NEW APPLICATION

0000141155

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

E-04204A-12-0504

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-12-____

UNS ELECTRIC, INC.

APPLICATION

TESTIMONY AND EXHIBITS

VOLUME 1 of 3

December 31, 2012

RECEIVED
2012 DEC 31 A 11:34
AZ CORP COMMISSION
DOCKET CONTROL

Arizona Corporation Commission
DOCKETED
DEC 31 2012
DOCKETED BY

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	DOCKET NO. E-04204A-12-____ **APPLICATION**

UNS Electric, Inc. ("UNS Electric" 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 an increase in its non-fuel base rates by $7.5 million, or approximately 4.6% over adjusted test year retail revenues of $163,982,000, to be effective no later than January 1, 2014.

UNS Electric is also seeking approval of: (i) a lost fixed cost recovery mechanism related to the Arizona Corporation Commission's ("Commission") Renewable Energy Standard ("REST") rules and Electric Energy Efficiency ("EE") rules; (ii) a transmission cost adjustment mechanism; (iii) a new approach to funding cost-effective demand-side management and energy efficiency programs; (iv) modifications to its Purchased Power and Fuel Adjustment Clause ("PPFAC"); (v) necessary modifications to the rate design and (vi) modifications to its Tariff, Rules and Regulations and certain existing compliance requirements.

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

I. SUMMARY.

UNS Electric's current rates were established in Decision No. 71914 (September 10, 2010), based on a test year ending December 31, 2008, with rates effective on October 1, 2010. As part of Decision No. 71914, the Commission allowed for post-decision rate-base treatment of the Black Mountain Generating Station ("BMGS"), provided that certain steps were completed regarding the acquisition of BMGS. Further, the Decision ordered UNS Electric to file a rate application no later than 12 months after the rate reclassification that uses a 12-month test year with data that reflects BMGS in rate base at least six months during the test year. In Decision No. 72213 (March 3, 2011), the Commission determined that BMGS was fully operational, in good condition, and confirmed the inclusion of BMGS in rate base without further order of the Commission. UNS Electric obtained the necessary approval from the Federal Energy Regulatory Commission ("FERC") to acquire BMGS on June 8, 2011. The acquisition closed on July 1, 2011.

In Decision No. 72743 (January 20, 2012) the Commission granted UNS Electric's motion to extend the rate case filing deadline contained in Decision No. 71914 to December 31, 2012. This was in order to allow UNS Electric to use a test year that includes a full year of data with BMGS in rate base, and to provide separation from the rate case filed on July 2, 2012 by UNS Electric's sister company, Tucson Electric Power Company ("TEP").

As a result, and in accordance with Decision No. 72743, the test year in this rate case ends June 30, 2012, and includes 12 months of data with BMGS in rate base.

A. Need for Increased Revenue Requirement. The Company is facing an erosion of its retail sales as a result of energy efficiency programs, the increase in use of distributed renewable energy technologies, and other forms of self-generation by its customers, and declining customer usage. Because a large portion of the Company's fixed costs are currently recovered on a per-kWh basis, this erosion of sales is expected to contribute to a significant under-recovery of costs over time.

Moreover, in the three-and-a-half years since the end of the last rate case test year (December 31, 2008), UNS Electric invested $157 million (including BMGS) to upgrade and maintain its system to ensure continued reliable service to its 91,000 customers. As a result, UNS Electric's rate base has increase by $23.6 million over the prior test year (this excludes BMGS, which is already included in rate base). UNS Electric's expenses also have increased since the prior test year. However, the Company has carefully managed its costs, which has resulted in operating expenses that have increased on average less than 1% annually since that time.

UNS Electric is also facing a significant increase in its capital spending needs for transmission and distribution facilities over the next several years. Much of this increase in capital spending is due to the planned upgrade of transmission facilities serving Santa Cruz County. These expenditures will result in a significant increase to the Company's fixed costs that are not reflected in this rate application. Other notable risks faced by UNS Electric include the Company's reliance on natural gas and wholesale power markets to meet most of the energy needs of its customers, as well as the large amount of long-term debt maturing in 2015. Preserving the Company's investment-grade credit rating is critical- UNS Electric will need to refinance $80 million of long-term debt maturing in August 2015. Since the cost of debt is a significant component of UNS Electric's revenue requirement, it is clearly in the interest of both the Company and its customers for UNS Electric to maintain or improve the investment grade Baa2 credit rating assigned to its senior debt obligations.

UNS Electric is, therefore, filing this rate case to: (i) enable it to continue to provide safe and reliable service; (ii) recover its full cost of service, including an appropriate return on invested capital; and (iii) maintain or improve its credit rating, all of which will benefit UNS Electric and its customers.

In this case, the Company is requesting a $7.5 million non-fuel base rate increase. Based on this non-fuel adjusted increase, the current average monthly bill for an average UNS Electric residential customer based on 1000 kWh consumption in the summer and 700 kWh consumption

in the winter, would increase from $82.51 to $86.15 (a 4.4% increase). UNS Electric took steps to mitigate the size of this rate increase, including proposing a lower return on fair value rate base than could be justified and reducing or eliminating certain management compensation expenses from the Company's revenue requirement.

B. Need for New and Updated Adjustor Mechanisms. UNS Electric is seeking the approval of certain adjustor mechanisms which will allow it to meet current and prospective regulatory mandates without jeopardizing the financial stability of the Company. Those adjustors include: (i) a lost fixed cost recovery ("LFCR") mechanism to address kWh sales lost as a result of the REST and EE rules; and (ii) a transmission cost recovery mechanism that is designed to provide for a more timely recovery of changes to the FERC-regulated Open Access Transmission Tariff ("OATT") rates. UNS Electric is also proposing a new method for determining the demand side management and energy efficiency program costs that will be recovered through its existing Demand Side Management Surcharge ("DSMS") as part of its Energy Efficiency Resource Plan ("EE Resource Plan") proposal.

C. Need for Updated Rate Design. UNS Electric is proposing to update its rate design and reduce customer confusion by simplifying its rate offerings. The current rate design, which relies heavily on volumetric rate elements to recover the majority of the Company's fixed costs, creates difficulties for UNS Electric in recovering its authorized revenue requirement. UNS Electric is proposing rates that will provide the Company with a better opportunity to recover its fixed costs and earn a reasonable return on its investment. The Company is proposing additional changes to its rate design to help ensure that all customers pay a more equitable share of the cost of providing safe and reliable service.

Moreover, in order to simplify customer bills and improve customer price signals, UNS Electric is also requesting to recover all of its fuel and purchased power costs through the Company's PPFAC. Currently, UNS Electric's fuel and purchased power costs are split and recovered through base rates and through the PPFAC. Additionally, UNS Electric further

proposes to modify the PPFAC to provide for different PPFAC rates for different customer classes in order to more fairly allocate fuel and purchased power costs.

II. KEY ELEMENTS OF THE RATE CASE.

A. Revenue Requirement.

The Company is requesting a $7.5 million non-fuel base rate increase, which represents a 4.6% increase over adjusted test year retail revenues, including fuel and purchased power costs. As a result of this increase, the current monthly bill for an average UNS Electric residential customer based on 1000 kWh consumption in the summer and 700 kWh consumption in the winter, would increase from $82.51 to $86.15 (a 4.4% increase). UNS Electric's revenue requirement increase is based on an Original Cost Rate Base ("OCRB") of $216.6 million and a Replacement Cost New Less Depreciation ("RCND") rate base of $356.1 million, resulting in Fair Value Rate Base ("FVRB") of $286.3 million using a traditional 50/50 weighting of OCRB and RCND.

UNS Electric proposes to use its actual capital structure in determining the weighted average cost of capital ("WACC"). UNS Electric's actual test year capital structure is 47.40% debt and 52.60% equity.

UNS Electric's cost of long-term debt is 5.97%. The Company proposes a cost of common equity of 10.50%. The Company's WACC, based on these cost rates and the test year capital structure, is 8.35%.

UNS Electric is further proposing a fair value rate of return ("FVROR") of 6.71%. This FVROR is based on the methodology used by the Commission in several recent rate cases. The FVROR also reflects a return on the fair value increment of rate base that is less than what UNS Electric believes it can justify.

B. Lost Fixed Cost Recovery Mechanism ("LFCR").

The Company is proposing an LFCR mechanism that is very similar to the mechanism approved for UNS Gas, Inc. in Decision No. 73142 (May 1, 2012) and Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012) – and to what Tucson Electric Power

Company ("TEP") proposed in its July 2, 2012 rate application. The LFCR is not a full decoupling mechanism; rather it is a mechanism narrowly tailored to provide UNS Electric an opportunity to recover non-fuel costs, costs that would otherwise go unrecovered due to lost kWh sales from compliance with the REST rules and EE rules. The Company is also including a fixed rate, or "opt-out", option as part of its LFCR proposal.

The Company needs such a mechanism, or a similar alternative mechanism (such as a full decoupling mechanism), to mitigate the negative financial impacts to the Company of complying with the EE rules and the rising number of distributed generation ("DG") resources in UNS Electric's service territory resulting from the REST rules, and to provide UNS Electric a reasonable opportunity to recover its authorized revenue requirement while pursuing these Commission mandates.

C. Proposals to Moderate Future Rate Impacts.

UNS Electric is making several proposals to moderate future rate increases. UNS Electric believes that adoption of these proposals will help customers to better manage their energy expenses. These proposals also can assist UNS Electric to synchronize recovery of costs, improve its opportunity to earn the authorized rate of return, and manage its capital expenditures and related financing needs, thus reducing the borrowing costs ultimately borne by its customers.

1. Transmission Cost Adjustment Mechanism ("TCA").

UNS Electric's proposed TCA will provide a mechanism to recover transmission costs associated with serving retail customers on a more timely basis. UNS Electric's proposed retail base rates will include a transmission cost element reflective of the current FERC OATT rate. As the OATT rate changes, the TCA will result in a corresponding adjustment to the transmission component of retail rates. The TCA will apply to all of UNS Electric's retail electric rate schedules and will be similar to the transmission cost adjustor approved for APS in Decision No. 67744 (April 7, 2005) and as modified in Decision No. 73183 (May 24, 2012). UNS Electric is proposing that the annual TCA adjustments be effective without affirmative Commission approval unless Staff requests review or the Commission orders otherwise.

2. *Energy Efficiency Resource Plan ("EE Resource Plan").*

UNS Electric is proposing its EE Resource Plan as an innovative solution for funding the cost of meeting the EE rules requirements. Under this proposed pilot program, which is similar to the pilot program proposed by TEP in its pending rate case, the Commission would approve a three-year EE program budget for UNS Electric. The program costs would be treated as a regulatory asset that would be amortized over four years. This proposal will result in a gradually-inclining rate in the DSMS – also to be set by the Commission in this rate case - while increasing program offerings each year to meet the rising EE Standard. Because UNS Electric would amortize its EE costs over a four-year period, the EE Resource Plan would allow DSMS surcharges to be significantly lower from 2014-2016 than they would be if those annual expenses were fully recovered each year under the current practice. Under UNS Electric's proposal, the Company would determine the most cost-effective EE option appropriate for its particular system, invest its capital to procure that resource and recover the associated costs – including the amortization expense and an appropriate return on investment – through the DSMS surcharge. This capital investment and recovery model is similar to that used for any other supply-side resource.

As a result, the EE Resource Plan would reduce and stabilize the rate impacts to our customers, better synchronize the benefits of EE with their associated costs, provide a base level of certainty to program offerings, and eliminate the need to provide a performance incentive. This will result in DSM/EE contractors having more certainty regarding program funding levels, and will provide UNS Electric with more certainty as to the amount and timing of energy savings it can rely on in its resource and system planning, while also reducing the burden on Commission Staff now tasked with annually reviewing implementation plans and the DSMS.

3. *Post-Test Year Plant.*

The Company is proposing to adjust UNS Electric's rate base to include approximately $13 million of used and useful solar projects and other plant additions as post-test year plant that is expected to be in service by June 30, 2013. Including these plant additions in rate base now

will help (i) moderate the size of any future rate increase required by UNS Electric and (ii) help mitigate increases of the REST surcharge. Further, it more closely aligns the recovery of costs with the benefits that are currently being provided to existing customers.

D. PPFAC.

UNS Electric is proposing several modifications to its PPFAC. First, the Company proposes to recover all of its fuel and purchased power costs through the PPFAC and to eliminate the current fuel component recovered through base rates.

Second, the Company is also proposing multiple PPFAC rates to differentiate between on-peak and off-peak fuel costs and to create rates that better reflect the cost of fuel for each customer class.

Third, the Company is requesting to recover some additional costs through the PPFAC, including wholesale credit support costs. The levels of these costs are tied directly to the acquisition of fuel and wholesale power and should be recovered through the PPFAC. Credit support is often required to provide assurance to a wholesale counter-party that UNS Electric will perform its obligation to purchase natural gas or wholesale power as specified by contract. Changes in the market value of forward energy contracts can create a need for wholesale credit support, and UNS Electric has had to provide credit support by obtaining letters of credit or cash collateral. The cost of obtaining and maintaining credit with trade counterparties is a real cost of doing business in the wholesale markets for fuel and purchased power.

E. Rate Design.

UNS Electric is proposing necessary changes to its rate design. First, the Company is proposing rates that more accurately reflect the current cost of service for each customer class – while also simplifying and modernizing rates. These changes include increases in the monthly customer charge for all customer classes, which allows for recovery of a greater share of the Company's fixed costs through fixed charges. This approach will assist UNS Electric in promoting conservation, will reduce the future magnitude of lost fixed cost recovery, and facilitate greater revenue stability.

Second, the Company is proposing additional changes to its rate design, including modifications to demand charges and to time-of-use ("TOU") periods.

Third, the Company is proposing to modify low-income customer rates by offering a flat $13.00 per month discount, removing the percent discount option and eliminating the exclusion from the PPFAC and DSM surcharges.

F. Rules and Regulations.

The Company is proposing modifications to its Rules and Regulations and to its Tariffs. These modifications are intended to modernize UNS Electric's Rules and Regulations and to clarify areas in the Rules and Regulations that have caused undue customer confusion. The Company is also seeking to eliminate or modify various compliance requirements from previous Commission decisions.

III. APPLICATION.

In support of this Application, UNS Electric 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 2498 Airway Avenue, Kingman, Arizona 86409.

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:

Bradley S. Carroll
UNS Electric, Inc.
88 East Broadway Blvd., MS HQE910
P. O. Box 711
Tucson, Arizona 85702
520-884-3679
bcarroll@tep.com

and

Michael W. Patten
Jason D. Gellman
Roshka, DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004
602-256-6100
mpatten@rdp-law.com

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 UNS Electric supporting the requests made within the Application and schedules:

Michael J. DeConcini	The overall condition of UNS Electric and an overview of its operations, capital spending and customer service. Overview of the Company's rate application and primary proposals, including the LFCR, TCA, the EE Resource Plan and modifications to the PPFAC.
Kentton C. Grant	Overview of UNS Electric's financial condition, including anticipated capital needs, credit rating and ratings agency concerns; capital structure, cost of debt and cost of credit support for fuel and purchased power procurement.
Ann E. Bulkley (consultant)	Cost of equity, fair value rate base and fair value rate of return.
Dallas J. Dukes	Revenue Requirement; rate base and income statement pro forma adjustments; post-test year plant adjustments;

	Reconstructed Cost New Less Depreciation (RCND); and depreciation expense based on presently approved depreciation rates modified to reflect estimated decommissioning cost for the Company's generation assets.
Jason J. Rademacher:	Income tax and property tax adjustments.
Denise A. Smith:	Proposed Energy Efficiency Resource Plan.
Craig A. Jones:	Cost of service study; proposed LFCR mechanism; proposed rate design; revisions to the base cost of fuel and purchase power and to the Company's PPFAC; and revisions to tariffs.
Lindy L. Sheehey	Revisions to UNS Electric's Rules and Regulations.

F. UNS Electric respectfully requests that this Commission set a date for a hearing on this Application such that new rates for the Company will become effective no later than January 1, 2014. At the hearing conducted pursuant to this rate request, UNS Electric 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 no longer 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 request for a permanent non-fuel base revenue increase of $7.5 million based on annualized test period sales is reasonable and necessary in order 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) the proposed LFCR mechanism is in accordance with Commission policy, so that the Company can recover lost revenues associated with compliance with Commission renewable energy DG and EE requirements, and is in the public interest;

(5) the proposed TCA addresses the need to timely recover transmission costs associated with serving retail customers at the level approved by FERC;

(6) the proposed EE Resource Plan provides a more cost effective and stable approach to implementing DSM and EE programs, and is in the public interest;

(7) transferring into base rates those costs of Company-owned renewable generation resources is in accordance with prior Commission orders and is in the public interest;

(8) including post-test year plant that will be in service by June 30, 2013 in rate base is in the public interest;

(9) modifying the Company's PPFAC to allow for recovery of additional costs and for price differentiation by customer class is in the public interest;

(10) 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; and

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

G. Further, UNS Electric requests that its next rate hearing be conducted in Tucson. UNS Electric's service territory includes both Santa Cruz County and Mohave County. Because its last rate case was conducted in Phoenix, UNS Electric believes it would be more equitable to its Santa Cruz County customers to have its next rate case hearing conducted in Tucson.

H. In addition to setting a hearing date, UNS Electric 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. UNS Electric further

requests that the Company be authorized to serve all discovery requests, answers and objections electronically. Finally, UNS Electric requests that a procedural schedule be established, including a settlement track option, so that a final order in this case can be rendered and new rates can be effective by January 1, 2014.

WHEREFORE, UNS Electric respectfully requests that the Commission:

(1) issue a procedural order establishing a date for hearing evidence concerning the Application, prescribing the time and form of public notice to UNS Electric customers, establishing procedures for intervention and discovery as described above, and providing for a settlement track option for the docket;

(2) issue a final order finding and concluding that the Company's rate application is just and reasonable and granting the Company the permanent rate increase of $7.5 million to allow it to recover its expenses and a reasonable opportunity to earn its authorized rate of return on its investment;

(3) issue a final order approving the new or modified rate and service schedules included with the Company's Application with an effective date no later than January 1, 2014;

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

(5) issue a final order approving the Company's proposed Lost Fixed Cost Recovery Mechanism;

(6) issue a final order approving the Company's proposed Transmission Cost Adjustment Mechanism;

(7) issue a final order approving the Company's proposed Energy Efficiency Resource Plan;

(8) issue a final order approving the proposed rate design described in the testimony accompanying this Application;

(9) issue a final order approving the Company's revised Rules and Regulations and modified compliance requirements; and

(10) grant the Company such additional relief as the Commission deems just and proper.

RESPECTFULLY SUBMITTED this 31st day of December 2012.

UNS ELECTRIC, INC.

By _____

Bradley S. Carroll
UNS Electric, Inc.
88 East Broadway, MS HQE910
P.O. Box 711
Tucson, Arizona 85702

and

Michael W. Patten
Jason D. Gellman
Roshka DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Attorneys for UNS Electric, Inc.

Original and 13 copies of the foregoing
filed this 31st day of December 2012, with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing hand-delivered/mailed
this 31st day of December 2012, to:

Lyn A. Farmer, Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Janice M. Alward, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Steve Olea, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Jodi A. Jerich, Director
Residential Utility Consumer Office
1110 West Washington Street, Ste. 220
Phoenix, Arizona 85007

By Mary Ippolito

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE - CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	DOCKET NO. E-04204A-12-____

Direct Testimony of

Michael J. DeConcini

on Behalf of

UNS Electric, Inc.

December 31, 2012

TABLE OF CONTENTS

I. Introduction 1

II. Summary 2

III. UNS Electric's Operations 6

IV. Capital Investment 11

V. Lost Fixed Cost Recovery Mechanism 13

VI. Transmission Cost Adjustment Mechanism 15

VII. Energy Efficiency Resource Plan 17

VIII. Purchased Power and Fuel Adjustment Clause 17
- A. Consolidation of Base Power Supply Rates into the PPFAC 17
- B. Additional Costs to be Recovered through the PPFAC 18
- C. Changes to the Plan of Administration 22

IX. Decommissioning Cost Estimates 23

X. Service Lives of Photovoltaic Assets 25

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Michael J. DeConcini. My business address is 88 East Broadway Boulevard, Tucson, Arizona 85701.

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

A. I am a Vice President for UNS Electric, Inc. ("UNS Electric" or "Company"). I also serve as Senior Vice President, Operations for both UNS Energy Corporation ("UNS Energy") and Tucson Electric Power Company ("TEP"). UNS Energy was known as UniSource Energy Corporation before the name change that took effect on May 4, 2012. I will simply refer to that company as UNS Energy throughout my testimony, even when describing actions taken under the company's previous name.

Q. Please describe your background, education and experience.

A. I have been employed by TEP since 1988, serving in various management capacities since 1994. I hold a Master of Business Administration degree from Arizona State University and a Bachelor of Science degree in Finance from Moorhead State University.

Q. Mr. DeConcini, what is the purpose of your Direct Testimony?

A. I provide a summary of the UNS Electric's rate request, the key issues in the case and the central factors necessitating a base rate increase.

I also describe the need for the Company's proposed Lost Fixed Cost Recovery ("LFCR") mechanism which is designed to recover certain revenues that are lost as a result of our efforts to comply with the Arizona Corporation Commission's ("Commission") Renewable Energy Standard and Tariff ("REST") and Energy Efficiency Standard ("EES").

In addition, I provide an overview of proposed methods to recover some ongoing and anticipated future costs related to compliance with the EES and transmission infrastructure investments in ways that will moderate the impact of those costs to our customers through future rates.

Finally, I will address modifications that the Company is requesting to the Plan of Administration ("POA") for its Purchased Power and Fuel Adjustment Clause ("PPFAC").

II. SUMMARY.

Q. What level of rate increase is UNS Electric requesting?

A. UNS Electric is requesting a non-fuel rate increase over adjusted test year revenues of $7.5 million, or 4.6 percent. For an average residential customer, this would represent a monthly bill increase of approximately $3.64 over current rates.

Q. What factors have contributed to the need for an increase over current rates?

A. There are two key factors: (i) an increase in costs required to maintain safe, reliable service and comply with regulatory mandates and (ii) a significant reduction in the level of sales growth in UNS Electric's service area

First, UNS Electric's current rates, which were approved by the Commission in Decision No. 71914 (September 30, 2010) ("2010 Rate Order") are based on costs incurred in 2008. Over the last 3.5 years, UNS Electric's costs have increased, due primarily to necessary capital investments to maintain and, in many areas, upgrade the reliability of our system. UNS Electric also has invested solar resources to meet the Commission's renewable energy requirements. Since 2008, UNS Electric's rate base has increased by $23.6 million

as a result of capital investment (this excludes Black Mountain Generating Station, which is already reflected in existing rates).

UNS Electric also has experienced rising costs of operating and maintaining the Company's system. However, the Company's diligent efforts to control such costs have limited the increase in operating and maintenance costs ("O&M") by only $600,000 over the prior test year. This increase in O&M expense represents an average annual increase of less than 1% per year.

Second, UNS Electric's retail sales growth rate has decreased significantly since the last test year and sales levels continue to experience downward pressure. In years past, the rising costs borne by UNS Electric were mitigated by growing energy sales driven by an expanding customer base and increasing use per-customer. That growth rate has declined significantly due to weak economic conditions, the rising number of distributed generation ("DG") resources installed in our service territory and increasing energy efficiency ("EE") measures. The potential for renewed sales growth in the short term will be challenging. One of UNS Electric's large customers, Guardian Fiberglass, has closed its operations, while other customers continue to look for ways to reduce their consumption or rely on self-generated electricity.

The table below shows UNS Electric's retail sales growth from 2004 to 2008 and from 2008 to 2012.

	Average Annual Growth in Retail Sales Volumes	
	2004 to 2008	**2008 to 2012**
Total Retail Sales Volumes	3.3%	1.5%
Total Retail Sales Volumes (Excluding Mining Customers	2.8%	0.4%

As shown in the table above, from 2008 to 2012 UNS Electric's retail sales volumes grew at an average of 1.5% per year, less than half the growth rate of 3.3% from 2004 through 2008. The lower sales growth reflects weak economic conditions and the impact of EE and renewable energy DG standards. To further illustrate the impact of the recession and the Commission's EE and DG standards on electricity consumption, UNS Electric's retail sales volumes, excluding mining customers, grew at an average annual rate of just 0.4% between 2008 and 2012, compared with 2.8% from 2004 to 2008. The decline in sales growth negatively impacts UNS Electric's ability to recover costs and earn a reasonable rate of return.

Q. Has the Company taken steps to mitigate the size of the rate increase it is requesting?

A. Yes. Beyond the significant cost containment efforts over the past three and a half years, UNS Electric has taken several steps in this rate case filing to moderate the requested rate increase for its customers including:

- Fair Value Rate of Return. As described in the testimony of UNS Electric witness Ann E. Bulkley from Concentric Energy Advisors, Inc., we are proposing to apply a rate of return on the fair value increment of rate base equal to only one-half of the real risk-free rate. This modification lowered UNS Electric's rate request by approximately $1.8 million.

- Expenses. UNS Electric has not requested recovery of over $300,000 in certain management compensation expenses from its revenue requirement.

Q. Did the acquisition of Black Mountain Generating Station ("BMGS") factor into the timing of UNS Electric's rate case application?

A. Yes. The 2010 Rate Order granted UNS Electric a rate increase and authorized rate base treatment of BMGS. On July 1, 2011, UNS Electric completed the acquisition of BMGS and placed BMGS into rate base by implementing a revenue neutral rate reclassification. As part of its order, the Commission directed UNS Electric to file, no later than 12 months after any rate reclassification, a rate application using a test year reflecting BMGS in rate base for no less than six months. Subsequently, in Decision No. 72743 (January 20, 2012), the Commission extended the rate case filing deadline to December 31, 2012.

Q. In addition to higher base rates, is UNS Electric proposing other modifications to its current rate structure?

A. Yes. UNS Electric is proposing the following modifications to its rate structure:

- adopting a ("Lost Fixed Cost Recovery Mechanism ("LFCR") to align our rate structure with Commission policies and mitigate the adverse financial impact of lost revenues resulting from Commission-mandated EE and DG requirements;
- approving a new approach towards meeting the EES that would moderate the recovery of the necessary and prudent ongoing costs of EES compliance;
- approving a Transmission Cost Adjustor mechanism ("TCA") to allow UNS Electric to timely recover changes in transmission rates under the Company's Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT");

- eliminating the power supply component of base rates and recovering these costs entirely through the PPFAC; and
- including approximately $13 million of post-test year net plant additions in rate base.

III. UNS ELECTRIC'S OPERATIONS.

Q. Please describe UNS Electric's service territory and customer base.

A. UNS Electric provides electric service to the majority of Mohave County and Santa Cruz County, including the cities of Kingman, Lake Havasu City and Nogales. The Company serves over 73,000 customers in Mohave County and over 18,000 customers in Santa Cruz County. Approximately 88% of UNS Electric customers are residential, 11% are commercial and less than 1% are industrial. UNS Electric's peak demand for 2012 was 437 MW.

