary term of the lease. TEP is proposing a continuation of that same cost recovery method in this rate case.

Q. Does TEP own an equity interest in any of the three separate leases comprising the Common Facilities Lease?

A. No, the Company has not purchased any ownership interest from the owner participants in these leases. Additionally, no changes have been made to the terms of the leases since TEP's last rate case.

Q. Have the scheduled rent payments under the Common Facilities Lease changed since TEP's last rate case?

A. Yes, but only slightly. This is due to changes in the benchmark LIBOR rate, which is used to establish the variable interest rate on the underlying lease debt. However, since most of the Common Facilities Lease debt has been hedged by TEP against changes in LIBOR, the Company is exposed to interest rate risk on only a portion of the lease debt outstanding.

Q. Please describe the interest rate hedging agreements that TEP entered into for the Common Facilities Lease debt.

A. In 2006, TEP entered into a fixed-for-floating interest rate swap on $36.8 million principal amount of lease debt. This hedge was required by lenders as a condition to the refinancing of the Common Facilities Lease debt that TEP completed that same year. The notional amount of debt hedged declines over time as the underlying lease debt is paid down, with a final maturity of January 2020. Under the swap agreement TEP pays a 5.77% fixed rate on the specified notional amount and receives an interest rate equal to six month LIBOR, a published benchmark interest rate. Since the common facilities lease debt has a variable interest rate tied to six month LIBOR, this swap agreement has the effect of fixing the interest rate paid by TEP on this tranche of lease debt through January 2020. As of the end of the test year, $28.5 million principal amount of this lease debt remained outstanding.

In May 2009, TEP entered into two additional interest rate swap agreements covering an additional $29.9 million of Common Facilities Lease debt. Like the 2006 swap agreement, the notional amount of debt hedged declined over time as the underlying lease debt was paid down. However, the terms of these agreements extended only to mid-

2014. As of the end of the test year, $13.7 million principal amount of this lease debt remained outstanding.

Q. Have these hedging arrangements been reflected in the lease expense that TEP is requesting in this proceeding?

A. Yes. Consistent with the methodology used in TEP's last rate case, the impact of the interest rate swap agreements is incorporated in the calculation of average lease expense.

Q. What lease expense is TEP proposing for the Common Facilities Lease?

A. The requested lease expense for the Common Facilities Lease is $10,611,000, which is nearly the same as the lease expense approved by the Commission in TEP's last rate case. **Exhibit KCG-3** sets forth a chart depicting scheduled lease payments over the primary term of the lease.

Q. Does TEP receive periodic payments from the owners of SGS Units 3 and 4 for use of the common facilities?

A. Yes. Certain of the common facilities originally built to serve SGS Units 1 & 2 also serve SGS Units 3 & 4. Consistent with the treatment approved in TEP's last rate case, the Company has reduced its revenue requirement by the annual amount of common facilities usage fees received from the owners of SGS Units 3 & 4.

Q. What options are available to TEP for purchasing or extending its leasehold interest in the common facilities beyond the current lease terms?

A. The Company has an optional fair market value lease renewal option as well as a fixed price purchase option under each of the three separate lease agreements. In aggregate, the fixed price to acquire the leased facilities is contractually set at $38 million in 2017 and $68 million in 2021. If TEP exercises these purchase options, the owner of SGS Unit

4 will be obligated to purchase a share of the common facilities from TEP in 2021, while the owner of SGS Unit 3 will have the option of either purchasing its share of the common facilities from TEP or continuing to make periodic payments to the Company for use of the facilities.

Q. Has TEP made leasehold improvements to the leased common facilities?

A. Yes. Replacements and betterments of these facilities are required periodically in order to ensure continued operation of SGS Units 1 and 2. To the extent any of these facilities are also used by SGS Units 3 & 4, the owners of those units pay a pro rata share of the required capital expenditures.

Q. What was the balance of Springerville common facility leasehold improvements as of the end of the test year?

A. TEP's balance of leasehold improvements was $20.7 million as of June 30, 2015.

Q. How were the Springerville common leasehold improvements treated in TEP's last rate order?

A. The test year balance was included in rate base, and the balance was amortized over the remaining life of the lease.

Q. How is TEP proposing to recover the leasehold improvements in this filing?

A. TEP has included these improvements in rate base and is proposing a longer ten-year recovery period for these investments. Assuming new retail rates go into effect in January 2017, there would only be four years left until the end of the lease. By using a ten-year amortization period, the rate impact on customers is reduced relative to a remaining life-of-lease recovery period.

IX. PURCHASE OF SGS COAL HANDLING FACILITIES.

Q. Please describe the leasehold interest TEP previously held in the SGS Coal Handling Facilities ("CHF"), and the current ownership status of those facilities.

A. From 1984 through 2001, TEP leased all of the SGS CHF through three separate long-term lease agreements. In 2001, TEP purchased the equity interest in one of the leases and subsequently terminated that lease agreement, resulting in direct ownership of a 13.3% interest in the SGS CHF. The remaining two lease agreements remained in effect through the scheduled expiration date of April 5, 2015. At that time, TEP exercised its fixed purchase price option and paid $120.3 million for the remaining 86.7% interest in the SGS CHF.

Shortly after the end-of-lease purchase by TEP, pursuant to a support and operating agreement between TEP and the owner of SGS Unit 4, the owner of SGS Unit 4 purchased a 17.05% interest in the SGS CHF from the Company for $23.7 million. Pursuant to a separate support and operating agreement with the owner of SGS Unit 3, the owner of that unit also has an option to purchase an equivalent interest in these facilities at the same price. The owner of SGS Unit 3 has until April 2016 to exercise this purchase option. If they decide not to purchase the facilities, they will be obligated to continue paying facility usage fees to TEP for continued use of the SGS CHF.

Q. What facilities were purchased by TEP at the end of the SGS CHF lease?

A. The SGS CHF include a rail spur from the mainline of the Burlington Northern Santa Fe railroad, a rotary coal-car dumper, a conveyor system that moves coal from the unloading hoppers to the storage piles for SGS Units 1&2, plus an additional coal conveyor and crusher system that provides coal to the pulverizer silos for SGS Units 1&2. The SGS

CHF also include a fuel oil handling system that is used to unload, store and transport fuel oil to SGS Units 1&2 when needed.

Q. Please describe how the purchase price applicable to the owners of SGS Units 3&4 was determined.

A. Prior to the construction of SGS Unit 3, a study was performed to determine which components of the SGS CHF could be shared by all units at the site. For the most part, those shared components consisted of the rail spur and the rotary coal car dumper that are presently serving all four units. After taking into account the original cost of the shared facilities in relation to the total cost of the SGS CHF, it was determined that a 17.05% interest in the SGS CHF should be allocated to each of the owners of SGS Units 3&4. The $23.7 million purchase price applicable to each of the owners of SGS Units 3&4 was then determined by multiplying the 17.05% interest by the $138.7 million end-of-lease purchase price specified in the three SGS CHF leases.

Q. Please explain why the purchase price applicable to SGS Units 3&4 was based on a $138.7 million end-of-lease purchase price when TEP paid only $120.3 million at the end of the leases in April 2015.

A. The difference is attributable to the lease equity interest that TEP purchased in 2001. The end-of-lease purchase option contained in that lease specified a fixed purchase price of $18.4 million. By purchasing the lease equity interest, TEP avoided having to pay this amount at the end of the lease in 2015. However, this amount was included in calculating the purchase price properly allocable to the owners of SGS Units 3&4.

Q. Please describe the purchase transaction TEP entered into in 2001, and how that purchase is reflected in the Company's rate request.

A. In December 2001, the Company paid a third-party investor $13.0 million for a lease equity interest covering a 13.3% undivided interest in the SGS CHF. In January 2002, TEP also purchased $13.0 million principal amount of lease obligation bonds associated with this lease interest. Following the purchase of the lease debt, TEP then caused the lease to be terminated and the Company took direct ownership of this 13.3% undivided interest in the CHF.

When TEP purchased the lease equity interest, it paid for the right to receive all of the remaining lease equity rents, as well as for the residual value of the asset at the end of the lease. In terms of value received by the Company, TEP was able to avoid $15.0 million in remaining lease equity rents as well as an $18.4 million end-of-lease purchase price for the assets. Since nearly all of the avoided rents were scheduled to be made in the later years of the lease, from 2012 through 2015, the relative value of the avoided rents and avoided end-of-lease purchase price can be determined with reasonable accuracy by simply comparing the nominal dollars involved. On a nominal dollar basis, of the $33.4 million in realized cash flow benefits, approximately 55% was attributable to the avoided end-of-lease purchase. Hence, TEP is requesting that $7.3 million (or 55%) of its original $13.3 million lease equity investment be included in rate base at this time. Although this investment was made almost 14 years before the end of the test-year in this rate case, the Company is not requesting that any carrying costs be included in this amount.

Q. What portion of the SGS CHF is allocable to the 50.5% share of SGS Unit 1 currently owned by third parties?

A. Using the same allocation approach described earlier for SGS Units 3&4, the amount that is allocable to the co-owner share of SGS Unit 1 is $23.1 million. That amount is based on

16.64% of the $138.7 million total end-of-lease purchase price referred to above. The percentage allocation of 16.64% was arrived at as follows:

% Allocable to SGS Units 1&2 = 100% - 17.05% - 17.05% = 65.9%

% Allocable to SGS Unit 1 = 65.9% x 50% = 32.95%

% Allocable to co-owner share = 32.95% x 50.5% = 16.64%

Q. What net acquisition cost is TEP proposing to include in rate base for the SGS CHF?

A. TEP is requesting that a net purchase price of $57.1 million be included in rate base, reflecting the portion of the purchase price allocable to the Company's current ownership of SGS Units 1 and 2. This amount is calculated as follows:

($millions)

$120.3	Purchase price paid for 86.7% interest in 2015
7.3	Portion of purchase price paid for 13.3% interest in 2001
(23.7)	Portion of CHF allocable to SGS Unit 3
(23.7)	Portion of CHF allocable to SGS Unit 4
(23.1)	Portion of CHF allocable to SGS Unit 1 co-owners
$ 57.1	

Q. During the test year, did TEP receive facility usage fees for the SGS CHF from the owners of SGS Units 3&4?

A. Yes. A full year of usage fees was received from the owner of SGS Unit 3, while the owner of SGS Unit 4 paid monthly usage fees through March 2015, shortly before their purchase of a 17.05% interest in the SGS CHF. For purposes of this rate filing, TEP has assumed that the owner of SGS Unit 3 will exercise their purchase option before the option expiration date of April 2016. Therefore, the Company's net purchase price has been reduced for this assumed third-party purchase, and the test year facility usage fees

for the SGS CHF have been removed from other revenues in calculating the Company's revenue requirement.

Q. During the test year, did TEP receive any facility usage fees for the SGS CHF from the co-owners of SGS Unit 1?

A. No.

Q. What is TEP proposing with respect to the portion of the SGS CHF allocable to the co-owners of SGS Unit 1?

A. As described later in my testimony, contingent upon dispatching the co-owner share of SGS Unit 1 to meet retail customer needs, the Company is proposing that it begin recovering the related operating costs through the PPFAC. A portion of those operating costs would be associated with use of the SGS CHF.

X. PURCHASE OF 49.5% INTEREST IN SGS UNIT 1.

Q. Please describe the leasehold interest TEP previously held in SGS Unit 1, and the process by which TEP acquired its current ownership interest in the unit.

A. Since 1992, TEP leased SGS Unit 1 and a 50% undivided interest in related common facilities under seven separate lease agreements, all of which expired on January 1, 2015. Through the exercise of purchase options for selected lease interests, as well as an earlier purchase of lease equity, TEP became the owner of a 49.5% undivided interest in SGS Unit 1 as of January 1, 2015. TEP chose not to exercise purchase options on two of the lease interests covering a 50.5% undivided interest in SGS Unit 1. The status of this third-party ownership interest is discussed below in the next section of my testimony. Under the terms of existing agreements, TEP remains the operator of SGS Unit 1.

In 2006, TEP purchased its initial ownership interest in SGS Unit 1 through a purchase of lease equity from one of the lease owner-participants. TEP paid $48 million to acquire a lease equity interest covering a 14.1% undivided interest in SGS Unit 1 and related common facilities. Shortly thereafter, TEP caused the lease to be amended to eliminate the equity portion of rent payments. This reduction in lease payments was fully reflected in the revenue requirement for SGS Unit 1 in the last two rate orders for the Company. Following the purchase, TEP continued making rent payments to an indenture trustee for the purpose of making principal and interest payments on lease obligation bonds that were still outstanding. After those bonds were paid in full, and the lease expired in January 2015, TEP took direct ownership of a 14.1% undivided interest in SGS Unit 1 and related common facilities.

With respect to the other six leases covering an 85.9% share in SGS Unit 1, the Company submitted a notice to all of the owner-participants in 2011 stating TEP's interest in purchasing their ownership interests at the end of the leases. Pursuant to the terms of those leases, TEP had a right to purchase each of the interests at fair market value. Following a brief negotiation period, a formal appraisal process was initiated by TEP pursuant to the lease agreements. One appraiser was selected by TEP, another was selected by the owner-participants, and a third appraiser was selected by mutual agreement. The lease documents specified that the fair market value of SGS Unit 1 was to be determined by averaging the two closest appraisals and discarding the third appraisal. The end result of this process was an appraised value of $159 million for the 85.9% interest not already owned by TEP, which equates to $478 per kW of generating capacity.

In early 2012, following completion of the appraisal process, two of the owner-participants met with TEP to discuss their concerns with the appraised value. Subsequent to that meeting, in April 2012, TEP filed a petition in the United States District Court seeking to

have the appraisal confirmed as an arbitration award. All of the owner-participants contested the petition, and following oral argument and briefing in the matter, TEP's request was denied due to lack of jurisdiction. In February 2013, TEP appealed the ruling to the United States Court of Appeals. However, the appeal was still pending as the deadline for the exercise of TEP's purchase options approached. After consulting with three of the owner-participants who had been long-term investors in the SGS Unit 1 lease, TEP exercised its purchase options in August 2013 for a 35.4% interest in the unit at the appraised value of $478/kW. Based on written assurances from the selling owner-participants that they would honor the purchase price, TEP withdrew its appeal. On December 30, 2014 and January 2, 2015, TEP completed the purchases of the selected ownership interests at an aggregate purchase price of $65 million, which reflected the appraised value of $478/kW.

Q. Why did TEP elect not to purchase the remaining 50.5% share of SGS Unit 1 and related common facilities?

A. First, it was unlikely, based on prior communications with the two remaining owner-participants, that they would have honored TEP's purchase option at the appraised value of $478/kW. Second, as described in the testimony of Company witness Michael Sheehan, the Company had already identified an attractive alternative resource, the natural gas-fired Gila River Unit 3, by the time TEP had to make a decision with respect to SGS Unit 1.

Q. What amount is TEP proposing to include in rate base for the 14.1% interest it acquired in 2006?

A. TEP is requesting rate base treatment of its original $48 million investment, less $5.3 million of previous rent reduction benefits retained by TEP. The resulting net investment of $42.7 million is included in the Company's proposed rate base.

When TEP purchased the lease equity interest covering a 14.1% share of SGS Unit 1, it purchased the rights to the equity portion of remaining lease payments as well as the residual value of the asset at the end of the lease. As a result, TEP was able to amend the lease and eliminate the equity portion of rent payments over the remainder of the lease term, which totaled $40.3 million from 2007 through 2014. In TEP's 2008 rate order (Decision No. 70628 (December 1, 2008)), a revenue requirement was adopted that fully passed onto customers the reduction in rental payments over the period 2009 through 2014, which totaled $35.0 million. As a result, customers received most of the rent savings resulting from the lease equity purchase, while TEP retained only $5.3 million of equity rent reductions realized in 2007 and 2008.

The purchase of lease equity also allowed TEP to avoid an end-of-lease purchase of the 14.1% (55 MW) share of SGS Unit 1. At the time of the purchase, the market value of coal-fired generating capacity was much higher than it is today, with similar assets changing hands at values well in excess of $1000/kW. Although the value of coal-fired generation has since declined, due in large part to lower natural gas prices and increased environmental regulation, TEP acted prudently by locking-in a high quality generation resource based on the information available to it at the time. On a per-kW basis, the $42.7 million net investment equates to $776/kW of generating capacity, which is higher than the ultimate appraised value of $478/kW that TEP paid for a 35.4% share of SGS Unit 1 at the end of the lease. However, it is reasonable when compared to the estimated market value of other coal-fired generating assets at the time of the purchase in 2006. Additionally, TEP is not proposing to add carrying costs to its net investment, even though it will not begin recovering this investment until new rates go into effect, presumably in 2017.

Q. What amount is TEP proposing to include in rate base for its purchase of a 35.4% share of SGS Unit 1 at the end of the lease term?

A. TEP is requesting the $65 million purchase price plus transaction costs and related legal costs. This purchase price was based on the appraised value of $478/kW that was determined in 2011 pursuant to the terms of the lease agreement. Based on the appraisal process described earlier, TEP believes this price represented the fair market value of the unit at the time the appraisal was performed.

Q. How is TEP proposing to treat the leasehold improvements that it made to SGS Unit 1 and the common facilities during the term of the lease agreement?

A. Upon termination of the leases covering the 49.5% share of SGS Unit 1 now owned by TEP, the leasehold improvements associated with that share of the unit were reclassified to plant-in-service and are reflected as such in the Company's rate filing. At the same time, the leasehold improvements associated with the 50.5% co-owner share were reclassified as a regulatory asset and remain on the same 10-year amortization schedule approved in TEP's last rate case. The leasehold improvements to SGS Unit 1 and the related common facilities were required in order to keep the facilities in good operating condition in accordance with the leases and other governing agreements, and to comply with various state and federal regulations.

XI. STATUS OF REMAINING 50.5% INTEREST IN SGS UNIT 1.

Q. Please describe the current situation with the co-owners of SGS Unit 1.

A. The two co-owners of SGS Unit 1, both of whom were former lessors under a long-term lease with TEP, have filed various legal actions against the Company in state court in New York, with the American Arbitration Association, and at the Federal Energy Regulatory Commission. They have also failed to pay TEP for their share of the operating and capital

costs of SGS Unit 1 since the leases expired in January 2015. In June 2015, the Company began selectively dispatching the co-owner's unscheduled power from their share of SGS Unit 1 as permitted under the governing agreements, and selling the power in the wholesale market.

Q. What is TEP's position on the legal claims made by the co-owners?

A. TEP believes that it has fully complied with all of its obligations under the governing agreements, has denied the co-owner's allegations, and intends to vigorously defend itself against these claims.

Q. What is the timeframe for resolving this litigation?

A. It is difficult to say with any certainty due to the legal complexities involved.

Q. Does TEP expect to continue dispatching the co-owner share of SGS Unit 1?

A. Yes. So long as there remains unscheduled capacity available, the Company intends to exercise its dispatch rights to this portion of SGS Unit 1.

Q. Does this 50.5% share of SGS Unit 1 have value to TEP as a system resource?

A. Yes. As described in the testimony of Company witness Michael Sheehan, SGS Unit 1 has considerable value as a system resource available for dispatch and delivery to retail customers.

Q. In this rate filing, what is TEP proposing with respect to the co-owner share of SGS Unit 1?

A. To the extent this generating capacity is available for dispatch by TEP, the Company is proposing that it begin dispatching this share of SGS Unit 1 to meet retail customer needs and to begin recovering the related operating costs through the Company's PPFAC,

commencing the effective date of the Commission's rate order. The specific costs that would be subject to recovery are described in the testimony of TEP witness Michael Sheehan, and would be offset by any wholesale revenues realized from dispatching this capacity as a system resource. If the status of this 50.5% share of SGS Unit 1 were to change, and became no longer available for dispatch as a system resource, the related operating costs would no longer be recoverable through the PPFAC. Additionally, if TEP is ultimately reimbursed by the SGS Unit 1 co-owners for costs recovered through the PPFAC, TEP would commit to crediting the PPFAC balance for any such receipts. The Company believes this is a reasonable approach, given the uncertain timing and outcome of the pending litigation with the co-owners.

Q. Earlier you stated that a portion of the SGS Coal Handling Facilities ("CHF") is allocable to the co-owner share of SGS Unit 1. What costs related to the CHF is the Company proposing for contingent PPFAC recovery?

A. A monthly facilities charge of $306,856 is appropriate, based on the monthly amounts historically paid by the owners of SGS Units 3&4 for use of the SGS CHF, and the relative percentage share of SGS CHF allocable to the co-owners of SGS Unit 1. That amount is calculated as follows:

Monthly fees paid by owners of SGS Unit 3&4	$628,833
x Relative size of SGS CHF allocation	(16.64/34.10)
Monthly facilities charge for 50.5% of SGS Unit 1	$306,856

Any additional operating costs related to this portion of the SGS CHF, such as labor and materials, would also be subject to recovery through the PPFAC as proposed by TEP.

Q. Is TEP seeking to recover any other costs related to the co-owner share of SGS Unit 1?

A. Yes. During the test year, and following expiration of the SGS Unit 1 lease, TEP made approximately $2 million of capital investments in SGS Unit 1. The SGS Unit 1 co-owners have been billed for 50.5% of these capital expenditures, but have yet to make payment to TEP. Since these expenditures were required to keep SGS Unit 1 in good operating condition in accordance with the governing agreements, and since TEP is presently using 49.5% this generating unit to serve retail customers, TEP is proposing to include the full $2 million of plant investments in rate base, with approximately half included as plant-in-service and the other half included as a regulatory asset and amortized over a 10-year period. Should the Company be reimbursed by the co-owners for their share of these investments, TEP would commit to returning this amount to customers, with interest, in its next rate case.

XII. SUMMARY OF SCHEDULES.

Q. Please describe Schedule D in the Company's Application.

A. Schedules D-1 through D-4 contain the Company's actual and proposed capital structure, cost of debt and WACC for the test year ended June 30, 2015. These schedules also include a projected capital structure, cost of debt and WACC for the twelve months ending June 30, 2016.

Q. Please describe Schedule F in the Company's Application.

A. Schedule F consists of four parts, Schedules F-1 through F-4.

Schedule F-1 contains a summary income statement for the test year ended June 30, 2015. This same information is presented on a projected basis for the twelve months

ending June 30, 2016. The projected year information is also presented assuming that the requested rate increase was implemented on July 1, 2015.

Schedule F-2 contains a summary cash flow statement for the test year ended June 30, 2015. This same information is presented on a projected basis for the twelve months ending June 30, 2016. The projected year information is also presented assuming that the requested rate increase was implemented on July 1, 2015.

Schedule F-3 contains information on the Company's capital investments during the test year ended June 30, 2015. The same information is presented on a projected basis for calendar years 2015, 2016 and 2017.

Schedule F-4 contains a description of key forecast assumptions used in preparing the projected information appearing in Schedules F-1 through F-3.

Q. Please comment on the projected information appearing in Schedules F-1 and F-2.

A. The financial projections that assume a continuation of current rates through December 2016 were taken from a base case financial forecast prepared for TEP. It should be noted that this forecast is based on numerous assumptions regarding sales growth, wholesale energy prices, natural gas prices, operating and capital expenditures, the Company's future generation resource portfolio, and other factors that are subject to change over time. Additional financial projections are provided in Schedules F-1 and F-2 that assume implementation of the Company's requested rate increase as of July 1, 2015. These additional projections are included for purposes of complying with the Commission's rate filing requirements. Since the Company will not be able to change its retail rates until it is ordered to do so by the Commission, projections assuming that the requested rates were implemented in July 2015 are of limited analytical value.

Q. Does this conclude your Direct Testimony?

A. Yes.

Exhibit KCG-1

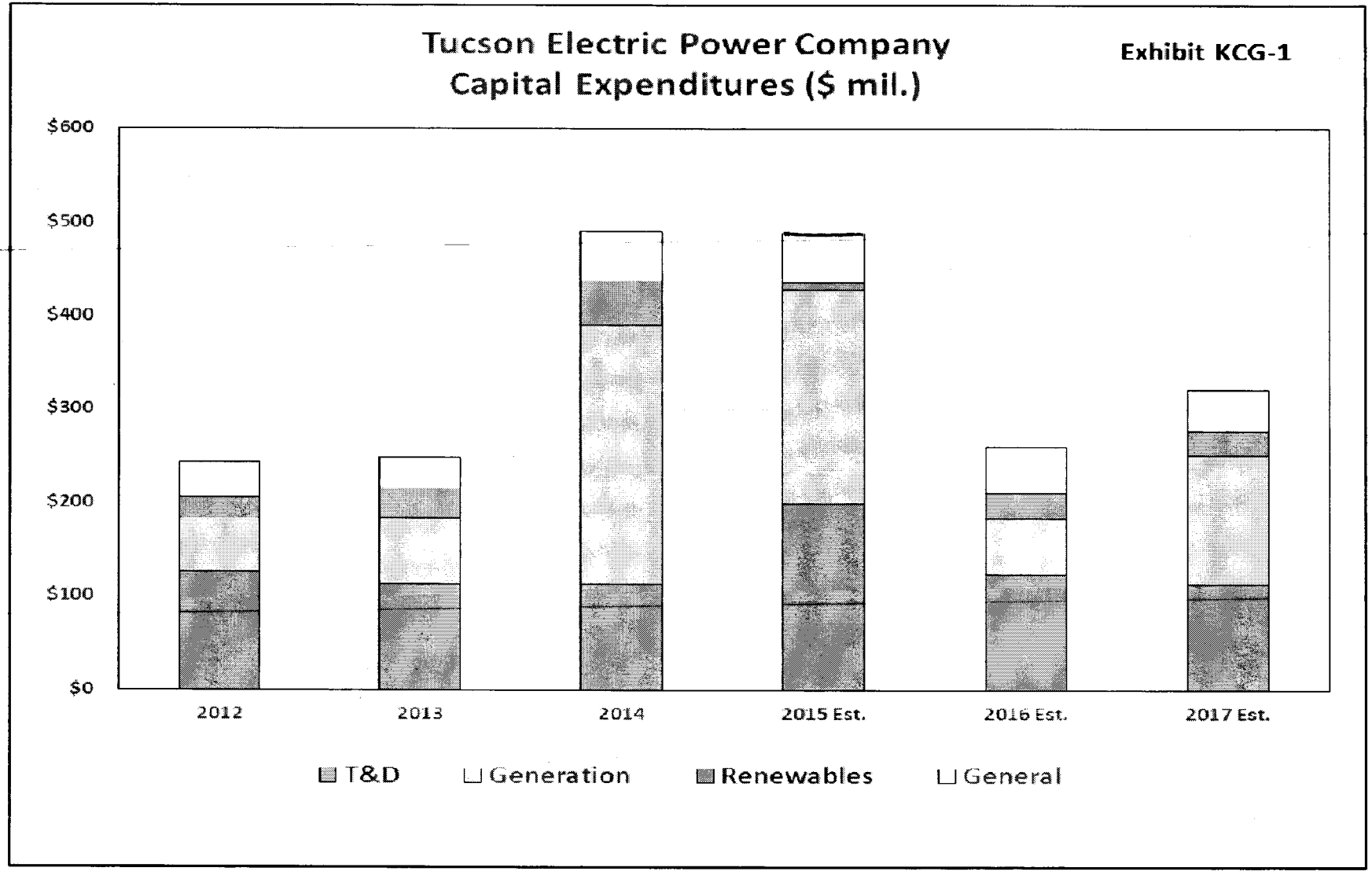
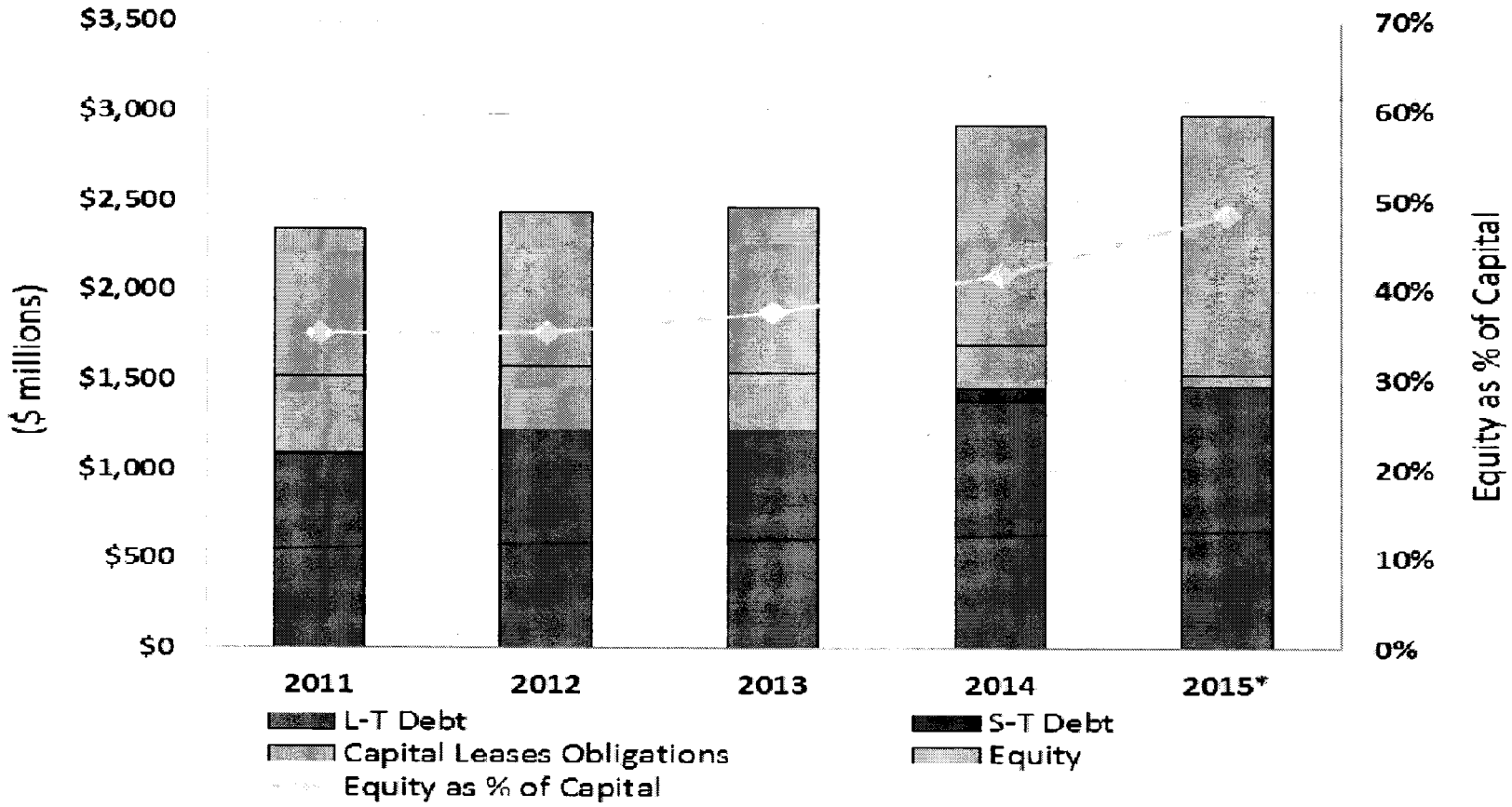

Tucson Electric Power Company
Capital Expenditures ($ mil.)
Exhibit KCG-1
$600
$500
$400
$300
$200
$100
$0
2012
2013
2014
2015 Est.
2016 Est.
2017 Est.
T&D
Generation
Renewables
General

Exhibit KCG-2

Tucson Electric Power Company
Capital Structure

Exhibit KCG-2

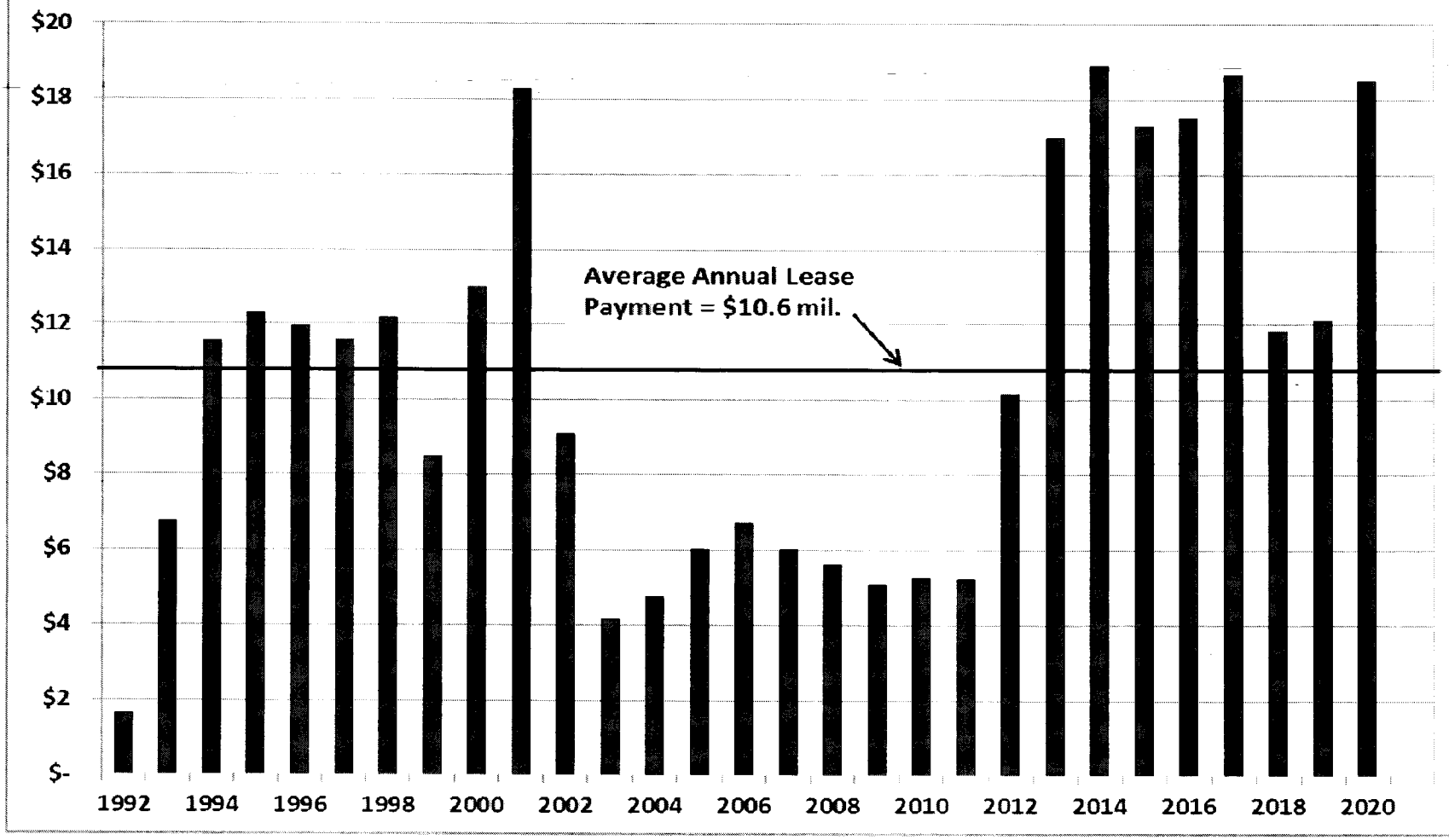


* Balance as of June 30, 2015, adjusted for August bond redemptions.

Exhibit KCG-3

Exhibit KCG-3

Tucson Electric Power Company
SGS Common Facilities Lease Payments



Direct Testimony of

Ann E. Buckley

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Ann E. Bulkley

on Behalf of

Tucson Electric Power Company

November 3, 2015

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AEB-6 Risk Premium
AEB-7 Cost Recovery Mechanisms
AEB-8 S&P Credit Analysis
AEB-9 Capital Structure
AEB-10 Fair Value Rate of Return
AEB-11 Comparable Transactions
Attachment A- Resume and Testimony Listing

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Ann E. Bulkley. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752.

Q. What is your position with Concentric Energy Advisors, Inc. ("Concentric")?

A. I am employed by Concentric as a Vice President.

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

A. I am submitting this Direct Testimony on behalf of Tucson Electric Power Company ("TEP" or the "Company"). TEP is a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy"). UNS Energy was purchased in August 2014 by Fortis, Inc. ("Fortis"). Fortis is an investor-owned utility holding company based in St. John's, Newfoundland and Labrador, Canada.

Q. Please describe your education and experience.

A. I hold a Bachelor's degree in Economics and Finance from Simmons College and a Master's degree in Economics from Boston University, with approximately 20 years of experience consulting to the energy industry. I have advised numerous energy and utility clients on a wide range of financial and economic issues with primary concentrations in valuation and utility rate matters. Many of these assignments have included the determination of the cost of capital for valuation and ratemaking purposes. I have included my resume and a summary of testimony that I have filed in other proceedings as Attachment A.

Q. Please describe Concentric's activities in energy and utility engagements.

A. Concentric provides financial and economic advisory services to many and various energy and utility clients across North America. Our regulatory, economic, and market analysis services include utility ratemaking and regulatory advisory services; energy market assessments; market entry and exit analysis; corporate and business unit strategy development; demand forecasting; resource planning; and energy contract negotiations. Our financial advisory activities include buy and sell-side merger, acquisition and divestiture assignments; due diligence and valuation assignments; project and corporate finance services; and transaction support services. In addition, we provide litigation support services on a wide range of financial and economic issues on behalf of clients throughout North America.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. What is the purpose of your Direct Testimony?

A. The purpose of my Direct Testimony is to present evidence and provide a recommendation regarding the Company's Return On Equity ("ROE") [1] and to provide an assessment of the capital structure to be used for ratemaking purposes as proposed in the Direct Testimony of Company Witness Kentton C. Grant. My Direct Testimony also provides evidence and a recommendation as to the appropriate Fair Value Rate Of Return ("FVROR") and to the reasonableness of the Company's proposed Fair Value Rate Base ("FVRB"). My analyses and recommendations are supported by the data presented in Exhibit AEB-1 through Exhibit AEB-12, which were prepared by me or under my direction.

[1] Throughout my Direct Testimony, I interchangeably use the terms "ROE" and "Cost of Equity".

Q. Please provide a brief overview of the analyses that led to your ROE recommendation.

A. As discussed in more detail in Section VI, in developing my ROE recommendation, I applied the Constant Growth and Multi-Stage forms of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), and the Risk Premium approach. I also considered several additional risk factors that affect the Company's required ROE: (1) the Company's capital expenditure requirements; and (2) the regulatory environment in which the Company operates. Finally, I considered the Company's proposed capital structure as compared to the capital structures of the proxy companies. While I did not make any specific adjustments to my ROE estimates for any of these factors, I did take them into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results.

Q. What are your conclusions regarding the appropriate Cost of Equity and FVROR for the Company?

A. My analyses indicate that the Company's Cost of Equity should be within the range of 10.00 percent to 10.60 percent. Considering the results of the analyses summarized in Chart 1 and discussed in greater detail in the remainder of my testimony, I believe that a reasonable ROE for TEP is 10.35 percent. I also believe that the appropriate return on the Fair Value Increment for TEP is 1.42 percent and the resulting FVROR is 5.69 percent.

Q. What are your conclusions regarding the Company's Fair Value Rate Base ("FVRB")?

A. Based on the results of my Comparable Transactions analysis I conclude that the Company's estimate of the FVRB is conservative.

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

A. The remainder of my Direct Testimony is organized as follows: Section III provides a summary of my analyses and conclusions; Section IV reviews the regulatory guidelines pertinent to the development of the cost of capital; Section V discusses current and projected capital market conditions and the effect of those conditions on the Company's Cost of Equity; Section VI explains my selection of a proxy group of electric utilities; Section VII describes my analyses and the analytical basis for the recommendation of the appropriate ROE for TEP; Section VIII provides a discussion of specific regulatory, business, and financial risks that have a direct bearing on the ROE to be authorized for the Company in this case; Section IX discusses the capital structure of the Company as compared with the proxy group; Section X presents my conclusions and recommendation for the market Cost of Equity; Section XI discusses my analysis of the Company's proposed FVRB; and Section XII discusses the estimation of the FVROR.

III. SUMMARY OF ANALYSIS AND CONCLUSIONS

Q. Please summarize the key factors considered in your analyses and upon which you base your recommended ROE.

A. My analyses and recommendations considered the following:

- The *Hope* and *Bluefield* decisions[2] that established the standards for determining a fair and reasonable allowed ROE, including consistency of the allowed return with other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and that the end result must lead to just and reasonable rates.
- The effect of current and projected capital market conditions on the ROE estimation models and on investors' return requirements.
- The Company's regulatory, business, and financial risks relative to the proxy group of comparable companies and the implications of those risks in arriving at the appropriate ROE.

Q. Please summarize the ROE estimation models that you considered to establish the range of ROEs for TEP.

A. I considered the results of two forms of the DCF model: the Constant Growth DCF and the Multi-Stage DCF. In addition, I considered two risk premium approaches: the CAPM and a Bond Yield Plus Risk Premium methodology. Chart 1 summarizes the range of results established using each of these estimation methodologies.

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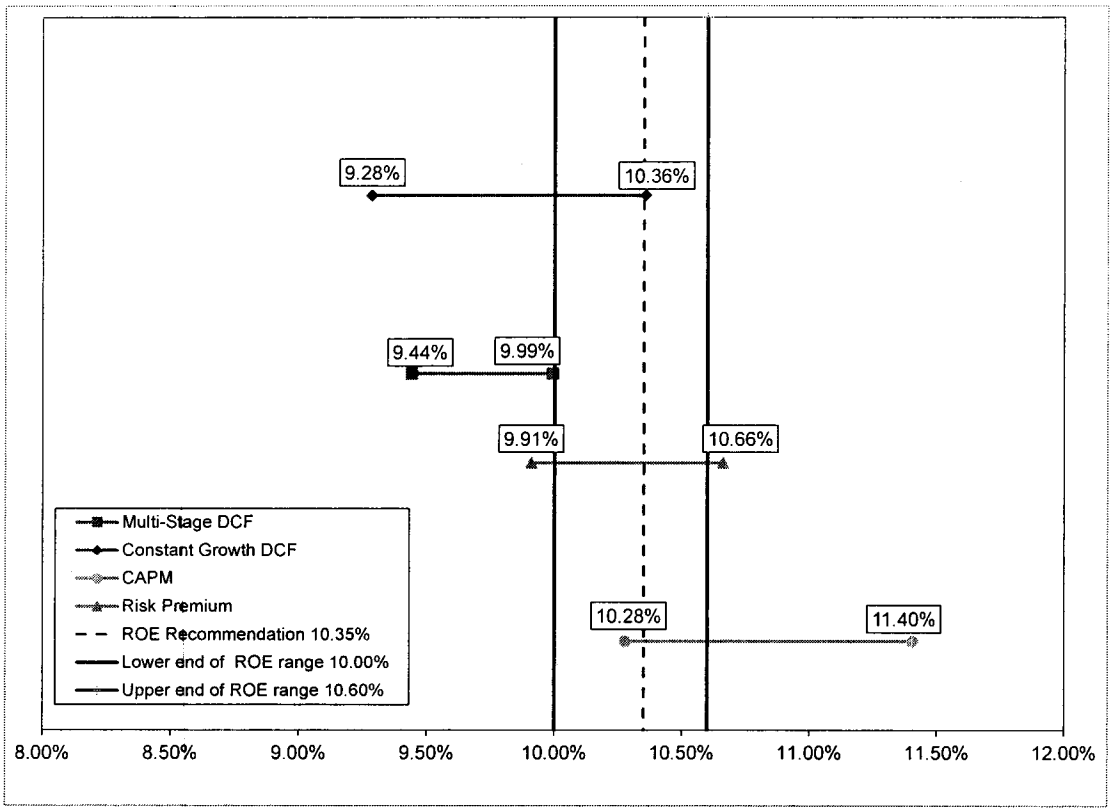
[2] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

Chart 1: Summary of Cost of Equity Analytical Results



As shown on Chart 1, the range of the DCF model results is very wide, particularly in relation to the results of the other methodologies. As discussed in more detail in Section VIII, the DCF models are influenced by market conditions that are not projected to be sustained in the long term. Those conditions have a tendency to result in lower estimates of the Return on Equity using the DCF model. As shown in Exhibit AEB-1, the DCF models produce individual company results as low as 4.06 percent, which is below the Company's embedded cost of long-term debt.

Recent, somewhat anomalous market conditions have had an effect on the assumptions used in the ROE estimation models, particularly the DCF model. Therefore, I agree with the position that the Arizona Corporation Commission ("Commission") has previously stated that considering the DCF results alone would not result in an appropriate Cost of

Equity under current circumstances.[3] As discussed in more detail in the remainder of my Direct Testimony, this conclusion is also supported by the Surface Transportation Board ("STB") and the Federal Energy Regulatory Commission ("FERC"). Both regulatory commissions have determined that it is appropriate to consider the results of both the DCF and CAPM models in estimating the ROE.

While I have concerns about the results produced by the DCF models, my ROE recommendation is based on the results of the DCF model and a forward-looking CAPM analysis, taking into consideration the business and company-specific risk factors. The Bond Yield Plus Risk Premium analysis, while not relied on specifically for the ROE recommendation, corroborates the range established for my recommendation.

Q. What is your recommended ROE for TEP?

A. The analytical results presented in Chart 1 provide the range of results for the proxy group companies. I also considered the level of regulatory, business, and financial risk faced by the Company relative to the proxy group in order to establish where TEP's ROE falls within the range. Based on the analytical results in Chart 1, a reasonable range of ROE estimates for TEP is from 10.00 percent to 10.60 percent, and within that range, 10.35 percent is a reasonable and appropriate estimate of the Company's ROE. This recommendation reflects the range of results for the proxy group companies, the relative risk of TEP as compared to the proxy group, and current capital market conditions. The required ROE should be a forward-looking estimate; therefore, the analyses supporting my recommendation rely on forward-looking inputs and assumptions (*e.g.,* projected growth rates in the DCF model, forecasted risk-free rate and Market Risk Premium in the CAPM analysis, etc.) and takes into consideration the current high valuations of utility

[3] *See* Decision No. 69663 (June 28, 2007), at 49.

stocks and the market's expectation for higher interest rates. The use of historical inputs and assumptions would tend to understate the required ROE for TEP, especially under current and projected conditions in capital markets.

Q. Please summarize the analysis that you conducted to validate the FVRB for TEP.

A. Consistent with Commission precedent, the Company has estimated the FVRB by weighting equally its Original Cost Rate Base ("OCRB") and an estimate of the Replacement Cost New, Depreciated ("RCND") of those assets. I relied on a Comparable Transactions analysis to test the FVRB that is being relied on in the FVROR analysis.

I estimated the market value of TEP's assets by comparing the Company's proposed FVRB to the market value of comparable companies in recent arms-length transactions. To create a consistent basis of comparison among the transactions (which took place amid different market conditions), I normalized the transaction values using the corporate value of the acquired company, which incorporates the book value of debt and equity, resulting in a premium to corporate value resulting from the transactions. I estimated the market value of TEP's assets by applying the median premium of 43.64 percent to the Company's OCRB. That analysis resulted in an estimated market value for TEP's assets of $3,023 million.

Q. What do you conclude from that analysis?

A. Based on the results of the Comparable Transactions analysis, I conclude that the Company's proposed FVRB of $2,913.3 million is conservative relative to the higher estimate of market value discussed above.

Q. How did you estimate the FVROR?

A. I estimated the FVROR using the approach relied on by the Commission in several recent rate cases. In applying that method, I also conclude that the minimum rate of return that should be applied to the fair value "increment" of rate base is the real risk-free rate of return, which I estimate to be 2.84 percent. Notwithstanding the market expectation that the risk-free rate should represent the floor on investments that are not risk-free, the Company has conservatively proposed the use of 50.0 percent of the risk-free rate in the estimate of the FVROR calculation. As shown in Tables 1 and 2, the result of that analysis is a FVROR of 5.69 percent.

Table 1: Estimation of the FVRB

Capital	$ Millions	Percent	Weighted FVRB
OCRB	$ 2,104.7	50.00	$ 1,052.3
RCND	$ 3,721.9	50.00	$ 1,860.9
FVRB			$ 2,913.3

Table 2: Estimation of the FVROR

Capital	$ Millions	Percent	Cost Rate	Weighted Cost Rate
Long-Term Debt	$ 1,051.7	36.10%	4.32%	1.56%
Common Equity	1,053.0	36.14%	10.35%	3.74%
Fair Value Increment	808.6	27.76%	1.42%	0.39%
Total	$ 2,913.3	100.00%		5.69%

IV. REGULATORY GUIDELINES

Q. Please describe the guiding principles to be used in establishing the cost of capital for a regulated utility.

A. The United States Supreme Court's precedent-setting *Hope* and *Bluefield* cases established the standards for determining the fairness or reasonableness of a utility's allowed ROE. Among the standards established by the Court in those cases are: (1) consistency with other businesses having similar or comparable risks; (2) adequacy of the return to support credit quality and access to capital; and (3) that the end result, as opposed to the methodology employed, is the controlling factor in arriving at just and reasonable rates.[4]

Based on those recognized standards, the return authorized in this case should provide the Company with the opportunity to earn an ROE that is:

- Adequate to attract capital on reasonable terms, thereby enabling the Company to provide safe, reliable service;
- Sufficient to ensure the financial soundness of the Company's operations; and
- Commensurate with returns on investments in comparable risk enterprises.

The allowed ROE should enable the Company to finance capital expenditures on reasonable terms and optimize its financial flexibility over the period during which rates are expected to remain in effect.

[4] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

Q. Has the Commission provided similar guidance in establishing the appropriate return on common equity?

A. Yes, it has. The Commission has noted that under the Arizona Constitution, a public utility is entitled to a fair return on the fair value of its property devoted to public uses. The Commission is required to find the fair value of the utility's property and to use that value to establish just and reasonable rates.[5]

Q. Why is it important for a utility to be allowed the opportunity to earn an ROE that is adequate to attract capital at reasonable terms?

A. An ROE that is adequate to attract capital at reasonable terms enables the Company to continue to provide safe, reliable electric utility service while maintaining its financial integrity. To the extent the Company has the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged.

Q. What are your conclusions regarding regulatory guidelines and capital market expectations?

A. It is important for the ROE authorized in this proceeding to take into consideration current and projected capital market conditions, as well as investors' expectations and requirements for both risks and returns. Further, in light of the Company's capital investment requirements, it is important that TEP be afforded the opportunity to maintain a financial profile that will enable it to access the capital markets at reasonable rates.

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[5] *See, e.g., Arizona Corp. Comm'n v. Ariz. Water Co.*, 85 Ariz. 198, 203, 335 P.2d 412, 415 (1959).

V. CAPITAL MARKET CONDITIONS

Q. Why is it important to analyze capital market conditions?

A. It is important to consider the effect of capital market conditions on the inputs and assumptions used in the ROE estimation models and to consider whether or not those market conditions are sustainable over the period that the recommended ROE would be in effect.

Q. What factors are affecting the Cost of Equity for regulated utilities in the current and projected capital markets?

A. The Cost of Equity for regulated utility companies is being affected by several factors in the current and projected capital markets. These factors include: (1) the market's expectation for substantially higher interest rates; (2) current low yields on utility stocks; (3) current high valuations on utility shares relative to historical levels and relative to the broader market; and (4) increasing credit spreads between yields on Treasury bonds and utility bonds. In this section of my Direct Testimony, I will discuss each of these factors and how it affects the Cost of Equity for regulated utilities.

Q. What effect do rising interest rates have on the Cost of Equity for regulated utilities?

A. The potential for rising interest rates indicates that the calculated cost of equity for the proxy companies using current market data is likely to be a conservative estimate of investors' required return. Consequently, rising interest rates would support selection of a return toward the upper end of a reasonable range of equity cost rate estimates that are

based on current market data. As an alternative, the analyses I present include estimated returns based on near-term projected interest rates.

Q. What is the financial market's perspective on the probable timing of an increase in short-term interest rates by the Federal Reserve?

A. The August 2015 issue of Blue Chip surveyed leading economists and market participants concerning their views regarding the timing of an increase in short-term interest rates by the Federal Reserve. Blue Chip reports that 100% of market participants surveyed expect the Federal Reserve will start raising short-term interest rates before the end of 2015.[6] The mid-point of the current Federal Funds rate is 0.125%. The median expectation of FOMC members from the June 2015 FOMC meeting put the fed funds rate at 0.625% at the end of 2015 and at 1.675% at the end of 2016.[7]

Q. What are your conclusions regarding the effect of higher interest rates for electric utilities such as TEP?

A. Many income-oriented investors hold utility stocks for their dividend yields. During periods in which interest rates are expected to increase, the dividend yields of utility stocks become less attractive for income-oriented investors relative to bond yields, placing pressure on utility share prices relative to the broader market, as measured by the S&P 500 Index. The potential for rising interest rates indicates that the calculated Cost of Equity for the proxy companies using any Cost of Equity estimation technique relying on discounted cash flows is likely to lag investors' required return during the period that TEP's rates will be in effect. Consequently, a consensus expectation of rising interest

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6 Blue Chip Financial Forecasts, Volume 34, No. 7, July 1, 2015, at 14.

7 *Ibid.*

rates supports selection of a return for TEP based not only on the DCF model, but also a forward-looking CAPM analysis.

Q. How has the period of abnormally low interest rates affected the valuation and dividend yields of utility shares?

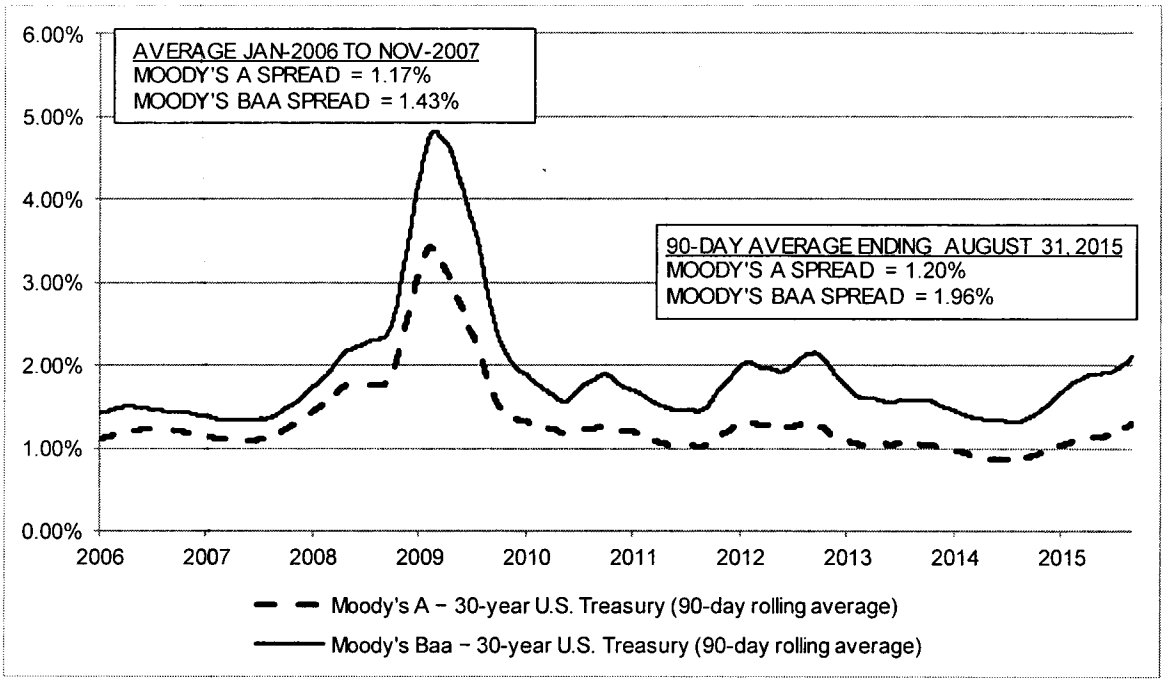
A. The ROE that is established in this proceeding is intended to reflect investors' required return over the forward-looking period during which the established rates will be in effect. The Federal Reserve's Quantitative Easing program resulted in higher asset prices for many common stocks and lower interest rates on government bonds. The prices of shares of public utility companies experienced the higher asset valuations over the past several years, as investors sought higher returns and more attractive yields than were being offered by bonds. Consequently, the current share price of many utility stocks has increased to levels above Value Line's target price for the 2018-2020 time period, while the dividend yield of those same utility stocks has declined to unusually low levels. While Federal market intervention reduced interest rates on government bonds over the last several years, the expectation is that interest rates will be rising over the period when the rates that are established for TEP in this proceeding will be in effect. Therefore, it is not appropriate to base the allowed ROE entirely on the historical level of interest rates. This is especially true when there is an expectation that interest rates are at an inflection point.

Q. Are there indications that investor risk sentiment is increasing in financial markets?

A. Yes. Even as Treasury bond yields have remained relatively low in 2015, yields on corporate bonds have increased steadily throughout the year. Consequently, as shown on Chart 2, credit spreads between government and utility bonds have increased to the

highest level since the credit and financial crisis. In particular, the spread between Baa-rated utility debt and Treasury bonds is nearly 200 basis points.

Chart 2: Credit Spreads for Moody's A- and Baa-rated Utility Bonds



Q. Have you conducted any analysis of investor risk sentiment as compared with the market conditions at the time of TEP's last rate proceeding?

A. Yes, I have. Incremental credit spreads are a widely-recognized measure of investor risk sentiment. Wider credit spreads indicate that investors are requiring a higher premium (*i.e.*, a higher interest rate) to compensate them for the higher risk associated with longer-term or lower-rated debt instruments. My analysis compared the average credit spreads between various government and corporate bonds as of July 31, 2015 to the average spreads as of June 27, 2013, which was the date of the Commission's decision in TEP's previous rate case. As shown on Table 3, the average credit spreads as of July 2015 are generally similar to or higher than those in June 2013.

Table 3: Credit Spreads

Bond Yields	Current Credit Spreads 7/31/15	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	0.76%	0.53%	0.80%
Moody's Baa-rated Utility Bond – 30-year U.S. Treasury	1.92%	1.59%	3.03%
Moody's A-rated Utility Bond – 30-year U.S. Treasury	1.16%	1.06%	2.23%

In particular, the spread between the Moody's Baa-rated utility bond index and the Moody's A-rated utility bond index has increased from 53 basis points at the time of TEP's last rate decision to 76 basis points as of July 2015, which is approaching the 80 basis point spread that prevailed during the Great Recession of 2007-2009. Similarly, the spread between the Moody's Baa-rated utility bond index and the 30-year Treasury yield has increased from 159 basis points to 192 basis points, and the spread between the Moody's A-rated utility bond index and the 30-year Treasury yield has increased from 106 basis points to 116 basis points. These wider credit spreads are an indication of higher risk sentiment among utility bond investors, despite lower yields on U.S. Treasury bonds. It is reasonable to reflect higher investor risk sentiment through a higher Cost of Equity.

Q. What do credit spreads indicate about the market?

A. Higher credit spreads are an indication that bond investors are becoming more concerned about future economic conditions and the ability of corporations to withstand any downturn that may occur in the economy. Recently, The Wall Street Journal reported on the trend toward higher credit spreads as follows:

> The U.S. corporate bond market is starting to flash caution signals about the broader economy. The difference in yield, called the "spread," between bonds from America's strongest companies and ultrasafe U.S. Treasury securities has been steadily increasing, a trend that in the past has foreshadowed economic problems. Wider spreads mean that investors want more yield relative to Treasurys to own bonds from U.S. companies. It can signal that investors are less confident about companies' business prospects and financial health, though other factors likely also are at play. Spreads in investment-grade corporate bonds – debt from companies rated triple-B minus or higher – are on track to increase for the second year in a row, according to Barclays data. That would be the first time since the financial crisis in 2007 and 2008 that spreads widened in two consecutive years.
>
> ***
>
> Investors and analysts say they are closely watching the action to determine whether trouble is brewing once again. Concerns are growing about companies' ability to pay back the massive debt load taken on in recent years, as ultralow interest rates spurred corporate finance chiefs to sell record amounts of debt.[8]

Q. What is the financial market's perspective on the probable timing of an increase in short-term interest rates by the Federal Reserve?