Q. What have been the growth rates in the number of customers in UNS Electric's service areas?

A. The average number of retail customers grew by less than 1% annually in 2009 through 2012. We estimate that UNS Electric's retail customer base will increase at an annual rate of slightly less than 1% in 2013 through 2015.

Q. Please provide more detail about UNS Electric's generation assets.

A. The Company owns and operates BMGS, which is a 90-MW gas-fired facility located in Mohave County near Kingman, Arizona and the Valencia Power Plant ("Valencia") which is located in Nogales, Arizona. Valencia consists of four natural gas and diesel-fueled combustion turbine units and provides approximately 63 MW of resource capacity. The facility is directly interconnected with the distribution system serving the city of

Nogales and the surrounding areas. In addition, UNS Electric owns two solar photovoltaic projects totaling 2.5 MW.

Q. How does UNS Electric meet its energy requirements?

A. UNS Electric acquires the majority of its power primarily through a portfolio of long, intermediate and short-term purchases for base load and on-peak power requirements. This combined with the output from the Company's generating facilities, is expected to provide 70 to 100% of the estimated 450 MW of peak capacity required through December 31, 2013. For 2013, UNS Electric has 90 to 100% of its peak summer (June through September) capacity hedged and a total of 50% of its total energy requirements for the entire year. The remaining capacity necessary to serve daily peak loads will be purchased through the day-ahead and real-time markets.

Q. Please describe the operational performance of BMGS since it was acquired by UNS Electric in June 2011.

A. The units have had extremely high operating availability and starting reliability. For July 2011 to December 2011, BMGS Unit 1 had a 99.96% Equivalent Availability Factor ("EAF") and a Forced Outage Factor ("FOF") equal to 0.00%, Unit 2 for the same time period had a 98.64% EAF and a 1.36% FOF. For January 2012 through November 2012 BMGS Unit 1 had a 99.11% EAF and a 0.57% FOF while Unit 2 had a 99.6% EAF and a 0.00% FOF. For the period of July 2011 through December 2011 both units had a 100% starting reliability or 86 starts in 86 attempts. For January 2012 through November 2012 the units had a starting reliability of 98.63% - a total of 217 successful starts and 3 aborted starts.

Q. Please describe UNS Electric's power supply contracts.

A. UNS Electric has entered into multiple summer power supply contracts. Approximately 30% of all requirements are fixed price capacity purchases, and approximately 35% are gas indexed capacity purchases. The remaining system capacity requirements (which cannot be met by BMGS and Valencia) are met by the short-term purchases described above. All long-term contracts were purchased through competitive requests for proposals ("RFPs"). UNS Electric also uses the over-the-counter broker market for incremental purchases.

Q. Does UNS Electric have a hedging policy for fuel and wholesale power purchases?

A. Yes. UNS Electric developed its Fuel and Wholesale Hedging Policy ("Hedging Policy") that measures the price risk associated with purchased power, fuel (primarily natural gas) and index-priced contracts. This risk is then hedged by fixing portions of the price risk over a three-year period before delivery using various methodologies. The risk is hedged in monthly increments so that a minimum of 45% of UNS Electric's energy is hedged two months before the beginning of the month when the physical resource is delivered.

Q. Is this the same hedging policy that UNS Electric developed and discussed in its last rate case?

A. Yes.

Q. Please describe the Company's commitment to providing safe and reliable service.

A. Providing safe, reliable and economic electric service is the principal focus of UNS Electric's business. Since acquiring the Citizens electric assets in 2003, the Company has strived to improve the system at a distribution, transmission, generation and operational level. As I discussed above, UNS Electric is developing diverse resources to meet the load in its service area. And as set forth below, the Company is continuing its

efforts to upgrade the quality of service it provides. As a result, UNS Electric has provided and will continue to provide safe and reliable service to its customers.

Q. Could you provide an overview of UNS Electric's operations from a safety standpoint?

A. Safety is an essential part of UNS Electric'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:

- active safety leadership;
- increased employee involvement in safety activities; and
- regulatory compliance.

The focused implementation of this strategy throughout the Company has resulted in a significant improvement in our total recordable incident rate, which fell from 6.6 in 2008 to 3.26 in 2011 and was 2.10 through November 2012. UNS Electric's continuous improvement approach to safety puts the Company into the top 50% in the Bureau of Labor Statistics safety rankings among electric utilities of a similar size.

UNS Electric is committed to effective and efficient operations and providing top tier reliability without compromising on safety. The Company's system reliability compares favorably on two common industry benchmarks: System Average Interruption Duration Index ("SAIDI") and Customer Average Interruption Duration Index ("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 1st, 2nd, 3rd and 4th quartiles to indicate how individual

utilities compare to their peers. UNS Electric's performance earned the Company a spot in EEI's first or second quartile each year from 2009 to 2011. The reliability of UNS Electric's distribution operations provides customers with significant benefits, including safety, productivity, comfort and convenience.

Q. Please describe UNS Electric's ongoing efforts to upgrade its transmission system.

A. The Company recently commenced construction activities to upgrade the present 115 kilovolt ("kV") transmission line to serve its customers in Santa Cruz County. UNS Electric received a Certificate of Environmental Compatibility ("CEC") from the Arizona Power Plant and Transmission Line Siting Committee on July 15, 2009; the Commission approved the CEC in Decision No. 72182 (October 7, 2009). The CEC allows UNS Electric to: (1) interconnect the northern end of the transmission line with a major import substation (the Vail Substation); (2) upgrade the voltage of the line to 138kV from 115 kV; and (3) replace aging wooden H-frame structures with durable steel monopoles. UNS Electric expects to complete construction before the summer of 2014. This will improve the capacity to meet the demand in Santa Cruz County while also improving the reliability of the transmission line serving those customers.

Q. How does UNS Electric assess the need for near-term improvements to its distribution systems?

A. UNS Electric employees conduct a thorough performance analysis of the Company's distribution system each year to identify the circuits most critical to continued reliability. Those circuits are then inspected by UNS Electric journeymen linemen to assess the condition of insulators, guy wires, poles, cross arms, ground wire attachments, static and neutral wires, conductors and other distribution equipment and to evaluate the threat posed by nearby vegetation. UNS Electric crews also patrol assigned geographic areas to assess

and report any significant changes in the condition of the distribution system. Any issues identified on these patrols or inspections are addressed as needed.

IV. CAPITAL INVESTMENT.

Q. You have stated that one factor for filing this rate case is the capital investment that UNS Electric has made since the last test year. Would you explain that in more detail?

A. As discussed above, the Company has invested a significant amount of capital in its continuing efforts to maintain and improve its electric system. As set forth below, UNS Electric will also have significant capital expenditures in the near future. It is important that the Company maintain or improve its credit rating to ensure that it has access to capital markets on reasonable terms – which will help keep rates down in the future.

Q. Please provide details regarding UNS Electric's capital investment since the last test year (which ended December 31, 2008).

A. The following table outlines investments in capital projects from 2009 through June 30, 2012.

($ Millions)	2009	2010	2011	2012*	Total Capital Investments
Capital Expenditures	$28	$23	$92	$14	$157

*Through June 30, 2012

UNS Electric's cumulative capital investments for the 3.5 years prior to and including the test year (2009 – June 30, 2012) totaled $157 million. This total includes: $63 million for the purchase of BMGS; $49 million for delivery system improvements; $13 million to accommodate new customer demands; and $5 million for solar photovoltaic projects.

UNS Electric's system improvements include additions and upgrades to substation transformers in the Lake Havasu district to meet customer demands, improve reliability and system contingency. Other significant projects include improvements to the Yucca substation, including the installation of SCADA controls linked to the Kingman dispatch center.

In the Kingman district, improvements include a new substation, substation improvements and five miles of new 69-kV transmission line. These projects improved system performance and reliability.

Q. Please describe UNS Electric's plans for future capital expenditures.

A. The following table outlines the estimated capital expenditures for the last six months of 2012 and planned capital expenditures for 2013 through 2017.

($ Millions)	2012*	2013	2014	2015	2016	2017	Total Capital Investments
Capital Expenditures	$21.5	$56	$27	$33	$29	$37	$203.5

*July through December 2012

The higher level of capital spending in 2013 is due primarily to capital expenditures of approximately $35.8 million required for upgrading UNS Electric's 115-kV transmission line to 138-kV. UNS Electric also plans to invest about $5 million annually in 2013 through 2017 for renewable energy projects.

Q. Has UNS Electric proposed recovery of capital costs incurred after the June 30, 2012 test year was complete?

A. Yes. Our proposed revenue requirement reflects recovery of approximately $13 million post-test year capital investments which are in service or which are expected to be placed into service by June 30, 2013 and will be used and useful at the time new rates become

effective. The plant costs included in the test year rate base will be adjusted to reflect the actual cost of plant placed in service. These projects include approximately $8 million of general plant investments and approximately $5 million for UNS Electric's 1.22 MW solar photovoltaic array, which was previously approved by the Commission.

V. LOST FIXED COST RECOVERY MECHANISM.

Q. What is the LFCR?

A. The LFCR is a mechanism narrowly tailored to collect delivery service costs that would have been recovered through usage lost to EE programs and DG systems. It is not intended to recover lost fixed costs attributable to other factors, such as weather or general economic conditions. As such, it is not a full decoupling mechanism.

The LFCR would serve to align the interests of the Commission and our customers with the Company's need to mitigate the adverse financial impacts inherent in the Commission's EE and DG requirements. This mechanism would provide UNS Electric with an opportunity to recover its prudently incurred system costs despite sales reductions that result from compliance with the REST and EES.

Q. Why are you proposing the Commission approve an LFCR mechanism for UNS Electric?

A. UNS Electric's current rate structure is designed to recover the Company's authorized revenue requirement primarily through usage-based kilowatt hour ("kWh") sales. The volumetric rate charged for those sales is calculated based on the system-wide usage, based largely on the sales volumes experienced during the rate case test year. A majority of the costs included in UNS Electric's revenue requirement, however, do not vary with kWh sales, but are fixed in nature.

Given the current rate structure, when kWh sales decline as a result of EE programs and DG systems developed pursuant to the EES and REST, UNS Electric is unable to recover the fixed costs that are embedded in its volumetric-based rates.

As a result, without a mechanism in place to capture and recover these lost revenues, UNS Electric's rates are inadequate as they do not provide the Company with a reasonable opportunity to recover certain costs or achieve its Commission-authorized rate of return. The proposed LFCR mechanism would alleviate this inequity, while aligning the Company's financial well-being with the Commission's mandates and our customers' desire to participate in EE and DG programs. Adoption of this mechanism reduces the financial penalties resulting from compliance with the EES and REST and counterbalances the additional financial risk those Commission mandates have created for the Company.

Q. Has the Commission previously approved a similar mechanism?

A. The LFCR mechanism the Company is proposing is similar to the lost-fixed cost recovery mechanisms that the Commission approved for Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012) and UNS Gas in Decision No. 73142 (May 1, 2012). UNS Electric's proposed LFCR is basically the same as the LFCR proposed by TEP in its rate case filed July 2, 2012.

Q. Will UNS Electric's LFCR provide both a variable and fixed rate (opt-out) options for residential customers?

A. Yes. Residential customers who do not want to be charged the standard LFCR variable rate charge based on kWh usage will have the option of choosing a fixed, monthly LFCR charge. UNS Electric will implement an extensive customer education and outreach program to help customers understand the new LFCR and available options. UNS

Electric witness Craig Jones explains in his Direct Testimony how the LFCR will operate and sponsors the LFCR's associated POA.

Q. If the Commission does not approve the LFCR as proposed, are you proposing an alternative?

A. If the LFCR is not approved, the Company recommends the Commission approve a full decoupling mechanism designed to recover all fixed cost revenues on a per-customer basis, similar to the decoupling mechanism approved by the Commission in Decision No. 72723 (January 6, 2012) for Southwest Gas Corporation.

VI. TRANSMISSION COST ADJUSTMENT MECHANISM.

Q. What is the TCA?

A. The purpose of the TCA is to provide UNS Electric with timely recovery of transmission costs associated with serving retail customers at the level approved by FERC. UNS Electric's proposed base rates include a transmission component based on the Company's current OATT. The FERC-approved OATT rates are designed to recover transmission costs from users of the UNS Electric transmission facilities. The OATT rates are recalculated and reset annually through a FERC-approved formula using data contained in UNS Electric's FERC Form 1 filing. The TCA will enable UNS Electric to recover future changes in the OATT rate.

Q. How will UNS Electric's customers benefit from adoption of the TCA?

A. The timely recovery of costs required to provide transmission services to retail customers will provide necessary cash flow to help UNS Electric finance transmission capital additions and support its current investment grade credit ratings. Stable cash flows and an investment grade credit rating help to lower financing costs for the benefit of our

customers. The TCA, like the PPFAC, would provide retail customers with more accurate price signals. Additionally, the implementation of the TCA may reduce the frequency of, and need to file, general rate cases, thereby reducing the impact on our customers and reducing the amount of Commission resources expended on UNS Electric-related issues.

Q. Has the Commission previously approved a TCA mechanism?

A. Yes. In Decision No. 67744 (April 7, 2005), the Commission approved a TCA for APS. Decision No. 73183 (May 24, 2012) modified the TCA process for APS. APS's TCA ties the collection of transmission costs to the costs found in APS's FERC-approved OATT, which is what UNS Electric proposes in this case.

Q. How will the TCA be implemented?

A. The TCA charge will apply to all Standard Offer retail electric schedules. The Standard Offer rate schedules include a transmission component in base rates which represents UNS Electric's current FERC-approved OATT costs. The TCA will be limited to the recovery (or refund) of costs associated with future changes in UNS Electric's OATT rate. Annually, on the date that the OATT rate adjusts pursuant to the approved formula, UNS Electric will file a notice with Docket Control that includes the revised TCA tariff. The revised TCA will reflect the annual change in the formula rate. For those customers that do not have a demand component, the TCA will be a monthly kWh charge; for those that are "demand-billed", the TCA will be a per-kW charge. In short, UNS Electric's proposed TCA is very similar to that approved for APS most recently in Decision No. 73183. Mr. Jones is sponsoring the TCA POA which provides more details on the TCA process.

VII. ENERGY EFFICIENCY RESOURCE PLAN.

Q. How would UNS Electric's Energy Efficiency Resource Plan ("EE Resource Plan") improve the current regulatory framework for complying with the EE Rules?

A. UNS Electric's proposal provides an alternative solution for financing the cost of complying with the EE Rules that would reduce and stabilize the rate impacts to our customers, better synchronize the benefits of EE with their associated costs, provide a base level of certainty to program offerings and eliminate the need to provide a performance incentive. Details of the proposed EE Resource Plan, including the related POA, are provided in the Direct Testimony of UNS Electric witness Denise A. Smith.

VIII. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE.

Q. Are you proposing any modifications to the PPFAC?

A. Yes, the Company is proposing necessary modifications to the PPFAC including: (i) eliminating the current base power supply rates and recovering those costs through the PPFAC; (ii) adopting PPFAC rates that are differentiated to reflect on-peak and off-peak differences; and (iii) revising the costs to be recovered through the PPFAC. We are also proposing changes to the PPFAC POA.

A. Consolidation of Base Power Supply Rates into the PPFAC.

Q. Please describe the consolidation of the base fuel and purchased power rates into the PPFAC.

A. UNS Electric's current unbundled rates include, among other things, a base power supply rate for each pricing plan. Each customer class has its own base power supply rate. The current PPFAC is calculated to recover the difference between revenues recovered

through the base power supply rates and the actual fuel and purchased power costs. Thus, the PPFAC effectively adjusts the base power supply rate on an annual basis. Our proposal is to consolidate the two into the PPFAC. After the consolidation, we will continue to have some differentiation in the fuel and purchased power rates based on the usage. The PPFAC rates will be differentiated to reflect on-peak vs. off-peak usage periods, which is currently provided for through variations in the base power supply rates. Mr. Jones provides additional detail on this rate design change in his Direct Testimony.

B. <u>Additional Costs to be Recovered through the PPFAC</u>.

Q. In general, what costs are currently included in the PPFAC?

A. As described more completely in the existing UNS Electric PPFAC POA, the PPFAC recovers costs associated with the following FERC accounts:

- 501 Steam Power Generation – Fuel
- 547 Other Power Generation – Fuel
- 555 Purchased Power
- 565 Transmission of Electricity by Others

Q. What revenues are included in the PPFAC and offset the fuel and purchased power costs?

A. Pursuant to the Company's PPFAC POA, all short-term off-system wholesale revenue recorded in FERC Account 447 is credited back to UNS Electric's customers through the PPFAC.

Q. What additional costs is UNS Electric proposing to recover through the PPFAC?

A. UNS Electric is proposing to include any credit costs and broker fees associated with power supply and procurement. Additionally, the Company is proposing to recover future greenhouse gas costs through the PPFAC.

Q. Why is the Company proposing to recover costs associated with credit through the PPFAC?

A. The cost of obtaining and maintaining credit with trading counterparties is a real cost of doing business in the wholesale markets for fuel and purchased power. Prepayments, cash escrow accounts and standby letters of credit are all common forms of credit support in these markets. As described in the Direct Testimony of UNS Electric witness Kentton C. Grant, the amount of credit support required can vary significantly over time due to changes in wholesale market prices, changes in purchase volumes, and changes in the cost of credit generally. Since these credit costs are incurred in order to support UNS Electric's procurement of fuel and purchased power, and those costs are out of the Company's control, these costs should be recovered by UNS Electric. The most logical place for that to occur is through the PPFAC. Therefore, the Company is requesting that costs associated with obtaining the necessary credit to purchase fuel and power be recovered through the PPFAC.

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

A. The amount of credit support has varied significantly over the past three years. As discussed in Mr. Grant's testimony, the Company was required to provide as much as $30 million in credit support during 2009 due primarily to falling gas and wholesale power prices in the forward markets. During the test year ending June 30, 2012, the amount of credit support provided by UNS Electric in the form of letters of credit and cash collateral was much lower, averaging $5.6 million. Although Mr. Grant has calculated the cost of

providing credit support during the test year at only $145,000, it is a fluctuating cost that is not within UNS Electric's control and is a required cost of providing service to our customers that should be recovered through the PPFAC. For purposes of cost verification, the Company will continue to track the outstanding balance of letters of credit and cash collateral provided, and will continue to apply the actual cost rates for letters of credit and short-term borrowings as specified in the Company's revolving credit agreement.

Q. What other reasons justify recovery of credit costs through the PPFAC?

A. The Commission has long recognized the volatility of fuel and purchased power costs as justification for the PPFAC. The Commission has also recognized that a PPFAC allows utilities to respond to such volatility without incurring the cost and time of a rate case. Credit costs are a direct and inextricable part of procuring fuel and purchase power which are not within the Company's control and should be included in the PPFAC.

Further, the fact that the necessary and prudent credit costs directly linked to procuring fuel and power on behalf of our customers varies makes the PPFAC the appropriate mechanism to recover these costs. In contrast, setting a fixed amount for the recovery of those costs in base rates does not accurately reflect the actual costs; and any changes in such costs would inappropriately benefit the Company or its customers depending on circumstances that are beyond the Company's control.

Q. Please describe how broker fees add to the efficiency of the procurement of purchased power.

A. Broker fees are assessed by the entity arranging the transaction between a buyer and seller. UNS Electric often utilizes third-party brokers for the procurement of its day-ahead and forward power requirements. These brokers play an important role in

facilitating an efficient wholesale energy market. Through brokers, UNS Electric has access to a multitude of sellers that it would not ordinarily have a chance to access. This increase in the supply of sellers helps to lower the overall price UNS Electric and ultimately our customers pay, as it helps ensure that those services are acquired at a competitive market price.

Q. How are broker fees currently recovered by the Company?

A. Broker fees are included in the recovery of operating expenses in an amount established in UNS Electric's 2010 Rate Order. These costs are directly linked to power purchases, vary with the amount of energy purchased, are not within UNS Electric's control, and should be recovered through the PPFAC.

Q. Is there precedent by the Commission to permit broker fee recovery through a fuel and purchased power adjustment mechanism?

A. Yes. The Commission now permits APS to recover broker fees recorded in FERC Account 557 through its Power Supply Adjustor Mechanism (Decision No. 73183).

Q. Is the Company proposing any other costs associated with fuel and purchased power to be added to the list of PPFAC eligible costs?

A. Yes. UNS Electric is proposing to include greenhouse gas ("GHG") costs in PPFAC recoverable costs. Although the Company does not currently incur GHG costs, the Environmental Protection Agency ("EPA") has just approved GHG New Source Performance Standards or "NSPS" rules for new power plants and has indicated it is reviewing GHG rules for existing power plants. Therefore, UNS Electric believes this rate case is the appropriate time to modify the PPFAC POA for its inclusion. Based upon EPA action, and the possibility of Congressional or State action, it is a very real possibility that UNS Electric could incur GHG expenses prior to the filing of its next rate

case and therefore GHG costs should be included in the Company's PPFAC. Recovering these costs through the PPFAC is reasonable because such costs are directly related to the procurement of fuel and purchased power and will only be incurred by our customers pursuant to a mandate from the government.

C. Changes to the Plan of Administration.

Q. Is the Company proposing any changes to the PPFAC POA?

A. Yes. UNS Electric is proposing several changes to the PPFAC POA. These changes are included in the POA sponsored by Mr. Jones in his Direct Testimony. I discuss several of those changes below.

Q. Please describe the proposed change to the compliance filing report due date in Section 8 of the POA.

A. Currently, the monthly reports are due within 30 days of the end of the reporting period. UNS Electric proposes to change the due date to 45 days.

Q. Why is UNS Electric proposing to increase the filing due date from 30 days to 45 days after the end of the reporting period?

A. The Company proposes this extension of time in the preparation of the monthly filing for three reasons:

1. Not all of the data included in the filing is always available in time to enable filing in 30 days. Extending the filing date will allow for more complete and accurate PPFAC filings, and will eliminate the need for re-filing and/or revision, and additional footnotes explaining the changes;

2. The extended deadline will allow time for additional analytical review during the preparation and review process, which would be beneficial to the Commission, Commission Staff and UNS Electric should questions arise; and

3. The extended deadline will allow more time for cross-training of UNS Electric staff so that the filing can be prepared on a consistently timely basis.

IX. DECOMMISSIONING COST ESTIMATES.

Q. Please describe the purpose of this section of your Direct Testimony?

A. I will identify and explain the estimated decommissioning costs for the generation assets owned by UNS Electric. That information was given to Company witness Dallas J. Dukes in developing new generation Negative Net Salvage ("NNS") rates used in computing his depreciation annualization adjustment. Additionally, I am addressing the service lives of the recently deployed solar assets.

Q. Please explain what you mean by the term "decommissioning".

A. Decommissioning is the process of permanently removing a power plant from active use at the end of its service life. It includes dismantling the physical plant, disposing of the materials, and restoring the site to its preoperational condition. Under the traditional capital recovery methods used in cost-based utility ratemaking, capital assets are depreciated using rates that reflect the installed cost of assets, negative net salvage, and the expected service lives of the respective assets. NNS represents the cost to remove and dispose of assets at the end of their service lives, less any cost recoveries realized through scrap sales or potential for reuse of materials and equipment.

Q. Is this the first time decommissioning studies have been presented in connection with a UNS Electric rate case?

A. Yes. The estimates prepared for this proceeding are the first such studies performed by UNS Electric and submitted to the Commission for its review in connection with a depreciation rate request. Accordingly, UNS Electric's generation assets have to this point been depreciated using rates reflecting capital recovery only, with no provision for the costs of removal. As described in Mr. Dukes' testimony, UNS Electric is requesting the implementation of new interim NNS rates for its generation based on current estimates of removal costs for generation assets.

Q. Please describe the decommissioning studies.

A. In 2011, in connection with an upcoming rate case filing, TEP initiated studies for the purpose of developing estimates of decommissioning costs for each generating unit in which it has an ownership interest. Since such estimates had never been prepared for UNS Electric generating assets, it was decided that the scope of the studies should include Valencia and BMGS, as well.

Our key objective was to produce updated estimates of the decommissioning cost for each generating facility. Each study sought to estimate the cost of entirely dismantling all existing generating units, disposing of the removed equipment and materials in an appropriate and safe manner, and restoring the land to its pre-construction condition. TEP and UNS Electric employees maintained close communications with representatives of the firm throughout the course of their studies, and provided them with drawings and other necessary specifications, as well as facilitated site visits. Copies of the study covering UNS Electric's generation will be provided to Commission Staff as part of the working papers supporting the Company's Application.

Q. What firm produced the decommissioning studies and resulting cost estimates?

A. Burns & McDonnell of Kansas City, Missouri was retained to perform the studies.

Q. Have TEP and UNS Electric reviewed the decommissioning study reports and cost estimates from the consultants?

A. Members of my staff and I thoroughly reviewed the reports and asked numerous clarifying questions. When I was satisfied that the reports provide reasonable estimates of the current costs of removing generation assets, I provided them to Mr. Dukes for his use in computing interim NNS rates and preparing the depreciation annualization adjustment.

X. SERVICE LIVES OF PHOTOVOLTAIC ("PV") ASSETS.

Q. Please describe UNS Electric's deployment of solar generation plant.

A. UNS Electric began installing photovoltaic systems in 2011 to comply with renewable energy mandates approved by the Commission. In November, installation of a 1.22 MW PV system was installed at the location of La Senita Elementary School in Kingman. Powered by SOLON systems and modules, the facility will provide a faster, more cost-effective way for UNS Electric to integrate solar power into its renewable energy portfolio. The Company plans on complying with the Commission's renewable energy standards through cost-effective investments in PV and other renewable generation capacity, which the Company also indicated in its Integrated Resource Plan ("IRP") filed with the Commission in April 2012.

Q. How have these solar assets been depreciated?

A. UNS Electric has just begun deploying such technology, so there is no historical retirement data upon which the base an expected service life. It is noted that UNS Electric

affiliate TEP has been deploying such technology since 1998 and also has no retirement data upon which to base a depreciation rate. However, TEP has been depreciating its PV assets at a rate of 5% per year, based on an estimated 20-year service life, since the first solar installation in 1998.

Q. What is your recommendation for UNS Electric regarding PV facilities?

A. I am recommending use of the 20-year service life, and corresponding 5% depreciation rate, with no NNS factor until sufficient retirements occur to support the use of some other depreciation rate.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	DOCKET NO. E-04204A-12-____

Direct Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

December 31, 2012

TABLE OF CONTENTS

I. Introduction 1

II. Financial Condition of UNS Electric 3

III. Capital Structure 6

IV. Cost of Debt 7

V. Weighted Average Cost of Capital 8

VI. Fair Value Rate Base and Fair Value Rate of Return 9

VII. Cost of Credit Support for Fuel and Purchased Power Procurement 10

VIII. Summary of Schedules 13

Exhibits:

Exhibit KCG-1 Moody's Investors Service Credit Opinion Dated May 25, 2012

Exhibit KCG-2 Credit Support Provided for Fuel and Purchased Power Procurement

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 UNS Electric, Inc. ("UNS Electric" or the "Company")?