A. The September 2015 issue of the Blue Chip Financial Forecasts ("Blue Chip") surveyed leading economists and market participants concerning their views regarding the timing of a possible increase in short-term interest rates by the Federal Reserve. Blue Chip reports that almost 96 percent of market participants surveyed expect the Federal Reserve

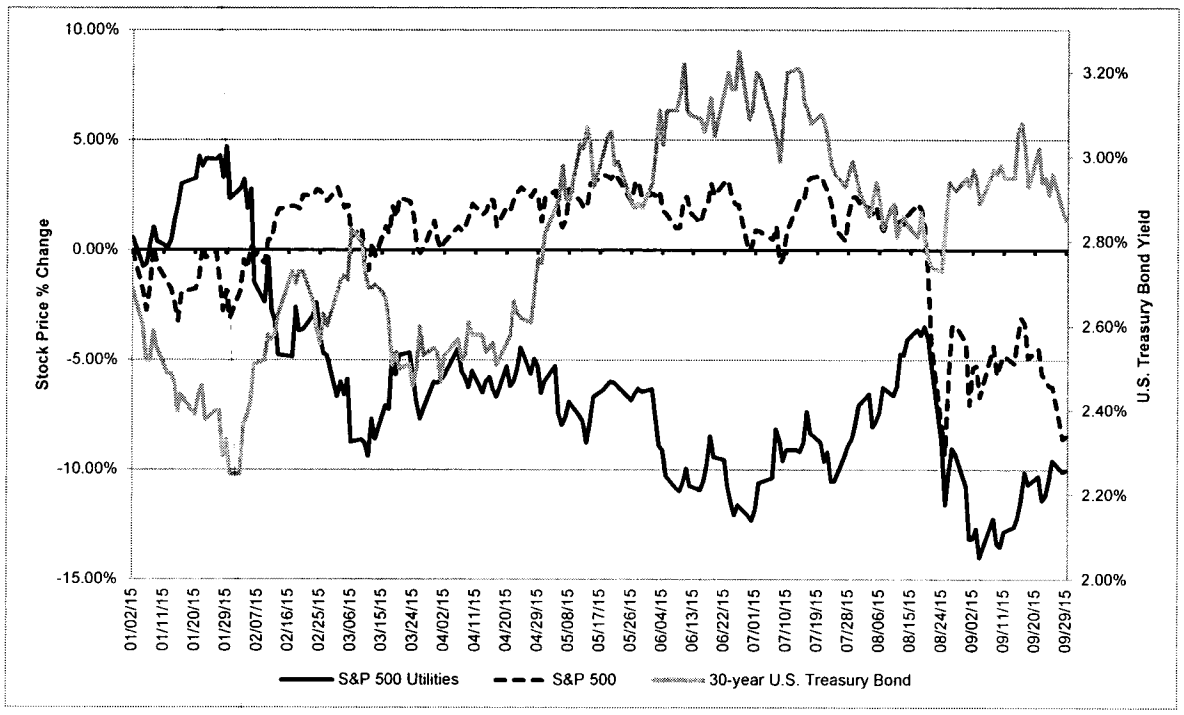
[8] "U.S. Bonds Flash a Warning Sign," The Wall Street Journal, September 28, 2015, at C1.

will start raising short-term interest rates before the end of 2015.[9] According to Blue Chip, yields on 30-year Treasury bonds are forecasted to increase to 4.80 percent between 2017 and 2021.[10]

Q. How have equity markets reacted to widening credit spreads and the prospect for higher interest rates?

A. Equity markets have been declining in recent weeks as investors prepare for higher interest rates, and as credit spreads signal possible economic turmoil ahead. As shown in Chart 3, utility stocks underperformed the broader market from February through August 2015, as investors reacted to the gradual rise in Treasury bond yields. The broader market, as measured by the S&P 500, has been declining steadily and sometimes sharply since mid-August.

Chart 3: Stock Performance Relative to U.S. Treasury Yields – 2015



[9] Blue Chip Financial Forecasts, Volume 34, No. 9, September 1, 2015, at 14.
[10] Blue Chip Financial Forecasts, Volume 34, No. 6, June 1, 2015, at 14.

Q. What are your conclusions about the effect of capital market conditions on the cost of equity?

A. Against this backdrop of rising interest rates, widening credit spreads, and higher investor risk sentiment, the cost of capital for all companies, including regulated utilities, has increased. As such, the return on equity for TEP should be based on prevailing market conditions, not based on the low interest rate environment of the past few years.

Q. What conclusions do you draw from your analysis of capital market conditions?

A. Because the utility sector has been trading at higher prices than the historical range it is important to consider whether or not those multiples and relationships will remain constant over time, as is assumed in the DCF model. Furthermore, since interest rates are projected to increase substantially, it is important to reflect that expectation in the specification of the CAPM and other risk premium models.

VI. PROXY GROUP SELECTION

Q. Why have you used a group of proxy companies to estimate the Cost of Equity for TEP?

A. In this proceeding, we are focused on estimating the Cost of Equity for TEP's electric utility operations in Arizona. Since the Cost of Equity is a market-based concept, and given that TEP does not make up the entirety of a publicly traded entity, it is necessary to establish a group of companies that is both publicly traded and comparable to TEP in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process.

Even if the Company's electric utility operations in Arizona did constitute the entirety of a publicly-traded entity, it is possible that transitory events could bias its market value over a given period of time. A significant benefit of using a proxy group is that it moderates the effects of unusual events that may be associated with any one company. The proxy companies used in my analyses all possess a set of operating and risk characteristics that are substantially comparable to the Company, and thus provide a reasonable basis to derive and estimate the appropriate ROE for TEP.

Q. Please provide a brief profile of TEP.

A. TEP serves the greater Tucson metropolitan area in Pima County, as well as Fort Huachuca in neighboring Cochise County.[11] TEP currently has an investment grade long-term rating of A3 from Moody's, which was upgraded from Baa1 on February 27, 2015 and is also rated BBB+ by Standard and Poor's.[12]

Q. How did you select the companies included in your proxy group?

A. I began with the group of 46 companies that Value Line classifies as electric utilities and I simultaneously applied the following screening criteria to exclude companies that:

- Do not pay consistent quarterly cash dividends because such companies cannot be analyzed using the Constant Growth DCF model.
- Do not have positive long-term earnings growth forecasts from at least two equity analysts.

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[11] Fortis Inc. 2014 Annual Report, page 121.

[12] Moody's Investors Service, Credit Opinion TEP, Inc., February 27, 2015. SNL Energy, "S&P Upgrades Tucson Electric Ratings", October 28, 2014.

- Do not have investment grade long-term issuer ratings from both S&P and Moody's.
- Derive less than 60.0 percent of their total operating income from regulated operations.
- Derive less than 90.0 percent of their total regulated operating income from regulated electric operations.
- Were party to a merger or transformative transaction during the analytical period considered.

Q. Did you consider other factors in addition to the screening criteria discussed above?

A. Yes, I did. I also considered whether each company that passed the screening criteria was, in fact, generally comparable to TEP in terms of business and financial risk. On that basis, I excluded one additional company: Edison International.

Since November 2012, Edison International has been addressing the financial implications of the Edison Mission Energy ("EME") bankruptcy. In 2014 the court approved the plan of reorganization for EME which includes payments to creditors that will continue through 2016.[13] Due to the ongoing bankruptcy proceeding of EME, it is not reasonable to include Edison International in the proxy group at this time.

Q. What is the composition of your proxy group?

A. My proxy group consists of the companies shown in Table 4.

[13] United States Bankruptcy Court, Northern District of Illinois, Eastern Division, Case No. 12-49219 (JPC), decision entered February 19, 2014, at 2. *See also* Edison International 2014 SEC Form 10-K, p. 9.

Table 4: Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
American Electric Power Company, Inc.	AEP
Duke Energy Corporation	DUK
Empire District Electric Company	EDE
Eversource Energy	ES
Great Plains Energy Inc.	GXP
IDACORP, Inc.	IDA
Otter Tail Corporation	OTTR
Pinnacle West Capital Corporation	PNW
PNM Resources, Inc.	PNM
Portland General Electric Company	POR
Westar Energy, Inc.	WR

VII. COST OF EQUITY ESTIMATION

Q. Please briefly discuss the ROE in the context of the regulated rate of return.

A. The overall rate of return for a regulated utility is based on its weighted average cost of capital, in which the cost rates of the individual sources of capital are weighted by their respective book values. While the costs of debt and preferred stock can be directly observed, the Cost of Equity is market-based and, therefore, must be estimated based on observable market data.

Q. How is the required ROE determined?

A. The required ROE is estimated by using one or more analytical techniques that rely on market-based data to quantify investor expectations regarding required equity returns, adjusted for certain incremental costs and risks. Informed judgment is then applied to

determine where the Company's Cost of Equity falls within the range of results. The key consideration in determining the Cost of Equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets in general, as well as the subject company (in the context of the proxy group) in particular.

Q. What methods did you use to determine the Company's ROE?

A. I considered the results of the DCF models and the CAPM analysis, corroborated by the Bond Yield Plus Risk Premium methodology. As discussed in more detail below, a reasonable ROE estimate appropriately considers alternative methodologies and the reasonableness of their individual and collective results.

Q. Why is it important to use more than one analytical approach?

A. It is important to use more than one approach because the Cost of Equity is not directly observable, and therefore must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the Cost of Equity, analysts and investors are inclined to gather and evaluate as much relevant data as reasonably can be analyzed. A number of models have been developed to estimate the Cost of Equity. Analysts and academics understand that ROE models are tools to be used in the ROE estimation process and that strict adherence to any single approach, or the specific results of any single approach, can lead to flawed conclusions. Consistent with the *Hope* finding, it is the analytical result, not the methodology, that is controlling in arriving at ROE determinations. A reasonable ROE estimate, therefore, considers alternative methodologies, observable market data, and the reasonableness of their individual and collective results.

A. Constant Growth DCF Model

Q. Are DCF models widely used to estimate the ROE for regulated utilities?

A. Yes. DCF models are widely used in regulatory proceedings and have sound theoretical bases, although neither the DCF model nor any other model can be applied without considerable judgment in the selection of data and the interpretation of results. As discussed later in this section of my testimony, the currently high P/E ratios for utility companies, and the expectation that the P/E ratios of the proxy companies will decline in the near term raises concerns with the use of the DCF approach as the sole indicator of the Cost of Equity at this time.

Q. Please describe the DCF approach.

A. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_\infty}{(1+k)^\infty} \quad [1]$$

Where P_0 represents the current stock price, $D_1 \ldots D_\infty$ are all expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the following form:

$$k = \frac{D_0(1+g)}{P_0} + g \quad [2]$$

Equation [2] is often referred to as the Constant Growth DCF model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate.

Q. What assumptions are required for the Constant Growth DCF model?

A. The Constant Growth DCF model requires the following assumptions: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings ratio; and (4) a discount rate greater than the expected growth rate. To the extent that any of these assumptions is violated, considered judgment and/or specific adjustments should be applied to the results.

Q. What market data did you use to calculate the dividend yield in your Constant Growth DCF model?

A. The dividend yield in my Constant Growth DCF model is based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading days ended July 31, 2015.

Q. Why did you use 30-, 90-, and 180-day averaging periods?

A. It is important to use an average of recent trading days to calculate the term P_0 in the DCF model to ensure that the ROE is not skewed by anomalous events that may affect stock prices on any given trading day. The averaging period should also be reasonably representative of expected capital market conditions over the long-term. In my view, the use of the 30-, 90-, and 180-day averaging periods reasonably balances those considerations.

Q. Did you make any adjustments to the dividend yield to account for periodic growth in dividends?

A. Yes, I did. Since utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be

evenly distributed over calendar quarters. Given that assumption, it is reasonable to apply one-half of the expected annual dividend growth rate for purposes of calculating the expected dividend yield component of the DCF model. This adjustment ensures that the expected first year dividend yield is, on average, representative of the coming twelve-month period, and does not overstate the aggregated dividends to be paid during that time.

Q. Why is it important to select appropriate measures of long-term growth in applying the DCF model?

A. In its Constant Growth form, the DCF model (*i.e.*, Equation [2]) assumes a single growth estimate in perpetuity. In order to reduce the long-term growth rate to a single measure, one must assume a constant payout ratio, and that earnings per share, dividends per share and book value per share all grow at the same constant rate. Over the long run, however, dividend growth can only be sustained by earnings growth. It, therefore, is important to incorporate a variety of sources of long-term earnings growth rates into the Constant Growth DCF model.

Q. Which sources of long-term earnings growth rates did you use?

A. My Constant Growth DCF model incorporates three sources of long-term earnings growth rates: (1) Zacks Investment Research; (2) Thomson First Call (provided by Yahoo! Finance); and (3) Value Line Investment Survey.

B. Multi-Stage DCF Model

Q. What other forms of the DCF model did you consider?

A. In order to address some of the limiting assumptions underlying the Constant Growth form of the DCF model, I also considered the results of a Multi-Stage DCF model. As with the Constant Growth form, the Multi-Stage DCF model defines the Cost of Equity as the discount rate that sets the current price equal to the discounted value of future cash flows.

Q. What are the benefits of a three-stage model?

A. The Multi-Stage model, which is an extension of the Constant Growth form, enables the analyst to specify growth rates over multiple stages. Further, the three-stage model allows for a gradual transition from the first stage growth rate to the long-term growth rate, thereby avoiding the often-unrealistic assumption that growth will change abruptly between the first and final stages.

Q. Please generally describe the structure of your Multi-Stage DCF model.

A. The Multi-Stage DCF model sets the subject company's current stock price equal to the present value of future cash flows received over three "stages". In all three stages, cash flows are equal to the annual dividend payments that stockholders receive. Stage one is a short-term growth period that consists of the first five years; stage two is a transition period from the short-term growth rate to the long-term growth rate which occurs over five years (*i.e.*, years six through 10); and stage three is a long-term growth period that begins in year 11 and continues in perpetuity (*i.e.*, year 200). The ROE is then calculated as the rate of return that results from the initial stock investment and the dividend payments over the analytical period.

Q. Please summarize the earnings per share growth rates used in your Multi-Stage DCF model.

A. I began with the current annualized dividend as of July 31, 2015 for each proxy group company. In the first stage of the model, the current annualized dividend is escalated based on the average of the three- to five-year earnings growth estimates reported by First Call, Zacks, and Value Line. For the third stage of the model, I relied on long-term projected growth in Gross Domestic Product ("GDP"). The second stage growth rate is a transition from the first stage growth rate to the long-term growth rate on a geometric average basis.

Q. How did you calculate the long-term GDP growth rate?

A. As shown on Exhibit AEB-3, the long-term growth rate of 5.40 percent is based on the real GDP growth rate of 3.25 percent from 1929 through 2014,[14] and a projected inflation rate of 2.09 percent. The rate of inflation of 2.09 percent is an average based on three measures: (1) the average long-term projected growth rate in the Consumer Price Index ("CPI") of 2.30 percent;[15] (2) the compound annual growth rate of the CPI for all urban consumers for 2025-2040 of 2.11 percent as projected by the Energy Information Administration ("EIA"); and (3) the compound annual growth rate of the GDP chain-type price index for 2025-2040 of 1.85 percent, also reported by the EIA.[16]

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14 U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.1, July 30, 2015.

15 Blue Chip Financial Forecasts, Vol. 34, No.6, June 1, 2015, at 14.

16 U.S. Energy Information Administration, Annual Energy Outlook 2015, Table 20, Macroeconomic Indicators.

Q. Why did you use a historical GDP growth rate rather than a current estimate of GDP growth?

A. Based on current and recent market conditions, the use of a historical growth rate is more appropriate than using a current estimate of real GDP growth. Economists have reviewed historical growth patterns related to severe financial crises and have concluded that estimates of GDP growth have generally been understated in the decade following severe financial crises. Specifically, 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. In that regard, the current U.S. economic growth situation is similar to that following the two most severe economic events in U.S. history (*i.e.*, the 1929 stock market crash and the 1973 oil shock). Economists that have examined the repercussions of those two historical crises (and similar severe financial crises in other countries) have found that GDP growth rates tended to be lower during the decade following such events.[17] Therefore, it would not be appropriate to assume that current projections of GDP growth are representative of long-term GDP growth starting in 2025 and continuing for the next 200 years.

Q. Have you performed an analysis to determine whether real GDP growth is slower in the decade immediately after a severe financial crisis than in subsequent decades?

A. Yes. I compared the average real GDP growth in the first ten years immediately following the two historical economic crises most comparable to the recent financial crisis (*i.e.*, the 1929 stock market crash and the 1973 oil shock) to the average real GDP growth in the next two decades following each crisis (*i.e.*, eleven to 30 years after the

[17] *See,* Reinhart, Carmen M. and Vincent R. Reinhart, "After the Fall," NBER Working Paper 16334, September 2010, in Federal Reserve Bank of Kansas City Economic Policy Symposium Volume, *Macroeconomic Challenges: The Decade Ahead* at Jackson Hole, Wyoming, on August 26-28, 2010, at 2.

events). I did the same for each of the 20th-century U.S. recessions for which sufficient data are available. My findings are presented in Table 5.

Table 5: Real GDP Growth Rates Following U.S. Economic Downturns[18]

Event	Compound Average Real GDP Growth Rate		
	Decade Following Crisis	Next Two Decades	Difference (Basis Points)
Major Economic Crises			
1929 Stock Market Crash	2.06%	4.72%	266
1973 Oil Shock	2.55%	3.39%	83
Other Recessions			
1937	6.68%	4.15%	-253
1945	3.77%	3.59%	-18
1948	3.79%	3.95%	16
1953	3.60%	3.23%	-37
1957	4.84%	3.13%	-170
1960	4.41%	3.28%	-112
1969	3.57%	3.01%	-56
1980	3.32%	2.45%	-88
1981	3.52%	2.62%	-90

Table 5 shows that real GDP growth in the first ten years following the 1929 stock market crash and the 1973 oil shock was substantially lower than real GDP growth in the next two decades following each event. In contrast, eight out of the nine other 20th-century U.S. economic downturns analyzed showed the opposite pattern. In light of the academic research cited above and the findings presented in Table 5, it is reasonable to believe that current projections of real GDP growth are under-stated. For that reason, the most reasonable means to forecast long-term GDP growth is to assume a return to long-term historical rates of real GDP growth and to estimate long-term nominal GDP growth based largely on market-based, long-term inflation estimates.

18 Real GDP data are from the U.S. Bureau of Economic Analysis. The years in which each recession started are from the National Bureau of Economic Research ("NBER"), "US Business Cycle Expansions and Contractions," available at http://www.nber.org/cycles.html. Note that this table excludes the three most recent recessions, which started in 1990, 2001, and 2007 owing to a lack of sufficient data for GDP growth in the following years to calculate comparable long-term GDP growth rates.

C. Discounted Cash Flow Model Results

Q. Please summarize the results of your DCF analyses.

A. Table 6 (*see* also Exhibit AEB-1 and Exhibit AEB-2) presents the results of the Constant Growth and Multi-Stage DCF models. The Constant Growth DCF model produces a range of mean results from 9.28 percent to 9.59 percent. The Multi-Stage DCF analysis produces a range of mean results from 9.44 percent to 9.78 percent.

Table 6: Discounted Cash Flow Results

Constant Growth DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	8.77%	9.59%	10.36%
90-Day Average Price	8.65%	9.46%	10.23%
180-Day Average Price	8.47%	9.28%	10.05%
Multi-Stage DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	9.56%	9.78%	9.99%
90-Day Average Price	9.43%	9.64%	9.85%
180-Day Average Price	9.24%	9.44%	9.64%

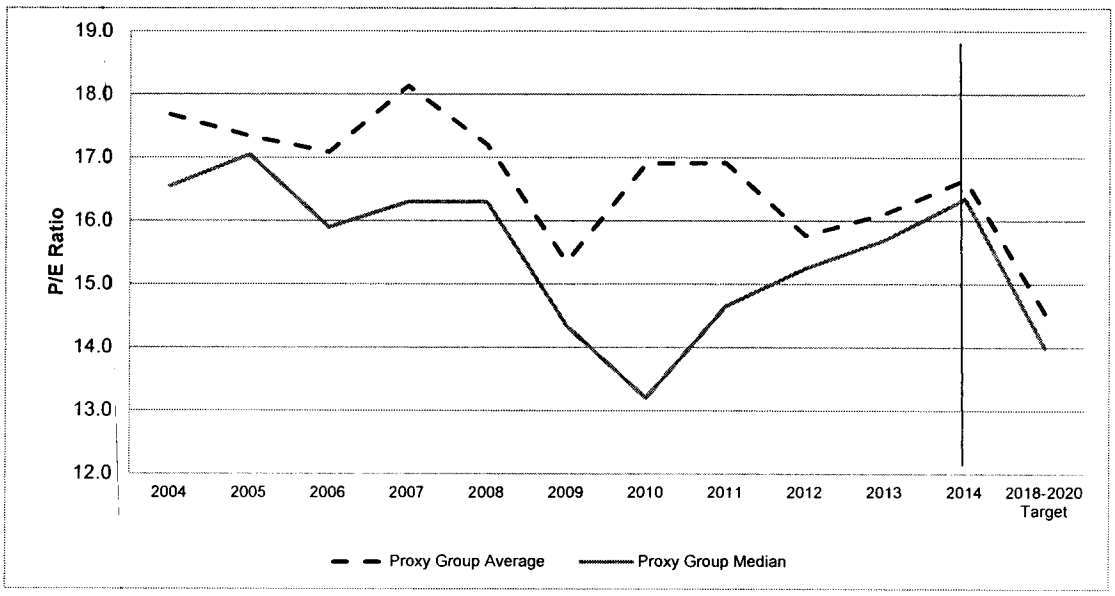
Q. How did you calculate the range of results for the Constant Growth and Multi-Stage DCF Models?

A. I calculated the low result for both DCF models using the minimum growth rate (*i.e.*, the lowest of the First Call, Zacks, and Value Line earnings growth rates) for each of the proxy group companies. Thus, the low result reflects the minimum DCF result for the proxy group. I used a similar approach to calculate the high results, using the highest growth rate for each proxy group company. The mean results were calculated using the average growth rates from all three sources.

Q. How do you explain the low results from the DCF models?

A. In its commentary on the electric utility industry, Value Line observes that many of the companies are currently trading at prices near their three-to-five year price targets.[19] Value Line cautions investors that current valuations already reflect the projected earnings growth for these companies, and that investors should look elsewhere for better return potential. These high valuations help explain why the results of the Constant Growth DCF analysis are currently so low. As shown in Chart 4, below, the average P/E ratio for the proxy companies was higher at the end of 2014 than the average projected P/E ratio for the group for the period from 2018-2020. The expectation for lower P/E ratios for the proxy companies suggests that the current results from the DCF model should be considered with caution.

Chart 4: Average Historical P/E Ratios for Proxy Companies



[19] Value Line Investment Survey, Electric Utility (West) Industry, January 31, 2015.

Q. Does the Multi-Stage DCF model discussed above address your concern about utility valuations?

A. No, it does not. While the Multi-Stage DCF model provides for changes in growth over time, it does not address the very high P/E ratios for utility stocks and the effects of those high valuations on the dividend yield in the DCF model.

Q. What are your conclusions about the results of the DCF models?

A. I agree with the position that Commission has previously stated (*i.e.,* that considering the DCF results alone would not result in an appropriate Cost of Equity under current circumstances).[20] As discussed previously, one primary assumption of the DCF models is for a constant P/E ratio. That assumption is heavily influenced by the market price of utility stocks. To the extent that these stock prices are inflated, as is suggested by the high P/E ratios and the expectation by analysts that those P/E ratios are not sustainable in the short term, it is important to consider the results of the DCF models with caution. Therefore, while I have considered the range of results established using the DCF methodologies, my recommendation also gives some weight to the results of the CAPM and also considers the indications from the Bond Yield Plus Risk Premium analysis.

[20] *See* Decision No. 69663 (June 28, 2007), at 49.

Q. Are you aware of any decisions wherein a Regulatory agency that determines the Cost of Equity has considered the effectiveness of the traditional ROE estimation models?

A. Yes. Recently, in Opinion No. 531, the FERC recognized that the inputs to the DCF model have been affected by anomalous market conditions and therefore for the first time, is considering the use of other ROE estimation models.

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. Therefore, while the DCF model remains the Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.[21]

Q. Has the FERC provided any guidance on how it will address the anomalous conditions in the market that affect the assumptions used in the DCF model?

A. Yes, the FERC has traditionally relied on the mean of the range of results from the DCF model, which they refer to as the "zone of reasonableness". In Opinion No. 531, the FERC indicated that it will look at other ROE estimation methodologies to inform their judgement as to where, within the zone of reasonableness, the ROE should be determined. In particular, the FERC found risk premium based approaches informative.

[21] 147 FERC ¶ 61,234, para. 41.

> We are concerned that market conditions in the record are anomalous, thereby making it more difficult to determine the return necessary for public utilities to attract capital. In these circumstances, we have less confidence that the midpoint of the zone of reasonableness established in this proceeding accurately reflects the equity returns necessary to meet the *Hope* and *Bluefield* capital attraction standards. We find it is 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 resulting midpoint.[22]
>
> The NETOs [New England Transmission Owners] presented five alternative benchmark methodologies in this proceeding: risk premium analysis, the CAPM, comparison of electric ROEs with natural gas pipeline ROEs, comparison of electric utility DCF results with non-utility DCF results, and expected earnings analysis. Of those five, we find the risk premium analysis, the CAPM, and expected earnings analyses informative, and each produces a midpoint (or median) ROE higher than the midpoint of our DCF analysis here. In considering these other methodologies, we do not depart from our use of the DCF methodology; rather, we use the record evidence to inform the just and reasonable placement of the ROE within the zone of reasonableness established in the record by the DCF methodology.[23]
>
> [W]e conclude that 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, based on the record in this case, including the unusual capital market conditions present, we conclude that the just and reasonable 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.[24]

The FERC's decision supports my conclusion that because the results of the DCF model have been affected by anomalous market conditions, in setting the appropriate ROE, it is important to consider the results of other ROE estimation models.

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22 *Ibid.*, para. 145.
23 *Ibid.*, para. 146.
24 *Ibid.*, para. 142.

Q. Are there other regulatory agencies that have recognized that the DCF models are currently understating the cost of equity?

A. Yes. The Surface Transportation Board ("STB"), which regulates the U.S. railroad industry, began evaluating the effectiveness of the Constant Growth DCF model in September 2006. The STB instituted a broad rulemaking to obtain public comment on the most appropriate methodology to use for estimating the ROE for railroads. In January 2008, the STB replaced the Constant Growth DCF model with the CAPM, with the expectation that the CAPM would produce more accurate estimates of the industry's cost of capital. In January 2009, as a result of its exploration of the various forms of ROE estimation models and the review of public comments on the merits and shortcomings of each of the models, the STB issued a decision modifying its sole reliance on the CAPM method to include an equal weighting of the CAPM and the Multi-Stage DCF results. In reaching this decision, the STB concluded that:

> Indeed, if our exploration of this issue has revealed nothing else, it has shown that there is no single simple or correct way to estimate the cost of equity for the railroad industry, and countless reasonable options are available. Both the CAPM and the multi-stage DCF models we propose to use have strengths and weaknesses, and both take different paths to estimate the same illusory figure. By using an average of the results produced by both models, we harness the strengths of both models while minimizing their respective weaknesses.[25]

This decision supports my view that it is appropriate to consider the results of various financial models to estimate the Cost of Equity within the context of capital market conditions, and that the models that are most appropriate to be used to estimate the ROE may evolve over time as market conditions change.

[25] Surface Transportation Board, Use of a Multi-Stage Discounted Cash Flow Model in Determining the Railroad Industry's Cost of Capital, Decision STB Ex Parte No. 664 (Sub-No. 1), released January 28, 2009, at 15.

Q. Is it relevant that the STB does not regulate the energy industry?

A. No. The STB decision is an ROE decision, and therefore it is relevant regardless of the industry. That decision describes the rigorous analysis and the methodologies that a regulatory body used to review financial models and to select the most appropriate models in the context of capital market conditions in order to estimate the Cost of Equity.

In summary, as the STB decision points out, the models used to estimate the ROE are used by the investment community for all types of investments, and therefore it is not important that the STB does not regulate energy companies. Rather, what is important is that the methodologies used reflect what investors consider in establishing their return requirements.

D. CAPM Analysis

Q. Please briefly describe the Capital Asset Pricing Model.

A. The CAPM is a risk premium approach that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. This second component is the product of the market risk premium and the Beta coefficient, which measures the relative riskiness of the security being evaluated.

The CAPM is defined by four components, each of which must theoretically be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \quad [3]$$

Where:

K_e = the required market ROE;

β = Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

In this specification, the term $(r_m - r_f)$ represents the market risk premium. According to the theory underlying the CAPM, since unsystematic risk can be diversified away, investors should only be concerned with systematic or non-diversifiable risk. Non-diversifiable risk is measured by Beta, which is defined as:

$$\beta = \frac{Covariance(r_e, r_m)}{Variance(r_m)} \quad [4]$$

The variance of the market return (*i.e.*, $Variance\ (r_m)$) is a measure of the uncertainty of the general market, and the covariance between the return on a specific security and the general market (*i.e.*, $Covariance\ (r_e, r_m)$) reflects the extent to which the return on that security will respond to a given change in the general market return. Thus, Beta represents the risk of the security relative to the general market.

Q. What risk-free rate did you use in your CAPM analysis?

A. I relied on three sources for my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds (*i.e.*, 3.09 percent);[26] (2) the projected 30-year U.S. Treasury bond yield for 2015 through 2016 of 3.57 percent;[27] and (3) the projected 30-year U.S. Treasury bond yield for 2017 through 2021 of 4.80 percent.[28]

[26] Bloomberg Professional, as of July 31, 2015.
[27] Blue Chip Financial Forecasts, Vol. 34, No. 7, July 1, 2015, at 2.
[28] Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14.

Q. Why did you consider both the current average yield on 30-year Treasury bonds and the projected near-term and longer-term Treasury bond yields?

A. The inputs and assumptions used in the CAPM analysis should reflect the forward-looking cost of equity. As discussed in Section V of my Direct Testimony, leading economists surveyed by Blue Chip are expecting a substantial increase in long-term interest rates over the next five years. This is an important consideration for equity investors as they assess their return requirements. A CAPM analysis based entirely on the current average risk-free rate of 3.09 percent fails to take into consideration the effect of the market's expectations for interest rate increases on the Cost of Equity. For that reason, I have used projected yields on the 30-year Treasury security as the risk free rate because those yields reflect investor expectations with respect to inflation during the period in which rates will be in effect.

Q. What Beta coefficients did you use in your CAPM analysis?

A. As shown on Exhibit AEB-4, I used the average Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line. Bloomberg calculates Beta coefficients based on two years of weekly returns relative to the S&P 500 Index. Value Line's calculation is based on five years of weekly returns relative to the New York Stock Exchange Composite Index.

Q. How did you estimate the market risk premium in the CAPM?

A. I estimated the market risk premium based on the expected return on S&P 500 Index less the 30-year Treasury bond yield. The expected return on the S&P 500 Index is calculated using the Constant Growth DCF model discussed earlier in my Direct Testimony for the companies in the S&P 500 Index for which dividend yields and long-term earnings projections are available. Based on an estimated market capitalization-weighted dividend

yield of 2.07 percent and a weighted long-term growth rate of 11.23 percent, the estimated required market return for the S&P 500 Index is 13.41 percent. The implied market risk premium over the current 30-day average of the 30-year U.S. Treasury bond yield, and the short- and near-term projected yields on the 30-year U.S. Treasury bond, range from 8.61 percent to 10.33 percent.

Q. Why is a forward-looking market risk premium more appropriate than a historical market risk premium?

A. The historical market risk premium fails to consider the inverse relationship between interest rates and the market risk premium. As shown in my Bond Yield plus Risk Premium analysis, as interest rates decrease, the market risk premium increases. The historical market risk premium reported by Morningstar is based on an income only return on government bonds of 5.10 percent (which is significantly higher than the current yield on government bonds) subtracted from the long-term return on large company stocks of 12.10 percent.[29] Therefore, the historical market risk premium is under-stated relative to current or near-term projected interest rates, which are well below the long-term average yield of 5.10 percent. As such, it is more appropriate to use a forward-looking market risk premium that reflects projected total returns for the S&P 500 less the current and projected yield on Treasury securities.

Q. What are the results of your CAPM analyses?

A. As shown in Table 7 (*see* also Exhibit AEB-5), my CAPM analysis produces a range of returns from 10.28 percent to 11.40 percent. The mean return using the Bloomberg average Beta coefficient and three measures of the risk-free rate is 10.50 percent. Using

[29] Morningstar, Inc., Ibbotson SBBI 2015 Classic Yearbook, at Table 6-7.

the Value Line average Beta coefficient and three measures of the risk-free rate, the mean result is 11.17 percent.

Table 7: Forward-Looking CAPM Results

	Current Risk-Free Rate (3.09%)	2015-2016 Projected Risk-Free Rate (3.57%)	2017-2021 Projected Risk-Free Rate (4.80%)	Mean Result
Bloomberg Beta	10.28%	10.42%	10.80%	10.50%
Value Line Beta	11.00%	11.12%	11.40%	11.17%

E. Bond Yield Plus Risk Premium Analysis

Q. Please describe the Bond Yield Plus Risk Premium approach you employed.

A. In general terms, this approach is based on the fundamental principle that equity investors bear the residual risk associated with equity ownership and therefore require a premium over the return they would have earned as a bondholder. That is, since returns to equity holders are more risky than returns to bondholders, equity investors must be compensated to bear that risk. Risk premium approaches, therefore, estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds. In my analysis, I used actual authorized returns for electric utilities as the historical measure of the Cost of Equity to determine the risk premium.

Q. Are there other considerations that should be addressed in conducting this analysis?

A. Yes. It is important to recognize both academic literature and market evidence indicating that the equity risk premium (as used in this approach) is inversely related to the level of interest rates. That is, as interest rates increase (decrease), the equity risk premium decreases (increases). Consequently, it is important to develop an analysis that: (1) reflects the inverse relationship between interest rates and the equity risk premium; and

(2) relies on recent and expected market conditions. Such an analysis can be developed based on a regression of the risk premium as a function of U.S. Treasury bond yields. If we let authorized ROEs for electric utilities serve as the measure of required equity returns and define the yield on the long-term U.S. Treasury bond as the relevant measure of interest rates, the risk premium simply would be the difference between those two points.[30]

Q. Is the Bond Yield Plus Risk Premium analysis relevant to investors?

A. Yes. Investors are aware of ROE awards in other jurisdictions, and they consider those awards as a benchmark for a reasonable level of equity returns for utilities of comparable risk operating in other jurisdictions. Since my Bond Yield Plus Risk Premium analysis is based on authorized ROEs for electric utilities relative to corresponding Treasury yields, it provides relevant information to assess the return expectations of investors. However, I have relied on this analysis to corroborate the reasonableness of my DCF and CAPM results and to inform my ultimate ROE recommendation, not as the primary basis for my recommendation.

Q. What did your Bond Yield Plus Risk Premium analysis reveal?

A. As shown on Chart 5, from 1992 through July 2015, there was a strong negative relationship between risk premia and interest rates. To estimate that relationship, I conducted a regression analysis using the following equation:

$$RP = a + b(T) \quad [5]$$

[30] *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 methodology similar to the regression approach described below, including using allowed ROEs as the relevant data source, and came to similar conclusions regarding the inverse relationship between 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 66.

Where:

RP = Risk Premium (difference between allowed ROEs and the yield on 30-year U.S. Treasury bonds)

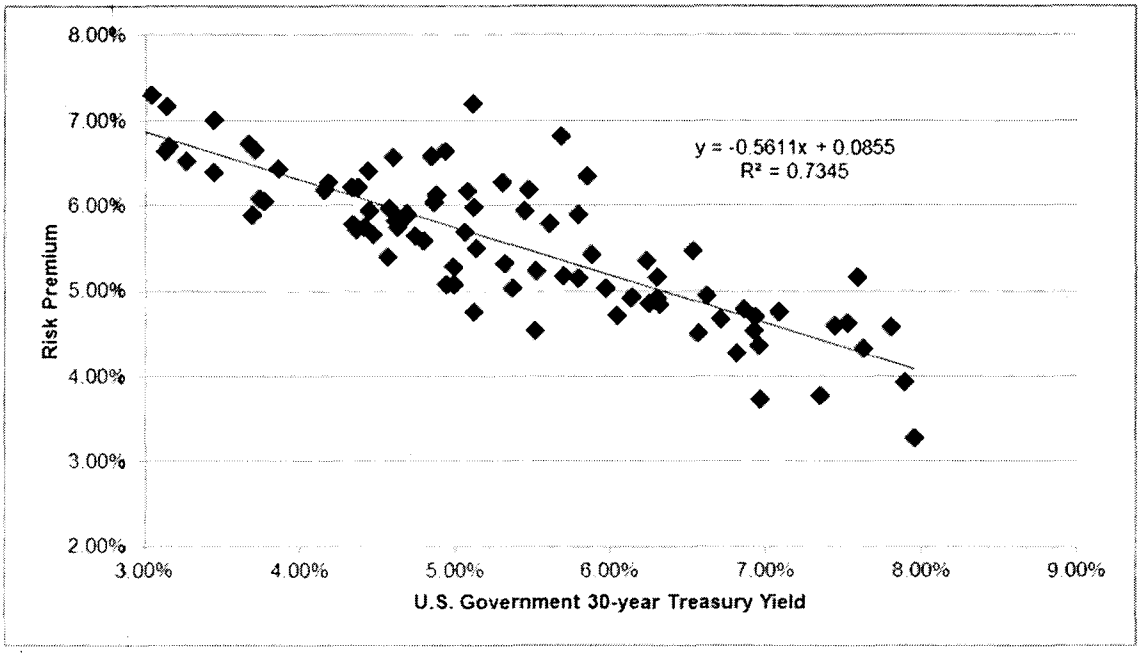
a = intercept term

b = slope term

T = 30-year U.S. Treasury bond yield

Data regarding allowed ROEs were derived from 641 rate cases from 1992 through July 2015 as reported by Regulatory Research Associates. This equation's coefficients were statistically significant at the 99.0 percent level.

Chart 5: Risk Premium Results



As shown on Exhibit AEB-6, based on the current 30-day average of the 30-year U.S. Treasury bond yield (*i.e.*, 3.09 percent), the risk premium would be 6.82 percent, resulting in an estimated ROE of 9.91 percent. Based on the near-term (2015-2016) projections of the 30-year U.S. Treasury bond yield (*i.e.*, 3.57 percent), the risk premium would be 6.55 percent, resulting in an estimated ROE of 10.12 percent. Based on longer-

term (2017-2021) projections of the 30-year U.S. Treasury bond yield (*i.e.*, 4.80 percent), the risk premium would be 5.86 percent, resulting in an estimated ROE of 10.66 percent.

VIII. REGULATORY AND BUSINESS RISKS

Q. Do the mean DCF, CAPM, and Risk Premium results for the proxy group provide an appropriate estimate of the cost of equity for TEP?

A. No. These results provide only a range of the appropriate estimate of the Company's Cost of Equity. There are several additional factors that must be taken into consideration when determining where the Company's Cost of Equity falls within the range of results. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. Environmental Regulation

Q. Please provide an overview of the risks associated with TEP's generation portfolio and ongoing changes in environmental regulations.

A. In 2014, TEP's generation portfolio was approximately 54 percent coal-fired generating assets.[31] While there are other risks related to a largely coal-fired fleet, including extended and unplanned outages, the uncertainty surrounding federal environmental regulations present significant risk to utilities' coal-fired generating assets.

Q. Please describe the risks associated with the ownership of coal-fired generation.

A. The risks and potential costs related to coal-fired generation assets are highlighted in the EPA's "Clean Power Plan", which requires carbon dioxide reduction targets on a state-

[31] Tucson Electric Power SEC Form 10-K, at 3.

by-state basis and allows individual states to determine the approach to meeting those target levels. More stringent environmental regulation of coal-fired generating units results in a need for utilities to increase investment in environmental upgrades to those generating facilities. For several years, Fitch Ratings ("Fitch") has stated that the increasing operating and capital costs that utilities may face as a result of environmental investments would be viewed as credit negative. In addition, Fitch noted that the increasing number of coal plant retirements will increase "a measure of risk for investors."[32] These factors result in increased risk associated with environmental regulation.

More recently, S&P identified that there are three main approaches for generators to address the carbon-reduction policies that affect coal-fired generation; 1) investing in "scrubbers" to meet the emissions requirements, 2) retrofitting the generators to burn natural gas or 3) retiring the generator. S&P noted that for utility generators, the increased costs could affect the companies' credit profiles.

> Higher costs could become a key credit issue for regulated utilities given the importance of managing customer rate increases, which has implications for relations with regulators, as well as economic and political ramifications that could heighten business risk. Any rating actions would likely not occur until there is further clarity from a utility about early plant retirements and related cost recovery. For utilities that have significant coal-fired generation, recovery mechanisms will be extremely important to continue to support operating cash flow and maintain robust financial measures.[33]

Finally, in August 2015, S&P noted that the two year extension on the timing for implementation provides utilities some benefits including minimizing early closure costs, and deferring the need for rate cases. However, S&P 's view is that for investor owned

[32] Source: SNL Financial, Fitch: Coal retirements a credit risk, but one that can be managed, March 2, 2012.
[33] S&P Research, The Clean Power Plan Will Spur Further Coal Plant Closings, but How Will U.S. Utilities Recover the Costs? (September 2, 2014).

utilities, "the effect on credit ratings centers on the risk of full recovery of compliance costs, including stranded costs of shuttered coal plants".[34]

Q. What is your conclusion with respect to the effect of the risk associated with environmental regulation on TEP's Cost of Equity?

A. A significant percentage of TEP's generation portfolio could require additional investment to comply with proposed and future environmental regulations. It is clear that the financial community recognizes the additional risks to credit quality associated with the capital investment required to meet environmental regulations. In my view, those factors support an ROE above the proxy group mean.

B. TEP's Capital Expenditure Plan

Q. Please summarize the Company's capital expenditure requirements.

A. The Company's current projections include approximately $250 million per year in capital investments for the period from 2016 through 2019.[35] In addition, as discussed in the testimony of Company Witness Kentton C. Grant, the Company may be required to make additional capital expenditures to comply with the Clean Power Plan and additional investment for renewable energy, gas-fired generation and related bulk transmission. In addition, TEP's local distribution system may also need additional investment to accommodate increasing amounts of distributed generation.

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[34] Standard & Poor's, Rating Research, The U.S. EPA Finalizes Its Clean Power Plan, But Questions Still Remain, August 6, 2015.

[35] TEP 2014 10-K, at 33.

Q. Do credit rating agencies recognize the risks associated with elevated levels of capital expenditures?

A. Yes, they do. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, a July 2014 report from S&P explains:

> [T]here is little doubt that the U.S. electric industry needs to make record capital expenditures to comply with the proposed carbon pollution rules over the next several years, while maintaining safety standards and grid stability. We believe the higher capital spending and subsequent rise in debt levels could strain these companies' financial measures, resulting in an almost consistent negative discretionary cash flow throughout this higher construction period. To meet the higher capital spending requirements, companies will require ongoing and steady access to the capital markets, necessitating that the industry maintains its high credit quality. We expect that utilities will continue to effectively manage their regulatory risk by using various creative means to recover their costs and to finance their necessary higher spending.[36]

Therefore, to the extent that TEP's rates do not permit it to recover its full cost of doing business, the Company will face increased recovery risk and thus increased pressure on its credit metrics.

Q. What are your conclusions regarding the effect of the Company's capital spending requirements on its risk profile and cost of capital?

A. The risk posed by ongoing capital expenditure requirements and uncertain investments related to the Clean Power Plan and other distribution system investments indicates that TEP should be afforded the opportunity to earn an ROE at the upper end of the reasonable range of ROEs.

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[36] Standard and Poor's, Ratings Direct, "U.S. Regulated Electric Utilities' Annual Capital Spending Is Poised to Eclipse $100 Billion," July 2014.

C. TEP's Regulatory Environment

Q. Please explain how the regulatory environment affects investors' risk assessments.

A. The ratemaking process is premised on the principle that, in order for investors and companies to commit the capital needed to provide safe and reliable utility service, the subject utility must have the opportunity to recover the return of, and the market-required return on, invested capital. Regulatory commissions recognize that because utility operations are capital intensive, regulatory decisions should enable the utility to attract capital at reasonable terms; doing so balances the long-term interests of investors and customers. TEP is no exception. It must finance its operations and requires the opportunity to earn a reasonable return on its invested capital in order to maintain its financial profile. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' risk assessments.

From the perspective of debt investors, the authorized return should enable the Company to generate the cash flow needed to meet its near-term financial obligations, make the capital investments needed to maintain and expand its system, and maintain sufficient levels of liquidity to fund unexpected events. This financial liquidity must be derived not only from internally generated funds, but also by efficient access to capital markets. Moreover, because fixed income investors have many investment alternatives, even within a given market sector, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions.

From the perspective of equity investors, the authorized return must be adequate to provide a risk-comparable return on the equity portion of the Company's capital investments. Because equity investors are the residual claimants on the Company's cash

flows (which is to say that the equity return is subordinate to interest payments), they are particularly concerned with the strength of regulatory support and its effect on future cash flows.

Q. Please explain how credit rating agencies consider regulatory risk in establishing a company's credit rating.

A. While both S&P and Moody's consider regulatory risk in establishing credit ratings, Moody's has published a report quantifying the importance of this metric. Moody's establishes credit ratings based on four key factors: (1) regulatory framework; (2) the ability to recover costs and earn returns; (3) diversification; and (4) financial strength, liquidity, and key financial metrics. Of these criteria, regulatory framework and the ability to recover costs and earn returns are each given a broad rating factor of 25.0 percent. Therefore, Moody's assigns regulatory risk a 50.0 percent weighting in the overall assessment of business and financial risk for regulated utilities.[37]

S&P has also identified regulatory risk as an important factor. In its assessment of U.S. utility regulatory environments, S&P stated, "we believe the fundamental regulatory environment in the jurisdictions in which a utility operates often influences credit quality the most."[38]

Q. How does the regulatory environment in which a utility operates affect its access to and cost of capital?

A. The regulatory environment can significantly affect both the access to, and cost of capital in several ways. First, the proportion and cost of debt capital available to utility

[37] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, December 23, 2013, at 6.

[38] Standard & Poor's, *Assessing U.S. Utility Regulatory Environments*, March 11, 2010, at 2.

companies are influenced by the rating agencies' assessment of the regulatory environment. As noted by Moody's, "For rate regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."[39] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting: "Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation."[40]

Q. Have you conducted any analysis of the regulatory environment in Arizona relative to the jurisdictions in which the companies in your proxy group operate?

A. Yes. S&P classifies each regulatory jurisdiction into five categories ranging from "Strong" to "Weak" based on the level of credit supportiveness. Within each category, regulatory jurisdictions are ranked according to their credit supportiveness from most credit supportive to least credit supportive. For my analysis of the credit supportiveness of the regulatory jurisdictions in which the proxy companies operate, I assigned a numerical ranking to each jurisdiction ranked by S&P, from most credit supportive ("1") to least credit supportive ("53"). As shown in Exhibit AEB-8, the proxy group average ranking was 25.13, which would be classified as Strong/Adequate and rank slightly above average for credit supportiveness, while the Arizona jurisdictional ranking was 30, which is somewhat below average in credit supportiveness.

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[39] Moody's Investors Service, *Rating Methodology: Regulated Electric and Gas Utilities*, December 23, 2013, at 9.

[40] *Ibid.*

Q. What are your conclusions regarding the perceived risks related to the Arizona regulatory environment?

A. As discussed throughout this section of my testimony, both Moody's and S&P have identified the supportiveness of the regulatory environment as an important consideration in developing their overall credit ratings for regulated utilities. The S&P credit supportiveness ranking for Arizona indicates somewhat greater risk than the average for the proxy companies. For that reason, I conclude that it would be reasonable to consider a Cost of Equity toward the upper end of the range established by the proxy group.

IX. CAPITAL STRUCTURE

Q. What is TEP's proposed capital structure?

A. As described in the Direct Testimony of Mr. Grant, the Company's proposed capital structure consists of 50.03 percent common equity and 49.97 percent long-term debt, based on the test year actual capital structure and pro forma adjustment for a pending bond redemption for the period ending June 30, 2015.

Q. Please discuss your analysis of the capital structures of the proxy group companies.

A. My analysis of the proxy group companies' actual capital structures is provided in Exhibit AEB-9. As shown in that exhibit, I calculated the mean proportions of common equity and long-term debt over the most recent eight quarters[41] for each of the proxy group companies at the operating company level. The Company's proposed equity ratio of 50.03 percent is well below the mean of the proxy group of 54.00 percent and at the

[41] Source: SNL Financial and FERC Form 1 quarterly reports.

low end of the range of mean common equity ratios for the proxy group companies of 47.20 percent to 64.33 percent.

Q. What is your conclusion regarding an appropriate capital structure for TEP?

A. Considering the actual capital structures of the proxy group's operating companies, I believe that TEP's proposed common equity ratio of 50.03 percent is reasonable.

X. CONCLUSIONS AND RECOMMENDATION

Q. What is your conclusion regarding a fair ROE for TEP?

A. Based on the various quantitative and qualitative analyses presented in my Direct Testimony, and in light of the business and financial risks of TEP compared to the proxy group, it is my view that an ROE of 10.35 percent is fair and reasonable and would balance the interests of customers and shareholders. Specifically, my ROE recommendation would enable the Company to maintain its financial integrity and therefore its ability to attract capital at reasonable rates under a variety of economic and financial market conditions, while continuing to provide safe, reliable and affordable electric utility service to customers in Arizona.

Table 8: Summary of Analytical Results

Constant Growth DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	8.77%	9.59%	10.36%
90-Day Average Price	8.65%	9.46%	10.23%
180-Day Average Price	8.47%	9.28%	10.05%
Multi-Stage DCF			
	Mean Low	**Mean**	**Mean High**
30-Day Average Price	9.56%	9.78%	9.99%
90-Day Average Price	9.43%	9.64%	9.85%
180-Day Average Price	9.24%	9.44%	9.64%
Capital Asset Pricing Model			
	Current Risk-Free Rate (3.09%)	**2015-2016 Projected Risk-Free Rate (3.57%)**	**2017-2021 Projected Risk-Free Rate (4.80%)**
Bloomberg Beta	10.28%	10.42%	10.80%
Value Line Beta	11.00%	11.12%	11.40%
Bond Yield Plus Risk Premium			
	Current Risk-Free Rate (3.09%)	**2015-2016 Projected Risk-Free Rate (3.57%)**	**2017-2021 Projected Risk-Free Rate (4.80%)**
Bond Yield Plus Risk Premium	9.91%	10.12%	10.66%

Q. What is your conclusion with respect to TEP's proposed capital structure?

A. My conclusion is that the Company's proposed capital structure consisting of 50.03 percent common equity and 49.97 percent long-term debt is reasonable compared to the mean capital structures for the proxy group companies.

XI. FAIR VALUE RATE BASE

Q. What is the fair value standard in Arizona?

A. As the Commission noted in its decision regarding *Chaparral City Water Company*,[42] the Arizona Constitution requires the use of a fair value rate base in establishing rates. Article XV, Section 14 of the Arizona Constitution states:

> The corporation commission shall, to aid it in the proper discharge of its duties, ascertain the fair value of the property within the state of every public service corporation doing business therein; and every public service corporation doing business within the state shall furnish to the commission all evidence in its possession, and all assistance in its power, requested by the commission in aid of the determination of the value of the property within the state of such public service corporation.[43]

As interpreted by the Arizona Court of Appeals, this paragraph requires the Commission to find the fair value of a public service corporation's property and to use that value to set just and reasonable rates.[44]

Q. How has the Commission applied the fair value standard in prior cases?

A. The fair value standard, as applied by the Commission in recent rate cases, includes the estimation of two components: (1) the FVRB; and (2) the FVROR on the FVRB.[45]

Q. How has the Commission estimated the FVRB?

A. In several recent cases, the Commission has determined that it was appropriate to estimate the FVRB by weighting equally the OCRB and the RCND. The RCND

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42 Decision No. 70441 (July 28, 2008), at 20-21.

43 Arizona Constitution, Article XV, Section 14.

44 Decision No. 71914, (September 30, 2010) at 48-49. *See also*, Decision No. 70441 (July 28, 2008), at 20-21.

45 Decision No. 71914 (September 30, 2010), at 51.

estimates the current replacement cost value of the utility system by escalating the utility's original investments in rate base assets by inflation, since the installation year of the asset. In order to recognize physical and functional depreciation of the assets, the replacement cost is then adjusted for the accounting depreciation of the assets based on the expected useful life of the asset, as determined through the company's depreciation study.

Q. How do you define "fair value"?

A. Used in the regulatory context of determining a just and reasonable rate of return, "fair value" is the price at which a property would change hands between a willing buyer and a willing seller, when neither party is under any compulsion to enter into a transaction, and when both parties have reasonable knowledge of relevant facts.[46] That definition is consistent with the Internal Revenue Code and Revenue Ruling 59-60 ("Ruling 59-60"), which notes that court decisions regarding fair value further assume that the buyer and seller are "able, as well as willing, to trade and to be well informed about the property and concerning the market for such property."[47]

Q. Do you have any concerns with the methodology that the Commission has used to estimate the FVRB?

A. Yes, I do. Applying a 50.0 percent weight to the OCRB to estimate the FVRB is inconsistent with valuation theory that is relied upon by investors. Valuation theory identifies three traditional approaches that are used to estimate the value of an asset: (1) the Income Approach; (2) the Cost Approach; and (3) the Comparable Transactions Approach. The Income Approach establishes the value of the asset based on the present discounted value of the expected income from the asset. Using the Cost Approach, an

46 *See* Shannon P. Pratt, Valuing a Business, 5th ed. McGraw Hill, 2008, at 41-42.
47 IRS Revenue Ruling 59-60, 1959-1 CB 237-IRC Sec. 2031.

investor estimates the value of the asset based on the current cost of a reasonably comparable replacement asset, adjusted to reflect all forms of depreciation that are present in the subject asset. Finally, using the Comparable Transactions or Market Multiples Approach the investor relies on the use of market data on the sale of comparable assets to estimate the value of the assets.

While different circumstances of the asset or the investor can affect whether or not all three approaches are considered or how much emphasis should be placed on any given approach, the objective of each approach is to use available market data to derive a market-based value of an asset. An approach which places a 50.0 percent weight on the depreciated original cost of the assets at the time those assets were installed suggests that the accounting value of an investment has a relationship to the current market value of the asset. This is not the case, as is recognized both in the market place and in academia.[48]

Q. Have you conducted any analysis to assess the reasonableness of using the RCND as the FVRB for TEP?

A. Yes, I have. As noted above, there are three main approaches to valuation typically relied upon by investors and analysts: (1) the Income Approach; (2) the Cost Approach; and (3) the Comparable Transactions Approach. The Income Approach is not appropriate in circumstances such as this where the value of the assets is used to determine the income

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48 *See* Pratt, Reilly, Schweihs, Valuing a Business, 4th ed. Irwin, 2000, at 308, which states: Under any standard of value, the true economic value of a business enterprise equals the company's accounting book value only by coincidence. More likely than not, the true economic value of a company will be either higher or lower than its accounting book value. There is no theoretical support, conceptual reasoning, or empirical data to suggest that the value of a business enterprise (under any standard of value) will necessarily equal the company's accounting book value. From a valuation perspective, the terms *book value* or *net book value* are merely accounting jargon. This is because book value is not related to economic value, or to the valuation process, at all...In any event, accounting book value is not a recommended business valuation method.

of the assets. The RCND is the Company's estimate of the current value of the assets using the Cost Approach. As shown in Exhibit AEB-10, page 1, the FVRB of $2,913.3 million is calculated by weighting equally the Company's OCRB of $2,104.7 million and the Company's estimated RCND of $3,721.9 million.

In order to determine the reasonableness of the Company's proposed FVRB, which includes a 50.0 percent weight on original cost rate base, I relied on the Comparable Transactions Approach to estimate the market value of the Company's OCRB.

Q. Please explain how you applied the Comparable Transactions Approach to determine the reasonableness of the Company's FVRB.

A. I compared the Company's FVRB estimate to the market value of comparable companies in recent arms-length transactions. I normalized the transaction values using the percentage premium over the corporate value of the acquired company. This metric incorporates the book value of debt and equity to estimate a premium to corporate value resulting from the transactions to create a consistent basis of comparison among the transactions (which took place amid different market conditions). I then estimated the market value of TEP's assets by applying the median premium of 43.64 percent to the Company's OCRB. That analysis resulted in an estimated market value for TEP's assets of $ 3,023 million. As shown on Exhibit AEB-11, the median premium is significantly lower than the premium that resulted from the acquisition of UNS Energy by Fortis, Inc. in 2014. Therefore, the estimated market value that results from applying the median premium to TEP's assets is conservative.

Q. How did you establish the universe of transactions that were analyzed for comparability to the TEP system?

A. I began by developing a database of announced and executed transactions involving the sale of electric and diversified utility companies and assets. Those data were compiled using the SNL Financial utility merger-screening tool. I also reviewed publicly-available information such as press releases, investor presentations, SEC filings, and regulatory commission filings. Once that preliminary list of transactions was developed, I then applied the following screening criteria to establish a final group of transactions for which I calculated the transaction premium.

1. I included transactions that involved the sale of state-regulated investor-owned electric and diversified utilities;
2. I included transactions that resulted in the sale of the entire company, excluding partial system or asset sales; and
3. I included transactions with a value of between $100 million and $10 billion.

There were 43 transactions that met my screening criteria.

Q. What period of time did you consider in developing your list of comparable transactions?

A. My Comparable Transactions analysis was performed on utility transmission and distribution asset transactions that were announced between January 1, 1997 and July 31, 2015. In my view, that period is sufficiently long to avoid the bias that could result from limiting the analysis to a shorter period, yet produces a sufficient number of observations.

Q. Please summarize the result of that analysis.

A. Table 9 summarizes the range of acquisition premiums for the comparable transactions. As shown in Table 9 and in Exhibit AEB-11, the median acquisition premium was 43.64 percent. Applying that premium to TEP's OCRB of $ 2,104.8 million indicates an implied market value for TEP's assets of approximately $ 3,023 million.

Table 9: Comparable Transaction Multiples

	Transaction Premium	Implied Valuation ($M)
Minimum	-1.75%	$2,068
Maximum	116.90%	$4,565
Mean	47.22%	$3,098
Median	**43.64%**	**$3,023**
Standard Deviation	29.15%	$614

Q. What do you conclude from the Comparable Transactions Approach discussed above?

A. The results of the Comparable Transactions Approach demonstrate that the Company's proposed FVRB is conservative relative to the estimated fair market value of the Company's assets.

XII. FAIR VALUE RATE OF RETURN

Q. Does the fair value standard also require consideration of the fair return on the fair value of the Company's assets?

A. Yes. As noted above, the Arizona Constitution requires that the Commission establish just and reasonable rates using the fair value of the Company's property. In establishing

the revenue requirement, the Commission would also need to establish the appropriate ROE to apply to the equity component of the FVRB.

Q. How has the Commission estimated the FVROR on the FVRB?

A. In several recent cases, the Commission has determined the FVROR by applying the market ROE and the cost of debt to the Company's OCRB based on the percent of equity and debt in the Company's proposed capital structure. The Commission then applies a different rate, traditionally one half of the risk-free rate, to what has been commonly referred to as the "fair value increment."[49] The fair value increment is the difference between the OCRB and the Company's proposed FVRB. The FVROR is then the sum of the returns on each of the three components: (1) equity capital, (2) debt capital, and (3) the fair value increment, weighted by the percentage of each in the FVRB.

Q. What does the fair value increment represent?

A. As described in the Commission's Decision No. 70665, the fair value increment represents the appreciation in the value of the assets to their current value from the value at which they entered service. Therefore, the sum of the OCRB and the fair value increment is meant to represent the total fair value of the utility's property.[50]

Q. What rate of return should be applied to the fair value increment?

A. Based on the risk differential between equity and debt investments, equity holders will require a greater return than the risk-free rate. As such, the range of returns on the fair value increment should be between the risk-free rate and the Cost of Equity established

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49 Decision No. 70665 (December 24, 2008), at 32.

50 *Ibid.*

by the results of the proxy group analysis. By contrast, there is no basis whatsoever for reducing this return component to one-half of the risk-free rate.

Q. How does your recommended range compare with the range of returns considered in prior cases?

A. In TEP's last rate case, Staff recommended applying a return to the fair value increment ranging between zero and half of the real risk-free rate.[51]

Q. Do you agree with this methodology of determining the rate of return to be applied to the fair value increment?

A. No, I do not. Since equity investors are the residual claimants after bondholders and preferred stockholders, it is inconceivable to me that an investor would accept a rate of return that is less than the cost of debt for an equity position in any investment. At the very least, the market expectation is that investments that are not risk-free should earn a rate of return that exceeds the risk-free rate. Furthermore, the application of 50.0 percent of the risk-free rate as a measure of the Cost of Equity on the fair value increment is subjective and has no basis in financial theory. The risk-free rate, which was used by the staff to establish the range of returns applied to the fair value increment, sets the low-end of the range of returns that I believe would be appropriate to apply to the fair value increment.

[51] Docket No. E 01933A-12-0291, Direct Testimony of Dr. S. Keith Berry, at 31-36.

Q. How have you estimated the FVROR in this case?

A. While I do not agree with all aspects of the Commission's approach, as shown on page 1 of Exhibit AEB-10, I have estimated the FVROR using the methodology the Commission has approved in recent cases.