A. I am a Vice President of UNS Electric. I also serve as Vice President and Treasurer for UniSource Energy Services, an intermediate holding company for UNS Electric, and as Vice President of Finance and Rates for UNS Energy Corporation ("UNS Energy"), the ultimate parent company for UNS Electric.

Q. Please describe your background and work experience.

A. I have been employed by Tucson Electric Power Company ("TEP"), a corporate affiliate of UNS Electric, since 1995. I was originally hired as a senior financial analyst and was subsequently promoted in 1997 to Director of Capital Resources and elected Assistant Treasurer. Shortly after that I was promoted to Manager of Financial Planning; and in 2003, I became a General Manager in the Shared Services Unit. In 2007, I was elected Vice President of Finance and Rates for both TEP and UNS Energy Corporation (formerly known as UniSource Energy Corporation). In 2010, I was elected Treasurer for both TEP and UniSource Energy Services. 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 UNS Electric 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"). Finally, I discuss the cost of providing credit support for fuel and wholesale power procurement, and recommend an appropriate method of rate recovery for those costs.

Q. Please summarize your recommendations.

A. I recommend a weighted average cost of capital of 8.35% based on a capital structure consisting of 52.60% common equity and 47.40% long-term debt, a cost of long-term

debt of 5.97%, and a cost of common equity of 10.50% as determined by UNS Electric witness Ann E. Bulkley. I also recommend that the cost of credit support provided for fuel and wholesale power procurement be recovered through the Company's purchased power and fuel adjustment clause ("PPFAC") instead of through non-fuel base rates.

II. FINANCIAL CONDITION OF UNS ELECTRIC.

Q. Please describe the current financial condition of UNS Electric.

A. The Company is in good financial condition. It has a healthy mix of debt and equity capital, an improved level of operating cash flow, and is finally earning a rate of return close to its cost of capital. In recognition of this improvement, Moody's Investors Service ("Moody's") recently upgraded the senior unsecured credit rating for UNS Electric to Baa2 from Baa3. Since the previous rating of Baa3 was only one notch above speculative-grade, this recent upgrade was important in terms of providing the Company's creditors with additional confidence that UNS Electric will remain creditworthy on a going-forward basis. A copy of the most recent credit opinion published by Moody's is attached to my testimony as **Exhibit KCG-1**.

Q. Please comment on the progress that UNS Electric has made in de-leveraging its balance sheet.

A. Certainly. The Company's long-term debt, measured as a percentage of total capitalization, has fallen from approximately 64% in 2003 to 47% as of June 30, 2012. This has been accomplished by reinvesting 100% of the earnings of UNS Electric back into the business since it was formed in 2003 when UNS Energy purchased the electric utility assets from Citizens Communications Company and formed UNS Electric. This de-leveraging has also been accomplished through contributions of equity capital received from UNS Electric's parent company, the most recent example of which was a

$20 million contribution in 2011 to help finance the Company's purchase of the Black Mountain Generating Station ("BMGS"). As a result, UNS Electric has achieved a mix of debt and equity capital that is consistent with industry norms and supports an investment-grade credit rating.

Q. Please comment on the recent improvement in cash flow and earnings at UNS Electric.

A. Operating cash flow has improved primarily as a result of the $7.3 million non-fuel rate increase approved by the Commission for UNS Electric in September 2010 (Decision No. 71914) – as well as the Company's purchase of the BMGS and related rate reclassification that occurred in July 2011. As was discussed by Company witnesses in UNS Electric's last rate case, the purchase and rate base treatment of the BMGS was expected to improve net operating cash flow as a result of the return allowed on this investment, the rate recognition of non-cash depreciation expense, and the use of accelerated tax depreciation on the Company's income tax returns. This improvement in cash flow has helped the Company to avoid additional debt financing of its capital expenditures, thereby contributing to the recent upgrade in UNS Electric's credit rating.

With respect to earnings, the Company has finally reached a point where it is earning a rate of return close to its cost of capital. This was certainly not the case in years past, when UNS Electric routinely earned rates of return far below authorized levels. For example, over the three year period from 2007 through 2009, the return on equity ("ROE") realized by UNS Electric ranged from a low of 4.6% to a high of only 6.8%. The recent improvement in earnings is due in part to the rate relief granted in 2010, as well as to careful cost management at UNS Electric.

Q. From a financial perspective, what are some of the key challenges still facing UNS Electric?

A. There are several key challenges that, if left unaddressed, could serve to reverse the recent gains made by the Company.

First and foremost, the Company is facing an erosion of its retail sales as a result of energy efficiency programs, the deployment of renewable energy technologies by its customers, and a decision by UNS Electric's largest customer to rely on self-generation for most of its energy needs. Since a large portion of the Company's fixed costs are currently recovered through volumetric rates (i.e., on a per-kWh basis), this erosion of sales is expected to contribute to a significant under-recovery of costs over time. As a result, UNS Electric is proposing a lost fixed cost recovery ("LFCR") mechanism to address the impact of sales lost due to Commission-mandated programs for energy efficiency and distributed renewable energy. Additionally, as discussed in the Direct Testimony of UNS Electric witness Craig A. Jones, the Company is proposing additional changes to its rate design to help ensure that all customers pay a reasonable share of the cost of providing safe and reliable service.

UNS Electric is also facing a significant increase in its capital spending needs over the next several years. As discussed in the Direct Testimony of UNS Electric witness Michael J. DeConcini, much of this increase in capital spending is due to the planned upgrade of transmission facilities serving Santa Cruz County. These expenditures will result in a significant increase to the Company's fixed costs that are not reflected in the current rate application. Therefore, as discussed in Mr. DeConcini's Direct Testimony, the Company is proposing a transmission cost adjustment mechanism ("TCA") that is designed to provide for a more timely recovery of costs incurred on transmission projects subject to regulation by the Federal Energy Regulatory Commission.

Other notable risks faced by UNS Electric include the Company's reliance on natural gas and wholesale power markets to meet the energy needs of its customers, as well as the large amount of long-term debt maturing in 2015. As discussed later in my testimony, significant swings can occur in the amount of credit support required in connection with the procurement and hedging of the Company's natural gas and purchased power needs. Significant under-recovery of fuel and purchased power costs can also occur prior to the annual PPFAC rate adjustment due to unanticipated increases in the cost of natural gas and wholesale power. For these reasons, it is important for the Company to have ample liquidity available under its revolving credit facility and to have a PPFAC mechanism that is designed to fully recover costs within a reasonable period of time. Maintenance of the Company's investment-grade credit rating is also crucial, especially since UNS Electric will need to refinance $80 million of long-term debt maturing in August 2015. Since the cost of debt is a significant component of UNS Electric's revenue requirement, it is clearly in the interest of both the Company and its customers for UNS Electric to maintain or improve the Baa2 credit rating recently assigned to its senior debt obligations.

III. CAPITAL STRUCTURE.

Q. Please describe the capital structure for UNS Electric as of the end of the test year.

A. The capital structure for UNS Electric as of June 30, 2012 consisted of $130.0 million principal amount of long-term debt and $143.3 million of common equity. After adjusting for unamortized debt issuance expenses, the long-term debt balance as of June 30, 2012 was $129.1 million. As reflected in the following table, the Company's test year capital structure consisted of 47.40% long-term debt and 52.60% common equity:

($ Thousands)	6/30/12	% of Total
Long-Term Debt	$129,135	47.40%
Common Equity	143,287	52.60%
Total Capital	$272,422	100.00%

Q. Do you recommend using the actual test year capital structure for rate setting purposes?

A. Yes, I do. As noted earlier, a 53% ratio of common equity to total capital is in line with industry norms and helps support the Company's investment-grade credit rating.

IV. COST OF DEBT.

Q. What was UNS Electric's embedded cost of debt for the test year?

A. As shown on page 1 of Schedule D-2 in the Company's Application, the weighted average cost of debt for UNS Electric for the test year was 5.99%. However, due to the refinancing of the Company's credit facility in November 2011, which lowered the commitments fees on that facility, by the end of the test year the annualized cost of debt for UNS Electric was modestly lower at 5.97%.

Q. What cost of debt do you recommend in this case?

A. I recommend use of the 5.97% cost at the end of the test year. This cost reflects: (i) the interest rate on two series of long-term notes issued by UNS Electric in 2008; (ii) the cost of a four-year term loan entered into by UNS Electric in 2011; (iii) the amortization of debt issuance costs; and (iv) 50% of the issuance cost amortization and commitment fees on the $100 million revolving credit facility shared with UNS Gas, Inc. Although UNS Electric had no loans outstanding on the revolving credit facility at the end of the test year, maintenance of this facility is critical for purposes of funding seasonal working

capital needs, financing temporary balances of under-recovered fuel and purchased power costs under the Company's PPFAC, providing required credit support to fuel and wholesale power suppliers, and funding a portion of capital expenditures from time to time. As such, it is appropriate to reflect the annual fixed cost of this facility in the cost of debt for UNS Electric. This is the same approach the Commission approved in the previous two UNS Electric rate cases.

Q. How does the 5.97% cost of debt compare with the cost approved in UNS Electric's last rate case?

A. It is significantly lower. A 7.05% cost of debt was approved in the Company's last rate order (Decision No. 71914). Most of the reduction is attributable to the cost of a four-year term loan that UNS Electric entered into in connection with the Company's purchase of the BMGS in 2011. As may be seen in Schedule D-2, that $30 million term loan was obtained at an all-in cost of 2.10%, which reflects the sum of a 1.125% credit margin payable to the lending bank plus a 0.97% fixed-for-floating interest rate swap. By entering into the swap agreement, under which UNS Electric pays a fixed rate of 0.97% on a notional amount of $30 million and receives a floating rate equal to 3-month London Interbank Offered Rate ("LIBOR"), the Company was able to lock in a low cost of financing for the BMGS purchase through August 2015.

V. WEIGHTED AVERAGE COST OF CAPITAL.

Q. What is the WACC for UNS Electric?

A. Based on the test year capital structure for UNS Electric, a 5.97% cost of long-term debt, and a 10.50% cost of common equity recommended by Ms. Bulkley, the Company's WACC is 8.35%. This value is calculated as follows:

	% of Capital Structure	Component Cost	Weighted Average Cost
Common Equity	52.60%	10.50%	5.52%
Long-Term Debt	47.40%	5.97%	2.83%
Total	100.00%		8.35%

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

Q. What value for FVROR is UNS Electric proposing in its rate application?

A. As discussed in the Ms. Bulkley's testimony, the Company proposes a FVROR of 6.71% using the same methodology advocated by Staff and adopted by the Commission in several recent rate cases. Although the Company can justify a higher value for FVROR, 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 and FVRB).

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

A. UNS Electric relied on the approach traditionally adopted by the Commission, using the average of original cost rate base ("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 UNS Electric 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 mechanism, UNS Electric 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 UNS Electric 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 UNS Electric, 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 UNS Electric. 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 UNS Electric's energy hedging program?

A. Yes. UNS Electric'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 UNS Electric'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 UNS Electric been required to provide?

A. **Exhibit KCG-2** shows the historical level of credit support provided by UNS Electric since January 2009. As may be seen, the Company was required to provide as much as $30 million in credit support during 2009 due primarily to falling gas and wholesale power prices in the forward markets. Credit support during that year took the form of cash collateral deposited with suppliers, letters of credit issued for the benefit of suppliers, and pre-payments of amounts owed to certain other suppliers. Since 2009, the amount of credit support required from UNS Electric has declined, averaging only $5.6 million during the test year ended June 30, 2012. This lower level of credit support is due in part to more stable forward prices in the natural gas and wholesale power markets, improvement in UNS Electric's credit ratings and greater diversification of suppliers by UNS Electric.

Q. What is the cost to UNS Electric when it provides credit support to a provider of fuel or wholesale power?

A. These costs include the cost of obtaining letters of credit under UNS Electric's revolving credit facility, as well as the cost of borrowing under the Company's credit facility to fund cash collateral deposits and pre-payments to suppliers. Due to the relatively small amount of credit support required during the test year, as well as a refinancing of the Company's revolving credit facility in 2011, total credit support costs for the test year were only $145,000. However, credit support costs were substantially higher in previous years, totaling $506,000 in 2009, $592,000 in 2010, and $356,000 in 2011.

The cost of obtaining a letter of credit under UNS Electric's revolving credit facility is presently equal to 1.25% of the face value of the letter of credit, prorated for the number of days outstanding using a 30/360 day pricing convention. An additional 0.25% is paid by UNS Electric as a fronting fee to the issuing bank, again prorated for the number of days outstanding. The cost of obtaining a loan under UNS Electric's revolving credit facility is presently 1.25% over the applicable 1-month or 3-month LIBOR benchmark rate. Since interest income on cash collateral deposits accrues to the benefit of UNS Electric, and can be earned at a rate comparable to LIBOR, the net cost of making a cash collateral deposit is equal to the bank margin rate of 1.25%. The dollar cost of a cash collateral deposit can therefore be calculated by applying the bank margin rate to the balance of the cash deposit, and prorating that amount for the number of days outstanding using a 30/360 day pricing convention. Under UNS Electric's current credit facility, the net cost of credit support is very similar whether a letter of credit is obtained or cash collateral is provided.

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

A. In Decision No. 71914, they were included in the Company's non-fuel revenue requirement as an adjustment to operating expense in the amount of $195,500.

Q. Where are credit support costs recorded on UNS Electric's books?

A. These costs, consisting of interest on revolving credit loans and fees on bank letters of credit, are recorded as either short-term interest expense or other interest expense. Based on the proposed recovery of these costs through the Company's PPFAC, which is explained below, UNS Electric did not adjust test year operating expense to include credit support costs in its non-fuel revenue requirement.

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

A. Since wholesale credit support costs are incurred as a result of UNS Electric's fuel and purchased power procurement, and since these costs are highly variable, I recommend that these costs be recovered through the Company's PPFAC. These costs may be readily quantified using the pricing defined in UNS Electric's revolving credit facility for letters of credit and short-term borrowings, and are easy to track, verify and reconcile for purposes of recovery through the PPFAC. Only those costs that have been fully documented would be eligible for recovery through the PPFAC.

VIII. 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, 2012. These schedules also

include a projected capital structure, cost of debt and WACC for the twelve months ending June 30, 2013.

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, 2012. This same information is presented on a projected basis for the twelve months ending June 30, 2013. The projected year information is also presented assuming that the requested rate increase was implemented on July 1, 2012.

Schedule F-2 contains a summary cash flow statement for the test year ended June 30, 2012. This same information is presented on a projected basis for the twelve months ending June 30, 2013. The projected year information is also presented assuming that the requested rate increase was implemented on July 1, 2012.

Schedule F-3 contains information on the Company's capital investments during the test year ended June 30, 2012. The same information is presented on a projected basis for calendar years 2012, 2013 and 2014.

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 June 2013 were taken from a base case financial forecast prepared for UNS Electric. It should be noted that this forecast is based on numerous assumptions regarding sales growth,

generating plant performance, wholesale energy prices, natural gas prices, operating and capital expenditure levels, 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, 2012. 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 2012 are of limited analytical value.

Q. Does that conclude your direct testimony?

A. Yes, it does.

EXHIBIT

KCG-1

MOODY'S
INVESTORS SERVICE

Credit Opinion: UNS Electric, Inc.

Global Credit Research - 25 May 2012

Tucson, Arizona, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Sr Unsec Bank Credit Facility	Baa2
Bkd Senior Unsecured	Baa2
Ult Parent: UNS Energy Corporation	
Outlook	Positive
Sr Sec Bank Credit Facility	Ba1

Contacts

Analyst	Phone
Mitchell Moss/New York City	212.553.4478
William L. Hess/New York City	212.553.3837

Key Indicators

[1]**UNS Electric, Inc.**

ACTUALS	2011	2010	2009	2008
(CFO Pre-W/C + Interest) / Interest Expense	6.8x	6.2x	4.6x	4.9x
(CFO Pre-W/C) / Debt	34.3%	37.6%	20.5%	23.8%
(CFO Pre-W/C - Dividends) / Debt	34.3%	37.6%	20.5%	23.8%
Debt / Book Capitalization	47.1%	38.0%	57.9%	56.8%

[1] All ratios are calculated in accordance with the Regulated Electric and Gas Utilities Rating Methodology using Moody's standard adjustments

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

Improved regulatory environment in Arizona

Recovery mechanisms supportive of credit quality

Strong credit metrics

Cross-support within UES family

Corporate Profile

UNS Electric, Inc. (UNSE) is an electric utility serving approximately 91,000 retail customers in Arizona. UNSE and UNS Gas, Inc. (UNSG), a regulated gas utility in Arizona, are both subsidiaries of Unisource Energy Services (UES) which is the utilities' guarantor. UES is a wholly owned subsidiary of UNS Energy Corporation, whose largest subsidiary is Tucson Electric Power, a regulated electric utility in Arizona.

SUMMARY RATING RATIONALE

UNSE's Baa2 senior unsecured rating reflects the improved regulatory environment in Arizona, the interdependence that currently exists between UNSG and its affiliate UNSE as a result of their shared credit facility and parental guarantee and the relatively small size of the utility. The rating also reflects relatively strong credit metrics.

DETAILED RATING CONSIDERATIONS

Improved regulatory environment in Arizona

The evaluation of the ratings for UNS and its subsidiaries was driven by the recent favorable rate settlement of UNSG, which along with two other recent supportive settlements for Southwest Gas and Arizona Public Service, indicates an improvement in the Arizona regulatory environment.

In addition to base rate increases that were at or above 50% of the initial request, all three of these rate settlements included decoupling mechanisms and were decided in 11 to 13 months. This time frame for resolving rate cases is a considerable improvement over the 17 to 18 month average that had previously existed in Arizona. Historically, Moody's has considered the regulatory framework for UNS and its subsidiaries to be below average among U.S. utilities due to the lengthy decision process and corresponding regulatory lag, which along with a historical test period, meant that new rates were determined on a rate base that was typically more than two years old.

We view these recent rate cases as evidence that the Arizona Corporation Commission (ACC) is now committed to finalizing cases within about 13 months, following its earlier public statements supporting an accelerated decision timeline. Moreover, the ACC recently received a substantial increase to its budget from the governor of Arizona specifically for the purpose of improving the infrastructure and staff available to facilitate rate cases. With regard to decoupling, the favorable settlements follow the announcement of the new ACC policy in December 2010 to encourage utilities to apply for decoupling in rate cases.

UNS Electric achieved a supportive outcome in its 2010 rate decision, in which it received a rate increase of $7.4 million, over 50% of its initial request, reflecting a 9.75% ROE and an equity ratio of 46%. In that rate case, the company was also allowed to recover in rates the cost of acquiring the Black Mountain Generation Station, a 90 MW gas peaking facility, from UNS's development arm in 2011. While UNS Electric is required to make an administrative filing with the ACC this year, it has not announced an intention to file for a rate increase this year.

Recovery mechanisms supportive to credit quality

UNSE procures most of its power from the market via a portfolio of committed long and short-term contracts and spot purchases. UNSE's purchased power and fuel adjustment clause (PPFAC) has two components: a capped forward component and an uncapped true-up component that allows recovery of actual power costs over the subsequent twelve month period. We view the PPFAC as credit supportive. Our rating assumes the PPFAC will continue to function appropriately and deferral balances remain manageable.

In addition, UNSE is allowed to include a surcharge to recover its renewable investments and above-market cost of PPAs through a Renewable Energy Standard and Tariff (REST).

Strong credit metrics

UNSE's credit metrics are strong for its rating, with improvement seen as a result of its 2010 rate decision. Cash flow pre working capital (CFO pre-WC) + interest/interest was above 6 times in 2010 and 2011 and CFO pre-WC/debt was over 30% during this time. However, over the medium term, these levels are expected to drop to the 5 times range and over 22%, respectively, as the company anticipates the loss of a large mining customer.

Cross support of debt within UES

The rating recognizes the position of UNSE and UNSG as subsidiaries of UES. UES guarantees the debt at the utilities and their shared credit facility. UNSE contributes about 60% of UES' earnings. Due to the cross-support of debt and comparable size, the ratings of UNSE and UNSG are expected to remain the same.

Liquidity Profile

UNSE's liquidity is deemed adequate with sufficient cash flow generation to meet capital expenditures. UNSE has not historically paid a dividend to UES. UNSE has access to a shared $100 million credit facility with UNSG that expires November 2016. Each utility's maximum draw under the facility is $70 million and each utility is only liable for its own borrowings. As of May 21, 2012, UNSE had $15 million of cash and $4 million drawn under the credit facility and UNSG had $42 million of cash and no borrowings under the facility. The UNSG/UNSE credit facility's financial covenant requires each utility to maintain its debt to total capitalization ratio below 65%. As of March 31, 2012, the ratios were 49% at UNSE and 51% at UNSG.

Over the near-term, capital expenditures are expected to be $30-40 million annually, funded primarily by cash from operations. UNSE's nearest debt maturities are in 2015, which include a four-year term loan of $30 million and $50 in senior unsecured notes.

Rating Outlook

UNSE's stable outlook reflects our expectations of continued stable cash flows, timely recoveries of fuel and purchased power costs and that future capital expenditures will be financed in a manner intended to maintain UNSE's current financial position and flexibility.

What Could Change the Rating - Up

A further upgrade is unlikely at this time. While UNSE's credit metrics are strong for the rating, its rating is also constrained by the metrics of UNSG which are lower than UNSE. An improvement in UNSG's metrics to the lower A range, such as CFO pre-WC/debt sustained above 22%, could put upward pressure on the ratings.

What Could Change the Rating - Down

A downward revision could occur if there is a deterioration in the credit quality of UES or UNSG, if UNSE is unable to adequately recover its fuel and purchased power costs on a timely basis, or if UNSE's credit metrics decline to the lower end of the Baa ranges, for example, CFO pre-WC/debt below 16%.

Rating Factors

UNS Electric, Inc.

Regulated Electric and Gas Utilities Industry [1][2]	FYE 2011		Moody's 12-18 Month Forward View As of May 24, 2012	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Ba		Baa
Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		Baa		Baa
Factor 3: Diversification (10%)				
a) Market Position (10%)		Ba		Ba
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		A
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	5.9x	A	5.3x-5.9x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	31%	Aa	23-30%	A
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	31%	Aa	17-22%	A
e) Debt/Capitalization (3 Year Avg) (7.5%)	48%	Baa	45-48%	Baa
Rating:				

a) Indicated Rating from Grid		Baa2		Baa1
b) Actual Rating Assigned		Baa3		Baa2

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2011; Source: Moody's Financial Metrics

MOODY'S
INVESTORS SERVICE

© 2012 Moody's Investors Service, Inc. and/or its licensors and affiliates (collectively, "MOODY'S"). All rights reserved.

CREDIT RATINGS ISSUED BY MOODY'S INVESTORS SERVICE, INC. ("MIS") AND ITS AFFILIATES ARE MOODY'S CURRENT OPINIONS OF THE RELATIVE FUTURE CREDIT RISK OF ENTITIES, CREDIT COMMITMENTS, OR DEBT OR DEBT-LIKE SECURITIES, AND CREDIT RATINGS AND RESEARCH PUBLICATIONS PUBLISHED BY MOODY'S ("MOODY'S PUBLICATIONS") MAY INCLUDE MOODY'S CURRENT OPINIONS OF THE RELATIVE FUTURE CREDIT RISK OF ENTITIES, CREDIT COMMITMENTS, OR DEBT OR DEBT-LIKE SECURITIES. MOODY'S DEFINES CREDIT RISK AS THE RISK THAT AN ENTITY MAY NOT MEET ITS CONTRACTUAL, FINANCIAL OBLIGATIONS AS THEY COME DUE AND ANY ESTIMATED FINANCIAL LOSS IN THE EVENT OF DEFAULT. CREDIT RATINGS DO NOT ADDRESS ANY OTHER RISK, INCLUDING BUT NOT LIMITED TO: LIQUIDITY RISK, MARKET VALUE RISK, OR PRICE VOLATILITY. CREDIT RATINGS AND MOODY'S OPINIONS INCLUDED IN MOODY'S PUBLICATIONS ARE NOT STATEMENTS OF CURRENT OR HISTORICAL FACT. CREDIT RATINGS AND MOODY'S PUBLICATIONS DO NOT CONSTITUTE OR PROVIDE INVESTMENT OR FINANCIAL ADVICE, AND CREDIT RATINGS AND MOODY'S PUBLICATIONS ARE NOT AND DO NOT PROVIDE RECOMMENDATIONS TO PURCHASE, SELL, OR HOLD PARTICULAR SECURITIES. NEITHER CREDIT RATINGS NOR MOODY'S PUBLICATIONS COMMENT ON THE SUITABILITY OF AN INVESTMENT FOR ANY PARTICULAR INVESTOR. MOODY'S ISSUES ITS CREDIT RATINGS AND PUBLISHES MOODY'S PUBLICATIONS WITH THE EXPECTATION AND UNDERSTANDING THAT EACH INVESTOR WILL MAKE ITS OWN STUDY AND EVALUATION OF EACH SECURITY THAT IS UNDER CONSIDERATION FOR PURCHASE, HOLDING, OR SALE.

ALL INFORMATION CONTAINED HEREIN IS PROTECTED BY LAW, INCLUDING BUT NOT LIMITED TO, COPYRIGHT LAW, AND NONE OF SUCH INFORMATION MAY BE COPIED OR OTHERWISE REPRODUCED, REPACKAGED, FURTHER TRANSMITTED, TRANSFERRED, DISSEMINATED, REDISTRIBUTED OR RESOLD, OR STORED FOR SUBSEQUENT USE FOR ANY SUCH PURPOSE, IN WHOLE OR IN PART, IN ANY FORM OR MANNER OR BY ANY MEANS WHATSOEVER, BY ANY PERSON WITHOUT MOODY'S PRIOR WRITTEN CONSENT. All information contained herein is obtained by MOODY'S from sources believed by it to be accurate and reliable. Because of the possibility of human or mechanical error as well as other factors, however, all information contained herein is provided "AS IS" without warranty of any kind. MOODY'S adopts all necessary measures so that the information it uses in assigning a credit rating is of sufficient quality and from sources Moody's considers to be reliable, including, when appropriate, independent third-party sources. However, MOODY'S is not an auditor and cannot in every instance independently verify or validate information received in the rating process. Under no circumstances shall MOODY'S have any liability to any person or entity for (a) any loss or damage in whole or in part caused by, resulting from, or relating to, any error (negligent or otherwise) or other circumstance or contingency within or outside the control of MOODY'S or any of its directors, officers, employees or agents in connection with the procurement, collection, compilation, analysis, interpretation, communication, publication or delivery of any such information, or (b) any direct, indirect, special, consequential, compensatory or incidental damages whatsoever (including without limitation, lost profits), even if MOODY'S is advised in advance of the possibility of such damages, resulting from the use of or inability to use, any such information. The ratings, financial reporting analysis, projections, and other observations, if any, constituting part of the

information contained herein are, and must be construed solely as, statements of opinion and not statements of fact or recommendations to purchase, sell or hold any securities. Each user of the information contained herein must make its own study and evaluation of each security it may consider purchasing, holding or selling. NO WARRANTY, EXPRESS OR IMPLIED, AS TO THE ACCURACY, TIMELINESS, COMPLETENESS, MERCHANTABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE OF ANY SUCH RATING OR OTHER OPINION OR INFORMATION IS GIVEN OR MADE BY MOODY'S IN ANY FORM OR MANNER WHATSOEVER.

MIS, a wholly-owned credit rating agency subsidiary of Moody's Corporation ("MCO"), hereby discloses that most issuers of debt securities (including corporate and municipal bonds, debentures, notes and commercial paper) and preferred stock rated by MIS have, prior to assignment of any rating, agreed to pay to MIS for appraisal and rating services rendered by it fees ranging from $1,500 to approximately $2,500,000. MCO and MIS also maintain policies and procedures to address the independence of MIS's ratings and rating processes. Information regarding certain affiliations that may exist between directors of MCO and rated entities, and between entities who hold ratings from MIS and have also publicly reported to the SEC an ownership interest in MCO of more than 5%, is posted annually at www.moodys.com under the heading "Shareholder Relations — Corporate Governance — Director and Shareholder Affiliation Policy."

Any publication into Australia of this document is by MOODY'S affiliate, Moody's Investors Service Pty Limited ABN 61 003 399 657, which holds Australian Financial Services License no. 336969. This document is intended to be provided only to "wholesale clients" within the meaning of section 761G of the Corporations Act 2001. By continuing to access this document from within Australia, you represent to MOODY'S that you are, or are accessing the document as a representative of, a "wholesale client" and that neither you nor the entity you represent will directly or indirectly disseminate this document or its contents to "retail clients" within the meaning of section 761G of the Corporations Act 2001.

Notwithstanding the foregoing, credit ratings assigned on and after October 1, 2010 by Moody's Japan K.K. ("MJKK") are MJKK's current opinions of the relative future credit risk of entities, credit commitments, or debt or debt-like securities. In such a case, "MIS" in the foregoing statements shall be deemed to be replaced with "MJKK". MJKK is a wholly-owned credit rating agency subsidiary of Moody's Group Japan G.K., which is wholly owned by Moody's Overseas Holdings Inc., a wholly-owned subsidiary of MCO.

This credit rating is an opinion as to the creditworthiness of a debt obligation of the issuer, not on the equity securities of the issuer or any form of security that is available to retail investors. It would be dangerous for retail investors to make any investment decision based on this credit rating. If in doubt you should contact your financial or other professional adviser.

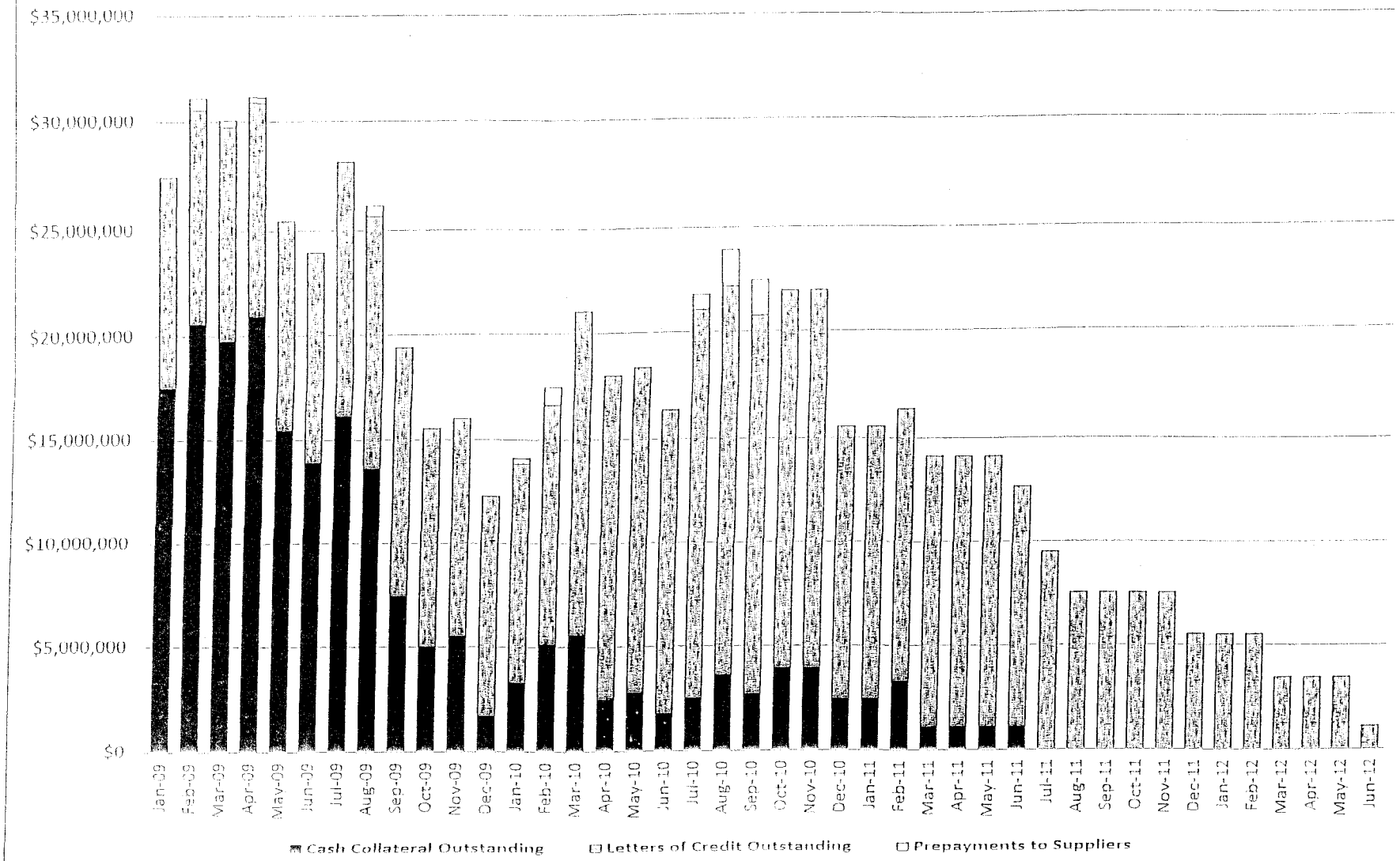
EXHIBIT

KCG-2

Exhibit KCG-2

UNS Electric, Inc.

Credit Support Required for Fuel & Power Procurement



BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	DOCKET NO. E-04204A-12

Direct Testimony of

Ann E. Bulkley

on Behalf of

UNS Electric, Inc.

December 31, 2012

TABLE OF CONTENTS

I. INTRODUCTION 1
II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY 2
III. SUMMARY OF ANALYSIS AND CONCLUSIONS 4
IV. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS 9
V. PROXY GROUP SELECTION 11
VI. COST OF EQUITY ESTIMATION 15
A. Constant Growth DCF Model 16
B. Multi-Stage DCF Model 19
C. Discounted Cash Flow Model Results 21
D. CAPM Analysis 23
E. Bond Yield Plus Risk Premium Analysis 25
VII. REGULATORY AND BUSINESS RISKS 28
A. UNS Electric's Regulatory Environment 28
B. UNS Electric's Capital Expenditure Plan 32
C. UNS Electric's Small Size 35
VIII. CAPITAL STRUCTURE 37
IX. EFFECT OF UNS ELECTRIC'S PROPOSED LFCR AND TCA MECHANISMS ON THE COST OF EQUITY 38
X. CAPITAL MARKET ENVIRONMENT 42
XI. CONCLUSIONS AND RECOMMENDATION 48
XII. FAIR VALUE RATE BASE 50
XIII. FAIR VALUE RATE OF RETURN. 55

Exhibits:

Exhibit AEB-1 Constant Growth DCF
Exhibit AEB-2 Multi-Stage DCF
Exhibit AEB-3 Calculation of Long-Term GDP Growth Rate
Exhibit AEB-4 BETAS
Exhibit AEB-5 Capital Asset Pricing Model
Exhibit AEB-6 Bond Yields Plus Risk Premium
Exhibit AEB-7 Comparison of 2013-2017 Capital Expenditures
Exhibit AEB-8 Size Premium Calculation
Exhibit AEB-9 Capital Structure Analysis

Exhibit AEB-10	Proxy Group Decoupling Mechanisms
Exhibit AEB-11	Fair Value Rate of Return
Exhibit AEB-12	Comparable Transactions Analysis
Attachment A	Resume and Summary of Testimony in Other Proceedings

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 UNS Electric, Inc. ("UNS Electric" or the "Company"). UNS Electric is a wholly-owned subsidiary of UNS Energy Corporation.

Q. Please describe your education and experience.

A. I have approximately 15 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 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 both 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 supervision.

Q. What are your conclusions regarding the appropriate cost of equity for the Company?

A. My analyses indicate that the Company's cost of equity is currently within the range of 10.30 percent to 10.75 percent. 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.[2]

---

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

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

Therefore, I base my recommendation on the results of several quantitative methodologies and qualitative analyses discussed throughout my Direct Testimony. Considering the results of those analyses, I believe that a reasonable ROE for UNS Electric is 10.50 percent.

Q. Please provide a brief overview of the analysis 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.

In addition to the analyses discussed above, my recommendation also takes into consideration: (1) the regulatory environment in which the Company operates; (2) the Company's capital expenditure plan; (3) the Company's small size relative to the proxy group; and (4) the Lost Fixed Cost Recovery ("LFCR") and Transmission Cost Adjustment ("TCA") mechanisms proposed by UNS Electric. 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 those factors, I did take them into consideration in aggregate when determining where the Company's ROE falls within the range of analytical results.

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

A. The remainder of my Direct Testimony is organized in eleven sections. Section III provides a summary of my analysis and conclusions. Section IV reviews the regulatory guidelines and financial considerations pertinent to the development of the cost of capital. Section V explains my selection of a proxy group of electric utilities. Section

VI describes my analyses and the analytical basis for the recommendation of the appropriate ROE for UNS Electric. Section VII 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 VIII discusses the capital structure of the Company as compared with the proxy group. Section IX discusses the effect of the Company's proposed LFCR and TCA mechanisms on the ROE. Section X discusses the current capital market conditions and the effect of those conditions on the Company's cost of equity. Section XI presents my conclusions and recommendation for the market cost of equity. Section XII discusses my analysis of the Company's proposed FVRB, and Section XIII 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[3] 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 capital market conditions 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.

[3] *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. Please summarize the ROE estimation models that you considered to establish the range of ROEs for UNS Electric.

A. I considered the results of two forms of the DCF model: the Constant Growth and the Multi-Stage forms of the model. In addition, I considered two risk premium approaches, the CAPM and a Bond Yield Plus Risk Premium methodology. Finally, I considered the level of regulatory, business, and financial risk faced by the Company relative to the proxy group. The results of my analyses are summarized in Table 1 below.

Table 1: Summary of Analytical Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average Price	9.00%	10.55%	12.81%
90-Day Average Price	8.97%	10.51%	12.78%
180-Day Average Price	9.06%	10.61%	12.88%
	Median Low	Median	Median High
30-Day Average Price	9.47%	10.57%	11.54%
90-Day Average Price	9.42%	10.53%	11.53%
180-Day Average Price	9.52%	10.63%	11.64%
Multi-Stage DCF			
	Mean Low	Mean	Mean High
30-Day Average Price	9.93%	10.38%	11.19%
90-Day Average Price	9.89%	10.35%	11.15%
180-Day Average Price	9.99%	10.45%	11.28%
	Median Low	Median	Median High
30-Day Average Price	9.93%	10.21%	10.81%
90-Day Average Price	9.84%	10.15%	10.74%
180-Day Average Price	9.92%	10.26%	10.81%
Capital Asset Pricing Model			
	Current Risk-Free Rate (2.87%)	2012-2014 Projected Risk-Free Rate (3.15%)	2014-2018 Projected Risk-Free Rate (5.10%)
Bloomberg Beta	9.87%	9.95%	10.53%
Value Line Beta	10.03%	10.11%	10.66%
Bond Yield Plus Risk Premium			
	Current Risk-Free Rate (2.87%)	2012-2014 Projected Risk-Free Rate (3.15%)	2014-2018 Projected Risk-Free Rate (5.10%)
Bond Yield Plus Risk Premium	10.01%	10.12%	10.86%

Q. What is your recommended ROE for UNS Electric?

A. The analytical results presented in Table 1 provide the range of results for the proxy group companies. Based on the analytical results presented in Table 1, I believe a reasonable range of ROE estimates for UNS Electric is from 10.30 percent to 10.75 percent, and within that range, 10.50 percent is a reasonable and appropriate estimate of the Company's ROE.

Q. Did you consider the effect of the Company's proposed LFCR and TCA mechanisms on the ROE?

A. Yes, I did. As with each of the other regulatory, business, and financial risks discussed below, I considered the Company's proposed LFCR and TCA mechanisms as compared with the revenue stabilization mechanisms that have been implemented by the proxy companies. I concluded that over 60.0 percent of my proxy group companies have some form of decoupling mechanism while nearly 80.0 percent have rate mechanisms in place to recover certain specific capital expenditures, like transmission costs. Since the risk-reducing effect of these rate mechanisms is included in the ROE estimates produced by my proxy group, I have not made any adjustment to the ROE for UNS Electric to reflect those mechanisms.

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

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 UNS Electric'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 UNS Electric's assets by applying the median premium of 39.70 percent to the Company's OCRB. That analysis resulted in an estimated market value for UNS Electric's assets of $302.6 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 $286.3 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 3.23 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 Table 2 below, the result of that analysis is a FVROR of 6.71 percent.

Table 2: Estimation of the FVROR

Capital	$ Millions	Percent	Cost Rate	Weighted Cost Rate
OCRB	$216.6			
RCND	$356.1			
FVRB	$286.3			
Long-Term Debt	$102.7	35.85%	5.97%	2.14%
Common Equity	$113.9	39.79%	10.50%	4.18%
Fair Value Increment	$69.8	24.36%	1.61%	0.39%
Total	$286.3	100.00%		6.71%

IV. REGULATORY GUIDELINES AND FINANCIAL CONSIDERATIONS.

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 widely recognized standards, the Commission's decision in this case should provide the Company with the opportunity to earn an ROE that is:

- Adequate to attract capital on favorable terms, thereby enabling the Company to provide safe, reliable service;
- Sufficient to ensure the financial soundness of the Company's operations; and

[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).

- Commensurate with returns on investments in enterprises having comparable risks.

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

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 provide safe, reliable electric service while maintaining its financial integrity. To the extent the Company is provided the opportunity to earn its market-based cost of capital, neither customers nor shareholders are disadvantaged. While the "capital attraction" and "financial integrity" standards are important principles in normal economic conditions, the practical implications of those standards are even more pronounced when considered in the context of the recent financial market environment.

---

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

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 the capital market conditions in which the Company must contend, as well as investors' expectations and requirements for both risks and returns. Further, in light of recent capital market conditions, the Company's capital investment plans, and upcoming debt maturities at UNS Electric, it is important that the Company be afforded the opportunity to maintain a financial profile that will enable it to access the capital markets at reasonable rates.

V. PROXY GROUP SELECTION.

Q. Why have you used a group of proxy companies to determine the cost of equity for UNS Electric?

A. Given that the Company is not publicly traded and that the cost of equity is a market-based concept, it is necessary to establish a group of companies that are both publicly traded and comparable to UNS Electric in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process. 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 UNS Electric.

Q. Please provide a brief profile of UNS Electric.

A. UNS Electric generates, transmits and distributes electricity to approximately 91,000 retail customers in non-contiguous service territories in the Mohave and Santa Cruz counties of Arizona.[6] As of December 31, 2011, UNS Electric represented

[6] UNS Energy Corporation, SEC Form 10-K for the fiscal year ended December 31, 2011, at K-17.

approximately 9.0 percent of UNS Energy Corporation's total assets.[7] UNS Electric currently has an investment grade long-term rating of Baa2 from Moody's, which was upgraded from Baa3 on May 23, 2012. Similarly, the Company's senior unsecured rating from Moody's is investment grade at Baa2.[8]

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

A. I began with the group of 49 companies that Value Line classifies as electric utilities and I simultaneously applied the following screening criteria:

- I excluded companies that do not pay consistent quarterly cash dividends because such companies cannot be analyzed using the Constant Growth DCF model.
- I excluded companies that do not have positive long-term earnings growth forecasts from at least two equity analysts.
- I excluded companies that did not have investment grade long-term issuer ratings from both S&P and Moody's.
- I excluded companies that derive less than 60.0 percent of their total operating income from regulated operations.
- I excluded companies that derive less than 90.0 percent of their total regulated operating income from regulated electric operations.
- Finally, I excluded companies that were party to a merger or transformative transaction during the analytical period considered.

Q. How many companies met your screening criteria?

A. The criteria discussed above resulted in an initial proxy group of the following 16 companies.

---

7 UNS Energy Corporation, SEC Form 10-K for the fiscal year ended December 31, 2011, at K-108.

8 SNL Financial

Table 3: Initial Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
American Electric Power Company, Inc.	AEP
Cleco Corporation	CNL
Edison International	EIX
Empire District Electric Company	EDE
FirstEnergy Corporation	FE
Great Plains Energy Inc.	GXP
Hawaiian Electric Industries, Inc.	HE
IDACORP, Inc.	IDA
Integrys Energy Group, Inc.	TEG
Otter Tail Corporation	OTTR
Pepco Holdings, Inc.	POM
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
Westar Energy, Inc.	WR

Q. Is this your final proxy group?

A. No, it is not. Edison International operates in two primary business segments: electric utility and nonutility power generation. The company experienced significant losses in its nonutility power generation segment in 2009 and 2011. In 2009, the nonutility power generation segment produced an operating income loss of $491 million after a settlement between Edison International and the Internal Revenue Service resolved federal tax disputes related to the company's cross-border, leveraged leases through 2009, and all other outstanding federal tax disputes and affirmative claims for tax years 1986 through 2002.[9] In 2011, Edison International recorded a loss of $1.09 billion in its competitive power generation business segment, Edison Mission Energy ("EME"), which was related to the impairment of several power plants, wind-related charges and

[9] Edison International, SEC Form 10-K for the fiscal year ended December 31, 2011, at v.

other expenses.[10] Furthermore, on November 1, 2012, Edison International reported to investors that EME will not be able to repay $500 million in bonds that mature in June 2013 and will likely not be able to make the interest payments on 2017, 2019, and 2027 unsecured bonds, which were due November 15, 2012. Failure to meet the interest payments will likely result in EME filing for bankruptcy protection under Chapter 11 of the bankruptcy code.[11] Due to the magnitude of the losses, and the likely bankruptcy of EME, it is not reasonable to include Edison International in the proxy group at this time.

In addition, Integrys Energy Group, Inc. recorded a noncash goodwill impairment loss of $291.1 million ($248.8 million after tax) in the first quarter of 2009, all within the natural gas utility segment.[12] This impairment charge distorts the three-year average of total regulated operating income derived from regulated electric operations and produces a result that is not representative of the company's ongoing operations. For example, the three-year average of total regulated operating income derived from regulated electric operations is 126 percent while regulated electric operations contributed only 52 percent and 49 percent of total regulated operating income for 2010 and 2011, respectively. Given that Integrys Energy Group, Inc. is evenly split between regulated electric and natural gas operations in more normal years, I did not include the company in my final proxy group.

Q. What is the composition of your final proxy group?

A. My final proxy group consists of the following 14 companies.

---

10 Edison International, SEC Form 10-K for the fiscal year ended December 31, 2011, at 54.

11 Edison International, SEC Form 8-K, November 1, 2012.

12 Integrys Energy Group, Inc., SEC Form 10-K for the fiscal year ended December 31, 2011, at 77.

Table 4: Final Proxy Group

Company	Ticker
ALLETE, Inc.	ALE
American Electric Power Company, Inc.	AEP
Cleco Corporation	CNL
Empire District Electric Company	EDE
FirstEnergy Corporation	FE
Great Plains Energy Inc.	GXP
Hawaiian Electric Industries, Inc.	HE
IDACORP, Inc.	IDA
Otter Tail Corporation	OTTR
Pepco Holdings, Inc.	POM
Pinnacle West Capital Corporation	PNW
Portland General Electric Company	POR
Southern Company	SO
Westar Energy, Inc.	WR

VI. COST OF EQUITY ESTIMATION.

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

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment. 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 information.

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 applied, based on the results of those analyses, to determine where the Company's cost of equity falls

within the range of results. The resulting adjusted cost of equity serves as the recommended ROE for ratemaking purposes. The key consideration in determining the cost of equity is to ensure that the methodologies employed reasonably reflect investors' views of the financial markets as well as the subject company's common stock.

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

A. As discussed below, I relied primarily on the results of the Constant Growth and Multi-Stage DCF models corroborated by the results of the CAPM and Risk Premium methodology.

A. Constant Growth DCF Model.

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

A. Yes, they are. 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. In a prior rate order, the Commission stated that the:

> [u]se of the DCF as the primary basis for determining the Company's reasonable estimated cost of equity capital is a methodology that has been used for many years by this Commission, as well as other regulatory commissions across the country.[13]

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:

---

[13] Decision No. 68487 (February 23, 2006), at 29.

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

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 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 are 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 November 16, 2012.

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 calculated 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. At the same time, it is important to reflect the volatile conditions present in the financial markets over the recent past. In my view, the use of the 30-, 90-, and 180-day averaging periods reasonably balances those concerns.

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 12-month period, and does not overstate the aggregated dividends to be paid during that time.

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

A. Yes, it is. 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 is therefore 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; (2) Thomson First Call (provided by Yahoo! Finance); and (3) Value Line.

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. The Multi-Stage model, which is an extension of the Constant Growth form, enables the analyst to specify growth rates over multiple stages. As with the Constant Growth form of the DCF model, the Multi-Stage form 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 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 through 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 November 16, 2012 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 5.55 percent is based on the real GDP growth rate of 3.24 percent from 1929 through 2011,[14] and a projected inflation rate of 2.24 percent. The rate of inflation of 2.24 percent is based on three measures: (1) the average long-term projected growth rate in the Consumer Price Index ("CPI") of 2.40 percent, as reported by Blue Chip Financial Forecasts;[15] (2) the compound annual growth rate of the CPI for all urban consumers for 2022-2035 of 2.27 percent as projected by the Energy Information Administration ("EIA") in the Annual Energy Outlook 2012; and (3) the compound annual growth rate of the GDP chain-type

[14] U.S. Department of Commerce, Bureau of Economic Analysis, National Income and Product Accounts Tables, Table 1.1.1, October 27, 2012.

[15] Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14.

price index for 2022-2035 of 2.06 percent, also reported by the EIA in the Annual Energy Outlook 2012.[16]

C. Discounted Cash Flow Model Results.

Q. Please summarize the results of your DCF analyses.

A. Table 5 below (*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 10.51 percent to 10.61 percent and a range of median results from 10.53 percent to 10.63 percent. The Multi-Stage DCF analysis produces a range of mean results from 10.35 percent to 10.45 percent and a range of median results from 10.15 percent to 10.26 percent.

[16] U.S. Energy Information Administration, Annual Energy Outlook 2012, Table 20, Macroeconomic Indicators.

Table 5: Discounted Cash Flow Analyses Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average Price	9.00%	10.55%	12.81%
90-Day Average Price	8.97%	10.51%	12.78%
180-Day Average Price	9.06%	10.61%	12.88%
	Median Low	Median	Median High
30-Day Average Price	9.47%	10.57%	11.54%
90-Day Average Price	9.42%	10.53%	11.53%
180-Day Average Price	9.52%	10.63%	11.64%
Multi-Stage DCF			
	Mean Low	Mean	Mean High
30-Day Average Price	9.93%	10.38%	11.19%
90-Day Average Price	9.89%	10.35%	11.15%
180-Day Average Price	9.99%	10.45%	11.28%
	Median Low	Median	Median High
30-Day Average Price	9.93%	10.21%	10.81%
90-Day Average Price	9.84%	10.15%	10.74%
180-Day Average Price	9.92%	10.26%	10.81%

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 and median results were calculated using the average of all three sources' growth rates.

Q. Did you undertake any additional analyses to support your DCF model results?

A. Yes, I did. As noted earlier, I also used the CAPM and the Risk Premium approach as a means of assessing the reasonableness of my Constant Growth and Multi-Stage DCF results.

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 times 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 estimates of the yield on U.S. Treasury bonds as my estimate of the risk-free rate: (1) the current 30-day average yield on 30-year U.S. Treasury bonds (*i.e.*, 2.87 percent);[17] (2) the projected 30-year U.S. Treasury bond yield for 2012 through 2014 of 3.15 percent;[18] and (3) the projected 30-year U.S. Treasury bond yield for 2014 through 2018 of 5.10 percent.[19]

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 the S&P 500 Index, less the 30-year U.S. 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 long-term earnings projections are available. Based on an estimated market capitalization-weighted dividend yield of 2.37 percent and a weighted long-term growth rate of 10.35 percent, the estimated required market return for the S&P 500 Index is 12.85 percent. The implied market risk premium over the current 30-day average of the 30-year U.S.

---

17 Bloomberg Professional

18 Blue Chip Financial Forecasts, Vol. 31, No. 11, November 1, 2012, at 2.

19 Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14.

Treasury bond yield, and the short- and longer-term projected yields on the 30-year U.S. Treasury bond, range from 7.75 percent to 9.98 percent.

Q. What is the next step in the CAPM analysis?

A. I considered the average Beta coefficients for the proxy group companies as reported by Bloomberg and Value Line (*see* **Exhibit AEB-4**). 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. What are the results of your CAPM analyses?

A. As shown in Table 6 below (*see* also **Exhibit AEB-5**), the results of my CAPM analysis using the average Bloomberg Beta coefficient suggest a mean ROE of 10.12 percent based on a range of returns from 9.87 percent to 10.53 percent. My CAPM analysis using the average Value Line Beta coefficient produces a range of returns from 10.03 percent to 10.66 percent and a mean of 10.27 percent.

Table 6: Forward-Looking CAPM Results

	Current Risk-Free Rate (2.90%)	**2012-2014 Projected Risk-Free Rate (3.15%)**	**2014-2018 Projected Risk-Free Rate (5.10%)**	**Mean Result**
Bloomberg Beta	9.87%	9.95%	10.53%	10.12%
Value Line Beta	10.03%	10.11%	10.66%	10.27%

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, there are. 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 more 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.[20]

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

A. As shown on Chart 1, from 1992 through 2012, 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:

---

[20] *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.