Q. How did you estimate the risk-free rate of return?

A. As shown on page 2 of Exhibit AEB-10, my estimate of the nominal risk-free rate of return is the average of the 2017-2021 projected yield on 30-year U.S. Treasury bonds of 4.80 percent and the 2022-2026 projected yield on 30-year U.S. Treasury bonds of 5.00 percent as reported in the Blue Chip Financial Forecasts.[52] I then adjusted the nominal risk-free rate of 4.90 percent by the rate of inflation, which I estimated to be 2.01 percent over the period from 2015-2026 (*see*, Exhibit AEB-10). The resulting real risk-free rate is then 2.84 percent.[53]

Q. Please explain how you estimated the rate of inflation.

A. The rate of inflation of 2.01 percent is based on three measures: (1) the average 2017-2021 and 2022-2026 projected growth rate in the CPI of 2.30 percent, as reported by Blue Chip Financial Forecasts;[54] (2) the compound annual growth rate of the CPI for all urban consumers for 2015-2026 of 1.98 percent as projected by the EIA in the Annual Energy Outlook 2015; and (3) the compound annual growth rate of the GDP chain-type price index for 2015-2026 of 1.74 percent, also reported by the EIA in the Annual Energy Outlook 2015.[55]

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52 Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14.

53 2.84% = (4.90% + 1) / (1 + 2.01%) – 1.

54 Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14.

55 U.S. Energy Information Administration, Annual Energy Outlook 2015, Table 20, Macroeconomic Indicators.

Q. How does this rate of inflation differ from the inflation rate used in your calculation of the long-term growth rate for the Multi-Stage DCF model?

A. While both rates of inflation depend on identical sources, the rate of inflation used to calculate the FVROR is based on the near-term (*i.e.*, 2015-2026) because the company is entitled to earn a return on its FVRB immediately and throughout the period in which rates will be in effect. The third stage of the Multi-Stage DCF model, on the other hand, does not begin until 10 years from now and continues into perpetuity so the long-term GDP growth rate is based on long-term inflation forecasts (*i.e.*, 2025-2040).

Q. Please explain how you applied the Commission's methodology to estimate the FVROR.

A. As shown on page 1 of Exhibit AEB-10 and in Tables 10 and 11 below, I calculated the difference between the Company's OCRB and the Company's proposed FVRB, which includes a 50.0 percent weight on original cost. That difference represents the appreciation in the value of the assets based on the "market value" of the OCRB, and has been commonly referred to as the "fair value increment."[56] The weighted average cost of debt and the market Cost of Equity were applied to the OCRB.

Q. Please explain how you estimated the rate of return that you applied to the fair value increment.

A. As discussed above, I believe that the appropriate range of returns that could be applied to the fair value increment ranges from the low-end measured by the risk-free rate to the high-end measured by the results of the returns on rate base for the proxy group discussed in Section VI of my Direct Testimony. Nevertheless, the Company has requested that I

[56] Decision No. 70665 (December 24, 2008), at 32.

estimate the FVROR by applying 50.0 percent of the risk-free rate or approximately 1.42 percent, to the fair value increment.

Table 10: Estimation of the FVRB

Capital	$ Millions	Percent	Weighted FVRB
OCRB	$ 2,104.7	50.00	$ 1,052.3
RCND	$ 3,721.9	50.00	$ 1,860.9
FVRB			$ 2,913.3

Table 11: Estimation of the FVROR

Capital	$ Millions	Percent	Cost Rate	Weighted Cost Rate
Long-Term Debt	$ 1,051.7	36.10%	4.32%	1.56%
Common Equity	1,053.0	36.14%	10.35%	3.74%
Fair Value Increment	808.6	27.76%	1.42%	0.39%
Total	$ 2,913.3	100.00%		5.69%

Q. What is the resulting FVROR?

A. As shown in Tables 10 and 11 (*see also*, Exhibit AEB-11) based on the calculation discussed previously, the FVROR that would be applied to the FVRB is 5.69 percent.

Q. Does this conclude your pre-filed Direct Testimony?

A. Yes, it does.

Exhibit AEB-1

30-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$47.54	4.25%	4.38%	6.50%	6.00%	N/A	6.25%	10.38%	10.63%	10.89%
American Electric Power Company, Inc.	AEP	$2.12	$54.84	3.87%	3.96%	5.00%	5.02%	4.90%	4.97%	8.86%	8.94%	8.98%
Duke Energy Corporation	DUK	$3.18	$72.86	4.36%	4.47%	5.00%	4.65%	4.70%	4.78%	9.12%	9.25%	9.47%
Empire District Electric Company	EDE	$1.04	$22.30	4.66%	4.76%	3.00%	5.00%	5.00%	4.33%	7.73%	9.10%	9.78%
Eversource Energy	ES	$1.67	$47.07	3.55%	3.68%	8.50%	6.35%	6.80%	7.22%	10.01%	10.89%	12.20%
Great Plains Energy Inc.	GXP	$0.98	$25.06	3.91%	4.02%	5.00%	6.37%	6.00%	5.79%	9.01%	9.81%	10.41%
IDACORP, Inc.	IDA	$1.88	$58.15	3.23%	3.28%	1.00%	4.00%	4.00%	3.00%	4.25%	6.28%	7.30%
Otter Tail Corporation	OTTR	$1.23	$26.71	4.60%	4.78%	9.00%	6.00%	N/A	7.50%	10.74%	12.28%	13.81%
Pinnacle West Capital Corporation	PNW	$2.38	$59.37	4.01%	4.10%	4.00%	5.29%	4.60%	4.63%	8.09%	8.73%	9.40%
PNM Resources, Inc.	PNM	$0.80	$25.48	3.14%	3.27%	9.00%	8.56%	8.00%	8.52%	11.27%	11.79%	12.28%
Portland General Electric Company	POR	$1.20	$34.21	3.51%	3.60%	6.00%	4.75%	5.20%	5.32%	8.34%	8.92%	9.61%
Westar Energy, Inc.	WR	$1.44	$35.72	4.03%	4.12%	6.00%	3.40%	3.50%	4.30%	7.50%	8.42%	10.15%
MEAN				**3.93%**	**4.04%**	**5.67%**	**5.45%**	**5.27%**	**5.55%**	**8.77%**	**9.59%**	**10.36%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of July 31, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$49.34	4.09%	4.22%	6.50%	6.00%	N/A	6.25%	10.22%	10.47%	10.73%
American Electric Power Company, Inc.	AEP	$2.12	$55.40	3.83%	3.92%	5.00%	5.02%	4.90%	4.97%	8.82%	8.89%	8.94%
Duke Energy Corporation	DUK	$3.18	$75.02	4.24%	4.34%	5.00%	4.65%	4.70%	4.78%	8.99%	9.12%	9.34%
Empire District Electric Company	EDE	$1.04	$23.28	4.47%	4.56%	3.00%	5.00%	5.00%	4.33%	7.53%	8.90%	9.58%
Eversource Energy	ES	$1.67	$48.34	3.45%	3.58%	8.50%	6.35%	6.80%	7.22%	9.91%	10.80%	12.10%
Great Plains Energy Inc.	GXP	$0.98	$25.73	3.81%	3.92%	5.00%	6.37%	6.00%	5.79%	8.90%	9.71%	10.30%
IDACORP, Inc.	IDA	$1.88	$59.46	3.16%	3.21%	1.00%	4.00%	4.00%	3.00%	4.18%	6.21%	7.23%
Otter Tail Corporation	OTTR	$1.23	$28.39	4.33%	4.50%	9.00%	6.00%	N/A	7.50%	10.46%	12.00%	13.53%
Pinnacle West Capital Corporation	PNW	$2.38	$60.43	3.94%	4.03%	4.00%	5.29%	4.60%	4.63%	8.02%	8.66%	9.33%
PNM Resources, Inc.	PNM	$0.80	$26.58	3.01%	3.14%	9.00%	8.56%	8.00%	8.52%	11.13%	11.66%	12.14%
Portland General Electric Company	POR	$1.20	$35.00	3.43%	3.52%	6.00%	4.75%	5.20%	5.32%	8.26%	8.84%	9.53%
Westar Energy, Inc.	WR	$1.44	$36.55	3.94%	4.02%	6.00%	3.40%	3.50%	4.30%	7.41%	8.32%	10.06%
MEAN				**3.81%**	**3.91%**	**5.67%**	**5.45%**	**5.27%**	**5.55%**	**8.65%**	**9.46%**	**10.23%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of July 31, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$51.76	3.90%	4.02%	6.50%	6.00%	N/A	6.25%	10.02%	10.27%	10.53%
American Electric Power Company, Inc.	AEP	$2.12	$57.32	3.70%	3.79%	5.00%	5.02%	4.90%	4.97%	8.69%	8.76%	8.81%
Duke Energy Corporation	DUK	$3.18	$78.37	4.06%	4.15%	5.00%	4.65%	4.70%	4.78%	8.80%	8.94%	9.16%
Empire District Electric Company	EDE	$1.04	$25.56	4.07%	4.16%	3.00%	5.00%	5.00%	4.33%	7.13%	8.49%	9.17%
Eversource Energy	ES	$1.67	$50.34	3.32%	3.44%	8.50%	6.35%	6.80%	7.22%	9.77%	10.65%	11.96%
Great Plains Energy Inc.	GXP	$0.98	$26.61	3.68%	3.79%	5.00%	6.37%	6.00%	5.79%	8.78%	9.58%	10.17%
IDACORP, Inc.	IDA	$1.88	$61.81	3.04%	3.09%	1.00%	4.00%	4.00%	3.00%	4.06%	6.09%	7.10%
Otter Tail Corporation	OTTR	$1.23	$29.73	4.14%	4.29%	9.00%	6.00%	N/A	7.50%	10.26%	11.79%	13.32%
Pinnacle West Capital Corporation	PNW	$2.38	$63.37	3.76%	3.84%	4.00%	5.29%	4.60%	4.63%	7.83%	8.47%	9.15%
PNM Resources, Inc.	PNM	$0.80	$27.87	2.87%	2.99%	9.00%	8.56%	8.00%	8.52%	10.98%	11.51%	12.00%
Portland General Electric Company	POR	$1.20	$36.33	3.30%	3.39%	6.00%	4.75%	5.20%	5.32%	8.13%	8.71%	9.40%
Westar Energy, Inc.	WR	$1.44	$38.34	3.76%	3.84%	6.00%	3.40%	3.50%	4.30%	7.22%	8.14%	9.87%
MEAN				**3.63%**	**3.73%**	**5.67%**	**5.45%**	**5.27%**	**5.55%**	**8.47%**	**9.28%**	**10.05%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of July 31, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

Exhibit AEB-2

30-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$47.54	$2.02	6.25%	6.11%	5.97%	5.83%	5.68%	5.54%	5.40%	10.35%
American Electric Power Company, Inc.	AEP	$54.84	$2.12	4.97%	5.04%	5.12%	5.19%	5.26%	5.33%	5.40%	9.54%
Duke Energy Corporation	DUK	$72.86	$3.18	4.78%	4.89%	4.99%	5.09%	5.20%	5.30%	5.40%	10.04%
Empire District Electric Company	EDE	$22.30	$1.04	4.33%	4.51%	4.69%	4.87%	5.05%	5.22%	5.40%	10.22%
Eversource Energy	ES	$47.07	$1.67	7.22%	6.91%	6.61%	6.31%	6.01%	5.70%	5.40%	9.78%
Great Plains Energy Inc.	GXP	$25.06	$0.98	5.79%	5.73%	5.66%	5.60%	5.53%	5.47%	5.40%	9.82%
IDACORP, Inc.	IDA	$58.15	$1.88	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	8.42%
Otter Tail Corporation	OTTR	$26.71	$1.23	7.50%	7.15%	6.80%	6.45%	6.10%	5.75%	5.40%	11.19%
Pinnacle West Capital Corporation	PNW	$59.37	$2.38	4.63%	4.76%	4.89%	5.02%	5.14%	5.27%	5.40%	9.61%
PNM Resources, Inc.	PNM	$25.48	$0.80	8.52%	8.00%	7.48%	6.96%	6.44%	5.92%	5.40%	9.60%
Portland General Electric Company	POR	$34.21	$1.20	5.32%	5.33%	5.34%	5.36%	5.37%	5.39%	5.40%	9.23%
Westar Energy, Inc.	WR	$35.72	$1.44	4.30%	4.48%	4.67%	4.85%	5.03%	5.22%	5.40%	9.54%
MEAN											**9.78%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of July 31, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.34	$2.02	6.25%	6.11%	5.97%	5.83%	5.68%	5.54%	5.40%	10.16%
American Electric Power Company, Inc.	AEP	$55.40	$2.12	4.97%	5.04%	5.12%	5.19%	5.26%	5.33%	5.40%	9.50%
Duke Energy Corporation	DUK	$75.02	$3.18	4.78%	4.89%	4.99%	5.09%	5.20%	5.30%	5.40%	9.90%
Empire District Electric Company	EDE	$23.28	$1.04	4.33%	4.51%	4.69%	4.87%	5.05%	5.22%	5.40%	10.01%
Eversource Energy	ES	$48.34	$1.67	7.22%	6.91%	6.61%	6.31%	6.01%	5.70%	5.40%	9.66%
Great Plains Energy Inc.	GXP	$25.73	$0.98	5.79%	5.73%	5.66%	5.60%	5.53%	5.47%	5.40%	9.70%
IDACORP, Inc.	IDA	$59.46	$1.88	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	8.35%
Otter Tail Corporation	OTTR	$28.39	$1.23	7.50%	7.15%	6.80%	6.45%	6.10%	5.75%	5.40%	10.85%
Pinnacle West Capital Corporation	PNW	$60.43	$2.38	4.63%	4.76%	4.89%	5.02%	5.14%	5.27%	5.40%	9.53%
PNM Resources, Inc.	PNM	$26.58	$0.80	8.52%	8.00%	7.48%	6.96%	6.44%	5.92%	5.40%	9.42%
Portland General Electric Company	POR	$35.00	$1.20	5.32%	5.33%	5.34%	5.36%	5.37%	5.39%	5.40%	9.15%
Westar Energy, Inc.	WR	$36.55	$1.44	4.30%	4.48%	4.67%	4.85%	5.03%	5.22%	5.40%	9.44%
MEAN											**9.64%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of July 31, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$51.76	$2.02	6.25%	6.11%	5.97%	5.83%	5.68%	5.54%	5.40%	9.94%
American Electric Power Company, Inc.	AEP	$57.32	$2.12	4.97%	5.04%	5.12%	5.19%	5.26%	5.33%	5.40%	9.36%
Duke Energy Corporation	DUK	$78.37	$3.18	4.78%	4.89%	4.99%	5.09%	5.20%	5.30%	5.40%	9.70%
Empire District Electric Company	EDE	$25.56	$1.04	4.33%	4.51%	4.69%	4.87%	5.05%	5.22%	5.40%	9.59%
Eversource Energy	ES	$50.34	$1.67	7.22%	6.91%	6.61%	6.31%	6.01%	5.70%	5.40%	9.49%
Great Plains Energy Inc.	GXP	$26.61	$0.98	5.79%	5.73%	5.66%	5.60%	5.53%	5.47%	5.40%	9.55%
IDACORP, Inc.	IDA	$61.81	$1.88	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	8.23%
Otter Tail Corporation	OTTR	$29.73	$1.23	7.50%	7.15%	6.80%	6.45%	6.10%	5.75%	5.40%	10.60%
Pinnacle West Capital Corporation	PNW	$63.37	$2.38	4.63%	4.76%	4.89%	5.02%	5.14%	5.27%	5.40%	9.33%
PNM Resources, Inc.	PNM	$27.87	$0.80	8.52%	8.00%	7.48%	6.96%	6.44%	5.92%	5.40%	9.24%
Portland General Electric Company	POR	$36.33	$1.20	5.32%	5.33%	5.34%	5.36%	5.37%	5.39%	5.40%	9.00%
Westar Energy, Inc.	WR	$38.34	$1.44	4.30%	4.48%	4.67%	4.85%	5.03%	5.22%	5.40%	9.25%
MEAN											**9.44%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of July 31, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$47.54	$2.02	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.27%
American Electric Power Company, Inc.	AEP	$54.84	$2.12	4.90%	4.98%	5.07%	5.15%	5.23%	5.32%	5.40%	9.52%
Duke Energy Corporation	DUK	$72.86	$3.18	4.65%	4.78%	4.90%	5.03%	5.15%	5.28%	5.40%	10.00%
Empire District Electric Company	EDE	$22.30	$1.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.83%
Eversource Energy	ES	$47.07	$1.67	6.35%	6.19%	6.03%	5.88%	5.72%	5.56%	5.40%	9.54%
Great Plains Energy Inc.	GXP	$25.06	$0.98	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.60%
IDACORP, Inc.	IDA	$58.15	$1.88	1.00%	1.73%	2.47%	3.20%	3.93%	4.67%	5.40%	8.02%
Otter Tail Corporation	OTTR	$26.71	$1.23	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.69%
Pinnacle West Capital Corporation	PNW	$59.37	$2.38	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	9.44%
PNM Resources, Inc.	PNM	$25.48	$0.80	8.00%	7.57%	7.13%	6.70%	6.27%	5.83%	5.40%	9.46%
Portland General Electric Company	POR	$34.21	$1.20	4.75%	4.86%	4.97%	5.08%	5.18%	5.29%	5.40%	9.10%
Westar Energy, Inc.	WR	$35.72	$1.44	3.40%	3.73%	4.07%	4.40%	4.73%	5.07%	5.40%	9.30%
MEAN											**9.56%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of July 31, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.34	$2.02	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.09%
American Electric Power Company, Inc.	AEP	$55.40	$2.12	4.90%	4.98%	5.07%	5.15%	5.23%	5.32%	5.40%	9.48%
Duke Energy Corporation	DUK	$75.02	$3.18	4.65%	4.78%	4.90%	5.03%	5.15%	5.28%	5.40%	9.86%
Empire District Electric Company	EDE	$23.28	$1.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.63%
Eversource Energy	ES	$48.34	$1.67	6.35%	6.19%	6.03%	5.88%	5.72%	5.56%	5.40%	9.43%
Great Plains Energy Inc.	GXP	$25.73	$0.98	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.49%
IDACORP, Inc.	IDA	$59.46	$1.88	1.00%	1.73%	2.47%	3.20%	3.93%	4.67%	5.40%	7.96%
Otter Tail Corporation	OTTR	$28.39	$1.23	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.37%
Pinnacle West Capital Corporation	PNW	$60.43	$2.38	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	9.36%
PNM Resources, Inc.	PNM	$26.58	$0.80	8.00%	7.57%	7.13%	6.70%	6.27%	5.83%	5.40%	9.29%
Portland General Electric Company	POR	$35.00	$1.20	4.75%	4.86%	4.97%	5.08%	5.18%	5.29%	5.40%	9.01%
Westar Energy, Inc.	WR	$36.55	$1.44	3.40%	3.73%	4.07%	4.40%	4.73%	5.07%	5.40%	9.21%
MEAN											**9.43%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of July 31, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$51.76	$2.02	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.87%
American Electric Power Company, Inc.	AEP	$57.32	$2.12	4.90%	4.98%	5.07%	5.15%	5.23%	5.32%	5.40%	9.34%
Duke Energy Corporation	DUK	$78.37	$3.18	4.65%	4.78%	4.90%	5.03%	5.15%	5.28%	5.40%	9.66%
Empire District Electric Company	EDE	$25.56	$1.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.24%
Eversource Energy	ES	$50.34	$1.67	6.35%	6.19%	6.03%	5.88%	5.72%	5.56%	5.40%	9.27%
Great Plains Energy Inc.	GXP	$26.61	$0.98	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.35%
IDACORP, Inc.	IDA	$61.81	$1.88	1.00%	1.73%	2.47%	3.20%	3.93%	4.67%	5.40%	7.85%
Otter Tail Corporation	OTTR	$29.73	$1.23	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.14%
Pinnacle West Capital Corporation	PNW	$63.37	$2.38	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	9.17%
PNM Resources, Inc.	PNM	$27.87	$0.80	8.00%	7.57%	7.13%	6.70%	6.27%	5.83%	5.40%	9.11%
Portland General Electric Company	POR	$36.33	$1.20	4.75%	4.86%	4.97%	5.08%	5.18%	5.29%	5.40%	8.87%
Westar Energy, Inc.	WR	$38.34	$1.44	3.40%	3.73%	4.07%	4.40%	4.73%	5.07%	5.40%	9.03%
MEAN											**9.24%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of July 31, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$47.54	$2.02	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.42%
American Electric Power Company, Inc.	AEP	$54.84	$2.12	5.02%	5.08%	5.15%	5.21%	5.27%	5.34%	5.40%	9.56%
Duke Energy Corporation	DUK	$72.86	$3.18	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.10%
Empire District Electric Company	EDE	$22.30	$1.04	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.43%
Eversource Energy	ES	$47.07	$1.67	8.50%	7.98%	7.47%	6.95%	6.43%	5.92%	5.40%	10.14%
Great Plains Energy Inc.	GXP	$25.06	$0.98	6.37%	6.21%	6.05%	5.89%	5.72%	5.56%	5.40%	9.98%
IDACORP, Inc.	IDA	$58.15	$1.88	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.63%
Otter Tail Corporation	OTTR	$26.71	$1.23	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	11.72%
Pinnacle West Capital Corporation	PNW	$59.37	$2.38	5.29%	5.31%	5.33%	5.35%	5.36%	5.38%	5.40%	9.79%
PNM Resources, Inc.	PNM	$25.48	$0.80	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	9.72%
Portland General Electric Company	POR	$34.21	$1.20	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.41%
Westar Energy, Inc.	WR	$35.72	$1.44	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.02%
MEAN											**9.99%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of July 31, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.34	$2.02	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.24%
American Electric Power Company, Inc.	AEP	$55.40	$2.12	5.02%	5.08%	5.15%	5.21%	5.27%	5.34%	5.40%	9.51%
Duke Energy Corporation	DUK	$75.02	$3.18	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.96%
Empire District Electric Company	EDE	$23.28	$1.04	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.21%
Eversource Energy	ES	$48.34	$1.67	8.50%	7.98%	7.47%	6.95%	6.43%	5.92%	5.40%	10.01%
Great Plains Energy Inc.	GXP	$25.73	$0.98	6.37%	6.21%	6.05%	5.89%	5.72%	5.56%	5.40%	9.86%
IDACORP, Inc.	IDA	$59.46	$1.88	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.56%
Otter Tail Corporation	OTTR	$28.39	$1.23	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	11.35%
Pinnacle West Capital Corporation	PNW	$60.43	$2.38	5.29%	5.31%	5.33%	5.35%	5.36%	5.38%	5.40%	9.71%
PNM Resources, Inc.	PNM	$26.58	$0.80	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	9.54%
Portland General Electric Company	POR	$35.00	$1.20	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.31%
Westar Energy, Inc.	WR	$36.55	$1.44	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.91%
MEAN											**9.85%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of July 31, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$51.76	$2.02	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.01%
American Electric Power Company, Inc.	AEP	$57.32	$2.12	5.02%	5.08%	5.15%	5.21%	5.27%	5.34%	5.40%	9.37%
Duke Energy Corporation	DUK	$78.37	$3.18	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.76%
Empire District Electric Company	EDE	$25.56	$1.04	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.77%
Eversource Energy	ES	$50.34	$1.67	8.50%	7.98%	7.47%	6.95%	6.43%	5.92%	5.40%	9.83%
Great Plains Energy Inc.	GXP	$26.61	$0.98	6.37%	6.21%	6.05%	5.89%	5.72%	5.56%	5.40%	9.71%
IDACORP, Inc.	IDA	$61.81	$1.88	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.43%
Otter Tail Corporation	OTTR	$29.73	$1.23	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	11.09%
Pinnacle West Capital Corporation	PNW	$63.37	$2.38	5.29%	5.31%	5.33%	5.35%	5.36%	5.38%	5.40%	9.50%
PNM Resources, Inc.	PNM	$27.87	$0.80	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	9.35%
Portland General Electric Company	POR	$36.33	$1.20	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.17%
Westar Energy, Inc.	WR	$38.34	$1.44	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.70%
MEAN											**9.64%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of July 31, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

Exhibit AEB-3

CALCULATION OF LONG-TERM GDP GROWTH RATE

Step 1	
Real GDP ($ Billions) [1]	
1929	$ 1,056.6
2014	$ 15,961.7
Compound Annual Growth Rate	**3.25%**
Step 2	
Consumer Price Index (YoY % Change) [2]	
2022-2026	2.30%
Average	2.30%
Consumer Price Index (All-Urban) [3]	
2025	2.89
2040	3.95
Compound Annual Growth Rate	2.11%
GDP Chain-type Price Index (2009=1.000) [3]	
2025	1.31
2040	1.73
Compound Annual Growth Rate	1.85%
Average Inflation Forecast	**2.09%**
Long-Term GDP Growth Rate	**5.40%**

Notes:

[1] Bureau of Economic Analysis, July 30, 2015

[2] Blue Chip Financial Forecasts, Vol. 34, No.6, June 1, 2015, at 14

[3] Energy Information Administration, Annual Energy Outlook 2015, Table 20

Exhibit AEB-4

BETA
AS OF July 31, 2015

		[1]	[2]
		Bloomberg	Value Line
ALLETE, Inc.	ALE	0.71	0.80
American Electric Power Company, Inc.	AEP	0.66	0.70
Duke Energy Corporation	DUK	0.49	0.60
Empire District Electric Company	EDE	0.63	0.70
Eversource Energy	ES	0.65	0.75
Great Plains Energy Inc.	GXP	0.72	0.85
IDACORP, Inc.	IDA	0.79	0.80
Otter Tail Corporation	OTTR	0.89	0.90
Pinnacle West Capital Corporation	PNW	0.69	0.70
PNM Resources, Inc.	PNM	0.78	0.85
Portland General Electric Company	POR	0.70	0.80
Westar Energy, Inc.	WR	0.65	0.75
Mean		0.696	0.767

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line; dated May 22, 2015, June 19, 2015 and July 31, 2015.