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

Where:

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

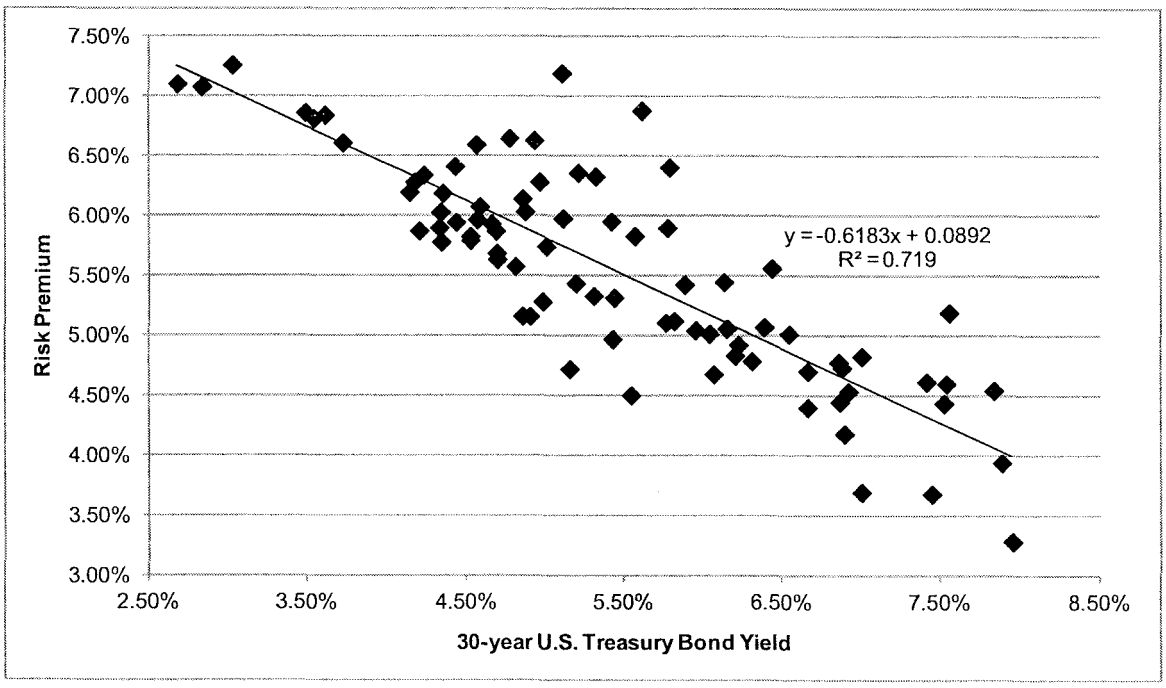
a = intercept term

b = slope term

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

Data regarding allowed ROEs were derived from 553 rate cases from 1992 through September 30, 2012 as reported by Regulatory Research Associates. This equation's coefficients were statistically significant at the 99.0 percent level.

Chart 1: 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.*, 2.87 percent), the risk premium would be 7.14 percent, resulting in an estimated ROE of 10.01 percent. Based on the near-term (2012-2014)

projections of the 30-year U.S. Treasury bond yield (*i.e.*, 3.15 percent), the risk premium would be 6.97 percent, resulting in an estimated ROE of 10.12 percent. Based on longer-term (2014-2018) projections of the 30-year U.S. Treasury bond yield (*i.e.*, 5.10 percent), the risk premium would be 5.76 percent, resulting in an estimated ROE of 10.86 percent.

VII. REGULATORY AND BUSINESS RISKS.

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

A. These results provide only a range of the appropriate estimate of the Company's cost of equity. In my view, 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 risk factors include: (1) Regulatory Environment; (2) Capital Expenditure Plan; and (3) the Size of the Utility. These factors, which are discussed below, should be considered with respect to their overall effect on the Company's risk profile.

A. UNS Electric'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 services, 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. UNS Electric faces the same challenge in financing 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.

Further, the financial community monitors not only the regulatory environment in which utility companies operate, but also the current and expected conditions of the capital markets from which utilities must attract long-term capital. As such, it is important to consider the capital market conditions with which UNS Electric must contend, as well as investors' expectations and requirements relating to both risks and returns in the estimation of the Company's required ROE. UNS Electric must also be afforded the

opportunity to maintain (or enhance) its financial integrity and to earn a reasonable return, taking into consideration the current market conditions and the Company's specific business risk profile.

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.[21]

Standard & Poor's 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 influence credit quality the most."[22]

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 companies are influenced by the rating agencies' assessment of the regulatory

---

21 Moody's Global Infrastructure Finance, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009, at 4.

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

environment. As noted by Moody's, "the predictability and supportiveness of the regulatory framework in which a regulated utility operates is a key credit consideration and the one that differentiates the industry from most other corporate sectors."[23] Moody's further highlighted the relevance of a stable and predictable regulatory environment to a utility's credit quality, noting:

> For a regulated utility company, we consider the characteristics of the regulatory environment in which it operates. These include how developed the regulatory framework is; its track record for predictability and stability in terms of decision making; and the strength of the regulator's authority over utility regulatory issues. A utility operating in a stable, reliable, and highly predictable regulatory environment will be scored higher on this factor than a utility operating in a regulatory environment that exhibits a high degree of uncertainty or unpredictability. Those utilities operating in a less developed regulatory framework or one that is characterized by a high degree of political intervention in the regulatory process will receive the lowest scores on this factor.[24]

Q. Is regulatory risk an important consideration for UNS Electric?

A. Yes, it is. In a recent credit opinion, Moody's noted the improved regulatory environment in Arizona and recovery mechanisms that are supportive of credit quality.[25] Moody's also stated that its conclusion regarding the improved regulatory environment in Arizona is based on the Commission finalizing three recent rate cases within 13 months and its more supportive rate treatment, approving full or partial decoupling mechanisms for UNS Gas, Inc., Southwest Gas Corporation, and Arizona Public Service Company. Therefore, supportive regulatory treatment in this case will be an important factor in Moody's rating of UNS Electric.

---

[23] Moody's Global Infrastructure Finance, *Rating Methodology: Regulated Electric and Gas Utilities*, August 2009, at 6.

[24] *Ibid.*

[25] Moody's Investors Service, *Credit Opinion: UNS Electric, Inc.*, May 25, 2012.

B. UNS Electric's Capital Expenditure Plan.

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

A. The Company's current projections include approximately $182.0 million in capital investments for the period from 2013 through 2017.[26] The Company's capital expenditure plan includes approximately: (1) $35.7 million for new distribution plant; (2) $54.8 million for distribution replacements and betterments; (3) $40.8 million for transmission plant; (4) $19.9 million for general plant; (5) $4.0 million for generation plant; and (6) $26.9 million for renewable generation plant.[27] Given that the Company's net utility plant as of December 31, 2011 was approximately $280.7 million,[28] the $182.0 million anticipated capital expenditures represent 64.85 percent of UNS Electric's net utility plant as of December 31, 2011.

Q. How is the Company's risk profile affected by the substantial increase in its planned capital expenditures?

A. As with any utility faced with a substantial capital expenditure plan, the Company's risk profile is adversely affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery, or the delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics.

Q. Do credit rating agencies recognize the risks associated with increased 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

---

26 Company projection of capital spending as of December 2012.

27 The specific capital investment programs are discussed in greater detail in the Direct Testimony of Mr. Michael J. DeConcini.

28 UNS Electric, Inc., FERC Form 1 for the year ended December 31, 2011, at 110.

credit metrics and, therefore, credit ratings. In a recent report, S&P noted the importance of timely cost recovery:

> As companies spend on investments, a significant consideration for regulated utilities will be how quickly regulators allow them to fully recover these costs. If the costs are significant, any delays or denials in the recovery could hurt a utility's credit quality. Thus, regulatory support is necessary to successfully implement such projects. Cost recovery through base rates and rate mechanisms that provide for predictable and timely cash flow could offset the costs of a company's capital spending. These mechanisms help provide timely and consistent recovery of costs and bolster financial measures by limiting cash-flow drains and reducing the amount of debt needed during construction. Ultimately, the dollar amount of the costs and the timeliness in recovering them will be important factors affecting our view of a utility's credit quality.[29]

Q. Will the Company need continued access to the capital markets in order to finance its capital expenditure plan?

A. UNS Electric has indicated that it expects to have only a modest need for new long-term debt capital in order to finance its current capital expenditure plan. The Company expects to issue additional long-term debt in 2015 in conjunction with the refinancing of $80 million of maturing long-term debt.

Q. Have you conducted an analysis of the Company's projected capital expenditures relative to the proxy companies?

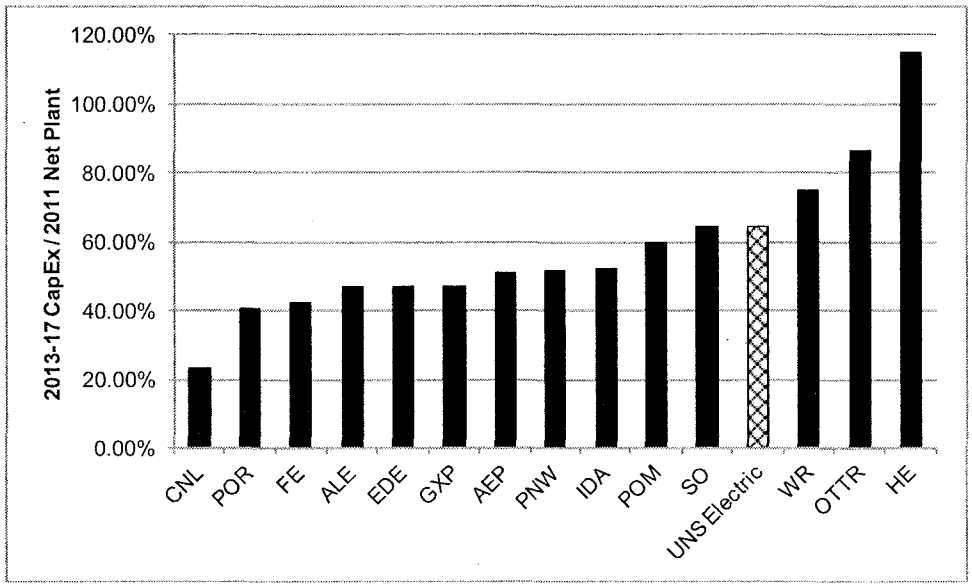
A. Yes, I have. I compared the ratio of projected capital expenditures from 2013 through 2017 to net utility plant as of December 31, 2011, for UNS Electric and each of the proxy group companies. As shown on **Exhibit AEB-**7, the Company's percentage of projected capital expenditures to net utility plant is 1.27 times the median ratio for the proxy group companies. Chart 2 below demonstrates that UNS Electric's projected

---

[29] Standard & Poor's, *U.S. Utilities' Capital Spending Is Rising, And Cost-Recovery Is Vital*, May 14, 2012, at 7.

capital spending as a percentage of net utility plant is higher than the majority of the proxy group companies over this time period.

Chart 2: Comparison of Capital Expenditures (2013-2017)[30]



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

A. It is clear that, on a relative basis, the Company's capital expenditure program is significant because of its high ratio relative to net utility plant, which would likely materially dilute the Company's current earnings and cash flows, absent rate relief. It also is clear that the credit rating agencies recognize the additional risks associated with substantial capital expenditures and that those risks are reflected in credit ratings. Taking into consideration the projected level of capital spending, the additional long-term debt projected to be issued in 2015, and the $80 million of long-term debt maturing in 2015, it is important that the authorized ROE in this proceeding provide the Company with the opportunity to maintain and potentially improve its financial integrity.

30 Capital expenditures for UNSE reflect an updated budget period of 2013 through 2017, while the analysis of the proxy companies is based on publicly available data for the same period.

C. UNS Electric's Small Size.

Q. Please explain the risk associated with small size.

A. Both the financial and academic communities have long accepted the proposition that the cost of equity for small firms is subject to a "size effect". While empirical evidence of the size effect often is based on studies of industries beyond regulated utilities, utility analysts also have noted the risk associated with small market capitalizations. Specifically, an analyst for Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[31]

Small size, therefore, leads to two categories of increased risk for investors: (1) liquidity risk (*i.e.*, the risk of not being able to sell one's shares in a timely manner due to the relatively thin market for the securities); and (2) fundamental business risks.

Q. How does UNS Electric compare in size to the proxy companies?

A. UNS Electric is substantially smaller than the median for the proxy group companies both in terms of number of customers and market capitalization. **Exhibit AEB-8** provides the actual market capitalization for the proxy group companies and estimates the implied market capitalization for UNS Electric (*i.e.*, the implied market capitalization if UNS Electric were a stand-alone publicly-traded entity). To do so, I relied on the proposed equity component of the Company's rate base, or $113.9 million (*i.e.*, 52.60% x $216.6 million). I then applied the median market-to-book ratio for the proxy group of 1.38 to UNS Electric's implied common equity balance and arrived at an implied market capitalization of $156.7 million. That implied market capitalization is approximately 5.33 percent of the median market capitalization for the proxy group.

---

[31] Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly, October 15, 1995.

Q. How does the smaller size of UNS Electric affect its business risk relative to the proxy group?

A. In general, smaller companies are less able to withstand adverse events that affect their revenues and expenses. The impact of weather variability, the loss of large customers to bypass opportunities, or the destruction of demand as a result of general macroeconomic conditions or fuel price volatility will have a proportionately greater impact on the earnings and cash flow volatility of smaller utilities. Similarly, capital expenditures for non-revenue producing investments, such as system maintenance and replacements, will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. Taken together, these risks affect the return required by investors for smaller companies.

Q. How did you estimate the size premium for UNS Electric?

A. In its *Ibbotson SBBI 2012 Valuation Yearbook*, Morningstar, Inc. presents its calculation of the size premium for the New York Stock Exchange, American Stock Exchange, and NASDAQ[32] broken down into market capitalization deciles.[33] As shown in **Exhibit AEB-8**, according to recent market data, the median market capitalization of the proxy group was approximately $2.9 billion, which corresponds to the fourth decile of the Morningstar, Inc. market capitalization data. Based on Morningstar, Inc.'s analysis, that decile corresponds to a size premium of 1.17 percent (*i.e.*, 117 basis points). UNS Electric's implied market capitalization of $156.7 million falls within the tenth decile, which comprises market capitalization levels of $1.0 million to $206.8 million and corresponds to a size premium of 6.10 percent (*i.e.*, 610 basis points). The difference between those size premia is 493 basis points (*i.e.*, 6.10 percent minus 1.17 percent).

---

32 National Association of Securities Dealers Automated Quotation System

33 Morningstar, Inc., Ibbotson SBBI 2012 Valuation Yearbook, at 202.

Q. Have you considered the smaller size of UNS Electric in your recommended ROE?

A. While I have estimated the small size effect, I am not proposing a specific adjustment for this factor. Rather, I have considered the small size of UNS Electric in my assessment of business risks in order to determine where, within a reasonable range of returns, UNS Electric's required ROE falls.

VIII. CAPITAL STRUCTURE.

Q. What is UNS Electric's proposed capital structure?

A. As described in the Direct Testimony of Mr. Grant, the Company's proposed capital structure consists of 52.60 percent common equity and 47.40 percent long-term debt.

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 and median proportions of common equity and long-term debt over the most recent eight quarters[34] for each of the proxy group companies at the operating company level. The Company's proposed equity ratio of 52.60 percent is well within the range established by the proxy companies of 46.32 percent to 60.00 percent.

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

A. Considering the actual capital structures of the proxy group's operating companies I believe that UNS Electric's proposed common equity ratio of 52.60 percent is reasonable.

---

[34] The source data for this analysis is the operating company data provided in the FERC Form 1. Due to the timing of those filings, my average capital structure analysis uses the quarterly capital structures reported for the proxy group companies for the period from October 2010 through September 2012, which is the most recent eight quarters of data available at the operating company level.

IX. EFFECT OF UNS ELECTRIC'S PROPOSED LFCR AND TCA MECHANISMS ON THE COST OF EQUITY.

Q. Please summarize the Company's proposed LFCR mechanism.

A. As discussed in greater detail in the Direct Testimony of Mr. Craig A. Jones, the Company is proposing an LFCR mechanism that would recover lost revenue that is the direct result of the Commission's Electric Energy Efficiency rules and Renewable Energy Standard Tariff ("REST") rules. As discussed by Mr. Jones, the Company's proposal is not a full decoupling mechanism, but rather is designed to recover only the losses attributable to quantifiable results through the Company's energy efficiency efforts and promotion of distributed generation.[35]

Q. Please summarize the Company's proposed TCA mechanism.

A. As discussed in greater detail in the Direct Testimony of UNS Electric witness Mr. Michael J. DeConcini, UNS Electric is proposing base rates that include a transmission cost element based on the current Federal Energy Regulatory Commission ("FERC") Open Access Transmission Tariff ("OATT"). The TCA will reflect future changes to the OATT, as either a charge or credit, relative to the current OATT rate. Thus, as the OATT changes over time, the TCA will provide timely recognition of those changes in the Company's retail rates.

Q. How do rating agencies view the implementation of revenue stabilization mechanisms, like the LFCR and TCA mechanisms?

A. Ratings agencies generally view these mechanisms favorably. For example, S&P recently commented on revenue stabilization mechanisms and their relationship to a utility's creditworthiness:

---

[35] *See* Direct Testimony of Mr. Craig A. Jones, at Section VIII.A.

> Regulatory jurisdictions apply a host of other rate mechanisms or special tariffs to allow timely recovery of costs, including those associated with electricity transmission, bad debt, extraordinary storm damage costs, property taxes, pensions, infrastructure replacement, and legislatively mandated energy efficiency and renewable resource projects. Finally, the greater the percentage of a utility's rates that they recover through fixed charges rather than volume-based charges, the greater the support for credit quality.[36]

Q. If the Commission were to adopt the Company's proposed LFCR and TCA mechanisms, what is the appropriate standard to consider in establishing the Company's ROE?

A. Under the comparable earnings standard, the allowed ROE should represent a return commensurate with the returns on investments of similar risk. In this case, the proxy group companies would constitute the comparable earnings standard for UNS Electric. Therefore, the issue is not whether the Company's revenues would be less volatile with the LFCR and TCA mechanisms than without them; rather the relevant question is whether the Company would be more or less risky with its LFCR and TCA mechanisms as compared to the proxy group.

Q. Did you examine the rate mechanisms in place at the proxy group companies?

Yes, I did. I reviewed the rate mechanisms employed in each jurisdiction by the 40 operating companies represented by my proxy group. Given UNS Electric's request to implement the LFCR and TCA mechanisms, my review focused on decoupling and capital cost recovery mechanisms. The Company's requested TCA mechanism is an example of a broader group of capital cost tracking mechanisms. Because each proxy group company is investing in various types of assets (*e.g.*, generation, transmission, and distribution), rather than narrowly focusing on transmission cost recovery mechanisms, I expanded my review to include any form of capital cost tracker. **Exhibit**

---

[36] Standard & Poor's, *How Regulated U.S. Utilities Weather A Slow Economy*, May 15, 2012, at 4.

AEB-10 provides a summary of the decoupling and capital cost recovery mechanisms used by the proxy group companies. As shown in that exhibit, I calculated the percent of my proxy group companies that have some form of decoupling and capital cost recovery. I weighted the results based on the number of electric customers in each of the jurisdictions served by the proxy group companies. My analysis shows that 62.6 percent of my proxy group companies have some form of decoupling while 79.5 percent have at least one capital cost recovery mechanism in place. I note that eight of the jurisdictions served by my proxy group companies have implemented full decoupling mechanisms, all of which provide for greater revenue certainty than the Company's proposed LFCR mechanism.

Q. What do you conclude about UNS Electric's risk relative to the proxy group if the Company's LFCR and TCA mechanisms are approved?

A. As discussed above, a large percentage of my proxy group companies utilize similar forms of decoupling and capital cost recovery mechanisms. Therefore, implementation of the proposed LFCR and TCA mechanisms would not make UNS Electric less risky than the proxy group companies, but rather would make the Company more comparable to the proxy group because the proposed LFCR and TCA mechanisms provide for similar revenue stability to the structures that have been implemented by the proxy group companies.

Q. Should the implementation of the Company's proposed LFCR and TCA mechanisms have an effect on the Company's ROE?

A. No. My viewpoint is that the required ROE derived from my proxy group analysis already reflects the risk of a utility with significant revenue stabilization. As noted previously, the Company's proposed LFCR mechanism is designed to eliminate disincentives to achieving the Commission's energy efficiency and renewable energy

standards, and the proposed TCA mechanism is intended to provide for the more timely recovery of transmission costs subject to regulation by the FERC. As noted earlier, a comparison of the proxy group companies' rate structures to the Company's LFCR and TCA mechanisms demonstrates that the proposed mechanisms provide similar revenue stabilization as the mechanisms that have been implemented by the proxy group companies. Therefore, the Company would have a risk profile that is more like the proxy group if the LFCR and TCA mechanisms were to be implemented. Furthermore, there is no conclusive evidence of which I am aware indicating that companies that have implemented such structures either have lower required ROEs or have significantly different market valuations. Based on the comparability of the company's proposed LFCR and TCA mechanisms to the rate structures implemented by the proxy group companies, I conclude that approval of the Company's LFCR and TCA mechanisms should not cause any adjustment to my required ROE analysis, which was derived from data for proxy companies that already have such mechanisms in place.

Q. What would be the effect on the Company's relative risk profile if the Company were not proposing the LFCR and TCA mechanisms or if the Commission does not approve these mechanisms?

A. It is important to recall that the estimation of the cost of equity is a comparative analysis, and that for several years, rating agencies (*e.g.*, Moody's, in particular) have identified revenue stabilization mechanisms as an increasingly common ratemaking mechanism. Absent such a structure, UNS Electric would be susceptible to incrementally greater risks than the proxy group. Consequently, while the Commission's acceptance of the Company's proposed LFCR and TCA mechanisms would not result in a reduced cost of equity relative to UNS Electric's proxy group, the denial of such a structure would render the Company even more risky than its peers. As previously discussed, approval of the proposed LFCR and TCA mechanisms by the

Commission in this proceeding should make the Company more comparable to the proxy group companies.

X. CAPITAL MARKET ENVIRONMENT.

Q. How do economic conditions influence the required cost of capital and required ROE?

A. The required cost of capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. During times of capital market uncertainty, risk aversion increases; this causes investors to seek the relative safety of U.S. Treasury debt, resulting in lower U.S. Treasury bond yields. To the extent that observable measures of risk aversion, such as credit spreads and dividend yield spreads, remain elevated relative to historical norms, it would be incorrect to conclude that the cost of equity has materially decreased.

Q. How should current economic conditions be taken into consideration in determining the appropriate ROE for UNS Electric?

A. First, based on the continuing capital market uncertainty, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent that certain ROE estimates are incompatible with such metrics or inconsistent with basic financial principles, it is appropriate to consider whether alternative estimation techniques are likely to provide more meaningful and reliable results.

Second, in my view, the authorized rate of return in this proceeding will provide a signal to the financial community concerning UNS Electric's ability to meet its capital needs during a period in which its capital investments are increasing. If investors perceive a supportive regulatory environment, as evidenced by an allowed rate of return that compensates UNS Electric at a level commensurate with its risk, UNS Electric should be

able to attract equity capital at a reasonable cost. Conversely, if investors perceive a lack of connection between the allowed rate of return and current economic conditions, the regulatory environment would be seen as less supportive.

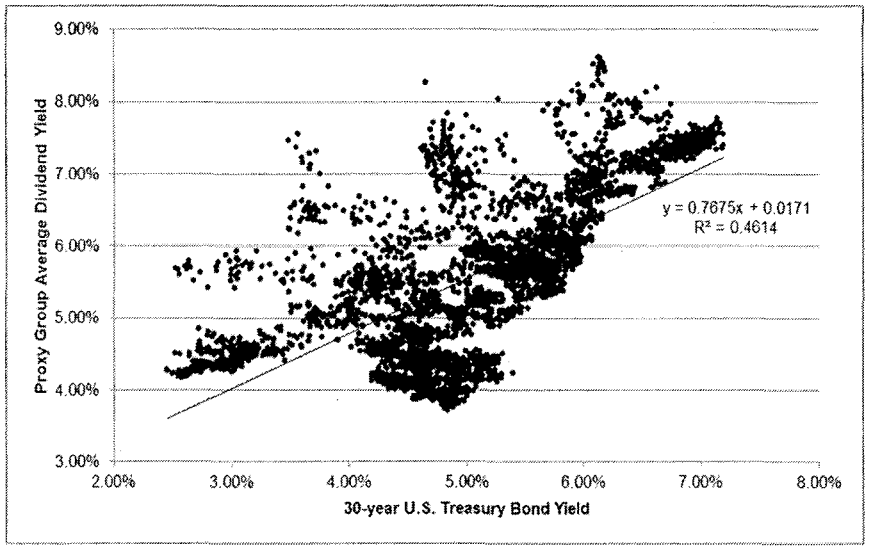
Q. Please describe the current interest rate environment.

A. Long-term Government Treasury interest rates are near the lowest level in the past 35 years. Consequently, the absolute level of utility bond yields are at their lowest levels in the past four business cycles. At the same time, however, credit spreads, or the difference between U.S. Treasury Bond yields and utility bond yields, have increased. Further, as discussed below, long-term interest rates on government bonds are projected to substantially increase over the next few years.

Q. Does the current level of interest rates have implications for the DCF and CAPM analyses?

A. Yes. The level of long-term interest rates has an effect on both the DCF and CAPM analyses. As such, the current level of interest rates and utility stock valuations could have a meaningful effect on the estimated ROE. In the case of the DCF model, for example, high stock valuations (associated with unusually low long-term interest rates) will tend to reduce dividend yields and, therefore, the estimated ROE. This relationship is demonstrated in Chart 3, below, which shows that higher U.S. Treasury bond yields have generally corresponded with lower proxy group company dividend yields over the 1996 to 2012 time period.

Chart 3: Relationship between 30-Year U.S. Treasury Bond Yields and Proxy Group Average Dividend Yields (1996-2012)



Similarly, unusually low long-term U.S. Treasury Bond yields will reduce the risk-free rate component of the CAPM, again reducing the ROE result. In an economy with increasing interest rates, the prices for utility stocks would tend to decrease, thereby increasing dividend yields from current levels. Assuming constant growth, the result would be an increase in the ROE.

Q. Is there a reasonable basis to conclude that interest rates will be increasing?

A. Yes, there is. As noted earlier, the 30-day average yield on a 30-year U.S. Treasury bond is currently 2.87 percent. The consensus estimate provided by Blue Chip Financial Forecasts for the yield on the 30-year U.S. Treasury bond is 3.15 percent through the end of 2013,[37] increasing to an average of 5.10 percent for the period from 2014 through 2018.[38] Thus, the consensus forecasts project a substantial increase in U.S. Treasury bond yields over the next several years.

[37] Blue Chip Financial Forecasts, Vol. 31, No. 11, November 1, 2012, at 2.
[38] Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14.

Q. What effect do rising interest rates have on the cost of equity?

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

Q. What additional analysis have you conducted to assess current capital market conditions?

A. I considered two widely-recognized measures of investor risk sentiment: (1) incremental credit spreads; and (2) the relationship between the dividend yields of the proxy group companies and U.S. Treasury bond yields. I compared current market conditions to the two-year period prior to the 2007-2009 recession (*i.e.*, January 2006 through November 2007), and to the capital market contraction period of 2002-2003. As shown in Table 7, those metrics indicate that current levels of risk aversion are significantly higher than the levels observed prior to the recent recession and the levels experienced during the 2002-2003 capital market contraction.

Table 7: Risk Sentiment Indicators[39]

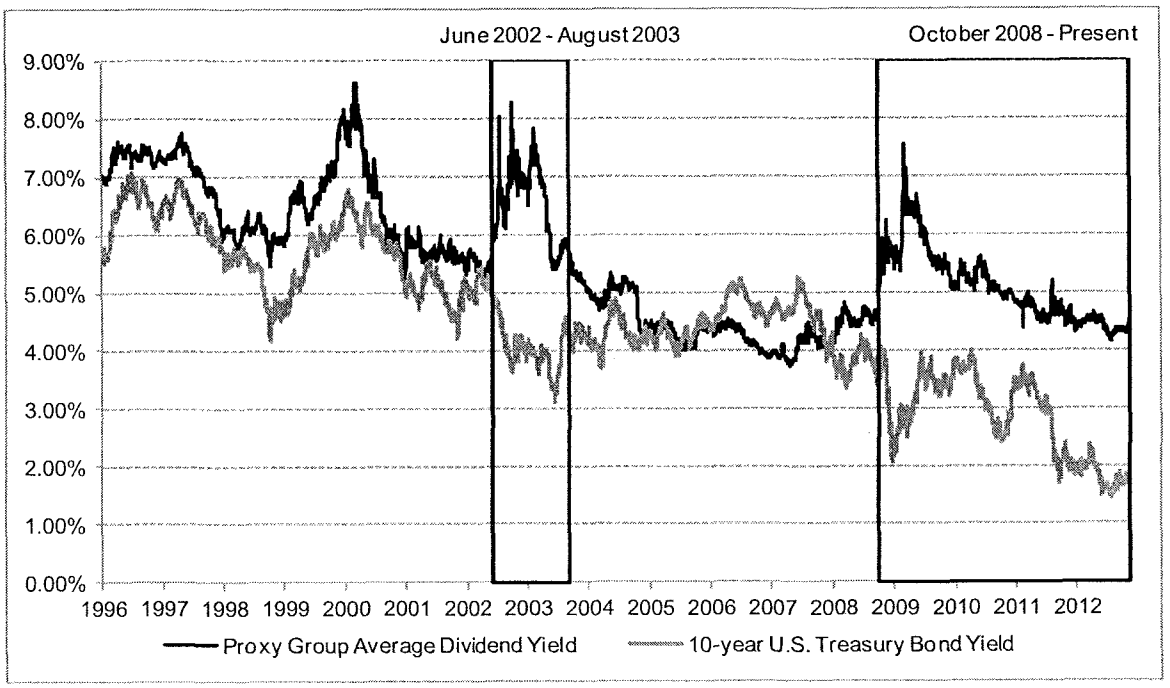
	Current (Nov. 16, 2012)[40]	Pre-recession (Jan-2006 through Nov-2007)	Contraction (Jan-2002 through Dec-2003)
Credit Spreads (Moody's Utility Bond Index) Baa-rated bond to A-rated bond	0.77%	0.25%	0.46%
Dividend Yield Spreads 10-year U.S. Treasury Bond to Proxy Group Average Dividend Yield	-2.66%	0.58%	-1.81%

Chart 4 (below) demonstrates that the average dividend yield for the proxy group has continued to exceed the ten-year U.S. Treasury bond yield since the beginning of the financial crisis in late 2008.

39 Bloomberg Professional Service

40 90-trading day average as of November 16, 2012.

Chart 4: Ten-year U.S. Treasury Bond Yield vs. Proxy Group Average Dividend Yield Inversion



Q. What conclusions do you draw from those analyses?

A. Those analyses clearly demonstrate that risk aversion, as measured by credit spreads and dividend yield spreads, is higher today than during either the pre-recession period or the 2002-2003 market dislocation that affected all market segments, including utilities. One outcome of the 2002-2003 market dislocation was a renewed emphasis on capital market access and the importance of maintaining a strong financial profile, both of which are equally important in the current market environment. The result of market uncertainty and risk aversion, of course, is an increased, not a decreased, cost of equity.

XI. CONCLUSIONS AND RECOMMENDATION.

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

A. Based on the various quantitative and qualitative analyses presented in my Direct Testimony, I believe that the proxy group produces a reasonable range of results from approximately 10.30 percent to 10.75 percent. Further, in light of the regulatory, business, and financial risks of UNS Electric compared to the proxy group, it is my view that an ROE of 10.50 percent is reasonable. It is my view, that a 10.50 percent ROE would reasonably balance the interests of customers and shareholders by enabling the Company to maintain its financial integrity and therefore its ability to attract capital at reasonable rates under a variety of different economic and financial market conditions.

Table 8: Summary of Analytical Results

Constant Growth DCF			
	Mean Low	Mean	Mean High
30-Day Average Price	9.00%	10.55%	12.81%
90-Day Average Price	8.97%	10.51%	12.78%
180-Day Average Price	9.06%	10.61%	12.88%
	Median Low	Median	Median High
30-Day Average Price	9.47%	10.57%	11.54%
90-Day Average Price	9.42%	10.53%	11.53%
180-Day Average Price	9.52%	10.63%	11.64%
Multi-Stage DCF			
	Mean Low	Mean	Mean High
30-Day Average Price	9.93%	10.38%	11.19%
90-Day Average Price	9.89%	10.35%	11.15%
180-Day Average Price	9.99%	10.45%	11.28%
	Median Low	Median	Median High
30-Day Average Price	9.93%	10.21%	10.81%
90-Day Average Price	9.84%	10.15%	10.74%
180-Day Average Price	9.92%	10.26%	10.81%
Capital Asset Pricing Model			
	Current Risk-Free Rate (2.87%)	2012-2014 Projected Risk-Free Rate (3.15%)	2014-2018 Projected Risk-Free Rate (5.10%)
Bloomberg Beta	9.87%	9.95%	10.53%
Value Line Beta	10.03%	10.11%	10.66%
Bond Yield Plus Risk Premium			
	Current Risk-Free Rate (2.87%)	2012-2014 Projected Risk-Free Rate (3.15%)	2014-2018 Projected Risk-Free Rate (5.10%)
Bond Yield Plus Risk Premium	10.01%	10.12%	10.86%

XII. 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*,[41] 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.[42]

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.[43]

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.[44]

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 weighing equally the OCRB and the RCND. The RCND estimates the current replacement cost value of the utility system by escalating the

---

41 Decision No. 70441 (July 28, 2008), at 20-21.
42 Arizona Constitution, Article XV, Section 14.
43 Decision No. 70441 (July 28, 2008), at 20-21.
44 Decision No. 71914 (September 30, 2010), at 51.

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.[45] 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."[46]

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 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

[45] *See* Shannon P. Pratt, Valuing a Business, 5th ed. McGraw Hill, 2008, at 41-42

[46] IRS Revenue Ruling 59-60, 1959-1 CB 237-IRC Sec. 2031.

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.[47]

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

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 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-11**,

---

[47] *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.

page 1, the FVRB of $286.3 million is calculated by weighting equally the Company's OCRB of $216.6 million and the Company's estimated RCND of $356.1 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, which incorporates the book value of debt and equity, resulting in 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 UNS Electric's assets by applying the median premium of 39.70 percent to the Company's OCRB. That analysis resulted in an estimated market value for UNS Electric's assets of $302.6 million.

Q. How did you establish the universe of transactions that were analyzed for comparability to the UNS Electric 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 36 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 within the past 16 years (*i.e.*, from January 1, 1997 through November 16, 2012). 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 (below) summarizes the range of acquisition premiums for the comparable transactions. As shown in Table 9 below and in **Exhibit AEB-12**, the median acquisition premium was 39.70 percent. Applying that premium to UNS Electric's OCRB of $216.6 million indicates an implied market value for UNS Electric's assets of $302.6 million.

Table 9: Comparable Transaction Multiples

	Transaction Premium	Implied Valuation ($M)
Minimum	-1.75%	$212.8
Maximum	116.90%	$469.7
Mean	45.59%	$315.3
Median	**39.70%**	**$302.6**
Standard Deviation	30.22%	$65.4

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.

XIII. 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."[48] 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, with all components 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.[49]

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 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 by the Commission in prior cases?

A. In UNS Electric's last rate case, Staff recommended applying a return to the fair value increment ranging between zero and the real risk-free rate.[50]

---

48 Decision No. 70665 (December 24, 2008), at 32.
49 *Ibid.*
50 Decision No. 71914 (September 30, 2010), at 47.

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.

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-11, 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-11, my estimate of the nominal risk-free rate of return is the average of the 2014-2018 projected yield on 30-year U.S. Treasury bonds of 5.10 percent and the 2019-2023 projected yield on 30-year U.S. Treasury bonds of 5.50 percent as reported in the Blue Chip Financial Forecasts.[51] I then adjusted the nominal risk-free rate of 5.30 percent by the rate of inflation, which I estimated to be 2.01 percent over the period from 2012-2023 (*see*, Exhibit AEB-11). The resulting real risk-free rate is then 3.23 percent.[52]

---

[51] Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14.

[52] 3.23% = (5.30% + 1) / (1 + 2.01%) – 1.

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 2014-2018 and 2019-2023 projected growth rate in the CPI of 2.40 percent, as reported by Blue Chip Financial Forecasts;[53] (2) the compound annual growth rate of the CPI for all urban consumers for 2012-2023 of 1.98 percent as projected by the EIA in the Annual Energy Outlook 2012; and (3) the compound annual growth rate of the GDP chain-type price index for 2012-2023 of 1.64 percent, also reported by the EIA in the Annual Energy Outlook 2012.[54]

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.*, 2012-2023) 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.*, 2022-2035).

Q. Please explain how you applied the Commission's methodology to estimate the FVROR.

A. As shown on page 1 of Exhibit AEB-11 and in Table 10 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

---

53 Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14.

54 U.S. Energy Information Administration, Annual Energy Outlook 2012, Table 20, Macroeconomic Indicators.

been commonly referred to as the "fair value increment."[55] 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 estimate the FVROR by applying 50.0 percent of the risk-free rate or approximately 1.61 percent, to the fair value increment.

Table 10: Estimated FVROR

Capital	$ Millions	Percent	Cost Rate	Weighted Cost Rate
OCRB	$216.6			
RCND	$356.1			
FVRB	$286.3			
Long-Term Debt	$102.7	35.85%	5.97%	2.14%
Common Equity	$113.9	39.79%	10.50%	4.18%
Fair Value Increment	$69.8	24.36%	1.61%	0.39%
Total	$286.3	100.00%		6.71%

Q. What is the resulting FVROR?

A. As shown in Table 10 above (*see also*, Exhibit AEB-11) based on the calculation discussed previously, the FVROR that would be applied to the FVRB is 6.71 percent.

Q. Does this conclude your pre-filed Direct Testimony?

A. Yes, it does.

[55] Decision No. 70665 (December 24, 2008), at 32.

EXHIBIT

AEB-1

30-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] First Call Earnings Growth	[6] Zacks Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$1.84	$40.98	4.49%	4.64%	6.00%	5.50%	9.00%	6.83%	10.11%	11.48%	13.69%
American Electric Power Company, Inc.	AEP	$1.88	$43.59	4.31%	4.38%	3.36%	3.48%	3.00%	3.28%	7.38%	7.66%	7.87%
Cleco Corporation	CNL	$1.35	$41.51	3.25%	3.32%	3.00%	3.00%	6.50%	4.17%	6.30%	7.49%	9.86%
Empire District Electric Company	EDE	$1.00	$21.26	4.70%	4.89%	10.20%	n/a	6.00%	8.10%	10.85%	12.99%	15.14%
FirstEnergy Corporation	FE	$2.20	$44.25	4.97%	5.06%	2.50%	2.50%	5.00%	3.33%	7.53%	8.39%	10.10%
Great Plains Energy Inc.	GXP	$0.85	$21.92	3.88%	4.03%	10.35%	8.17%	5.50%	8.01%	9.48%	12.04%	14.43%
Hawaiian Electric Industries, Inc.	HE	$1.24	$25.75	4.81%	5.01%	8.10%	7.05%	9.00%	8.05%	12.03%	13.06%	14.03%
IDACORP, Inc.	IDA	$1.52	$43.62	3.48%	3.54%	4.00%	4.00%	2.00%	3.33%	5.52%	6.88%	7.55%
Otter Tail Corporation	OTTR	$1.19	$23.88	4.98%	5.27%	5.00%	5.00%	24.00%	11.33%	10.11%	16.60%	29.58%
Pepco Holdings, Inc.	POM	$1.08	$19.46	5.55%	5.71%	5.23%	5.43%	7.00%	5.89%	10.93%	11.60%	12.75%
Pinnacle West Capital Corporation	PNW	$2.18	$52.10	4.18%	4.30%	5.07%	6.03%	5.00%	5.37%	9.29%	9.66%	10.34%
Portland General Electric Company	POR	$1.08	$27.00	4.00%	4.08%	2.67%	4.08%	5.50%	4.08%	6.72%	8.16%	9.61%
Southern Company	SO	$1.96	$45.14	4.34%	4.45%	5.18%	5.22%	5.00%	5.13%	9.45%	9.59%	9.68%
Westar Energy, Inc.	WR	$1.32	$29.27	4.51%	4.68%	10.00%	5.67%	6.50%	7.39%	10.31%	12.07%	14.74%
MEAN				**4.39%**	**4.53%**	**5.76%**	**5.01%**	**7.07%**	**6.02%**	**9.00%**	**10.55%**	**12.81%**
MEDIAN				**4.42%**	**4.55%**	**5.13%**	**5.22%**	**5.75%**	**5.63%**	**9.47%**	**10.57%**	**11.54%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-trading day average as of November 16, 2012
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Yahoo! Finance
[6] Source: Zacks
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 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] First Call Earnings Growth	[6] Zacks Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$1.84	$41.35	4.45%	4.60%	6.00%	5.50%	9.00%	6.83%	10.07%	11.44%	13.65%
American Electric Power Company, Inc.	AEP	$1.88	$43.14	4.36%	4.43%	3.36%	3.48%	3.00%	3.28%	7.42%	7.71%	7.91%
Cleco Corporation	CNL	$1.35	$42.05	3.21%	3.28%	3.00%	3.00%	6.50%	4.17%	6.26%	7.44%	9.81%
Empire District Electric Company	EDE	$1.00	$21.40	4.67%	4.86%	10.20%	n/a	6.00%	8.10%	10.81%	12.96%	15.11%
FirstEnergy Corporation	FE	$2.20	$45.49	4.84%	4.92%	2.50%	2.50%	5.00%	3.33%	7.40%	8.25%	9.96%
Great Plains Energy Inc.	GXP	$0.85	$21.98	3.87%	4.02%	10.35%	8.17%	5.50%	8.01%	9.47%	12.03%	14.42%
Hawaiian Electric Industries, Inc.	HE	$1.24	$26.97	4.60%	4.78%	8.10%	7.05%	9.00%	8.05%	11.81%	12.83%	13.80%
IDACORP, Inc.	IDA	$1.52	$42.91	3.54%	3.60%	4.00%	4.00%	2.00%	3.33%	5.58%	6.94%	7.61%
Otter Tail Corporation	OTTR	$1.19	$23.56	5.05%	5.34%	5.00%	5.00%	24.00%	11.33%	10.18%	16.67%	29.66%
Pepco Holdings, Inc.	POM	$1.08	$19.38	5.57%	5.74%	5.23%	5.43%	7.00%	5.89%	10.95%	11.62%	12.77%
Pinnacle West Capital Corporation	PNW	$2.18	$52.59	4.15%	4.26%	5.07%	6.03%	5.00%	5.37%	9.25%	9.62%	10.30%
Portland General Electric Company	POR	$1.08	$27.16	3.98%	4.06%	2.67%	4.08%	5.50%	4.08%	6.70%	8.14%	9.59%
Southern Company	SO	$1.96	$45.99	4.26%	4.37%	5.18%	5.22%	5.00%	5.13%	9.37%	9.50%	9.59%
Westar Energy, Inc.	WR	$1.32	$29.66	4.45%	4.61%	10.00%	5.67%	6.50%	7.39%	10.25%	12.00%	14.67%
MEAN				**4.36%**	**4.49%**	**5.76%**	**5.01%**	**7.07%**	**6.02%**	**8.97%**	**10.51%**	**12.78%**
MEDIAN				**4.40%**	**4.52%**	**5.13%**	**5.22%**	**5.75%**	**5.63%**	**9.42%**	**10.53%**	**11.53%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-trading day average as of November 16, 2012
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Yahoo! Finance
[6] Source: Zacks
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 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] First Call Earnings Growth	[6] Zacks Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$1.84	$41.00	4.49%	4.64%	6.00%	5.50%	9.00%	6.83%	10.11%	11.47%	13.69%
American Electric Power Company, Inc.	AEP	$1.88	$40.92	4.59%	4.67%	3.36%	3.48%	3.00%	3.28%	7.66%	7.95%	8.15%
Cleco Corporation	CNL	$1.35	$41.15	3.28%	3.35%	3.00%	3.00%	6.50%	4.17%	6.33%	7.52%	9.89%
Empire District Electric Company	EDE	$1.00	$20.90	4.78%	4.98%	10.20%	n/a	6.00%	8.10%	10.93%	13.08%	15.23%
FirstEnergy Corporation	FE	$2.20	$46.07	4.77%	4.85%	2.50%	2.50%	5.00%	3.33%	7.33%	8.19%	9.89%
Great Plains Energy Inc.	GXP	$0.85	$21.12	4.02%	4.18%	10.35%	8.17%	5.50%	8.01%	9.63%	12.19%	14.58%
Hawaiian Electric Industries, Inc.	HE	$1.24	$26.78	4.63%	4.82%	8.10%	7.05%	9.00%	8.05%	11.84%	12.87%	13.84%
IDACORP, Inc.	IDA	$1.52	$41.61	3.65%	3.71%	4.00%	4.00%	2.00%	3.33%	5.69%	7.05%	7.73%
Otter Tail Corporation	OTTR	$1.19	$22.69	5.24%	5.54%	5.00%	5.00%	24.00%	11.33%	10.38%	16.87%	29.87%
Pepco Holdings, Inc.	POM	$1.08	$19.20	5.63%	5.79%	5.23%	5.43%	7.00%	5.89%	11.00%	11.68%	12.82%
Pinnacle West Capital Corporation	PNW	$2.18	$50.67	4.30%	4.42%	5.07%	6.03%	5.00%	5.37%	9.41%	9.78%	10.46%
Portland General Electric Company	POR	$1.08	$26.27	4.11%	4.20%	2.67%	4.08%	5.50%	4.08%	6.84%	8.28%	9.72%
Southern Company	SO	$1.96	$45.83	4.28%	4.39%	5.18%	5.22%	5.00%	5.13%	9.38%	9.52%	9.61%
Westar Energy, Inc.	WR	$1.32	$29.05	4.54%	4.71%	10.00%	5.67%	6.50%	7.39%	10.34%	12.10%	14.77%
MEAN				**4.45%**	**4.59%**	**5.76%**	**5.01%**	**7.07%**	**6.02%**	**9.06%**	**10.61%**	**12.88%**
MEDIAN				**4.52%**	**4.66%**	**5.13%**	**5.22%**	**5.75%**	**5.63%**	**9.52%**	**10.63%**	**11.64%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-trading day average as of November 16, 2012
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Yahoo! Finance
[6] Source: Zacks
[7] Source: Value Line
[8] Equals Average([5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 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	$40.98	$1.84	6.83%	6.62%	6.41%	6.19%	5.98%	5.76%	5.55%	10.67%
American Electric Power Company, Inc.	AEP	$43.59	$1.88	3.28%	3.66%	4.04%	4.42%	4.79%	5.17%	5.55%	9.49%
Cleco Corporation	CNL	$41.51	$1.35	4.17%	4.40%	4.63%	4.86%	5.09%	5.32%	5.55%	8.68%
Empire District Electric Company	EDE	$21.26	$1.00	8.10%	7.68%	7.25%	6.83%	6.40%	5.98%	5.55%	11.33%
FirstEnergy Corporation	FE	$44.25	$2.20	3.33%	3.70%	4.07%	4.44%	4.81%	5.18%	5.55%	10.12%
Great Plains Energy Inc.	GXP	$21.92	$0.85	8.01%	7.60%	7.19%	6.78%	6.37%	5.96%	5.55%	10.31%
Hawaiian Electric Industries, Inc.	HE	$25.75	$1.24	8.05%	7.63%	7.22%	6.80%	6.38%	5.97%	5.55%	11.44%
IDACORP, Inc.	IDA	$43.62	$1.52	3.33%	3.70%	4.07%	4.44%	4.81%	5.18%	5.55%	8.73%
Otter Tail Corporation	OTTR	$23.88	$1.19	11.33%	10.37%	9.41%	8.44%	7.48%	6.51%	5.55%	12.86%
Pepco Holdings, Inc.	POM	$19.46	$1.08	5.89%	5.83%	5.77%	5.72%	5.66%	5.61%	5.55%	11.53%
Pinnacle West Capital Corporation	PNW	$52.10	$2.18	5.37%	5.40%	5.43%	5.46%	5.49%	5.52%	5.55%	9.92%
Portland General Electric Company	POR	$27.00	$1.08	4.08%	4.33%	4.57%	4.82%	5.06%	5.31%	5.55%	9.39%
Southern Company	SO	$45.14	$1.96	5.13%	5.20%	5.27%	5.34%	5.41%	5.48%	5.55%	10.02%
Westar Energy, Inc.	WR	$29.27	$1.32	7.39%	7.08%	6.78%	6.47%	6.16%	5.86%	5.55%	10.87%
MEAN											**10.38%**
MEDIAN											**10.21%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 16, 2012
[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	$41.35	$1.84	6.83%	6.62%	6.41%	6.19%	5.98%	5.76%	5.55%	10.63%
American Electric Power Company, Inc.	AEP	$43.14	$1.88	3.28%	3.66%	4.04%	4.42%	4.79%	5.17%	5.55%	9.53%
Cleco Corporation	CNL	$42.05	$1.35	4.17%	4.40%	4.63%	4.86%	5.09%	5.32%	5.55%	8.64%
Empire District Electric Company	EDE	$21.40	$1.00	8.10%	7.68%	7.25%	6.83%	6.40%	5.98%	5.55%	11.29%
FirstEnergy Corporation	FE	$45.49	$2.20	3.33%	3.70%	4.07%	4.44%	4.81%	5.18%	5.55%	10.00%
Great Plains Energy Inc.	GXP	$21.98	$0.85	8.01%	7.60%	7.19%	6.78%	6.37%	5.96%	5.55%	10.29%
Hawaiian Electric Industries, Inc.	HE	$26.97	$1.24	8.05%	7.63%	7.22%	6.80%	6.38%	5.97%	5.55%	11.18%
IDACORP, Inc.	IDA	$42.91	$1.52	3.33%	3.70%	4.07%	4.44%	4.81%	5.18%	5.55%	8.78%
Otter Tail Corporation	OTTR	$23.56	$1.19	11.33%	10.37%	9.41%	8.44%	7.48%	6.51%	5.55%	12.96%
Pepco Holdings, Inc.	POM	$19.38	$1.08	5.89%	5.83%	5.77%	5.72%	5.66%	5.61%	5.55%	11.55%
Pinnacle West Capital Corporation	PNW	$52.59	$2.18	5.37%	5.40%	5.43%	5.46%	5.49%	5.52%	5.55%	9.87%
Portland General Electric Company	POR	$27.16	$1.08	4.08%	4.33%	4.57%	4.82%	5.06%	5.31%	5.55%	9.37%
Southern Company	SO	$45.99	$1.96	5.13%	5.20%	5.27%	5.34%	5.41%	5.48%	5.55%	9.93%
Westar Energy, Inc.	WR	$29.66	$1.32	7.39%	7.08%	6.78%	6.47%	6.16%	5.86%	5.55%	10.80%
MEAN											**10.35%**
MEDIAN											**10.15%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 16, 2012
[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	$41.00	$1.84	6.83%	6.62%	6.41%	6.19%	5.98%	5.76%	5.55%	10.67%
American Electric Power Company, Inc.	AEP	$40.92	$1.88	3.28%	3.66%	4.04%	4.42%	4.79%	5.17%	5.55%	9.75%
Cleco Corporation	CNL	$41.15	$1.35	4.17%	4.40%	4.63%	4.86%	5.09%	5.32%	5.55%	8.71%
Empire District Electric Company	EDE	$20.90	$1.00	8.10%	7.68%	7.25%	6.83%	6.40%	5.98%	5.55%	11.42%
FirstEnergy Corporation	FE	$46.07	$2.20	3.33%	3.70%	4.07%	4.44%	4.81%	5.18%	5.55%	9.94%
Great Plains Energy Inc.	GXP	$21.12	$0.85	8.01%	7.60%	7.19%	6.78%	6.37%	5.96%	5.55%	10.48%
Hawaiian Electric Industries, Inc.	HE	$26.78	$1.24	8.05%	7.63%	7.22%	6.80%	6.38%	5.97%	5.55%	11.22%
IDACORP, Inc.	IDA	$41.61	$1.52	3.33%	3.70%	4.07%	4.44%	4.81%	5.18%	5.55%	8.89%
Otter Tail Corporation	OTTR	$22.69	$1.19	11.33%	10.37%	9.41%	8.44%	7.48%	6.51%	5.55%	13.22%
Pepco Holdings, Inc.	POM	$19.20	$1.08	5.89%	5.83%	5.77%	5.72%	5.66%	5.61%	5.55%	11.61%
Pinnacle West Capital Corporation	PNW	$50.67	$2.18	5.37%	5.40%	5.43%	5.46%	5.49%	5.52%	5.55%	10.04%
Portland General Electric Company	POR	$26.27	$1.08	4.08%	4.33%	4.57%	4.82%	5.06%	5.31%	5.55%	9.50%
Southern Company	SO	$45.83	$1.96	5.13%	5.20%	5.27%	5.34%	5.41%	5.48%	5.55%	9.95%
Westar Energy, Inc.	WR	$29.05	$1.32	7.39%	7.08%	6.78%	6.47%	6.16%	5.86%	5.55%	10.91%
MEAN											**10.45%**
MEDIAN											**10.26%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 16, 2012
[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	$40.98	$1.84	5.50%	5.51%	5.52%	5.53%	5.53%	5.54%	5.55%	10.27%
American Electric Power Company, Inc.	AEP	$43.59	$1.88	3.00%	3.43%	3.85%	4.28%	4.70%	5.13%	5.55%	9.42%
Cleco Corporation	CNL	$41.51	$1.35	3.00%	3.43%	3.85%	4.28%	4.70%	5.13%	5.55%	8.44%
Empire District Electric Company	EDE	$21.26	$1.00	6.00%	5.93%	5.85%	5.78%	5.70%	5.63%	5.55%	10.65%
FirstEnergy Corporation	FE	$44.25	$2.20	2.50%	3.01%	3.52%	4.03%	4.53%	5.04%	5.55%	9.89%
Great Plains Energy Inc.	GXP	$21.92	$0.85	5.50%	5.51%	5.52%	5.53%	5.53%	5.54%	5.55%	9.63%
Hawaiian Electric Industries, Inc.	HE	$25.75	$1.24	7.05%	6.80%	6.55%	6.30%	6.05%	5.80%	5.55%	11.11%
IDACORP, Inc.	IDA	$43.62	$1.52	2.00%	2.59%	3.18%	3.78%	4.37%	4.96%	5.55%	8.45%
Otter Tail Corporation	OTTR	$23.88	$1.19	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	10.64%
Pepco Holdings, Inc.	POM	$19.46	$1.08	5.23%	5.28%	5.34%	5.39%	5.44%	5.50%	5.55%	11.30%
Pinnacle West Capital Corporation	PNW	$52.10	$2.18	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	9.82%
Portland General Electric Company	POR	$27.00	$1.08	2.67%	3.15%	3.63%	4.11%	4.59%	5.07%	5.55%	9.06%
Southern Company	SO	$45.14	$1.96	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	9.98%
Westar Energy, Inc.	WR	$29.27	$1.32	5.67%	5.65%	5.63%	5.61%	5.59%	5.57%	5.55%	10.34%
MEAN											**9.93%**
MEDIAN											**9.93%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 16, 2012
[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	$41.35	$1.84	5.50%	5.51%	5.52%	5.53%	5.53%	5.54%	5.55%	10.23%
American Electric Power Company, Inc.	AEP	$43.14	$1.88	3.00%	3.43%	3.85%	4.28%	4.70%	5.13%	5.55%	9.46%
Cleco Corporation	CNL	$42.05	$1.35	3.00%	3.43%	3.85%	4.28%	4.70%	5.13%	5.55%	8.41%
Empire District Electric Company	EDE	$21.40	$1.00	6.00%	5.93%	5.85%	5.78%	5.70%	5.63%	5.55%	10.62%
FirstEnergy Corporation	FE	$45.49	$2.20	2.50%	3.01%	3.52%	4.03%	4.53%	5.04%	5.55%	9.76%
Great Plains Energy Inc.	GXP	$21.98	$0.85	5.50%	5.51%	5.52%	5.53%	5.53%	5.54%	5.55%	9.62%
Hawaiian Electric Industries, Inc.	HE	$26.97	$1.24	7.05%	6.80%	6.55%	6.30%	6.05%	5.80%	5.55%	10.86%
IDACORP, Inc.	IDA	$42.91	$1.52	2.00%	2.59%	3.18%	3.78%	4.37%	4.96%	5.55%	8.50%
Otter Tail Corporation	OTTR	$23.56	$1.19	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	10.71%
Pepco Holdings, Inc.	POM	$19.38	$1.08	5.23%	5.28%	5.34%	5.39%	5.44%	5.50%	5.55%	11.32%
Pinnacle West Capital Corporation	PNW	$52.59	$2.18	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	9.78%
Portland General Electric Company	POR	$27.16	$1.08	2.67%	3.15%	3.63%	4.11%	4.59%	5.07%	5.55%	9.03%
Southern Company	SO	$45.99	$1.96	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	9.90%
Westar Energy, Inc.	WR	$29.66	$1.32	5.67%	5.65%	5.63%	5.61%	5.59%	5.57%	5.55%	10.28%
MEAN											**9.89%**
MEDIAN											**9.84%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 16, 2012
[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	$41.00	$1.84	5.50%	5.51%	5.52%	5.53%	5.53%	5.54%	5.55%	10.27%
American Electric Power Company, Inc.	AEP	$40.92	$1.88	3.00%	3.43%	3.85%	4.28%	4.70%	5.13%	5.55%	9.68%
Cleco Corporation	CNL	$41.15	$1.35	3.00%	3.43%	3.85%	4.28%	4.70%	5.13%	5.55%	8.47%
Empire District Electric Company	EDE	$20.90	$1.00	6.00%	5.93%	5.85%	5.78%	5.70%	5.63%	5.55%	10.74%
FirstEnergy Corporation	FE	$46.07	$2.20	2.50%	3.01%	3.52%	4.03%	4.53%	5.04%	5.55%	9.71%
Great Plains Energy Inc.	GXP	$21.12	$0.85	5.50%	5.51%	5.52%	5.53%	5.53%	5.54%	5.55%	9.78%
Hawaiian Electric Industries, Inc.	HE	$26.78	$1.24	7.05%	6.80%	6.55%	6.30%	6.05%	5.80%	5.55%	10.90%
IDACORP, Inc.	IDA	$41.61	$1.52	2.00%	2.59%	3.18%	3.78%	4.37%	4.96%	5.55%	8.60%
Otter Tail Corporation	OTTR	$22.69	$1.19	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	10.90%
Pepco Holdings, Inc.	POM	$19.20	$1.08	5.23%	5.28%	5.34%	5.39%	5.44%	5.50%	5.55%	11.38%
Pinnacle West Capital Corporation	PNW	$50.67	$2.18	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	9.94%
Portland General Electric Company	POR	$26.27	$1.08	2.67%	3.15%	3.63%	4.11%	4.59%	5.07%	5.55%	9.16%
Southern Company	SO	$45.83	$1.96	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	9.91%
Westar Energy, Inc.	WR	$29.05	$1.32	5.67%	5.65%	5.63%	5.61%	5.59%	5.57%	5.55%	10.38%
MEAN											**9.99%**
MEDIAN											**9.92%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 16, 2012
[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	$40.98	$1.84	9.00%	8.43%	7.85%	7.28%	6.70%	6.13%	5.55%	11.37%
American Electric Power Company, Inc.	AEP	$43.59	$1.88	3.48%	3.83%	4.17%	4.52%	4.86%	5.21%	5.55%	9.54%
Cleco Corporation	CNL	$41.51	$1.35	6.50%	6.34%	6.18%	6.03%	5.87%	5.71%	5.55%	9.19%
Empire District Electric Company	EDE	$21.26	$1.00	10.20%	9.43%	8.65%	7.88%	7.10%	6.33%	5.55%	12.06%
FirstEnergy Corporation	FE	$44.25	$2.20	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	10.63%
Great Plains Energy Inc.	GXP	$21.92	$0.85	10.35%	9.55%	8.75%	7.95%	7.15%	6.35%	5.55%	11.00%
Hawaiian Electric Industries, Inc.	HE	$25.75	$1.24	9.00%	8.43%	7.85%	7.28%	6.70%	6.13%	5.55%	11.77%
IDACORP, Inc.	IDA	$43.62	$1.52	4.00%	4.26%	4.52%	4.78%	5.03%	5.29%	5.55%	8.87%
Otter Tail Corporation	OTTR	$23.88	$1.19	24.00%	20.93%	17.85%	14.78%	11.70%	8.63%	5.55%	18.69%
Pepco Holdings, Inc.	POM	$19.46	$1.08	7.00%	6.76%	6.52%	6.28%	6.03%	5.79%	5.55%	11.93%
Pinnacle West Capital Corporation	PNW	$52.10	$2.18	6.03%	5.95%	5.87%	5.79%	5.71%	5.63%	5.55%	10.10%
Portland General Electric Company	POR	$27.00	$1.08	5.50%	5.51%	5.52%	5.53%	5.53%	5.54%	5.55%	9.76%
Southern Company	SO	$45.14	$1.96	5.22%	5.28%	5.33%	5.39%	5.44%	5.50%	5.55%	10.04%
Westar Energy, Inc.	WR	$29.27	$1.32	10.00%	9.26%	8.52%	7.78%	7.03%	6.29%	5.55%	11.73%
MEAN											**11.19%**
MEDIAN											**10.81%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 16, 2012
[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	$41.35	$1.84	9.00%	8.43%	7.85%	7.28%	6.70%	6.13%	5.55%	11.32%
American Electric Power Company, Inc.	AEP	$43.14	$1.88	3.48%	3.83%	4.17%	4.52%	4.86%	5.21%	5.55%	9.59%
Cleco Corporation	CNL	$42.05	$1.35	6.50%	6.34%	6.18%	6.03%	5.87%	5.71%	5.55%	9.14%
Empire District Electric Company	EDE	$21.40	$1.00	10.20%	9.43%	8.65%	7.88%	7.10%	6.33%	5.55%	12.02%
FirstEnergy Corporation	FE	$45.49	$2.20	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	10.49%
Great Plains Energy Inc.	GXP	$21.98	$0.85	10.35%	9.55%	8.75%	7.95%	7.15%	6.35%	5.55%	10.99%
Hawaiian Electric Industries, Inc.	HE	$26.97	$1.24	9.00%	8.43%	7.85%	7.28%	6.70%	6.13%	5.55%	11.50%
IDACORP, Inc.	IDA	$42.91	$1.52	4.00%	4.26%	4.52%	4.78%	5.03%	5.29%	5.55%	8.93%
Otter Tail Corporation	OTTR	$23.56	$1.19	24.00%	20.93%	17.85%	14.78%	11.70%	8.63%	5.55%	18.84%
Pepco Holdings, Inc.	POM	$19.38	$1.08	7.00%	6.76%	6.52%	6.28%	6.03%	5.79%	5.55%	11.95%
Pinnacle West Capital Corporation	PNW	$52.59	$2.18	6.03%	5.95%	5.87%	5.79%	5.71%	5.63%	5.55%	10.06%
Portland General Electric Company	POR	$27.16	$1.08	5.50%	5.51%	5.52%	5.53%	5.53%	5.54%	5.55%	9.73%
Southern Company	SO	$45.99	$1.96	5.22%	5.28%	5.33%	5.39%	5.44%	5.50%	5.55%	9.96%
Westar Energy, Inc.	WR	$29.66	$1.32	10.00%	9.26%	8.52%	7.78%	7.03%	6.29%	5.55%	11.65%
MEAN											**11.15%**
MEDIAN											**10.74%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 16, 2012
[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	$41.00	$1.84	9.00%	8.43%	7.85%	7.28%	6.70%	6.13%	5.55%	11.36%
American Electric Power Company, Inc.	AEP	$40.92	$1.88	3.48%	3.83%	4.17%	4.52%	4.86%	5.21%	5.55%	9.81%
Cleco Corporation	CNL	$41.15	$1.35	6.50%	6.34%	6.18%	6.03%	5.87%	5.71%	5.55%	9.22%
Empire District Electric Company	EDE	$20.90	$1.00	10.20%	9.43%	8.65%	7.88%	7.10%	6.33%	5.55%	12.16%
FirstEnergy Corporation	FE	$46.07	$2.20	5.00%	5.09%	5.18%	5.28%	5.37%	5.46%	5.55%	10.42%
Great Plains Energy Inc.	GXP	$21.12	$0.85	10.35%	9.55%	8.75%	7.95%	7.15%	6.35%	5.55%	11.20%
Hawaiian Electric Industries, Inc.	HE	$26.78	$1.24	9.00%	8.43%	7.85%	7.28%	6.70%	6.13%	5.55%	11.54%
IDACORP, Inc.	IDA	$41.61	$1.52	4.00%	4.26%	4.52%	4.78%	5.03%	5.29%	5.55%	9.04%
Otter Tail Corporation	OTTR	$22.69	$1.19	24.00%	20.93%	17.85%	14.78%	11.70%	8.63%	5.55%	19.24%
Pepco Holdings, Inc.	POM	$19.20	$1.08	7.00%	6.76%	6.52%	6.28%	6.03%	5.79%	5.55%	12.01%
Pinnacle West Capital Corporation	PNW	$50.67	$2.18	6.03%	5.95%	5.87%	5.79%	5.71%	5.63%	5.55%	10.23%
Portland General Electric Company	POR	$26.27	$1.08	5.50%	5.51%	5.52%	5.53%	5.53%	5.54%	5.55%	9.88%
Southern Company	SO	$45.83	$1.96	5.22%	5.28%	5.33%	5.39%	5.44%	5.50%	5.55%	9.97%
Westar Energy, Inc.	WR	$29.05	$1.32	10.00%	9.26%	8.52%	7.78%	7.03%	6.29%	5.55%	11.78%
MEAN											**11.28%**
MEDIAN											**10.81%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 16, 2012
[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	$ 976.1
2011	13,299.1
Compound Annual Growth Rate	**3.24%**
Step 2	
Consumer Price Index (YoY % Change) [2]	
2019-2023	2.40%
Average	2.40%
Consumer Price Index (All-Urban) [3]	
2022	2.78
2035	3.72
Compound Annual Growth Rate	2.27%
GDP Chain-type Price Index (2005=1.000) [3]	
2022	1.349
2035	1.758
Compound Annual Growth Rate	2.06%
Average Inflation Forecast [4]	**2.24%**
Long-Term GDP Growth Rate	**5.55%**