Exhibit AEB-5

CAPITAL ASSET PRICING MODEL

	[4] Risk-Free Rate	[5] Average Beta	[6] Market Risk Premium	[7] ROE
Proxy Group Average Bloomberg Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	3.09%	0.696	10.33%	10.28%
[2] Blue Chip Consensus Forecast (Q3 2015 - Q4 2016)	3.57%	0.696	9.85%	10.42%
[3] Projected 30-year U.S. Treasury bond yield (2017 - 2021)	4.80%	0.696	8.61%	10.80%
			Mean:	10.50%
Proxy Group Average Value Line Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	3.09%	0.767	10.33%	11.00%
[2] Blue Chip Consensus Forecast (Q3 2015 - Q4 2016)	3.57%	0.767	9.85%	11.12%
[3] Projected 30-year U.S. Treasury bond yield (2017 - 2021)	4.80%	0.767	8.61%	11.40%
			Mean:	11.17%

[1] Source: Bloomberg Professional
[2] Source: Blue Chip Financial Forecasts, Vol. 34, No. 7, July 1, 2015, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14
[4] See Notes [1], [2], and [3]
[5] Source: Exhibit AEB-4
[6] Source: Exhibit AEB-5, at 2
[7] Equals [4] + ([5] x [6])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[8] Estimated Weighted Average Dividend Yield		2.07%	
[9] Estimated Weighted Average Long-Term Growth Rate		11.23%	
[10] S&P 500 Estimated Required Market Return		13.41%	
[11] Risk-Free Rate	3.09%	3.57%	4.80%
[12] Implied Market Risk Premium	10.33%	9.85%	8.61%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Alcoa Inc	AA	0.07%	1.22%	0.00%	5.00%	0.00%
LyondellBasell Industries NV	LYB	0.23%	3.33%	0.01%	5.00%	0.01%
American Express Co	AXP	0.40%	1.53%	0.01%	9.62%	0.04%
Verizon Communications Inc	VZ	0.99%	4.70%	0.05%	7.42%	0.07%
Avago Technologies Ltd	AVGO	0.17%	1.28%	0.00%	17.32%	0.03%
Boeing Co/The	BA	0.51%	2.52%	0.01%	11.28%	0.06%
Caterpillar Inc	CAT	0.25%	3.92%	0.01%	9.00%	0.02%
JPMorgan Chase & Co	JPM	1.32%	2.57%	0.03%	6.70%	0.09%
Chevron Corp	CVX	0.86%	4.84%	0.04%	-0.59%	-0.01%
Coca-Cola Co/The	KO	0.93%	3.21%	0.03%	6.40%	0.06%
AbbVie Inc	ABBV	0.64%	2.91%	0.02%	8.63%	0.05%
Walt Disney Co/The	DIS	1.06%	1.10%	0.01%	11.61%	0.12%
El du Pont de Nemours & Co	DD	0.26%	2.73%	0.01%	3.40%	0.01%
Exxon Mobil Corp	XOM	1.72%	3.69%	0.06%	10.79%	0.19%
Phillips 66	PSX	0.22%	2.82%	0.01%	5.49%	0.01%
General Electric Co	GE	1.37%	3.52%	0.05%	7.92%	0.11%
Hewlett-Packard Co	HPQ	0.29%	2.31%	0.01%	5.23%	0.01%
Home Depot Inc/The	HD	0.79%	2.02%	0.02%	13.86%	0.11%
International Business Machines Corp	IBM	0.82%	3.21%	0.03%	6.65%	0.05%
Johnson & Johnson	JNJ	1.44%	2.99%	0.04%	5.92%	0.09%
McDonald's Corp	MCD	0.50%	3.40%	0.02%	7.47%	0.04%
Merck & Co Inc	MRK	0.87%	3.05%	0.03%	6.65%	0.06%
3M Co	MMM	0.49%	2.71%	0.01%	9.15%	0.04%
Bank of America Corp	BAC	0.97%	1.12%	0.01%	6.65%	0.06%
Pfizer Inc	PFE	1.15%	3.11%	0.04%	4.20%	0.05%
Procter & Gamble Co/The	PG	1.08%	3.46%	0.04%	6.70%	0.07%
AT&T Inc	T	1.11%	5.41%	0.06%	4.23%	0.05%
Travelers Cos Inc/The	TRV	0.17%	2.30%	0.00%	7.64%	0.01%
United Technologies Corp	UTX	0.46%	2.55%	0.01%	8.71%	0.04%
Analog Devices Inc	ADI	0.10%	2.74%	0.00%	11.18%	0.01%
Wal-Mart Stores Inc	WMT	1.20%	2.72%	0.03%	7.10%	0.09%
Cisco Systems Inc	CSCO	0.75%	2.96%	0.02%	7.56%	0.06%
Intel Corp	INTC	0.72%	3.32%	0.02%	7.99%	0.06%
General Motors Co	GM	0.26%	4.57%	0.01%	12.18%	0.03%
Microsoft Corp	MSFT	1.94%	2.66%	0.05%	10.47%	0.20%
Dollar General Corp	DG	0.12%	1.09%	0.00%	12.01%	0.01%
Kinder Morgan Inc/DE	KMI	0.39%	5.66%	0.02%	9.33%	0.04%
Citigroup Inc	C	0.92%	0.34%	0.00%	20.61%	0.19%
Nielsen NV	NLSN	0.09%	2.31%	0.00%	14.00%	0.01%
American International Group Inc	AIG	0.44%	0.78%	0.00%	9.04%	0.04%
Honeywell International Inc	HON	0.43%	1.97%	0.01%	9.21%	0.04%
Altria Group Inc	MO	0.55%	3.82%	0.02%	7.62%	0.04%
HCA Holdings Inc	HCA	0.20%	n/a	n/a	10.96%	0.02%
Under Armour Inc	UA	0.09%	n/a	n/a	22.75%	0.02%
International Paper Co	IP	0.10%	3.34%	0.00%	9.03%	0.01%
Abbott Laboratories	ABT	0.39%	1.89%	0.01%	12.07%	0.05%
Aflac Inc	AFL	0.14%	2.44%	0.00%	9.55%	0.01%
Air Products & Chemicals Inc	APD	0.16%	2.27%	0.00%	9.23%	0.01%
Airgas Inc	ARG	0.04%	2.35%	0.00%	8.80%	0.00%
Royal Caribbean Cruises Ltd	RCL	0.10%	1.34%	0.00%	19.83%	0.02%
American Electric Power Co Inc	AEP	0.14%	3.75%	0.01%	5.10%	0.01%
Hess Corp	HES	0.09%	1.69%	0.00%	-2.85%	0.00%
Anadarko Petroleum Corp	APC	0.20%	1.45%	0.00%	8.33%	0.02%
Aon PLC	AON	0.15%	1.19%	0.00%	11.92%	0.02%
Apache Corp	APA	0.09%	2.18%	0.00%	8.50%	0.01%
Archer-Daniels-Midland Co	ADM	0.15%	2.36%	0.00%	3.98%	0.01%
AGL Resources Inc	GAS	0.03%	4.24%	0.00%	6.50%	0.00%
Automatic Data Processing Inc	ADP	0.19%	2.46%	0.00%	10.33%	0.02%
AutoZone Inc	AZO	0.11%	n/a	n/a	13.56%	0.02%
Avery Dennison Corp	AVY	0.03%	2.43%	0.00%	7.35%	0.00%
Baker Hughes Inc	BHI	0.13%	1.17%	0.00%	8.10%	0.01%
Ball Corp	BLL	0.05%	0.77%	0.00%	9.07%	0.00%
Bank of New York Mellon Corp/The	BK	0.25%	1.57%	0.00%	12.27%	0.03%
CR Bard Inc	BCR	0.08%	0.49%	0.00%	10.00%	0.01%
Baxter International Inc	BAX	0.11%	1.15%	0.00%	10.75%	0.01%
Becton Dickinson and Co	BDX	0.17%	1.58%	0.00%	11.19%	0.02%
Berkshire Hathaway Inc	BRK/B	0.91%	n/a	n/a	5.80%	0.05%
Best Buy Co Inc	BBY	0.06%	2.85%	0.00%	10.63%	0.01%
H&R Block Inc	HRB	0.05%	2.40%	0.00%	11.67%	0.01%
Boston Scientific Corp	BSX	0.12%	n/a	n/a	10.20%	0.01%
Bristol-Myers Squibb Co	BMY	0.57%	2.25%	0.01%	16.88%	0.10%
Brown-Forman Corp	BF/B	0.07%	1.16%	0.00%	8.70%	0.01%
Cabot Oil & Gas Corp	COG	0.06%	0.31%	0.00%	35.95%	0.02%
Campbell Soup Co	CPB	0.08%	2.53%	0.00%	3.64%	0.00%
Kansas City Southern	KSU	0.06%	1.33%	0.00%	13.73%	0.01%
Carnival Corp	CCL	0.16%	2.25%	0.00%	17.12%	0.03%
Qorvo Inc	QRVO	0.04%	n/a	n/a	16.84%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
CenturyLink Inc	CTL	0.08%	7.55%	0.01%	1.34%	0.00%
Chubb Corp/The	CB	0.15%	1.83%	0.00%	7.73%	0.01%
Cigna Corp	CI	0.19%	0.03%	0.00%	11.38%	0.02%
Frontier Communications Corp	FTR	0.03%	8.90%	0.00%	10.45%	0.00%
Clorox Co/The	CLX	0.08%	2.75%	0.00%	6.94%	0.01%
CMS Energy Corp	CMS	0.05%	3.39%	0.00%	5.90%	0.00%
Coca-Cola Enterprises Inc	CCE	0.06%	2.19%	0.00%	6.19%	0.00%
Colgate-Palmolive Co	CL	0.32%	2.23%	0.01%	8.41%	0.03%
Comerica Inc	CMA	0.04%	1.77%	0.00%	9.41%	0.00%
CA Inc	CA	0.07%	3.43%	0.00%	5.70%	0.00%
Computer Sciences Corp	CSC	0.05%	1.41%	0.00%	9.90%	0.00%
ConAgra Foods Inc	CAG	0.10%	2.27%	0.00%	0.30%	0.00%
Consolidated Edison Inc	ED	0.10%	4.09%	0.00%	3.00%	0.00%
SL Green Realty Corp	SLG	0.06%	2.08%	0.00%	5.78%	0.00%
Corning Inc	GLW	0.12%	2.57%	0.00%	4.19%	0.00%
CSX Corp	CSX	0.16%	2.30%	0.00%	9.44%	0.02%
Cummins Inc	CMI	0.12%	3.01%	0.00%	9.88%	0.01%
Danaher Corp	DHR	0.33%	0.59%	0.00%	12.73%	0.04%
Target Corp	TGT	0.27%	2.74%	0.01%	9.18%	0.02%
Deere & Co	DE	0.16%	2.54%	0.00%	6.80%	0.01%
Dominion Resources Inc/VA	D	0.22%	3.61%	0.01%	6.16%	0.01%
Dover Corp	DOV	0.05%	2.50%	0.00%	12.00%	0.01%
Dow Chemical Co/The	DOW	0.28%	3.57%	0.01%	6.93%	0.02%
Duke Energy Corp	DUK	0.27%	4.45%	0.01%	4.84%	0.01%
Eaton Corp PLC	ETN	0.15%	3.63%	0.01%	8.51%	0.01%
Ecolab Inc	ECL	0.18%	1.14%	0.00%	13.17%	0.02%
PerkinElmer Inc	PKI	0.03%	0.53%	0.00%	11.24%	0.00%
EMC Corp/MA	EMC	0.27%	1.71%	0.00%	10.44%	0.03%
Emerson Electric Co	EMR	0.18%	3.63%	0.01%	6.56%	0.01%
EOG Resources Inc	EOG	0.22%	0.87%	0.00%	5.06%	0.01%
Entergy Corp	ETR	0.07%	4.67%	0.00%	4.73%	0.00%
Equifax Inc	EFX	0.06%	1.14%	0.00%	12.67%	0.01%
EQT Corp	EQT	0.06%	0.16%	0.00%	25.00%	0.02%
XL Group PLC	XL	0.06%	1.68%	0.00%	5.87%	0.00%
FedEx Corp	FDX	0.25%	0.58%	0.00%	14.69%	0.04%
Macy's Inc	M	0.12%	2.09%	0.00%	9.30%	0.01%
FMC Corp	FMC	0.03%	1.36%	0.00%	6.75%	0.00%
Ford Motor Co	F	0.30%	4.05%	0.01%	15.44%	0.05%
NextEra Energy Inc	NEE	0.24%	2.93%	0.01%	6.21%	0.02%
Franklin Resources Inc	BEN	0.15%	1.32%	0.00%	9.24%	0.01%
Freeport-McMoRan Inc	FCX	0.06%	1.70%	0.00%	25.04%	0.02%
TEGNA Inc	TGNA	0.03%	1.92%	0.00%	5.00%	0.00%
Gap Inc/The	GPS	0.08%	2.52%	0.00%	10.28%	0.01%
General Dynamics Corp	GD	0.25%	1.85%	0.00%	8.64%	0.02%
General Mills Inc	GIS	0.18%	3.02%	0.01%	7.25%	0.01%
Genuine Parts Co	GPC	0.07%	2.77%	0.00%	8.74%	0.01%
WW Grainger Inc	GWW	0.08%	2.05%	0.00%	11.90%	0.01%
Halliburton Co	HAL	0.19%	1.72%	0.00%	12.93%	0.02%
Harley-Davidson Inc	HOG	0.06%	2.13%	0.00%	11.33%	0.01%
Harman International Industries Inc	HAR	0.04%	1.30%	0.00%	17.00%	0.01%
Joy Global Inc	JOY	0.01%	3.03%	0.00%	15.05%	0.00%
Harris Corp	HRS	0.05%	2.27%	0.00%	n/a	n/a
HCP Inc	HCP	0.09%	5.85%	0.01%	3.10%	0.00%
Helmerich & Payne Inc	HP	0.03%	4.76%	0.00%	18.57%	0.01%
Hershey Co/The	HSY	0.08%	2.30%	0.00%	8.73%	0.01%
Hormel Foods Corp	HRL	0.08%	1.69%	0.00%	6.60%	0.01%
Starwood Hotels & Resorts Worldwide Inc	HOT	0.07%	1.89%	0.00%	9.25%	0.01%
Mondelez International Inc	MDLZ	0.38%	1.51%	0.01%	10.51%	0.04%
CenterPoint Energy Inc	CNP	0.04%	5.12%	0.00%	6.33%	0.00%
Humana Inc	HUM	0.14%	0.64%	0.00%	12.55%	0.02%
Illinois Tool Works Inc	ITW	0.17%	2.17%	0.00%	9.08%	0.02%
Ingersoll-Rand PLC	IR	0.08%	1.89%	0.00%	10.22%	0.01%
Interpublic Group of Cos Inc/The	IPG	0.05%	2.25%	0.00%	5.80%	0.00%
International Flavors & Fragrances Inc	IFF	0.05%	1.63%	0.00%	9.70%	0.00%
Jacobs Engineering Group Inc	JEC	0.03%	n/a	n/a	8.42%	0.00%
Johnson Controls Inc	JCI	0.15%	2.28%	0.00%	7.63%	0.01%
Hanesbrands Inc	HBI	0.06%	1.29%	0.00%	11.00%	0.01%
Kellogg Co	K	0.12%	3.02%	0.00%	4.45%	0.01%
Perrigo Co PLC	PRGO	0.15%	0.26%	0.00%	13.95%	0.02%
Kimberly-Clark Corp	KMB	0.22%	3.06%	0.01%	7.42%	0.02%
Kimco Realty Corp	KIM	0.05%	3.89%	0.00%	5.02%	0.00%
Kohl's Corp	KSS	0.06%	2.94%	0.00%	8.58%	0.01%
Oracle Corp	ORCL	0.90%	1.50%	0.01%	7.89%	0.07%
Kroger Co/The	KR	0.20%	1.07%	0.00%	10.42%	0.02%
Legg Mason Inc	LM	0.03%	1.62%	0.00%	15.50%	0.00%
Leggett & Platt Inc	LEG	0.03%	2.59%	0.00%	n/a	n/a
Lennar Corp	LEN	0.05%	0.30%	0.00%	20.20%	0.01%
Leucadia National Corp	LUK	0.04%	1.06%	0.00%	n/a	n/a
Eli Lilly & Co	LLY	0.49%	2.37%	0.01%	9.60%	0.05%
L Brands Inc	LB	0.12%	2.48%	0.00%	11.06%	0.01%
Lincoln National Corp	LNC	0.07%	1.42%	0.00%	10.06%	0.01%
Loews Corp	L	0.07%	0.66%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.34%	1.61%	0.01%	16.68%	0.06%
Host Hotels & Resorts Inc	HST	0.08%	4.13%	0.00%	5.67%	0.00%
Marsh & McLennan Cos Inc	MMC	0.16%	2.14%	0.00%	11.53%	0.02%
Masco Corp	MAS	0.05%	1.36%	0.00%	14.66%	0.01%
Mattel Inc	MAT	0.04%	6.55%	0.00%	9.65%	0.00%
McGraw Hill Financial Inc	MHFI	0.14%	1.30%	0.00%	11.83%	0.02%
Medtronic PLC	MDT	0.58%	1.94%	0.01%	9.10%	0.05%
CVS Health Corp	CVS	0.66%	1.24%	0.01%	14.59%	0.10%
Micron Technology Inc	MU	0.10%	n/a	n/a	8.73%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Motorola Solutions Inc	MSI	0.07%	2.26%	0.00%	8.10%	0.01%
Murphy Oil Corp	MUR	0.03%	4.27%	0.00%	11.50%	0.00%
Mylan NV	MYL	0.14%	n/a	n/a	12.09%	0.02%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	10.27%	0.01%
Tenet Healthcare Corp	THC	0.03%	n/a	n/a	11.00%	0.00%
Newell Rubbermaid Inc	NWL	0.06%	1.76%	0.00%	9.52%	0.01%
Newmont Mining Corp	NEM	0.05%	0.58%	0.00%	2.08%	0.00%
Twenty-First Century Fox Inc	FOXA	0.23%	0.87%	0.00%	13.30%	0.03%
NIKE Inc	NKE	0.41%	0.97%	0.00%	11.21%	0.05%
NiSource Inc	NI	0.03%	3.55%	0.00%	-0.30%	0.00%
Noble Energy Inc	NBL	0.08%	2.04%	0.00%	4.23%	0.00%
Norfolk Southern Corp	NSC	0.13%	2.80%	0.00%	10.68%	0.01%
Eversource Energy	ES	0.08%	3.36%	0.00%	6.60%	0.01%
Northrop Grumman Corp	NOC	0.17%	1.85%	0.00%	6.57%	0.01%
Wells Fargo & Co	WFC	1.55%	2.59%	0.04%	12.17%	0.19%
Nucor Corp	NUE	0.07%	3.38%	0.00%	12.43%	0.01%
PVH Corp	PVH	0.05%	0.13%	0.00%	9.25%	0.00%
Occidental Petroleum Corp	OXY	0.28%	4.27%	0.01%	6.50%	0.02%
Omnicom Group Inc	OMC	0.09%	2.74%	0.00%	5.33%	0.00%
ONEOK Inc	OKE	0.04%	6.40%	0.00%	9.45%	0.00%
Owens-Illinois Inc	OI	0.02%	n/a	n/a	3.31%	0.00%
PG&E Corp	PCG	0.13%	3.47%	0.00%	5.20%	0.01%
Parker-Hannifin Corp	PH	0.08%	2.24%	0.00%	9.89%	0.01%
PPL Corp	PPL	0.11%	4.68%	0.01%	4.30%	0.00%
PepsiCo Inc	PEP	0.74%	2.92%	0.02%	5.96%	0.04%
Exelon Corp	EXC	0.14%	3.86%	0.01%	6.94%	0.01%
ConocoPhillips	COP	0.32%	5.88%	0.02%	7.50%	0.02%
PulteGroup Inc	PHM	0.04%	1.54%	0.00%	14.00%	0.01%
Pinnacle West Capital Corp	PNW	0.04%	3.86%	0.00%	5.37%	0.00%
Pitney Bowes Inc	PBI	0.02%	3.59%	0.00%	14.00%	0.00%
Plum Creek Timber Co Inc	PCL	0.04%	4.29%	0.00%	11.45%	0.00%
PNC Financial Services Group Inc/The	PNC	0.26%	2.08%	0.01%	7.80%	0.02%
PPG Industries Inc	PPG	0.15%	1.33%	0.00%	7.10%	0.01%
Praxair Inc	PX	0.17%	2.51%	0.00%	9.80%	0.02%
Precision Castparts Corp	PCP	0.14%	0.06%	0.00%	10.63%	0.01%
Progressive Corp/The	PGR	0.09%	2.25%	0.00%	8.08%	0.01%
Public Service Enterprise Group Inc	PEG	0.11%	3.74%	0.00%	5.34%	0.01%
Raytheon Co	RTN	0.17%	2.46%	0.00%	6.64%	0.01%
Robert Half International Inc	RHI	0.04%	1.45%	0.00%	11.47%	0.00%
Ryder System Inc	R	0.03%	1.81%	0.00%	13.23%	0.00%
SCANA Corp	SCG	0.04%	3.98%	0.00%	5.90%	0.00%
Edison International	EIX	0.10%	2.78%	0.00%	5.68%	0.01%
Schlumberger Ltd	SLB	0.54%	2.41%	0.01%	10.12%	0.06%
Charles Schwab Corp/The	SCHW	0.24%	0.69%	0.00%	22.44%	0.05%
Sherwin-Williams Co/The	SHW	0.13%	0.96%	0.00%	19.65%	0.03%
JM Smucker Co/The	SJM	0.07%	2.40%	0.00%	8.17%	0.01%
Snap-on Inc	SNA	0.05%	1.29%	0.00%	3.90%	0.00%
AMETEK Inc	AME	0.07%	0.68%	0.00%	9.35%	0.01%
Southern Co/The	SO	0.21%	4.85%	0.01%	4.18%	0.01%
BB&T Corp	BBT	0.15%	2.68%	0.00%	8.15%	0.01%
Southwest Airlines Co	LUV	0.12%	0.83%	0.00%	17.38%	0.02%
Southwestern Energy Co	SWN	0.04%	n/a	n/a	11.30%	0.00%
Stanley Black & Decker Inc	SWK	0.08%	2.09%	0.00%	10.67%	0.01%
Public Storage	PSA	0.18%	3.31%	0.01%	4.61%	0.01%
SunTrust Banks Inc	STI	0.12%	2.17%	0.00%	6.36%	0.01%
Sysco Corp	SYY	0.11%	3.30%	0.00%	8.94%	0.01%
TECO Energy Inc	TE	0.03%	4.07%	0.00%	5.50%	0.00%
Tesoro Corp	TSO	0.06%	1.75%	0.00%	20.48%	0.01%
Texas Instruments Inc	TXN	0.27%	2.72%	0.01%	9.38%	0.03%
Textron Inc	TXT	0.06%	0.18%	0.00%	9.26%	0.01%
Thermo Fisher Scientific Inc	TMO	0.29%	0.43%	0.00%	11.30%	0.03%
Tiffany & Co	TIF	0.06%	1.67%	0.00%	11.29%	0.01%
TJX Cos Inc/The	TJX	0.25%	1.20%	0.00%	11.14%	0.03%
Torchmark Corp	TMK	0.04%	0.88%	0.00%	8.04%	0.00%
Total System Services Inc	TSS	0.04%	0.87%	0.00%	11.00%	0.00%
Tyco International Plc	TYC	0.08%	2.16%	0.00%	12.30%	0.01%
Union Pacific Corp	UNP	0.44%	2.25%	0.01%	10.13%	0.04%
UnitedHealth Group Inc	UNH	0.60%	1.65%	0.01%	12.52%	0.08%
Unum Group	UNM	0.05%	2.06%	0.00%	8.50%	0.00%
Marathon Oil Corp	MRO	0.07%	4.00%	0.00%	5.21%	0.00%
Varian Medical Systems Inc	VAR	0.04%	n/a	n/a	12.75%	0.01%
Ventas Inc	VTR	0.12%	4.71%	0.01%	3.90%	0.00%
VF Corp	VFC	0.17%	1.66%	0.00%	12.12%	0.02%
Vornado Realty Trust	VNO	0.10%	2.58%	0.00%	9.59%	0.01%
ADT Corp/The	ADT	0.03%	2.43%	0.00%	6.70%	0.00%
Vulcan Materials Co	VMC	0.06%	0.44%	0.00%	30.15%	0.02%
Weyerhaeuser Co	WY	0.08%	3.78%	0.00%	2.73%	0.00%
Whirlpool Corp	WHR	0.07%	2.03%	0.00%	19.24%	0.01%
Williams Cos Inc/The	WMB	0.20%	4.50%	0.01%	3.75%	0.01%
WEC Energy Group Inc	WEC	0.08%	1.91%	0.00%	4.07%	0.00%
Xerox Corp	XRX	0.06%	2.54%	0.00%	9.00%	0.01%
Adobe Systems Inc	ADBE	0.21%	n/a	n/a	15.80%	0.03%
AES Corp/VA	AES	0.05%	3.13%	0.00%	6.25%	0.00%
Amgen Inc	AMGN	0.70%	1.79%	0.01%	8.63%	0.06%
Apple Inc	AAPL	3.59%	1.71%	0.06%	16.92%	0.61%
Autodesk Inc	ADSK	0.06%	n/a	n/a	12.90%	0.01%
Cintas Corp	CTAS	0.05%	0.99%	0.00%	11.70%	0.01%
Comcast Corp	CMCSA	0.69%	1.60%	0.01%	12.34%	0.08%
Molson Coors Brewing Co	TAP	0.06%	2.31%	0.00%	1.70%	0.00%
KLA-Tencor Corp	KLAC	0.04%	3.92%	0.00%	3.76%	0.00%
Marriott International Inc/MD	MAR	0.10%	1.38%	0.00%	14.42%	0.01%

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Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
McCormick & Co Inc/MD	MKC	0.05%	1.95%	0.00%	6.00%	0.00%
Nordstrom Inc	JWN	0.08%	1.94%	0.00%	11.14%	0.01%
PACCAR Inc	PCAR	0.12%	1.48%	0.00%	7.68%	0.01%
Costco Wholesale Corp	COST	0.33%	1.10%	0.00%	9.79%	0.03%
Sigma-Aldrich Corp	SIAL	0.09%	0.66%	0.00%	5.13%	0.00%
St Jude Medical Inc	STJ	0.11%	1.57%	0.00%	11.13%	0.01%
Stryker Corp	SYK	0.20%	1.35%	0.00%	9.97%	0.02%
Tyson Foods Inc	TSN	0.07%	0.90%	0.00%	6.00%	0.00%
Altera Corp	ALTR	0.08%	1.45%	0.00%	10.76%	0.01%
Applied Materials Inc	AMAT	0.11%	2.30%	0.00%	12.30%	0.01%
Time Warner Inc	TWX	0.38%	1.59%	0.01%	12.33%	0.05%
Bed Bath & Beyond Inc	BBBY	0.06%	n/a	n/a	6.61%	0.00%
American Airlines Group Inc	AAL	0.14%	1.00%	0.00%	15.89%	0.02%
Cardinal Health Inc	CAH	0.15%	1.82%	0.00%	11.55%	0.02%
Celgene Corp	CELG	0.54%	n/a	n/a	23.39%	0.13%
Cerner Corp	CERN	0.13%	n/a	n/a	19.32%	0.02%
Cincinnati Financial Corp	CINF	0.05%	3.33%	0.00%	n/a	n/a
Cablevision Systems Corp	CVC	0.03%	2.13%	0.00%	2.73%	0.00%
DR Horton Inc	DHI	0.06%	0.84%	0.00%	21.50%	0.01%
Flowserve Corp	FLS	0.03%	1.53%	0.00%	7.14%	0.00%
Electronic Arts Inc	EA	0.12%	n/a	n/a	10.57%	0.01%
Express Scripts Holding Co	ESRX	0.32%	n/a	n/a	12.53%	0.04%
Expeditors International of Washington Inc	EXPD	0.05%	1.54%	0.00%	11.10%	0.01%
Fastenal Co	FAST	0.06%	2.68%	0.00%	15.70%	0.01%
M&T Bank Corp	MTB	0.09%	2.14%	0.00%	8.09%	0.01%
Fiserv Inc	FISV	0.11%	n/a	n/a	13.36%	0.01%
Fifth Third Bancorp	FITB	0.09%	2.47%	0.00%	4.20%	0.00%
Gilead Sciences Inc	GILD	0.90%	1.46%	0.01%	12.82%	0.12%
Hasbro Inc	HAS	0.05%	2.34%	0.00%	10.20%	0.01%
Huntington Bancshares Inc/OH	HBAN	0.05%	2.06%	0.00%	8.64%	0.00%
Health Care REIT Inc	HCN	0.13%	4.76%	0.01%	4.69%	0.01%
Biogen Inc	BIIB	0.39%	n/a	n/a	14.45%	0.06%
Linear Technology Corp	LLTC	0.05%	2.93%	0.00%	7.77%	0.00%
Range Resources Corp	RRC	0.03%	0.41%	0.00%	15.15%	0.01%
Northern Trust Corp	NTRS	0.09%	1.88%	0.00%	13.59%	0.01%
Paychex Inc	PAYX	0.09%	3.62%	0.00%	9.89%	0.01%
People's United Financial Inc	PBCT	0.03%	4.12%	0.00%	n/a	n/a
Patterson Cos Inc	PDCO	0.03%	1.75%	0.00%	8.62%	0.00%
Pall Corp	PLL	0.07%	0.96%	0.00%	9.77%	0.01%
QUALCOMM Inc	QCOM	0.53%	2.98%	0.02%	10.80%	0.06%
Roper Technologies Inc	ROP	0.09%	0.60%	0.00%	13.37%	0.01%
Ross Stores Inc	ROST	0.11%	0.88%	0.00%	11.84%	0.01%
AutoNation Inc	AN	0.04%	n/a	n/a	12.43%	0.00%
Starbucks Corp	SBUX	0.45%	1.10%	0.00%	18.06%	0.08%
KeyCorp	KEY	0.07%	2.02%	0.00%	7.10%	0.00%
Staples Inc	SPLS	0.05%	3.26%	0.00%	0.75%	0.00%
State Street Corp	STT	0.16%	1.78%	0.00%	9.01%	0.01%
US Bancorp	USB	0.42%	2.26%	0.01%	8.12%	0.03%
Symantec Corp	SYMC	0.08%	2.64%	0.00%	8.11%	0.01%
T Rowe Price Group Inc	TROW	0.10%	2.70%	0.00%	12.18%	0.01%
Waste Management Inc	WM	0.12%	3.01%	0.00%	7.88%	0.01%
CBS Corp	CBS	0.13%	1.12%	0.00%	15.00%	0.02%
Allergan plc	AGN	0.68%	n/a	n/a	13.17%	0.09%
Whole Foods Market Inc	WFM	0.07%	1.43%	0.00%	12.47%	0.01%
Constellation Brands Inc	STZ	0.11%	1.03%	0.00%	12.21%	0.01%
Xilinx Inc	XLNX	0.06%	2.97%	0.00%	8.86%	0.00%
DENTSPLY International Inc	XRAY	0.04%	0.51%	0.00%	9.36%	0.00%
Zions Bancorporation	ZION	0.03%	0.77%	0.00%	8.47%	0.00%
Invesco Ltd	IVZ	0.09%	2.80%	0.00%	12.34%	0.01%
Intuit Inc	INTU	0.15%	0.95%	0.00%	14.48%	0.02%
Morgan Stanley	MS	0.40%	1.54%	0.01%	11.93%	0.05%
Microchip Technology Inc	MCHP	0.05%	3.34%	0.00%	6.00%	0.00%
ACE Ltd	ACE	0.18%	2.46%	0.00%	8.16%	0.02%
Chesapeake Energy Corp	CHK	0.03%	n/a	n/a	13.13%	0.00%
O'Reilly Automotive Inc	ORLY	0.13%	n/a	n/a	17.25%	0.02%
Allstate Corp/The	ALL	0.15%	1.74%	0.00%	9.91%	0.01%
FLIR Systems Inc	FLIR	0.02%	1.43%	0.00%	13.50%	0.00%
Equity Residential	EQR	0.14%	2.95%	0.00%	7.29%	0.01%
BorgWarner Inc	BWA	0.06%	1.05%	0.00%	10.90%	0.01%
Newfield Exploration Co	NFX	0.03%	n/a	n/a	5.76%	0.00%
Urban Outfitters Inc	URBN	0.02%	n/a	n/a	15.79%	0.00%
Simon Property Group Inc	SPG	0.30%	3.31%	0.01%	7.55%	0.02%
Eastman Chemical Co	EMN	0.06%	2.04%	0.00%	7.17%	0.00%
AvalonBay Communities Inc	AVB	0.12%	2.90%	0.00%	7.20%	0.01%
Prudential Financial Inc	PRU	0.21%	2.63%	0.01%	15.78%	0.03%
United Parcel Service Inc	UPS	0.37%	2.85%	0.01%	11.54%	0.04%
Apartment Investment & Management Co	AIV	0.03%	3.07%	0.00%	7.15%	0.00%
Walgreens Boots Alliance Inc	WBA	0.55%	1.49%	0.01%	15.65%	0.09%
McKesson Corp	MCK	0.27%	0.51%	0.00%	12.23%	0.03%
Lockheed Martin Corp	LMT	0.33%	2.90%	0.01%	8.13%	0.03%
AmerisourceBergen Corp	ABC	0.12%	1.10%	0.00%	13.62%	0.02%
Cameron International Corp	CAM	0.05%	n/a	n/a	2.27%	0.00%
Capital One Financial Corp	COF	0.23%	1.97%	0.00%	5.46%	0.01%
Waters Corp	WAT	0.06%	n/a	n/a	9.69%	0.01%
Dollar Tree Inc	DLTR	0.10%	n/a	n/a	15.00%	0.01%
Darden Restaurants Inc	DRI	0.05%	2.98%	0.00%	13.27%	0.01%
SanDisk Corp	SNDK	0.06%	1.99%	0.00%	5.10%	0.00%
Diamond Offshore Drilling Inc	DO	0.02%	2.28%	0.00%	-7.80%	0.00%
NetApp Inc	NTAP	0.05%	2.31%	0.00%	10.68%	0.01%
Citrix Systems Inc	CTXS	0.06%	n/a	n/a	14.38%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.04%	0.80%	0.00%	7.00%	0.00%

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Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
DaVita HealthCare Partners Inc	DVA	0.09%	n/a	n/a	10.22%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.10%	1.77%	0.00%	9.25%	0.01%
Iron Mountain Inc	IRM	0.03%	6.32%	0.00%	10.07%	0.00%
Estee Lauder Cos Inc/The	EL	0.11%	1.08%	0.00%	10.38%	0.01%
Yahoo! Inc	YHOO	0.18%	n/a	n/a	10.25%	0.02%
Principal Financial Group Inc	PFG	0.09%	2.74%	0.00%	10.17%	0.01%
Stericycle Inc	SRCL	0.06%	n/a	n/a	15.33%	0.01%
Universal Health Services Inc	UHS	0.07%	0.28%	0.00%	9.37%	0.01%
E*TRADE Financial Corp	ETFC	0.04%	n/a	n/a	17.42%	0.01%
Skyworks Solutions Inc	SWKS	0.09%	1.09%	0.00%	21.08%	0.02%
National Oilwell Varco Inc	NOV	0.08%	4.37%	0.00%	-9.91%	-0.01%
Quest Diagnostics Inc	DGX	0.06%	2.06%	0.00%	11.30%	0.01%
Rockwell Automation Inc	ROK	0.08%	2.23%	0.00%	8.40%	0.01%
Kraft Heinz Co/The	KHC	0.50%	2.77%	0.01%	11.60%	0.06%
American Tower Corp	AMT	0.21%	1.85%	0.00%	14.71%	0.03%
Regeneron Pharmaceuticals Inc	REGN	0.29%	n/a	n/a	20.97%	0.06%
Amazon.com Inc	AMZN	1.30%	n/a	n/a	47.77%	0.62%
Ralph Lauren Corp	RL	0.04%	1.59%	0.00%	10.63%	0.00%
Boston Properties Inc	BXP	0.10%	2.11%	0.00%	7.85%	0.01%
Amphenol Corp	APH	0.09%	0.99%	0.00%	6.69%	0.01%
Pioneer Natural Resources Co	PXD	0.10%	0.06%	0.00%	8.73%	0.01%
Valero Energy Corp	VLO	0.17%	2.44%	0.00%	-2.22%	0.00%
L-3 Communications Holdings Inc	LLL	0.05%	2.25%	0.00%	6.79%	0.00%
Western Union Co/The	WU	0.05%	3.06%	0.00%	7.70%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.17%	0.00%	10.44%	0.01%
Accenture PLC	ACN	0.33%	1.98%	0.01%	10.33%	0.03%
Yum! Brands Inc	YUM	0.20%	1.87%	0.00%	11.82%	0.02%
Prologis Inc	PLD	0.11%	3.94%	0.00%	4.99%	0.01%
FirstEnergy Corp	FE	0.07%	4.24%	0.00%	0.41%	0.00%
VeriSign Inc	VRSN	0.04%	n/a	n/a	10.40%	0.00%
Quanta Services Inc	PWR	0.03%	n/a	n/a	9.95%	0.00%
Henry Schein Inc	HSIC	0.06%	n/a	n/a	11.12%	0.01%
Ameren Corp	AEE	0.05%	3.99%	0.00%	6.77%	0.00%
Broadcom Corp	BRCM	0.15%	1.11%	0.00%	12.10%	0.02%
NVIDIA Corp	NVDA	0.06%	1.95%	0.00%	8.16%	0.00%
Sealed Air Corp	SEE	0.06%	0.98%	0.00%	10.11%	0.01%
Cognizant Technology Solutions Corp	CTSH	0.20%	n/a	n/a	16.01%	0.03%
Intuitive Surgical Inc	ISRG	0.10%	n/a	n/a	14.27%	0.01%
CONSOL Energy Inc	CNX	0.02%	0.24%	0.00%	12.40%	0.00%
Affiliated Managers Group Inc	AMG	0.06%	n/a	n/a	14.71%	0.01%
Aetna Inc	AET	0.20%	0.89%	0.00%	11.99%	0.02%
Republic Services Inc	RSG	0.08%	2.82%	0.00%	4.85%	0.00%
eBay Inc	EBAY	0.18%	n/a	n/a	8.09%	0.01%
Goldman Sachs Group Inc/The	GS	0.46%	1.27%	0.01%	18.98%	0.09%
Sempra Energy	SRE	0.13%	2.75%	0.00%	8.06%	0.01%
Moody's Corp	MCO	0.11%	1.23%	0.00%	13.50%	0.02%
Priceline Group Inc/The	PCLN	0.33%	n/a	n/a	18.88%	0.06%
F5 Networks Inc	FFIV	0.05%	n/a	n/a	15.41%	0.01%
Akamai Technologies Inc	AKAM	0.07%	n/a	n/a	15.80%	0.01%
Reynolds American Inc	RAI	0.32%	3.36%	0.01%	11.02%	0.04%
Devon Energy Corp	DVN	0.11%	1.94%	0.00%	3.73%	0.00%
Google Inc	GOOGL	0.99%	n/a	n/a	18.42%	0.18%
Red Hat Inc	RHT	0.08%	n/a	n/a	17.86%	0.01%
Hudson City Bancorp Inc	HCBK	0.03%	1.55%	0.00%	-3.00%	0.00%
Allegion PLC	ALLE	0.03%	0.63%	0.00%	14.50%	0.00%
Netflix Inc	NFLX	0.25%	n/a	n/a	32.49%	0.08%
Agilent Technologies Inc	A	0.07%	0.98%	0.00%	14.00%	0.01%
Anthem Inc	ANTM	0.21%	1.62%	0.00%	9.59%	0.02%
CME Group Inc/IL	CME	0.17%	2.08%	0.00%	12.36%	0.02%
Juniper Networks Inc	JNPR	0.06%	1.41%	0.00%	11.84%	0.01%
BlackRock Inc	BLK	0.29%	2.59%	0.01%	14.77%	0.04%
DTE Energy Co	DTE	0.07%	3.63%	0.00%	5.15%	0.00%
NASDAQ OMX Group Inc/The	NDAQ	0.04%	1.96%	0.00%	6.88%	0.00%
Philip Morris International Inc	PM	0.69%	4.68%	0.03%	6.29%	0.04%
Time Warner Cable Inc	TWC	0.28%	1.58%	0.00%	10.20%	0.03%
salesforce.com inc	CRM	0.25%	n/a	n/a	25.57%	0.06%
MetLife Inc	MET	0.32%	2.69%	0.01%	7.25%	0.02%
Monsanto Co	MON	0.25%	1.92%	0.00%	11.00%	0.03%
Coach Inc	COH	0.04%	4.33%	0.00%	10.90%	0.00%
Fluor Corp	FLR	0.04%	1.80%	0.00%	4.95%	0.00%
Dun & Bradstreet Corp/The	DNB	0.02%	1.48%	0.00%	10.25%	0.00%
Edwards Lifesciences Corp	EW	0.09%	n/a	n/a	15.20%	0.01%
Ameriprise Financial Inc	AMP	0.12%	2.13%	0.00%	11.65%	0.01%
Xcel Energy Inc	XEL	0.09%	3.69%	0.00%	5.00%	0.00%
Rockwell Collins Inc	COL	0.06%	1.56%	0.00%	9.88%	0.01%
FMC Technologies Inc	FTI	0.04%	n/a	n/a	7.58%	0.00%
Zimmer Biomet Holdings Inc	ZBH	0.11%	0.85%	0.00%	11.45%	0.01%
CBRE Group Inc	CBG	0.07%	n/a	n/a	10.50%	0.01%
MasterCard Inc	MA	0.56%	0.66%	0.00%	17.07%	0.10%
Signet Jewelers Ltd	SIG	0.05%	0.73%	0.00%	8.00%	0.00%
GameStop Corp	GME	0.03%	3.14%	0.00%	14.43%	0.00%
CarMax Inc	KMX	0.07%	n/a	n/a	14.98%	0.01%
Intercontinental Exchange Inc	ICE	0.13%	1.32%	0.00%	15.55%	0.02%
Fidelity National Information Services Inc	FIS	0.10%	1.59%	0.00%	12.42%	0.01%
Chipotle Mexican Grill Inc	CMG	0.12%	n/a	n/a	21.24%	0.03%
Pepco Holdings Inc	POM	0.04%	4.05%	0.00%	6.03%	0.00%
Wynn Resorts Ltd	WYNN	0.05%	1.94%	0.00%	9.50%	0.01%
Hospira Inc	HSP	0.08%	n/a	n/a	14.30%	0.01%
Assurant Inc	AIZ	0.03%	1.61%	0.00%	8.26%	0.00%
NRG Energy Inc	NRG	0.04%	2.58%	0.00%	23.90%	0.01%
Genworth Financial Inc	GNW	0.02%	n/a	n/a	5.00%	0.00%

STANDARD AND POOR'S 500 INDEX

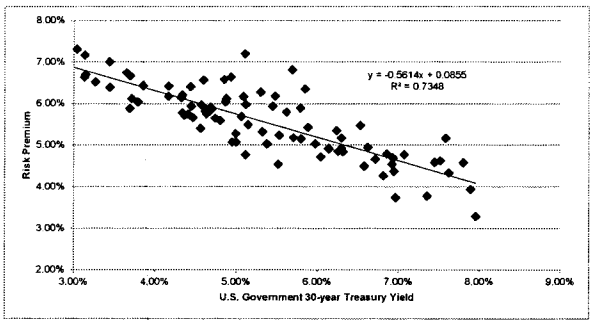
Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Regions Financial Corp	RF	0.07%	2.31%	0.00%	2.86%	0.00%
Monster Beverage Corp	MNST	0.16%	n/a	n/a	19.83%	0.03%
Teradata Corp	TDC	0.03%	n/a	n/a	8.82%	0.00%
Mosaic Co/The	MOS	0.08%	2.56%	0.00%	9.50%	0.01%
Expedia Inc	EXPE	0.07%	0.59%	0.00%	13.62%	0.01%
Discovery Communications Inc	DISCA	0.03%	n/a	n/a	15.80%	0.00%
CF Industries Holdings Inc	CF	0.07%	2.03%	0.00%	19.07%	0.01%
Viacom Inc	VIAB	0.10%	2.81%	0.00%	10.67%	0.01%
Wyndham Worldwide Corp	WYN	0.05%	2.04%	0.00%	10.00%	0.01%
Google Inc	GOOG	1.12%	n/a	n/a	18.42%	0.21%
Spectra Energy Corp	SE	0.11%	4.89%	0.01%	5.90%	0.01%
First Solar Inc	FSLR	0.02%	n/a	n/a	0.53%	0.00%
Mead Johnson Nutrition Co	MJN	0.09%	1.87%	0.00%	8.80%	0.01%
Ensco PLC	ESV	0.02%	3.62%	0.00%	-0.20%	0.00%
TE Connectivity Ltd	TEL	0.13%	2.17%	0.00%	10.45%	0.01%
Discover Financial Services	DFS	0.13%	2.01%	0.00%	9.22%	0.01%
TripAdvisor Inc	TRIP	0.05%	n/a	n/a	20.75%	0.01%
Dr Pepper Snapple Group Inc	DPS	0.08%	2.39%	0.00%	7.03%	0.01%
Scripps Networks Interactive Inc	SNI	0.03%	1.47%	0.00%	9.88%	0.00%
Visa Inc	V	0.76%	0.64%	0.00%	12.69%	0.10%
Xylem Inc/NY	XYL	0.03%	1.63%	0.00%	9.93%	0.00%
Marathon Petroleum Corp	MPC	0.15%	2.34%	0.00%	0.75%	0.00%
Level 3 Communications Inc	LVLT	0.09%	n/a	n/a	26.99%	0.03%
Tractor Supply Co	TSCO	0.07%	0.86%	0.00%	15.46%	0.01%
Transocean Ltd	RIG	0.03%	4.52%	0.00%	-18.20%	0.00%
Essex Property Trust Inc	ESS	0.08%	2.56%	0.00%	8.06%	0.01%
General Growth Properties Inc	GGP	0.12%	2.51%	0.00%	7.92%	0.01%
Realty Income Corp	O	0.06%	4.72%	0.00%	3.92%	0.00%
Seagate Technology PLC	STX	0.08%	4.27%	0.00%	7.44%	0.01%
WestRock Co	WRK	0.09%	2.38%	0.00%	7.32%	0.01%
Western Digital Corp	WDC	0.10%	2.32%	0.00%	5.02%	0.01%
Fossil Group Inc	FOSL	0.02%	n/a	n/a	12.53%	0.00%
JB Hunt Transport Services Inc	JBHT	0.05%	1.00%	0.00%	15.81%	0.01%
Lam Research Corp	LRCX	0.06%	1.56%	0.00%	5.06%	0.00%
Mohawk Industries Inc	MHK	0.08%	n/a	n/a	11.55%	0.01%
Pentair PLC	PNR	0.06%	2.10%	0.00%	15.52%	0.01%
Vertex Pharmaceuticals Inc	VRTX	0.17%	n/a	n/a	26.00%	0.04%
Facebook Inc	FB	1.10%	n/a	n/a	25.04%	0.28%
United Rentals Inc	URI	0.03%	n/a	n/a	12.20%	0.00%
Baxalta Inc	BXLT	0.12%	0.85%	0.00%	1.70%	0.00%
Delta Air Lines Inc	DAL	0.18%	1.22%	0.00%	21.19%	0.04%
Navient Corp	NAVI	0.03%	4.08%	0.00%	n/a	n/a
Mallinckrodt PLC	MNK	0.08%	n/a	n/a	18.80%	0.01%
Keurig Green Mountain Inc	GMCR	0.06%	1.53%	0.00%	14.80%	0.01%
Macerich Co/The	MAC	0.07%	3.28%	0.00%	6.31%	0.00%
Martin Marietta Materials Inc	MLM	0.05%	1.02%	0.00%	18.92%	0.01%
PayPal Holdings Inc	PYPL	0.25%	n/a	n/a	32.93%	0.08%
Alexion Pharmaceuticals Inc	ALXN	0.23%	n/a	n/a	22.97%	0.05%
Columbia Pipeline Group Inc	CPGX	0.05%	1.71%	0.00%	n/a	n/a
Endo International PLC	ENDP	0.09%	n/a	n/a	9.98%	0.01%
News Corp	NWSA	0.03%	n/a	n/a	11.68%	0.00%
Crown Castle International Corp	CCI	0.14%	4.00%	0.01%	21.60%	0.03%
Delphi Automotive PLC	DLPH	0.12%	1.28%	0.00%	13.73%	0.02%
Advance Auto Parts Inc	AAP	0.07%	0.14%	0.00%	13.94%	0.01%
Michael Kors Holdings Ltd	KORS	0.04%	n/a	n/a	28.71%	0.01%
Alliance Data Systems Corp	ADS	0.09%	n/a	n/a	14.60%	0.01%
Garmin Ltd	GRMN	0.05%	4.87%	0.00%	7.13%	0.00%
Cimarex Energy Co	XEC	0.05%	0.61%	0.00%	-0.23%	0.00%
Zoetis Inc	ZTS	0.13%	0.68%	0.00%	12.00%	0.02%
Equinix Inc	EQIX	0.08%	2.42%	0.00%	32.80%	0.03%
Discovery Communications Inc	DISCK	0.04%	n/a	n/a	15.80%	0.01%
						11.23%

Notes:
[8] Equals sum of Col. [15]
[9] Equals sum of Col. [17]
[10] Equals ([8] x (1 + (0.5 x [9]))) + [9]
[11] Source: Exhibit AEB-5, at 1
[12] Equals [10] - [11]
[13] Equals weight in S&P 500 based on market capitalization
[14] Source: Bloomberg Professional
[15] Equals [13] x [14]
[16] Source: Bloomberg Professional
[17] Equals [13] x [16]

Exhibit AEB-6

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Electric ROE	[2] 30-year U.S. Treasury Bond	[3] Risk Premium
1992.1	12.38%	7.80%	4.58%
1992.2	11.83%	7.89%	3.93%
1992.3	12.03%	7.45%	4.59%
1992.4	12.14%	7.52%	4.62%
1993.1	11.84%	7.07%	4.77%
1993.2	11.64%	6.86%	4.79%
1993.3	11.15%	6.31%	4.84%
1993.4	11.04%	6.14%	4.90%
1994.1	11.07%	6.57%	4.49%
1994.2	11.13%	7.35%	3.78%
1994.3	12.75%	7.58%	5.17%
1994.4	11.24%	7.96%	3.28%
1995.1	11.96%	7.63%	4.34%
1995.2	11.32%	6.94%	4.37%
1995.3	11.37%	6.71%	4.66%
1995.4	11.58%	6.23%	5.35%
1996.1	11.46%	6.29%	5.17%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	6.96%	3.74%
1996.4	11.56%	6.62%	4.94%
1997.1	11.08%	6.81%	4.27%
1997.2	11.62%	6.93%	4.68%
1997.3	12.00%	6.53%	5.47%
1997.4	11.06%	6.14%	4.92%
1998.1	11.31%	5.88%	5.43%
1998.2	12.20%	5.85%	6.35%
1998.3	11.65%	5.47%	6.18%
1998.4	12.30%	5.10%	7.20%
1999.1	10.40%	5.37%	5.03%
1999.2	10.94%	5.79%	5.15%
1999.3	10.75%	6.04%	4.71%
1999.4	11.10%	6.25%	4.85%
2000.1	11.21%	6.29%	4.92%
2000.2	11.00%	5.97%	5.03%
2000.3	11.68%	5.79%	5.89%
2000.4	12.50%	5.69%	6.81%
2001.1	11.38%	5.44%	5.93%
2001.2	10.88%	5.70%	5.18%
2001.3	10.76%	5.52%	5.23%
2001.4	11.57%	5.30%	6.27%
2002.1	10.05%	5.51%	4.54%
2002.2	11.41%	5.61%	5.79%
2002.3	11.25%	5.08%	6.17%
2002.4	11.57%	4.93%	6.64%
2003.1	11.43%	4.85%	6.58%
2003.2	11.16%	4.60%	6.56%
2003.3	9.88%	5.11%	4.76%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.88%	6.12%
2004.2	10.64%	5.32%	5.32%
2004.3	10.75%	5.06%	5.69%
2004.4	10.91%	4.86%	6.04%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.47%	5.66%
2005.3	10.85%	4.44%	6.41%
2005.4	10.59%	4.68%	5.91%
2006.1	10.38%	4.63%	5.75%
2006.2	10.63%	5.14%	5.49%
2006.3	10.06%	4.99%	5.07%
2006.4	10.39%	4.74%	5.65%
2007.1	10.39%	4.80%	5.59%
2007.2	10.27%	4.99%	5.28%
2007.3	10.02%	4.95%	5.07%
2007.4	10.43%	4.61%	5.81%
2008.1	10.15%	4.41%	5.75%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.94%
2008.4	10.39%	3.65%	6.74%
2009.1	10.45%	3.44%	7.01%
2009.2	10.58%	4.17%	6.42%
2009.3	10.46%	4.32%	6.14%
2009.4	10.54%	4.34%	6.21%
2010.1	10.45%	4.62%	5.82%
2010.2	10.08%	4.36%	5.71%
2010.3	10.29%	3.86%	6.43%
2010.4	10.34%	4.17%	6.17%
2011.1	9.96%	4.56%	5.40%
2011.2	10.12%	4.34%	5.78%
2011.3	10.36%	3.69%	6.67%
2011.4	10.34%	3.04%	7.31%
2012.1	10.30%	3.14%	7.17%
2012.2	9.92%	2.93%	6.98%
2012.3	9.78%	2.74%	7.04%
2012.4	10.07%	2.86%	7.21%
2013.1	9.77%	3.13%	6.64%
2013.2	9.84%	3.14%	6.70%
2013.3	9.83%	3.71%	6.12%
2013.4	9.82%	3.79%	6.04%
2014.1	9.57%	3.69%	5.88%
2014.2	9.83%	3.44%	6.39%
2014.3	9.79%	3.26%	6.52%
2014.4	9.78%	2.96%	6.81%
2015.1	9.66%	2.55%	7.11%
2015.2	9.50%	2.88%	6.61%
AVERAGE	10.83%	5.18%	5.65%
MEDIAN	10.75%	5.07%	5.75%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.857206905
R Square	0.734803677
Adjusted R Square	0.731921109
Standard Error	0.004639731
Observations	94

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005487535	0.005487535	254.9128044	2.93923E-28
Residual	92	0.001980494	2.15271E-05		
Total	93	0.007468029			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.085547929	0.001883455	45.42073817	8.38295E-65	0.081807225	0.08928863	0.081807225	0.089288634
U.S. Govt. 30-year Treasury	-0.561429644	0.035164101	-15.96598899	2.93923E-28	-0.631268583	-0.4915907	-0.631268583	-0.491590705

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-Day Average [4]	3.09%	6.82%	9.91%
Blue Chip Consensus Forecast (Q3 2015 - Q4 2016) [5]	3.57%	6.55%	10.12%
Blue Chip Consensus Forecast (2017-2021) [6]	4.80%	5.86%	10.66%
MEAN			10.23%

Notes:
[1] Source: Regulatory Research Associates, accessed August 17, 2015
[2] Source: Bloomberg Professional, quarterly bond yields are the average of the monthly prices; monthly prices represent the average of the daily last trading price of each day in the month
[3] Equals Column [1] – Column [2]
[4] Source: Bloomberg Professional
[5] Source: Blue Chip Financial Forecasts, Vol. 34, No. 7, July 1, 2015, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.085548 + (-0.561430 x Column [7])
[9] Equals Column [7] + Column [8]

Exhibit AEB-7

COMPARISON OF UNS ELECTRIC AND PROXY GROUP COMPANIES
CAPITAL COST RECOVERY MECHANISMS [1]

Parent Company	Operating Subsidiaries	States of Operation [2]	Capital Tracking Mechanism [3]
ALLETE, Inc.	Minnesota Power	Minnesota	Y
	Superior Water, Light and Power Company	Wisconsin [4]	N
American Electric Power Company, Inc.	AEP Texas Central Company	Texas	Y
	AEP Texas North Company	Texas	Y
	Appalachian Power Company	Virginia	Y
	Appalachian Power Company	West Virginia	Y
	Indiana Michigan Power Company	Indiana	Y
	Indiana Michigan Power Company	Michigan	N
	Kentucky Power Company	Kentucky	Y
	Kingsport Power Company	Tennessee	N
	Ohio Power Company	Ohio	Y
	Public Service Company of Oklahoma	Oklahoma	Y
	Southwestern Electric Power Company	Arkansas	Y
	Southwestern Electric Power Company	Louisiana	N
	Southwestern Electric Power Company	Texas	Y
	Wheeling Power Company	West Virginia	Y
Duke Energy Corporation	Duke Energy Carolinas, LLC	North Carolina	N
	Duke Energy Carolinas, LLC	South Carolina	N
	Florida Power Corporation	Florida	Y
	Duke Energy Indiana, Inc.	Indiana	Y
	Duke Energy Kentucky, Inc.	Kentucky	N
	Duke Energy Ohio, Inc.	Ohio	N
	Carolina Power & Light Company	North Carolina	N
	Carolina Power & Light Company	South Carolina	N
Empire District Electric Company	Empire District Electric Company	Arkansas [5]	Y
	Empire District Electric Company	Kansas	N
	Empire District Electric Company	Missouri	N
	Empire District Electric Company	Oklahoma [6]	Y
Eversource Energy	Connecticut Light and Power Company	Connecticut	Y
	NSTAR Electric Company	Massachusetts	Y
	Public Service Company of New Hampshire	New Hampshire	Y
	Western Massachusetts Electric Company	Massachusetts	Y
Great Plains Energy Inc.	Kansas City Power & Light Company	Kansas	N
	Kansas City Power & Light Company	Missouri	N
	KCP&L Greater Missouri Operations Company	Missouri	N
IDACORP, Inc.	Idaho Power Co.	Idaho	N
	Idaho Power Co.	Oregon	N
Otter Tail Corporation	Otter Tail Power Company	Minnesota	Y
	Otter Tail Power Company	North Dakota	Y
	Otter Tail Power Company	South Dakota [7]	Y
Pinnacle West Capital Corporation	Arizona Public Service Company	Arizona	Y
PNM Resources, Inc.	Public Service Company of New Mexico	New Mexico	N
	Texas-New Mexico Power Company	Texas	Y
Portland General Electric Company	Portland General Electric Company	Oregon	N
Westar Energy, Inc.	Kansas Gas and Electric Company	Kansas	Y
	Westar Energy (KPL)	Kansas	Y
Proxy Group Average			58.70%
Fortis Inc.	UNS Electric		Y

Notes
[1] Source: Regulatory Research Associates, Regulatory Focus, Adjustment Clauses - A State-by-State Overview, July 1, 2014,
[2] Electric Operations Only
[3] Capital costs include: transmission cost recovery, environmental compliance costs, and capital tracking mechanisms.
[4] Superior Water, Light and Power Company Tariff
[5] Empire District Electric Company Arkansas Tariff
[6] Empire District Electric Company Oklahoma Tariff
[7] Otter Tail Power Company South Dakota Tariff

Exhibit AEB-8

COMPARISON OF TEP ELECTRIC AND PROXY GROUP COMPANIES
S&P JURISDICTIONAL RANKINGS

		[1]	[2]
		S&P	
		Rank	Numeric Rank
ALLETE, Inc.	Minnesota	Strong/Adequate (14)	14
	Wisconsin	Strong (2)	2
American Electric Power Company, Inc.	Arkansas	Strong/Adequate (28)	28
	Indiana	Strong/Adequate (27)	27
	Kentucky	Strong (9)	9
	Louisiana	Strong/Adequate (13)	13
	Michigan	Strong (4)	4
	Ohio	Strong/Adequate (36)	36
	Oklahoma	Strong/Adequate (15)	15
	Tennessee	Strong/Adequate (22)	22
	Texas (PUC)	Strong/Adequate (44)	44
	Virginia	Strong/Adequate (19)	19
	West Virginia	Strong/Adequate (39)	39
Duke Energy Corporation	Florida	Strong (3)	3
	Indiana	Strong/Adequate (27)	27
	Kentucky	Strong (9)	9
	North Carolina	Strong (8)	8
	Ohio	Strong/Adequate (36)	36
	South Carolina	Strong (7)	7
Empire District Electric Company	Arkansas	Strong/Adequate (28)	28
	Kansas	Strong/Adequate (21)	21
	Oklahoma	Strong/Adequate (15)	15
	Missouri	Strong/Adequate (43)	43
Eversource Energy	Connecticut	Strong/Adequate (45)	45
	Massachusetts	Strong/Adequate (37)	37
	New Hampshire	Strong/Adequate (50)	50
Great Plains Energy Inc.	Kansas	Strong/Adequate (21)	21
	Missouri	Strong/Adequate (43)	43
IDACORP, Inc.	Idaho	Strong/Adequate (32)	32
	Oregon	Strong/Adequate (20)	20
Otter Tail Corporation	Minnesota	Strong/Adequate (14)	14
	North Dakota	Strong/Adequate (31)	31
	South Dakota	Strong/Adequate (29)	29
Pinnacle West Capital Corporation	Arizona	Strong/Adequate (30)	30
PNM Resources, Inc.	New Mexico	Strong/Adequate (49)	49
	Texas (PUC)	Strong/Adequate (44)	44
Portland General Electric Company	Oregon	Strong/Adequate (20)	20
Westar Energy, Inc.	Kansas	Strong/Adequate (21)	21
Proxy Group Average		Strong/Adequate (24) / Strong/Adequate (25)	25.13
TEP Electric	Arizona	Strong/Adequate (30)	30

Notes
[1] Source: Utility Regulatory Assessments for U.S. Investor-Owned Utilities, Standard and Poor's Ratings Services, January 7, 2014

Exhibit AEB-9

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO

Company	Ticker	2015Q1	2014Q4	2014Q3	2014Q2	2014Q3	2014Q2	2014Q1	2013Q4	Average
ALLETE, Inc.	ALE	58.70%	56.98%	56.18%	55.83%	56.79%	56.37%	58.08%	57.90%	57.10%
American Electric Power Company, Inc.	AEP	52.23%	52.11%	52.27%	52.31%	52.34%	52.36%	53.51%	53.61%	52.60%
Duke Energy Corporation	DUK	58.32%	57.62%	56.60%	56.03%	55.25%	56.09%	55.83%	56.41%	56.52%
Empire District Electric Company	EDE	51.47%	51.28%	53.31%	52.82%	52.73%	52.30%	52.37%	51.52%	52.23%
Eversource Energy	ES	53.84%	53.64%	53.44%	52.05%	51.25%	52.89%	54.51%	53.07%	53.09%
Great Plains Energy Inc.	GXP	53.21%	53.30%	53.42%	52.67%	52.56%	52.49%	52.51%	52.94%	52.89%
IDACORP, Inc.	IDA	49.38%	52.94%	52.92%	52.03%	51.72%	51.61%	50.51%	49.74%	51.36%
Otter Tail Corporation	OTTR	51.13%	49.80%	49.32%	47.60%	47.20%	53.72%	52.37%	52.35%	50.44%
Pinnacle West Capital Corporation	PNW	55.86%	57.54%	58.43%	57.32%	55.67%	57.39%	57.62%	55.94%	56.97%
PNM Resources, Inc.	PNM	52.30%	52.11%	52.96%	52.74%	53.49%	54.17%	54.36%	54.24%	53.29%
Portland General Electric Company	POR	44.11%	43.31%	44.86%	46.64%	49.21%	48.70%	50.43%	50.37%	47.20%
Westar Energy, Inc.	WR	66.54%	65.73%	65.95%	66.62%	63.45%	63.22%	61.28%	61.87%	64.33%
MEAN		53.93%	53.86%	54.14%	53.72%	53.47%	54.28%	54.45%	54.16%	54.00%
MEDIAN		52.75%	53.12%	53.37%	52.71%	52.65%	53.31%	53.93%	53.34%	52.99%
LOW		44.11%	43.31%	44.86%	46.64%	47.20%	48.70%	50.43%	49.74%	47.20%
HIGH		66.54%	65.73%	65.95%	66.62%	63.45%	63.22%	61.28%	61.87%	64.33%