Notes:

[1] Bureau of Economic Analysis, October 27, 2012
[2] Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14.
[3] Energy Information Administration, Annual Energy Outlook 2012, Table 20

EXHIBIT

AEB-4

BETA
AS OF NOVEMBER 16, 2012

		[1]	[2]
		Bloomberg	Value Line
ALLETE, Inc.	ALE	0.78	0.70
American Electric Power Company, Inc.	AEP	0.61	0.70
Cleco Corporation	CNL	0.74	0.65
Empire District Electric Company	EDE	0.74	0.65
FirstEnergy Corporation	FE	0.64	0.80
Great Plains Energy Inc.	GXP	0.77	0.75
Hawaiian Electric Industries, Inc.	HE	0.72	0.70
IDACORP, Inc.	IDA	0.80	0.70
Otter Tail Corporation	OTTR	0.76	0.90
Pepco Holdings, Inc.	POM	0.66	0.75
Pinnacle West Capital Corporation	PNW	0.70	0.70
Portland General Electric Company	POR	0.74	0.75
Southern Company	SO	0.50	0.55
Westar Energy, Inc.	WR	0.67	0.75
Average		0.701	0.718

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line; dated Aug. 24, 2012, Sept. 21, 2012, and Nov. 2, 2012

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	2.87%	0.701	9.98%	9.87%
[2] Near-term projected 30-year U.S. Treasury bond yield (Q4 2012 - Q1 2014)	3.15%	0.701	9.70%	9.95%
[3] Projected 30-year U.S. Treasury bond yield (2014 - 2018)	5.10%	0.701	7.75%	10.53%
			Average:	10.12%
Proxy Group Average Value Line Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	2.87%	0.718	9.98%	10.03%
[2] Near-term projected 30-year U.S. Treasury bond yield (Q4 2012 - Q1 2014)	3.15%	0.718	9.70%	10.11%
[3] Projected 30-year U.S. Treasury bond yield (2014 - 2018)	5.10%	0.718	7.75%	10.66%
			Average:	10.27%

Note:
[1] Source: Bloomberg Professional
[2] Source: Blue Chip Financial Forecasts, Vol. 31, No. 11, November 1, 2012, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, 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		2.37%	
[9] Estimated Weighted Average Long-Term Growth Rate		10.35%	
[10] S&P 500 Estimated Required Market Return		12.85%	
[11] Risk-Free Rate	2.87%	3.15%	5.10%
[12] Implied Market Risk Premium	9.98%	9.70%	7.75%

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.
3M Co	MMM	0.49%	2.67%	0.01%	11.50%	0.0561%
Abbott Laboratories	ABT	0.79%	3.24%	0.03%	10.04%	0.0795%
Abercrombie & Fitch Co	ANF	0.03%	1.71%	0.00%	17.80%	0.0048%
Accenture PLC	ACN	0.40%	2.45%	0.01%	12.50%	0.0495%
ACE Ltd	ACE	0.21%	2.54%	0.01%	9.65%	0.0202%
Adobe Systems Inc	ADBE	0.13%	n/a	n/a	12.50%	0.0161%
ADT Corp/The	ADT	0.08%	n/a	n/a	10.00%	0.0075%
Advanced Micro Devices Inc	AMD	0.01%	n/a	n/a	4.50%	0.0005%
AES Corp/VA	AES	0.06%	1.62%	0.00%	8.50%	0.0050%
Aetna Inc	AET	0.11%	1.72%	0.00%	10.50%	0.0114%
Aflac Inc	AFL	0.19%	2.78%	0.01%	14.77%	0.0278%
Agilent Technologies Inc	A	0.10%	1.12%	0.00%	10.03%	0.0100%
AGL Resources Inc	GAS	0.04%	4.87%	0.00%	4.00%	0.0014%
Air Products & Chemicals Inc	APD	0.13%	3.20%	0.00%	10.69%	0.0144%
Airgas Inc	ARG	0.05%	1.85%	0.00%	12.46%	0.0067%
Akamai Technologies Inc	AKAM	0.05%	n/a	n/a	14.50%	0.0074%
Alcoa Inc	AA	0.07%	1.47%	0.00%	10.00%	0.0070%
Alexion Pharmaceuticals Inc	ALXN	0.14%	n/a	n/a	40.23%	0.0566%
Allegheny Technologies Inc	ATI	0.02%	2.77%	0.00%	15.00%	0.0033%
Allergan Inc/United States	AGN	0.22%	0.23%	0.00%	13.06%	0.0284%
Allstate Corp/The	ALL	0.15%	2.26%	0.00%	9.00%	0.0134%
Altera Corp	ALTR	0.08%	1.31%	0.00%	7.75%	0.0060%
Altria Group Inc	MO	0.50%	5.63%	0.03%	6.44%	0.0325%
Amazon.com Inc	AMZN	0.81%	n/a	n/a	32.26%	0.2623%
Ameren Corp	AEE	0.06%	5.45%	0.00%	-4.00%	-0.0023%
American Electric Power Co Inc	AEP	0.16%	4.53%	0.01%	4.33%	0.0070%
American Express Co	AXP	0.48%	1.47%	0.01%	9.68%	0.0469%
American International Group Inc	AIG	0.37%	n/a	n/a	12.33%	0.0461%
American Tower Corp	AMT	0.23%	1.25%	0.00%	18.43%	0.0429%
Ameriprise Financial Inc	AMP	0.10%	3.08%	0.00%	10.55%	0.0101%
AmerisourceBergen Corp	ABC	0.08%	2.09%	0.00%	12.00%	0.0097%
Amgen Inc	AMGN	0.52%	1.70%	0.01%	9.34%	0.0483%
Amphenol Corp	APH	0.08%	0.71%	0.00%	18.50%	0.0140%
Anadarko Petroleum Corp	APC	0.28%	0.51%	0.00%	7.60%	0.0212%
Analog Devices Inc	ADI	0.09%	3.05%	0.00%	11.00%	0.0103%
Aon PLC	AON	0.14%	1.12%	0.00%	8.33%	0.0119%
Apache Corp	APA	0.23%	0.90%	0.00%	7.52%	0.0177%
Apartment Investment & Management Co	AIV	0.03%	3.26%	0.00%	10.82%	0.0031%
Apollo Group Inc	APOL	0.02%	n/a	n/a	9.80%	0.0017%
Apple Inc	AAPL	3.96%	2.01%	0.08%	20.63%	0.8161%
Applied Materials Inc	AMAT	0.10%	3.55%	0.00%	9.00%	0.0090%
Archer-Daniels-Midland Co	ADM	0.13%	2.80%	0.00%	10.00%	0.0131%
Assurant Inc	AIZ	0.02%	2.36%	0.00%	11.00%	0.0025%
AT&T Inc	T	1.50%	5.43%	0.08%	6.19%	0.0928%
Autodesk Inc	ADSK	0.06%	n/a	n/a	17.75%	0.0101%
Automatic Data Processing Inc	ADP	0.21%	3.18%	0.01%	9.67%	0.0205%
AutoNation Inc	AN	0.04%	n/a	n/a	20.48%	0.0082%
AutoZone Inc	AZO	0.11%	n/a	n/a	16.65%	0.0186%
AvalonBay Communities Inc	AVB	0.10%	3.01%	0.00%	10.12%	0.0102%
Avery Dennison Corp	AVY	0.03%	3.38%	0.00%	7.00%	0.0018%
Avon Products Inc	AVP	0.05%	1.70%	0.00%	11.00%	0.0053%
Baker Hughes Inc	BHI	0.14%	1.49%	0.00%	23.00%	0.0324%
Ball Corp	BLL	0.05%	0.92%	0.00%	10.00%	0.0053%
Bank of America Corp	BAC	0.78%	0.44%	0.00%	13.45%	0.1054%
Bank of New York Mellon Corp/The	BK	0.22%	2.20%	0.00%	17.63%	0.0388%
Baxter International Inc	BAX	0.29%	2.73%	0.01%	9.00%	0.0260%
BB&T Corp	BBT	0.16%	2.85%	0.00%	8.95%	0.0140%
Beam Inc	BEAM	0.07%	1.53%	0.00%	12.72%	0.0086%
Becton Dickinson and Co	BDX	0.12%	2.38%	0.00%	6.62%	0.0080%
Bed Bath & Beyond Inc	BBBY	0.10%	n/a	n/a	14.70%	0.0151%
Bemis Co Inc	BMS	0.03%	3.09%	0.00%	6.00%	0.0016%
Berkshire Hathaway Inc	BRK/B	0.75%	n/a	n/a	n/a	n/a
Best Buy Co Inc	BBY	0.04%	4.95%	0.00%	-1.40%	-0.0005%
Big Lots Inc	BIG	0.01%	n/a	n/a	10.95%	0.0014%
Biogen Idec Inc	BIIB	0.27%	n/a	n/a	15.83%	0.0421%
BlackRock Inc	BLK	0.25%	3.21%	0.01%	12.67%	0.0320%
BMC Software Inc	BMC	0.05%	n/a	n/a	15.00%	0.0072%
Boeing Co/The	BA	0.43%	2.49%	0.01%	11.37%	0.0483%
BorgWarner Inc	BWA	0.06%	n/a	n/a	18.74%	0.0108%
Boston Properties Inc	BXP	0.12%	2.58%	0.00%	5.78%	0.0070%
Boston Scientific Corp	BSX	0.06%	n/a	n/a	9.57%	0.0054%
Bristol-Myers Squibb Co	BMY	0.42%	4.29%	0.02%	7.65%	0.0319%
Broadcom Corp	BRCM	0.12%	1.31%	0.00%	14.50%	0.0180%
Brown-Forman Corp	BF/B	0.07%	1.56%	0.00%	12.50%	0.0084%
CA Inc	CA	0.08%	4.59%	0.00%	10.00%	0.0080%
Cablevision Systems Corp	CVC	0.02%	4.28%	0.00%	23.00%	0.0054%
Cabot Oil & Gas Corp	COG	0.08%	0.17%	0.00%	n/a	n/a

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.
Cameron International Corp	CAM	0.10%	n/a	n/a	17.00%	0.0175%
Campbell Soup Co	CPB	0.09%	3.17%	0.00%	6.25%	0.0058%
Capital One Financial Corp	COF	0.26%	0.36%	0.00%	9.72%	0.0251%
Cardinal Health Inc	CAH	0.11%	2.79%	0.00%	10.50%	0.0112%
CareFusion Corp	CFN	0.05%	n/a	n/a	10.20%	0.0048%
CarMax Inc	KMX	0.06%	n/a	n/a	12.79%	0.0078%
Carnival Corp	CCL	0.18%	2.68%	0.00%	15.00%	0.0265%
Caterpillar Inc	CAT	0.43%	2.54%	0.01%	11.00%	0.0470%
CBRE Group Inc	CBG	0.05%	n/a	n/a	13.33%	0.0061%
CBS Corp	CBS	0.16%	1.43%	0.00%	10.75%	0.0171%
Celgene Corp	CELG	0.25%	n/a	n/a	23.82%	0.0597%
CenterPoint Energy Inc	CNP	0.07%	4.14%	0.00%	5.67%	0.0038%
CenturyLink Inc	CTL	0.19%	7.73%	0.01%	0.71%	0.0013%
Cerner Corp	CERN	0.11%	n/a	n/a	19.00%	0.0200%
CF Industries Holdings Inc	CF	0.10%	0.82%	0.00%	12.00%	0.0118%
CH Robinson Worldwide Inc	CHRW	0.08%	2.23%	0.00%	14.80%	0.0112%
Charles Schwab Corp/The	SCHW	0.13%	1.88%	0.00%	17.97%	0.0233%
Chesapeake Energy Corp	CHK	0.09%	2.11%	0.00%	8.44%	0.0074%
Chevron Corp	CVX	1.60%	3.52%	0.06%	-0.92%	-0.0147%
Chipotle Mexican Grill Inc	CMG	0.07%	n/a	n/a	20.83%	0.0137%
Chubb Corp/The	CB	0.16%	2.17%	0.00%	7.44%	0.0117%
Cigna Corp	CI	0.11%	0.08%	0.00%	10.69%	0.0123%
Cincinnati Financial Corp	CINF	0.05%	4.18%	0.00%	5.00%	0.0025%
Cintas Corp	CTAS	0.04%	1.61%	0.00%	11.17%	0.0044%
Cisco Systems Inc	CSCO	0.76%	3.11%	0.02%	9.75%	0.0739%
Citigroup Inc	C	0.82%	0.11%	0.00%	10.49%	0.0857%
Citrix Systems Inc	CTXS	0.09%	n/a	n/a	15.80%	0.0139%
Cliffs Natural Resources Inc	CLF	0.04%	7.08%	0.00%	11.00%	0.0044%
Clorox Co/The	CLX	0.08%	3.45%	0.00%	8.30%	0.0064%
CME Group Inc/IL	CME	0.14%	3.32%	0.00%	14.73%	0.0212%
CMS Energy Corp	CMS	0.05%	4.13%	0.00%	6.00%	0.0029%
Coach Inc	COH	0.12%	2.20%	0.00%	12.71%	0.0157%
Coca-Cola Co/The	KO	1.31%	2.79%	0.04%	7.49%	0.0978%
Coca-Cola Enterprises Inc	CCE	0.07%	2.16%	0.00%	6.86%	0.0047%
Cognizant Technology Solutions Corp	CTSH	0.16%	n/a	n/a	17.96%	0.0283%
Colgate-Palmolive Co	CL	0.40%	2.36%	0.01%	8.66%	0.0343%
Comcast Corp	CMCSA	0.60%	1.83%	0.01%	14.44%	0.0864%
Comerica Inc	CMA	0.04%	2.14%	0.00%	6.64%	0.0028%
Computer Sciences Corp	CSC	0.04%	2.32%	0.00%	8.00%	0.0034%
ConAgra Foods Inc	CAG	0.09%	3.60%	0.00%	6.67%	0.0060%
ConocoPhillips	COP	0.53%	4.80%	0.03%	-0.49%	-0.0026%
CONSOL Energy Inc	CNX	0.06%	1.57%	0.00%	12.00%	0.0069%
Consolidated Edison Inc	ED	0.13%	4.40%	0.01%	3.26%	0.0042%
Constellation Brands Inc	STZ	0.04%	n/a	n/a	10.88%	0.0047%
Cooper Industries PLC	CBE	0.10%	1.10%	0.00%	14.67%	0.0144%
Corning Inc	GLW	0.13%	3.30%	0.00%	12.00%	0.0154%
Costco Wholesale Corp	COST	0.33%	1.15%	0.00%	12.93%	0.0426%
Coventry Health Care Inc	CVH	0.05%	1.18%	0.00%	12.00%	0.0055%
Covidien PLC	COV	0.21%	1.85%	0.00%	8.28%	0.0176%
CR Bard Inc	BCR	0.06%	0.84%	0.00%	9.20%	0.0058%
Crown Castle International Corp	CCI	0.15%	n/a	n/a	37.00%	0.0563%
CSX Corp	CSX	0.16%	2.95%	0.00%	15.00%	0.0234%
Cummins Inc	CMI	0.15%	2.09%	0.00%	13.00%	0.0189%
CVS Caremark Corp	CVS	0.45%	1.45%	0.01%	13.50%	0.0601%
Danaher Corp	DHR	0.29%	0.19%	0.00%	15.00%	0.0431%
Darden Restaurants Inc	DRI	0.05%	3.93%	0.00%	12.46%	0.0065%
DaVita HealthCare Partners Inc	DVA	0.09%	n/a	n/a	12.33%	0.0106%
Dean Foods Co	DF	0.02%	n/a	n/a	5.75%	0.0014%
Deere & Co	DE	0.27%	2.16%	0.01%	10.00%	0.0266%
Dell Inc	DELL	0.12%	3.62%	0.00%	7.33%	0.0090%
Denbury Resources Inc	DNR	0.05%	n/a	n/a	9.10%	0.0042%
DENTSPLY International Inc	XRAY	0.04%	0.57%	0.00%	11.50%	0.0050%
Devon Energy Corp	DVN	0.17%	1.53%	0.00%	5.51%	0.0093%
Diamond Offshore Drilling Inc	DO	0.07%	5.38%	0.00%	18.00%	0.0130%
DIRECTV	DTV	0.24%	n/a	n/a	16.48%	0.0389%
Discover Financial Services	DFS	0.16%	1.01%	0.00%	10.67%	0.0169%
Discovery Communications Inc	DISCA	0.06%	n/a	n/a	21.75%	0.0139%
Dollar Tree Inc	DLTR	0.07%	n/a	n/a	16.67%	0.0117%
Dominion Resources Inc/VA	D	0.23%	4.21%	0.01%	6.00%	0.0138%
Dover Corp	DOV	0.09%	2.27%	0.00%	14.67%	0.0129%
Dow Chemical Co/The	DOW	0.27%	4.61%	0.01%	14.33%	0.0380%
DR Horton Inc	DHI	0.05%	0.79%	0.00%	7.67%	0.0037%
Dr Pepper Snapple Group Inc	DPS	0.07%	3.17%	0.00%	7.41%	0.0053%
DTE Energy Co	DTE	0.08%	4.18%	0.00%	5.00%	0.0041%
Duke Energy Corp	DUK	0.34%	5.02%	0.02%	4.50%	0.0154%
Dun & Bradstreet Corp/The	DNB	0.03%	2.03%	0.00%	10.00%	0.0027%
E*TRADE Financial Corp	ETFC	0.02%	n/a	n/a	-57.27%	-0.0103%
Eastman Chemical Co	EMN	0.07%	1.87%	0.00%	10.33%	0.0070%
Eaton Corp	ETN	0.13%	3.11%	0.00%	10.00%	0.0132%
eBay Inc	EBAY	0.49%	n/a	n/a	14.60%	0.0712%
Ecolab Inc	ECL	0.16%	1.16%	0.00%	14.75%	0.0237%
Edison International	EIX	0.12%	2.92%	0.00%	3.98%	0.0046%
Edwards Lifesciences Corp	EW	0.08%	n/a	n/a	17.60%	0.0139%
El du Pont de Nemours & Co	DD	0.31%	4.10%	0.01%	6.68%	0.0208%
Electronic Arts Inc	EA	0.03%	n/a	n/a	16.83%	0.0053%
Eli Lilly & Co	LLY	0.42%	4.27%	0.02%	-0.23%	-0.0010%
EMC Corp/MA	EMC	0.40%	n/a	n/a	15.00%	0.0593%
Emerson Electric Co	EMR	0.28%	3.40%	0.01%	10.00%	0.0279%
Ensco PLC	ESV	0.10%	2.74%	0.00%	18.00%	0.0182%
Entergy Corp	ETR	0.09%	5.28%	0.00%	3.50%	0.0031%
EOG Resources Inc	EOG	0.25%	0.58%	0.00%	10.64%	0.0268%