COMMON EQUITY RATIO - ELECTRIC UTILITY OPERATING COMPANIES

Company	Ticker	2015Q1	2014Q4	2014Q3	2014Q2	2014Q1	2013Q4	2013Q3	2013Q2	Average
ALLETE (Minnesota Power)	ALE	57.56%	55.24%	53.98%	53.01%	55.16%	55.93%	54.90%	54.13%	54.99%
Superior Water, Light and Power Company	ALE	59.83%	58.72%	58.39%	58.65%	58.42%	56.81%	61.25%	61.67%	59.22%
AEP Texas Central Company	AEP	45.01%	42.39%	43.93%	43.18%	47.56%	46.75%	46.62%	47.89%	45.42%
AEP Texas North Company	AEP	47.15%	46.96%	47.06%	46.79%	46.82%	46.68%	46.03%	50.34%	47.23%
Appalachian Power Company	AEP	46.52%	45.83%	46.29%	46.00%	44.13%	43.52%	47.39%	45.29%	45.62%
Indiana Michigan Power Company	AEP	51.94%	51.36%	51.45%	51.39%	51.63%	50.80%	48.27%	47.77%	50.58%
Kentucky Power Company	AEP	44.19%	44.74%	46.25%	48.23%	50.30%	52.83%	46.02%	47.18%	47.47%
Kingsport Power Company	AEP	60.77%	61.00%	60.55%	60.91%	58.88%	60.85%	60.73%	60.33%	60.50%
Ohio Power Company	AEP	49.30%	48.96%	46.03%	44.79%	42.54%	39.71%	57.01%	56.06%	48.05%
Public Service Company of Oklahoma	AEP	44.66%	49.69%	49.43%	48.30%	47.51%	48.51%	50.46%	49.49%	48.51%
Southwestern Electric Power Company	AEP	46.25%	50.46%	50.60%	51.26%	51.18%	51.21%	50.22%	50.52%	50.21%
Wheeling Power Company	AEP	86.56%	79.75%	81.14%	82.27%	82.89%	82.79%	82.32%	81.26%	82.37%
Duke Energy Carolinas, LLC	DUK	57.01%	57.84%	56.60%	55.90%	55.56%	55.18%	53.80%	53.57%	55.68%
Duke Energy Florida, Inc.	DUK	52.74%	53.90%	50.98%	49.96%	49.22%	50.47%	50.61%	49.57%	50.93%
Duke Energy Indiana, Inc.	DUK	50.98%	50.28%	49.88%	50.69%	51.57%	50.85%	50.31%	51.11%	50.71%
Duke Energy Kentucky, Inc.	DUK	57.68%	56.58%	54.78%	54.36%	54.16%	53.23%	52.56%	54.56%	54.74%
Duke Energy Ohio, Inc.	DUK	79.18%	76.64%	76.40%	74.55%	70.11%	74.27%	74.25%	79.06%	75.56%
Duke Energy Progress, Inc.	DUK	52.33%	50.48%	50.99%	50.75%	50.85%	52.54%	53.43%	50.62%	51.50%
Empire District Electric Company	EDE	51.47%	51.28%	53.31%	52.82%	52.73%	52.30%	52.37%	51.52%	52.23%
Connecticut Light and Power Company	ES	53.26%	53.11%	52.72%	50.52%	52.33%	52.01%	51.43%	49.95%	51.92%
NSTAR Electric Company	ES	58.22%	57.84%	57.17%	55.95%	51.45%	57.35%	56.78%	55.65%	56.30%
Public Service Company of New Hampshire	ES	53.40%	53.29%	53.92%	52.44%	52.27%	51.90%	55.78%	55.52%	53.57%
Western Massachusetts Electric Company	ES	50.48%	50.31%	49.97%	49.29%	48.96%	50.31%	54.03%	51.15%	50.56%
Kansas City Power & Light Company	GXP	49.84%	49.53%	49.54%	48.67%	48.46%	48.46%	48.57%	47.70%	48.85%
KCP&L Greater Missouri Operations Company	GXP	56.57%	57.07%	57.30%	56.68%	56.66%	56.52%	56.46%	58.18%	56.93%
Idaho Power Co.	IDA	49.38%	52.94%	52.92%	52.03%	51.72%	51.61%	50.51%	49.74%	51.36%
Otter Tail Power Company	OTTR	51.13%	49.80%	49.32%	47.60%	47.20%	53.72%	52.37%	52.35%	50.44%
Arizona Public Service Company	PNW	55.86%	57.54%	58.43%	57.32%	55.67%	57.39%	57.62%	55.94%	56.97%
Public Service Company of New Mexico	PNM	46.11%	45.86%	47.43%	47.14%	46.70%	48.39%	49.79%	50.07%	47.69%
Texas-New Mexico Power Company	PNM	58.49%	58.35%	58.49%	58.35%	60.27%	59.95%	58.92%	58.41%	58.90%
Portland General Electric Company	POR	44.11%	43.31%	44.86%	46.64%	49.21%	48.70%	50.43%	50.37%	47.20%
Kansas Gas and Electric Company	WR	72.15%	71.99%	72.65%	77.67%	69.73%	69.54%	65.91%	65.08%	70.59%
Westar Energy (KPL)	WR	60.94%	59.48%	59.26%	55.58%	57.17%	56.90%	56.66%	58.66%	58.08%

Source: SNL Financial

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO

Company	Ticker	2015Q1	2014Q4	2014Q3	2014Q2	2014Q3	2014Q2	2014Q1	2013Q4	Average
ALLETE, Inc.	ALE	41.30%	43.02%	43.82%	44.17%	43.21%	43.63%	41.92%	42.10%	42.90%
American Electric Power Company, Inc.	AEP	47.77%	47.89%	47.73%	47.69%	47.66%	47.64%	46.49%	46.39%	47.40%
Duke Energy Corporation	DUK	41.68%	42.38%	43.40%	43.97%	44.75%	43.91%	44.17%	43.59%	43.48%
Empire District Electric Company	EDE	48.53%	48.72%	46.69%	47.18%	47.27%	47.70%	47.63%	48.48%	47.77%
Eversource Energy	ES	46.16%	46.36%	46.56%	47.95%	48.75%	47.11%	45.49%	46.93%	46.91%
Great Plains Energy Inc.	GXP	46.79%	46.70%	46.58%	47.33%	47.44%	47.51%	47.49%	47.06%	47.11%
IDACORP, Inc.	IDA	50.62%	47.06%	47.08%	47.97%	48.28%	48.39%	49.49%	50.26%	48.64%
Otter Tail Corporation	OTTR	48.87%	50.20%	50.68%	52.40%	52.80%	46.28%	47.63%	47.65%	49.56%
Pinnacle West Capital Corporation	PNW	44.14%	42.46%	41.57%	42.68%	44.33%	42.61%	42.38%	44.06%	43.03%
PNM Resources, Inc.	PNM	47.70%	47.89%	47.04%	47.26%	46.51%	45.83%	45.64%	45.76%	46.71%
Portland General Electric Company	POR	55.89%	56.69%	55.14%	53.36%	50.79%	51.30%	49.57%	49.63%	52.80%
Westar Energy, Inc.	WR	33.46%	34.27%	34.05%	33.38%	36.55%	36.78%	38.72%	38.13%	35.67%
MEAN		46.07%	46.14%	45.86%	46.28%	46.53%	45.72%	45.55%	45.84%	46.00%
MEDIAN		47.25%	46.88%	46.63%	47.29%	47.35%	46.69%	46.07%	46.66%	47.01%
LOW		33.46%	34.27%	34.05%	33.38%	36.55%	36.78%	38.72%	38.13%	35.67%
HIGH		55.89%	56.69%	55.14%	53.36%	52.80%	51.30%	49.57%	50.26%	52.80%

LONG-TERM DEBT RATIO - ELECTRIC UTILITY OPERATING COMPANIES

Company	Ticker	2015Q1	2014Q4	2014Q3	2014Q2	2014Q1	2013Q4	2013Q3	2013Q2	Average
ALLETE (Minnesota Power)	ALE	42.44%	44.76%	46.02%	46.99%	44.84%	44.07%	45.10%	45.87%	45.01%
Superior Water, Light and Power Company	ALE	40.17%	41.28%	41.61%	41.35%	41.58%	43.19%	38.75%	38.33%	40.78%
AEP Texas Central Company	AEP	54.99%	57.61%	56.07%	56.82%	52.44%	53.25%	53.38%	52.11%	54.58%
AEP Texas North Company	AEP	52.85%	53.04%	52.94%	53.21%	53.18%	53.32%	53.97%	49.66%	52.77%
Appalachian Power Company	AEP	53.48%	54.17%	53.71%	54.00%	55.87%	56.48%	52.61%	54.71%	54.38%
Indiana Michigan Power Company	AEP	48.06%	48.64%	48.55%	48.61%	48.37%	49.20%	51.73%	52.23%	49.42%
Kentucky Power Company	AEP	55.81%	55.26%	53.75%	51.77%	49.70%	47.17%	53.98%	52.82%	52.53%
Kingsport Power Company	AEP	39.23%	39.00%	39.45%	39.09%	41.12%	39.15%	39.27%	39.67%	39.50%
Ohio Power Company	AEP	50.70%	51.04%	53.97%	55.21%	57.46%	60.29%	42.99%	43.94%	51.95%
Public Service Company of Oklahoma	AEP	55.34%	50.31%	50.57%	51.70%	52.49%	51.49%	49.54%	50.51%	51.49%
Southwestern Electric Power Company	AEP	53.75%	49.54%	49.40%	48.74%	48.82%	48.79%	49.78%	49.48%	49.79%
Wheeling Power Company	AEP	13.44%	20.25%	18.86%	17.73%	17.11%	17.21%	17.68%	18.74%	17.63%
Duke Energy Carolinas, LLC	DUK	42.99%	42.16%	43.40%	44.10%	44.44%	44.82%	46.20%	46.43%	44.32%
Duke Energy Florida, Inc.	DUK	47.26%	46.10%	49.02%	50.04%	50.78%	49.53%	49.39%	50.43%	49.07%
Duke Energy Indiana, Inc.	DUK	49.02%	49.72%	50.12%	49.31%	48.43%	49.15%	49.69%	48.89%	49.29%
Duke Energy Kentucky, Inc.	DUK	42.32%	43.42%	45.22%	45.64%	45.84%	46.77%	47.44%	45.44%	45.26%
Duke Energy Ohio, Inc.	DUK	20.82%	23.36%	23.60%	25.45%	29.89%	25.73%	25.75%	20.94%	24.44%
Duke Energy Progress, Inc.	DUK	47.67%	49.52%	49.01%	49.25%	49.15%	47.46%	46.57%	49.38%	48.50%
Empire District Electric Company	EDE	48.53%	48.72%	46.69%	47.18%	47.27%	47.70%	47.63%	48.48%	47.77%
Connecticut Light and Power Company	ES	46.74%	46.89%	47.28%	49.48%	47.67%	47.99%	48.57%	50.05%	48.08%
NSTAR Electric Company	ES	41.78%	42.16%	42.83%	44.05%	48.55%	42.65%	43.22%	44.35%	43.70%
Public Service Company of New Hampshire	ES	46.60%	46.71%	46.08%	47.56%	47.73%	48.10%	44.22%	44.48%	46.43%
Western Massachusetts Electric Company	ES	49.52%	49.69%	50.03%	50.71%	51.04%	49.69%	45.97%	48.85%	49.44%
Kansas City Power & Light Company	GXP	50.16%	50.47%	50.46%	51.33%	51.54%	51.54%	51.43%	52.30%	51.15%
KCP&L Greater Missouri Operations Company	GXP	43.43%	42.93%	42.70%	43.32%	43.34%	43.48%	43.54%	41.82%	43.07%
Idaho Power Co.	IDA	50.62%	47.06%	47.08%	47.97%	48.28%	48.39%	49.49%	50.26%	48.64%
Otter Tail Power Company	OTTR	48.87%	50.20%	50.68%	52.40%	52.80%	46.28%	47.63%	47.65%	49.56%
Arizona Public Service Company	PNW	44.14%	42.46%	41.57%	42.68%	44.33%	42.61%	42.38%	44.06%	43.03%
Public Service Company of New Mexico	PNM	53.89%	54.14%	52.57%	52.86%	53.30%	51.61%	50.21%	49.93%	52.31%
Texas-New Mexico Power Company	PNM	41.51%	41.65%	41.51%	41.65%	39.73%	40.05%	41.08%	41.59%	41.10%
Portland General Electric Company	POR	55.89%	56.69%	55.14%	53.36%	50.79%	51.30%	49.57%	49.63%	52.80%
Kansas Gas and Electric Company	WR	27.85%	28.01%	27.35%	22.33%	30.27%	30.46%	34.09%	34.92%	29.41%
Westar Energy (KPL)	WR	39.06%	40.52%	40.74%	44.42%	42.83%	43.10%	43.34%	41.34%	41.92%

Source: SNL Financial

Exhibit AEB-10

UNS ELECTRIC
FAIR VALUE RATE OF RETURN
ARIZONA STAFF METHODOLOGY

	Amount ($M)	Weighting	Weighted Amount ($M)	
Original Cost Rate Base (OCRB)	$ 2,104.7	50.00%	$ 1,052.3	[1]
Replacement Cost New, Depreciated Rate Base (RCND)	$ 3,721.9	50.00%	1,860.9	[2]
Fair Value Rate Base (FVRB)			2,913.3	[3]
Appreciation Above OCRB			$ 808.6	[4]
FVRB / OCRB Multiple			1.38	

Capital	Amount ($M)	Percent	Cost Rate		Weighted Cost Rate	
Long-Term Debt	$ 1,051.7	36.10%	4.32%	[5]	1.56%	
Common Equity	1,053.0	36.14%	10.35%	[6]	3.74%	
Capital Financing OCRB	$ 2,104.7	72.24%			5.30%	
Appreciation Above OCRB Not Recognized on Utility's Books	808.6	27.76%	1.42%		0.39%	
Total	$ 2,913.3	100.00%			5.69%	[7]

[1] Direct Testimony of Dallas J. Dukes, Schedule B-1
[2] Direct Testimony of Dallas J. Dukes, Schedule B-1
[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

CALCULATION OF INFLATION RATE

Step 1		
Consumer Price Index (YoY % Change) [1]		
2017-2021	2.30%	
2022-2026	2.30%	
Average	2.30%	
Consumer Price Index (All-Urban) [2]		
2015		2.37
2026		2.94
Compound Annual Growth Rate		1.98%
GDP Chain-type Price Index (2005=1.000) [2]		
2015		1.11
2026		1.34
Compound Annual Growth Rate	1.74%	
Average Inflation Forecast	**2.01%**	
Step 2		
Nominal U.S. Treasury Bond Yield, 30-year [1]		
2017-2021	4.80%	
2022-2026	5.00%	
	4.90%	
Real Risk-Free Rate [3]	**2.84%**	
50.0% of Real Risk-Free Rate [4]	**1.42%**	

Notes:

[1] Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14.
[2] Energy Information Administration, Annual Energy Outlook 2015, Table 20
[3] Equals (4.90% + 1) / (1 + 2.01%) − 1
[4] Equals [3] x 50.0%

Exhibit AEB-11

Comparable Transactions Analysis

Calculation of Transaction Premium over Corporate Value

Named Range	Target	Buyer	[1] Date Announced	[2] Target Book Value Per Share	[3] Target Deal Value Per Share	[4] Premium to Equity	[5] Target Equity Ratio	[6] Transaction Premium to Corporate Value	[7] Implied TEP Valuation ($M)
UIL	UIL Holdings Corporation	Iberdrola, S.A.	02/25/15	$24.07	$52.75	119.20%	46.10%	54.95%	$3,261
HE	Hawaiian Electric Industries, Inc.	NextEra Energy, Inc.	12/03/14	$17.56	$33.50	90.73%	59.71%	54.17%	$3,245
CNL	Cleco Corporation	Investor group	10/20/14	$27.14	$55.37	103.99%	55.66%	57.88%	$3,323
TEG	Integrys Energy Group, Inc.	Wisconsin Energy Corporation	06/23/14	$42.17	$71.47	69.48%	56.42%	39.20%	$2,930
POM	Pepco Holdings, Inc.	Exelon Corporation	04/30/14	$17.28	$27.25	57.73%	52.88%	30.53%	$2,747
UNS	UNS Energy Corporation	Fortis Inc.	12/11/13	$22.75	$60.25	164.83%	61.58%	101.50%	$4,241
NVE	NV Energy, Inc.	Berkshire Hathaway Inc.	05/29/13	$15.05	$23.75	57.84%	46.99%	27.18%	$2,677
CHG	CH Energy Group, Inc.	Fortis Inc.	02/21/12	$33.72	$65.00	92.77%	55.96%	51.92%	$3,197
CV	Central Vermont Public Service Corporation	Gaz Métro LP	06/23/11	$20.59	$35.25	71.20%	61.29%	43.64%	$3,023
CEG	Constellation Energy Group Inc.	Exelon Corporation	04/28/11	$39.65	$38.59	-2.68%	65.30%	-1.75%	$2,068
DPL	DPL Inc.	AES Corporation	04/19/11	$10.52	$30.00	185.18%	63.13%	116.90%	$4,565
PGN	Progress Energy Inc.	Duke Energy Corporation	01/10/11	$34.21	$46.47	35.86%	46.68%	16.74%	$2,457
NST	NSTAR	Northeast Utilities	10/18/10	$18.60	$40.28	116.51%	51.31%	59.79%	$3,363
AYE	Allegheny Energy, Inc.	FirstEnergy Corporation	02/11/10	$18.36	$27.65	50.62%	42.53%	21.53%	$2,558
PSD	Puget Energy, Inc.	Investor Consortium	10/25/07	$18.45	$30.00	62.63%	50.35%	31.54%	$2,768
EAS	Energy East Corporation	Iberdrola, S.A.	06/25/07	$20.21	$28.50	41.01%	48.37%	19.83%	$2,522
ILA	Aquila, Inc.	Great Plains Energy, Inc.	02/06/07	$3.49	$4.54	30.18%	48.89%	14.76%	$2,415
DQE	Duquesne Light Holdings, Inc	Macquarie Consortium	07/05/06	$8.41	$20.00	137.82%	46.83%	64.55%	$3,463
GMP	Green Mountain Power Corporation	Gaz Métro LP	06/21/06	$22.79	$35.00	53.60%	61.71%	33.08%	$2,801
KSE	KeySpan Corp.	National Grid Group PLC	02/25/06	$25.60	$42.00	64.05%	56.78%	36.37%	$2,870
CIN	Cinergy Corp.	Duke Energy Corporation	05/08/05	$22.71	$45.80	101.69%	55.23%	56.16%	$3,287
RGS	RGS Energy Group, Inc.	Energy East Corporation	02/16/01	$22.19	$39.50	78.04%	55.15%	43.04%	$3,011
CIV	Conectiv	Potomac Electric Power Company	02/12/01	$13.10	$25.00	90.91%	54.41%	49.46%	$3,146
MonPow	Montana Power Company	NorthWestern Corporation	09/28/00	$9.86	$10.50	6.53%	77.59%	5.06%	$2,211
NMK	Niagara Mohawk Holdings, Inc.	National Grid Group PLC	09/04/00	$16.90	$19.00	12.39%	43.41%	5.38%	$2,218
GPUI	GPU, Inc.	FirstEnergy Corporation	08/08/00	$27.01	$36.50	35.12%	54.35%	19.09%	$2,506
IPL	IPALCO Enterprises, Inc.	AES Corporation	07/15/00	$7.76	$25.00	222.03%	49.21%	109.27%	$4,404
BGR	Bangor Hydro-Electric Company	NS Power Holdings Inc.	06/29/00	$18.34	$26.50	44.46%	46.73%	20.77%	$2,542
LGE	LG&E Energy Corp.	Powergen PLC	02/27/00	$8.80	$24.85	182.35%	63.37%	115.56%	$4,537
MEC	MidAmerican Energy Holdings Company	Investor group	10/24/99	$15.59	$35.05	124.81%	20.58%	25.69%	$2,645
UCM	Unicom Corporation	PECO Energy Company	09/22/99	$23.51	$34.40	46.36%	49.01%	22.72%	$2,583
FPC	Florida Progress Corporation	Carolina Power & Light Company	08/22/99	$19.70	$54.00	174.08%	51.35%	89.39%	$3,986
CMP	CMP Group, Inc.	Energy East Corporation	06/14/99	$16.79	$29.50	75.72%	78.19%	59.20%	$3,351
TNP	TNP Enterprises, Inc.	Investor Group	05/24/99	$23.21	$44.00	89.59%	40.00%	35.84%	$2,859
EUA	Eastern Utilities Associates	National Grid Group PLC	02/01/99	$18.29	$31.46	72.05%	61.42%	44.25%	$3,036
NES	New England Electric System	National Grid Group PLC	12/11/98	$29.30	$53.75	83.48%	62.49%	52.16%	$3,202
PPW	PacifiCorp	Scottish Power PLC	12/06/98	$13.47	$25.13	86.56%	54.51%	47.19%	$3,098
CES	Commonwealth Energy System	BEC Energy	12/05/98	$20.75	$44.10	112.58%	54.79%	61.68%	$3,403
CER	CILCORP Inc	AES Corporation	11/23/98	$26.24	$65.00	147.71%	62.91%	92.92%	$4,060
MEC	MidAmerican Energy Holdings Company	CalEnergy Company, Inc.	08/11/98	$12.99	$27.15	109.07%	25.20%	27.49%	$2,683
ORU	Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	05/10/98	$27.92	$58.50	109.52%	60.21%	65.94%	$3,493
NVP	Nevada Power Company	Sierra Pacific Resources	04/29/98	$16.33	$26.00	59.20%	52.88%	31.30%	$2,764
KU	KU Energy Corporation	LG&E Energy Corporation	05/20/97	$17.29	$40.71	135.48%	56.38%	76.39%	$3,712
							Min:	-1.75%	$2,068
							Max:	116.90%	$4,565
							Mean:	47.22%	$3,098
							Median:	43.64%	$3,023
							Std. Dev.:	29.15%	$614
							Count:	43	43

Attachment A

Ann E. Bulkley
Vice President

Ms. Bulkley has nearly two decades of management and economic consulting experience in the energy industry. Ms. Bulkley has extensive state and federal regulatory experience on both electric and natural gas issues including rate of return, cost of equity and capital structure issues. Ms. Bulkley has advised clients seeking to acquire utility assets, providing valuation services including an understanding of regulation, market expected returns, and the assessment of utility risk factors. Ms. Bulkley has assisted clients with valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and accounting and financial purposes. In addition, Ms. Bulkley has experience in the areas of contract and business unit valuation, strategic alliances, market restructuring and regulatory and litigation support.

REPRESENTATIVE PROJECT EXPERIENCE

Regulatory Analysis and Ratemaking

Ms. Bulkley has provided a range of advisory services relating to regulatory policy analysis and many aspects of utility ratemaking. Specific services have included: cost of capital and return on equity testimony, cost of service and rate design analysis and testimony, development of ratemaking strategies; development of merchant function exit strategies; analysis and program development to address residual energy supply and/or provider of last resort obligations; stranded costs assessment and recovery; performance-based ratemaking analysis and design; and many aspects of traditional utility ratemaking (e.g., rate design, rate base valuation).

Cost of Capital

Ms. Bulkley has provided expert testimony on the cost of capital testimony before several state regulatory commissions. In addition, Ms. Bulkley has prepared and provided supporting analysis for at least forty Federal and State regulatory proceedings over the past seven years. Ms. Bulkley's expert testimony experience includes:

- Northern States Power Company: Before the North Dakota Public Service Commission, provided expert testimony on the cost of capital for the company's North Dakota electric utility operations.
- WE Energies: Before the Michigan Public Service Commission, provided expert testimony in support of the company's cost of capital for its electric utility operations.
- Atmos Energy: Provided expert testimony in support of the company's return on equity and capital structure before the Public Utilities Commission for the State of Colorado.
- UNS Electric: Provided expert testimony in support of the company's return on equity and capital structure before the Arizona Corporation Commission.
- Portland Natural Gas Transmission: Provided testimony strategy as well as analytical support for cost of capital testimony before the Federal Energy Regulatory Commission.
- In addition to the specific cases listed above, Ms. Bulkley has provided testimony strategy as well as analytical support on cost of capital in several cases in the following states: Arizona, Colorado, Connecticut, Massachusetts, Minnesota, New Mexico, New York, North Carolina, South Carolina, South Dakota, Virginia, and Utah.

Valuation

Ms. Bulkley has provided valuation services to utility clients, unregulated generators and private equity clients for a variety of purposes including ratemaking, fair value, ad valorem tax, litigation and damages,

and acquisition. Ms. Bulkley's appraisal practices are consistent with the national standards established by the Uniform Standards of Professional Appraisal practice. In addition, Ms. Bulkley has relied on other simulation based valuation methodologies.

Representative projects/clients have included:

- Northern Indiana Fuel and Light: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Kokomo Gas: Provided expert testimony regarding the fair value of the company's natural gas distribution system assets. Valuation relied on cost approach.
- Prepared fair value rate base analyses for Northern Indiana Public Service Company for several electric rate proceedings. Valuation approaches used in this project included income, cost and comparable sales approaches.
- Confidential Utility Client: Prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.
- Prepared a valuation of a portfolio of generation assets for a large energy utility to be used for strategic planning purposes. Valuation approach included an income approach, a real options analysis and a risk analysis.
- Assisted clients in the restructuring of NUG contracts through the valuation of the underlying assets. Performed analysis to determine the option value of a plant in a competitively priced electricity market following the settlement of the NUG contract. .
- Prepared market valuations of several purchase power contracts for large electric utilities in the sale of purchase power contracts. Assignment included an assessment of the regional power market, analysis of the underlying purchase power contracts, a traditional discounted cash flow valuation approach, as well as a risk analysis. Analyzed bids from potential acquirers using income and risk analysis approached. Prepared an assessment of the credit issues and value at risk for the selling utility.
- Prepared appraisal of a portfolio of generating facilities for a large electric utility to be used for financing purposes.
- Prepared an appraisal of a fleet of fossil generating assets for a large electric utility to establish the value of assets transferred from utility property.
- Conducted due diligence on an electric transmission and distribution system as part of a buy-side due diligence team.
- Provided analytical support for and prepared appraisal reports of generation assets to be used in ad valorem tax disputes.
- Provided analytical support and prepared testimony regarding the valuation of electric distribution system assets in five communities in a condemnation proceeding.
- Valued purchase power agreements in the transfer of assets to a deregulated electric market.

Ratemaking

Ms. Bulkley has assisted several clients with analysis to support investor-owned and municipal utility clients in the preparation of rate cases. Sample engagements include:

- Assisted several investor-owned and municipal clients on cost allocation and rate design issues including the development of expert testimony supporting recommended rate alternatives.
- Worked with Canadian regulatory staff to establish filing requirements for a rate review of a newly regulated electric utility. Analyzed and evaluated rate application. Attended hearings and conducted investigation of rate application for regulatory staff. Prepared, supported and defended

recommendations for revenue requirements and rates for the company. Developed rates for gas utility for transportation program and ancillary services.

Strategic and Financial Advisory Services

Ms. Bulkley has assisted several clients across North America with analytically based strategic planning, due diligence and financial advisory services.

Representative projects include:

- Preparation of feasibility studies for bond issuances for municipal and district steam clients.
- Assisted in the development of a generation strategy for an electric utility. Analyzed various NERC regions to identify potential market entry points. Evaluated potential competitors and alliance partners. Assisted in the development of gas and electric price forecasts. Developed a framework for the implementation of a risk management program.
- Assisted clients in identifying potential joint venture opportunities and alliance partners. Contacted interviewed, and evaluated potential alliance candidates based on company-established criteria for several LDCs and marketing companies. Worked with several LDCs and unregulated marketing companies to establish alliances to enter into the retail energy market. Prepared testimony in support of several merger cases and participated in the regulatory process to obtain approval for these mergers.
- Assisted clients in several buy-side due diligence efforts, providing regulatory insight and developing valuation recommendations for acquisitions of both electric and gas properties.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Vice President
Assistant Vice President
Project Manager

Navigant Consulting, Inc. (1995 – 2002)
Project Manager

Cahners Publishing Company (1995)
Economist

EDUCATION

M.A., Economics, Boston University, 1995
B.A., Economics and Finance, Simmons College, 1991
Certified General Appraiser licensed in the Commonwealth of Massachusetts and the State of Michigan

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EXPERT TESTIMONY OF ANN E. BULKLEY

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Arizona Corporation Commission				
UNS Electric	12/12	UNS Electric	Docket No. E-04204A-12-0504	Return on Equity
UNS Electric	05/15	UNS Electric	Docket No. E-04204A-15-0142	Return on Equity
Arkansas Public Service Commission				
Arkansas Oklahoma Gas Corporation	10/13	Arkansas Oklahoma Gas Corporation	Docket No. 13-078-U	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	05/13	Atmos Energy Corporation	Docket No. 13AL-0496G	Return on Equity
Atmos Energy Corporation	04/14	Atmos Energy Corporation	Docket No. 14AL-0300G	Return on Equity
Atmos Energy Corporation	05/15	Atmos Energy Corporation	Docket No. 15AL-0299G	Return on Equity
Indiana Utility Regulatory Commission				
Indianapolis Power and Light Company	09/15	Indianapolis Power and Light Company	Cause No. 44576 Cause No. 44602	Fair Value
Kokomo Gas And Fuel Company	09/10	Kokomo Gas And Fuel Company	Cause No. 43942	Fair Value
Northern Indiana Fuel And Light Company, Inc.	09/10	Northern Indiana Fuel And Light Company, Inc.	Cause No. 43943	Fair Value
Northern Indiana Public Service Company	10/15	Northern Indiana Public Service Company	Cause No. 44688	Fair Value
Kansas Corporation Commission				
Atmos Energy Corporation	08/15	Atmos Energy Corporation	Docket No. 16-ATMG-079-RTS	Return on Equity
Massachusetts Department of Public Utilities				
Unitil Corporation	01/04	Fitchburg Gas and Electric	DTE 03-52	Integrated Resource Plan; Gas Demand Forecast
Michigan Public Service Commission				
Wisconsin Electric Power Company	12/11	Wisconsin Electric Power Company	Case No. U-16830	Return on Equity

EXPERT TESTIMONY OF ANN E. BULKLEY

Michigan Tax Tribunal				
Covert Township	07/14	New Covert Generating Co., LLC.	Docket No. 399578	Valuation of Electric Generation Assets
New Mexico Public Regulation Commission				
Southwestern Public Service	06/15	Southwestern Public Service	C-15-001398-UT	Return on Equity
Southwestern Public Service	10/15	Southwestern Public Service	C-15-00296-UT	Return on Equity
New York State Department of Public Service				
New York State Electric and Gas Company	05/15	New York State Electric and Gas Company	Case No. 15-G-0284	Return on Equity
North Dakota Public Service Commission				
Northern States Power Company	12/10	Northern States Power Company	C-PU-10-657	Return on Equity
Northern States Power Company	12/12	Northern States Power Company	C-PU-12-813	Return on Equity
Oklahoma Corporation Commission				
Arkansas Oklahoma Gas Corporation	01/13	Arkansas Oklahoma Gas Corporation	Cause No. PUD 201200236	Return on Equity
Public Utility Commission of Texas				
Southwestern Public Service Company	01/14	Southwestern Public Service Company	Docket No. 42004	Return on Equity
South Dakota Public Utilities Commission				
Northern States Power Company	06/14	Northern States Power Company	Docket No. EL14-058	Return on Equity