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.
EQT Corp	EQT	0.07%	1.46%	0.00%	30.00%	0.0215%
Equifax Inc	EFX	0.05%	1.43%	0.00%	11.00%	0.0053%
Equity Residential	EQR	0.13%	2.49%	0.00%	8.42%	0.0110%
Estee Lauder Cos Inc/The	EL	0.11%	1.27%	0.00%	13.95%	0.0149%
Exelon Corp	EXC	0.20%	7.18%	0.01%	-1.25%	-0.0025%
Expedia Inc	EXPE	0.06%	0.89%	0.00%	13.37%	0.0076%
Expeditors International of Washington Inc	EXPD	0.06%	1.57%	0.00%	9.30%	0.0055%
Express Scripts Holding Co	ESRX	0.34%	n/a	n/a	16.88%	0.0572%
Exxon Mobil Corp	XOM	3.14%	2.64%	0.08%	3.38%	0.1062%
F5 Networks Inc	FFIV	0.05%	n/a	n/a	18.00%	0.0098%
Family Dollar Stores Inc	FDO	0.06%	1.26%	0.00%	14.10%	0.0086%
Fastenal Co	FAST	0.10%	2.05%	0.00%	18.73%	0.0181%
Federated Investors Inc	FII	0.02%	5.06%	0.00%	8.00%	0.0013%
FedEx Corp	FDX	0.22%	0.65%	0.00%	10.74%	0.0232%
Fidelity National Information Services Inc	FIS	0.08%	2.29%	0.00%	12.86%	0.0105%
Fifth Third Bancorp	FITB	0.10%	2.84%	0.00%	2.78%	0.0028%
First Horizon National Corp	FHN	0.02%	0.43%	0.00%	8.33%	0.0015%
First Solar Inc	FSLR	0.02%	n/a	n/a	9.00%	0.0015%
FirstEnergy Corp	FE	0.14%	5.32%	0.01%	1.50%	0.0021%
Fiserv Inc	FISV	0.08%	n/a	n/a	11.71%	0.0092%
FLIR Systems Inc	FLIR	0.02%	1.47%	0.00%	12.50%	0.0029%
Flowserve Corp	FLS	0.05%	1.07%	0.00%	11.00%	0.0059%
Fluor Corp	FLR	0.07%	1.24%	0.00%	13.43%	0.0092%
FMC Corp	FMC	0.06%	0.70%	0.00%	11.59%	0.0066%
FMC Technologies Inc	FTI	0.08%	n/a	n/a	15.33%	0.0117%
Ford Motor Co	F	0.31%	1.90%	0.01%	10.47%	0.0328%
Forest Laboratories Inc	FRX	0.07%	n/a	n/a	14.16%	0.0097%
Fossil Inc	FOSL	0.04%	n/a	n/a	17.30%	0.0068%
Franklin Resources Inc	BEN	0.22%	0.84%	0.00%	12.67%	0.0275%
Freeport-McMoRan Copper & Gold Inc	FCX	0.28%	3.40%	0.01%	n/a	n/a
Frontier Communications Corp	FTR	0.03%	9.32%	0.00%	-10.51%	-0.0036%
GameStop Corp	GME	0.03%	3.91%	0.00%	10.43%	0.0026%
Gannett Co Inc	GCI	0.03%	4.71%	0.00%	6.00%	0.0019%
Gap Inc/The	GPS	0.13%	1.49%	0.00%	11.78%	0.0152%
General Dynamics Corp	GD	0.17%	3.28%	0.01%	8.00%	0.0140%
General Electric Co	GE	1.68%	3.38%	0.06%	10.33%	0.1739%
General Mills Inc	GIS	0.20%	3.32%	0.01%	7.75%	0.0159%
Genuine Parts Co	GPC	0.07%	3.28%	0.00%	8.32%	0.0062%
Genworth Financial Inc	GNW	0.02%	n/a	n/a	5.00%	0.0011%
Gilead Sciences Inc	GILD	0.45%	n/a	n/a	20.04%	0.0900%
Goldman Sachs Group Inc/The	GS	0.43%	1.73%	0.01%	11.03%	0.0479%
Goodyear Tire & Rubber Co/The	GT	0.02%	n/a	n/a	43.84%	0.0096%
Google Inc	GOOG	1.37%	n/a	n/a	14.55%	0.1988%
H&R Block Inc	HRB	0.04%	4.48%	0.00%	11.00%	0.0042%
Halliburton Co	HAL	0.23%	1.18%	0.00%	20.50%	0.0462%
Harley-Davidson Inc	HOG	0.08%	1.34%	0.00%	13.00%	0.0108%
Harman International Industries Inc	HAR	0.02%	1.61%	0.00%	17.50%	0.0035%
Harris Corp	HRS	0.04%	3.19%	0.00%	4.00%	0.0017%
Hartford Financial Services Group Inc	HIG	0.07%	1.96%	0.00%	9.50%	0.0067%
Hasbro Inc	HAS	0.04%	3.95%	0.00%	9.00%	0.0034%
HCP Inc	HCP	0.16%	4.49%	0.01%	5.24%	0.0084%
Health Care REIT Inc	HCN	0.12%	5.14%	0.01%	5.16%	0.0064%
Helmerich & Payne Inc	HP	0.04%	0.56%	0.00%	8.00%	0.0034%
Hershey Co/The	HSY	0.09%	2.34%	0.00%	8.10%	0.0075%
Hess Corp	HES	0.13%	0.82%	0.00%	2.05%	0.0027%
Hewlett-Packard Co	HPQ	0.20%	4.11%	0.01%	3.50%	0.0070%
HJ Heinz Co	HNZ	0.15%	3.55%	0.01%	7.33%	0.0109%
Home Depot Inc/The	HD	0.75%	1.87%	0.01%	15.90%	0.1187%
Honeywell International Inc	HON	0.37%	2.77%	0.01%	10.50%	0.0388%
Hormel Foods Corp	HRL	0.06%	1.94%	0.00%	8.50%	0.0055%
Hospira Inc	HSP	0.04%	n/a	n/a	5.99%	0.0023%
Host Hotels & Resorts Inc	HST	0.08%	2.32%	0.00%	9.97%	0.0079%
Hudson City Bancorp Inc	HCBK	0.03%	4.03%	0.00%	0.50%	0.0002%
Humana Inc	HUM	0.08%	1.59%	0.00%	9.80%	0.0081%
Huntington Bancshares Inc/OH	HBAN	0.04%	2.66%	0.00%	5.33%	0.0022%
Illinois Tool Works Inc	ITW	0.22%	2.58%	0.01%	7.48%	0.0163%
Ingersoll-Rand PLC	IR	0.11%	1.41%	0.00%	11.00%	0.0120%
Integrys Energy Group Inc	TEG	0.03%	5.17%	0.00%	5.50%	0.0018%
Intel Corp	INTC	0.80%	4.46%	0.04%	10.27%	0.0822%
IntercontinentalExchange Inc	ICE	0.07%	n/a	n/a	13.45%	0.0099%
International Business Machines Corp	IBM	1.68%	1.82%	0.03%	9.50%	0.1599%
International Flavors & Fragrances Inc	IFF	0.04%	2.21%	0.00%	3.00%	0.0012%
International Game Technology	IGT	0.03%	1.89%	0.00%	14.25%	0.0039%
International Paper Co	IP	0.12%	3.50%	0.00%	5.00%	0.0060%
Interpublic Group of Cos Inc/The	IPG	0.03%	2.50%	0.00%	12.50%	0.0041%
Intuit Inc	INTU	0.14%	1.15%	0.00%	13.50%	0.0188%
Intuitive Surgical Inc	ISRG	0.17%	n/a	n/a	18.38%	0.0311%
Invesco Ltd	IVZ	0.08%	2.95%	0.00%	12.50%	0.0104%
Iron Mountain Inc	IRM	0.04%	3.30%	0.00%	13.00%	0.0058%
Jabil Circuit Inc	JBL	0.03%	1.82%	0.00%	12.00%	0.0035%
Jacobs Engineering Group Inc	JEC	0.04%	n/a	n/a	13.23%	0.0053%
JC Penney Co Inc	JCP	0.03%	n/a	n/a	22.00%	0.0063%
JDS Uniphase Corp	JDSU	0.02%	n/a	n/a	n/a	n/a
JM Smucker Co/The	SJM	0.07%	2.48%	0.00%	7.50%	0.0055%
Johnson & Johnson	JNJ	1.53%	3.53%	0.05%	6.39%	0.0977%
Johnson Controls Inc	JCI	0.14%	3.03%	0.00%	12.78%	0.0175%
Joy Global Inc	JOY	0.05%	1.28%	0.00%	16.80%	0.0078%
JPMorgan Chase & Co	JPM	1.20%	3.04%	0.04%	7.25%	0.0868%
Juniper Networks Inc	JNPR	0.07%	n/a	n/a	14.00%	0.0094%
Kellogg Co	K	0.15%	3.25%	0.01%	8.25%	0.0128%
KeyCorp	KEY	0.06%	2.49%	0.00%	6.32%	0.0038%

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.
Kimberly-Clark Corp	KMB	0.27%	3.48%	0.01%	8.44%	0.0226%
Kimco Realty Corp	KIM	0.06%	4.53%	0.00%	14.83%	0.0089%
Kinder Morgan Inc/Delaware	KMI	0.27%	4.46%	0.01%	7.00%	0.0187%
KLA-Tencor Corp	KLAC	0.06%	3.61%	0.00%	10.00%	0.0059%
Kohl's Corp	KSS	0.10%	2.51%	0.00%	12.00%	0.0114%
Kraft Foods Group Inc	KRFT	0.21%	n/a	n/a	6.00%	0.0125%
Kroger Co/The	KR	0.10%	2.45%	0.00%	8.91%	0.0092%
L-3 Communications Holdings Inc	LLL	0.06%	2.70%	0.00%	1.45%	0.0008%
Laboratory Corp of America Holdings	LH	0.06%	n/a	n/a	12.25%	0.0076%
Lam Research Corp	LRCX	0.05%	n/a	n/a	10.00%	0.0047%
Legg Mason Inc	LM	0.03%	1.75%	0.00%	13.00%	0.0034%
Leggett & Platt Inc	LEG	0.03%	4.37%	0.00%	15.00%	0.0045%
Lennar Corp	LEN	0.05%	0.44%	0.00%	8.00%	0.0037%
Leucadia National Corp	LUK	0.04%	1.22%	0.00%	n/a	n/a
Life Technologies Corp	LIFE	0.06%	n/a	n/a	9.73%	0.0062%
Lincoln National Corp	LNC	0.05%	2.02%	0.00%	4.10%	0.0021%
Linear Technology Corp	LLTC	0.06%	3.20%	0.00%	10.33%	0.0060%
Lockheed Martin Corp	LMT	0.23%	5.20%	0.01%	7.83%	0.0179%
Loews Corp	L	0.13%	0.61%	0.00%	n/a	n/a
Lorillard Inc	LO	0.12%	5.38%	0.01%	9.15%	0.0109%
Lowe's Cos Inc	LOW	0.29%	2.00%	0.01%	16.50%	0.0480%
LSI Corp	LSI	0.03%	n/a	n/a	15.33%	0.0043%
Ltd Brands Inc	LTD	0.11%	2.16%	0.00%	12.68%	0.0134%
LyondellBasell Industries NV	LYB	0.21%	3.41%	0.01%	9.67%	0.0208%
M&T Bank Corp	MTB	0.10%	2.88%	0.00%	16.54%	0.0164%
Macy's Inc	M	0.13%	1.99%	0.00%	10.27%	0.0132%
Marathon Oil Corp	MRO	0.17%	2.20%	0.00%	1.40%	0.0024%
Marathon Petroleum Corp	MPC	0.15%	2.58%	0.00%	11.00%	0.0162%
Marriott International Inc/DE	MAR	0.09%	1.51%	0.00%	20.22%	0.0175%
Marsh & McLennan Cos Inc	MMC	0.15%	2.66%	0.00%	8.08%	0.0121%
Masco Corp	MAS	0.04%	2.01%	0.00%	10.00%	0.0042%
Mastercard Inc	MA	0.44%	0.26%	0.00%	17.93%	0.0792%
Mattel Inc	MAT	0.10%	3.51%	0.00%	9.00%	0.0087%
McCormick & Co Inc/MD	MKC	0.06%	1.95%	0.00%	8.00%	0.0049%
McDonald's Corp	MCD	0.67%	3.66%	0.02%	9.63%	0.0648%
McGraw-Hill Cos Inc/The	MHP	0.11%	2.01%	0.00%	9.50%	0.0107%
McKesson Corp	MCK	0.17%	0.87%	0.00%	14.33%	0.0248%
Mead Johnson Nutrition Co	MJN	0.11%	1.82%	0.00%	11.50%	0.0123%
MeadWestvaco Corp	MWV	0.04%	3.49%	0.00%	10.00%	0.0040%
Medtronic Inc	MDT	0.33%	2.53%	0.01%	6.43%	0.0215%
Merck & Co Inc	MRK	1.04%	3.90%	0.04%	4.69%	0.0489%
MetLife Inc	MET	0.27%	2.34%	0.01%	10.00%	0.0274%
MetroPCS Communications Inc	PCS	0.03%	n/a	n/a	11.12%	0.0035%
Microchip Technology Inc	MCHP	0.05%	4.79%	0.00%	10.00%	0.0046%
Micron Technology Inc	MU	0.04%	n/a	n/a	12.54%	0.0056%
Microsoft Corp	MSFT	1.78%	3.47%	0.06%	10.95%	0.1948%
Molex Inc	MOLX	0.02%	3.46%	0.00%	11.67%	0.0023%
Molson Coors Brewing Co	TAP	0.05%	3.21%	0.00%	3.34%	0.0017%
Mondelez International Inc	MDLZ	0.36%	2.04%	0.01%	7.86%	0.0284%
Monsanto Co	MON	0.36%	1.76%	0.01%	11.92%	0.0433%
Monster Beverage Corp	MNST	0.06%	n/a	n/a	17.00%	0.0106%
Moody's Corp	MCO	0.08%	1.42%	0.00%	11.00%	0.0088%
Morgan Stanley	MS	0.25%	1.24%	0.00%	11.00%	0.0280%
Mosaic Co/The	MOS	0.12%	2.02%	0.00%	4.53%	0.0053%
Motorola Solutions Inc	MSI	0.12%	1.97%	0.00%	n/a	n/a
Murphy Oil Corp	MUR	0.09%	2.22%	0.00%	10.00%	0.0087%
Mylan Inc/PA	MYL	0.08%	n/a	n/a	10.54%	0.0088%
Nabors Industries Ltd	NBR	0.03%	n/a	n/a	8.00%	0.0024%
NASDAQ OMX Group Inc/The	NDAQ	0.03%	2.27%	0.00%	7.65%	0.0023%
National Oilwell Varco Inc	NOV	0.24%	0.74%	0.00%	13.50%	0.0324%
NetApp Inc	NTAP	0.09%	n/a	n/a	13.00%	0.0114%
Netflix Inc	NFLX	0.04%	n/a	n/a	21.71%	0.0078%
Newell Rubbermaid Inc	NWL	0.05%	2.87%	0.00%	9.13%	0.0044%
Newfield Exploration Co	NFX	0.03%	n/a	n/a	11.50%	0.0030%
Newmont Mining Corp	NEM	0.18%	3.03%	0.01%	-3.00%	-0.0054%
News Corp	NWSA	0.29%	0.73%	0.00%	13.13%	0.0377%
NextEra Energy Inc	NEE	0.23%	3.56%	0.01%	5.13%	0.0117%
NIKE Inc	NKE	0.27%	1.81%	0.00%	12.30%	0.0327%
NiSource Inc	NI	0.06%	4.02%	0.00%	n/a	n/a
Noble Corp	NE	0.07%	1.55%	0.00%	13.00%	0.0088%
Noble Energy Inc	NBL	0.13%	1.09%	0.00%	7.00%	0.0091%
Nordstrom Inc	JWN	0.09%	1.97%	0.00%	12.67%	0.0111%
Norfolk Southern Corp	NSC	0.14%	3.55%	0.01%	15.00%	0.0213%
Northeast Utilities	NU	0.10%	3.58%	0.00%	7.53%	0.0072%
Northern Trust Corp	NTRS	0.09%	2.56%	0.00%	4.08%	0.0037%
Northrop Grumman Corp	NOC	0.12%	3.46%	0.00%	3.33%	0.0041%
NRG Energy Inc	NRG	0.04%	1.82%	0.00%	-13.70%	-0.0049%
Nucor Corp	NUE	0.10%	3.70%	0.00%	8.50%	0.0085%
NVIDIA Corp	NVDA	0.06%	2.64%	0.00%	14.33%	0.0081%
NYSE Euronext	NYX	0.04%	5.32%	0.00%	10.00%	0.0044%
O'Reilly Automotive Inc	ORLY	0.08%	n/a	n/a	17.67%	0.0145%
Occidental Petroleum Corp	OXY	0.48%	2.93%	0.01%	-2.63%	-0.0125%
Omnicom Group Inc	OMC	0.10%	2.61%	0.00%	6.00%	0.0058%
ONEOK Inc	OKE	0.07%	2.89%	0.00%	16.00%	0.0119%
Oracle Corp	ORCL	1.15%	0.80%	0.01%	15.05%	0.1734%
Owens-Illinois Inc	OI	0.02%	n/a	n/a	8.67%	0.0021%
PACCAR Inc	PCAR	0.12%	1.91%	0.00%	10.25%	0.0121%
Pall Corp	PLL	0.05%	1.69%	0.00%	12.74%	0.0069%
Parker Hannifin Corp	PH	0.10%	2.05%	0.00%	6.00%	0.0057%
Patterson Cos Inc	PDCO	0.03%	1.59%	0.00%	12.33%	0.0038%
Paychex Inc	PAYX	0.09%	4.16%	0.00%	9.50%	0.0087%

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.
Peabody Energy Corp	BTU	0.05%	1.36%	0.00%	12.00%	0.0064%
Pentair Ltd	PNR	0.07%	1.96%	0.00%	12.50%	0.0094%
People's United Financial Inc	PBCT	0.03%	5.48%	0.00%	7.00%	0.0023%
Pepco Holdings Inc	POM	0.04%	5.63%	0.00%	5.00%	0.0018%
PepsiCo Inc	PEP	0.84%	3.15%	0.03%	5.98%	0.0503%
PerkinElmer Inc	PKI	0.03%	0.93%	0.00%	11.41%	0.0032%
Perrigo Co	PRGO	0.08%	0.35%	0.00%	10.97%	0.0083%
PetSmart Inc	PETM	0.06%	0.98%	0.00%	18.08%	0.0105%
Pfizer Inc	PFE	1.40%	3.69%	0.05%	3.63%	0.0509%
PG&E Corp	PCG	0.14%	4.50%	0.01%	4.00%	0.0055%
Philip Morris International Inc	PM	1.14%	4.00%	0.05%	10.60%	0.1209%
Phillips 66	PSX	0.23%	2.18%	0.00%	10.00%	0.0228%
Pinnacle West Capital Corp	PNW	0.04%	4.38%	0.00%	4.52%	0.0020%
Pioneer Natural Resources Co	PXD	0.10%	0.08%	0.00%	15.69%	0.0158%
Pitney Bowes Inc	PBI	0.02%	13.61%	0.00%	n/a	n/a
Plum Creek Timber Co Inc	PCL	0.05%	4.07%	0.00%	5.00%	0.0027%
PNC Financial Services Group Inc	PNC	0.23%	2.94%	0.01%	3.64%	0.0083%
PPG Industries Inc	PPG	0.14%	2.04%	0.00%	7.00%	0.0099%
PPL Corp	PPL	0.13%	5.05%	0.01%	-1.50%	-0.0020%
Praxair Inc	PX	0.25%	2.11%	0.01%	10.59%	0.0261%
Precision Castparts Corp	PCP	0.20%	0.07%	0.00%	13.07%	0.0264%
priceline.com Inc	PCLN	0.24%	n/a	n/a	18.17%	0.0444%
Principal Financial Group Inc	PFG	0.06%	3.19%	0.00%	13.00%	0.0080%
Procter & Gamble Co/The	PG	1.46%	3.36%	0.05%	7.56%	0.1100%
Progressive Corp/The	PGR	0.11%	1.81%	0.00%	7.75%	0.0084%
Prologis Inc	PLD	0.12%	3.43%	0.00%	3.93%	0.0047%
Prudential Financial Inc	PRU	0.18%	3.28%	0.01%	14.50%	0.0260%
Public Service Enterprise Group Inc	PEG	0.12%	4.82%	0.01%	0.30%	0.0004%
Public Storage	PSA	0.20%	3.06%	0.01%	5.61%	0.0110%
PulteGroup Inc	PHM	0.05%	n/a	n/a	10.00%	0.0048%
QEP Resources Inc	QEP	0.04%	0.30%	0.00%	15.00%	0.0057%
QUALCOMM Inc	QCOM	0.84%	1.61%	0.01%	15.00%	0.1262%
Quanta Services Inc	PWR	0.04%	n/a	n/a	17.83%	0.0079%
Quest Diagnostics Inc	DGX	0.07%	2.08%	0.00%	11.63%	0.0085%
Ralph Lauren Corp	RL	0.07%	1.06%	0.00%	12.33%	0.0090%
Range Resources Corp	RRC	0.09%	0.24%	0.00%	10.00%	0.0087%
Raytheon Co	RTN	0.14%	3.67%	0.01%	9.00%	0.0129%
Red Hat Inc	RHT	0.07%	n/a	n/a	17.00%	0.0127%
Regions Financial Corp	RF	0.07%	0.63%	0.00%	8.00%	0.0057%
Republic Services Inc	RSG	0.08%	3.48%	0.00%	6.60%	0.0052%
Reynolds American Inc	RAI	0.18%	5.77%	0.01%	7.31%	0.0133%
Robert Half International Inc	RHI	0.03%	2.25%	0.00%	14.33%	0.0043%
Rockwell Automation Inc	ROK	0.09%	2.46%	0.00%	10.67%	0.0092%
Rockwell Collins Inc	COL	0.06%	2.22%	0.00%	8.28%	0.0050%
Roper Industries Inc	ROP	0.08%	0.51%	0.00%	15.00%	0.0127%
Ross Stores Inc	ROST	0.10%	1.04%	0.00%	13.00%	0.0125%
Rowan Cos Plc	RDC	0.03%	n/a	n/a	13.00%	0.0041%
RR Donnelley & Sons Co	RRD	0.01%	11.32%	0.00%	5.00%	0.0007%
Ryder System Inc	R	0.02%	2.80%	0.00%	8.97%	0.0016%
Safeway Inc	SWY	0.03%	4.22%	0.00%	9.86%	0.0031%
SAIC Inc	SAI	0.03%	4.36%	0.00%	3.87%	0.0012%
Salesforce.com Inc	CRM	0.16%	n/a	n/a	26.60%	0.0424%
SanDisk Corp	SNDK	0.08%	n/a	n/a	16.85%	0.0128%
SCANA Corp	SCG	0.05%	4.30%	0.00%	4.34%	0.0021%
Schlumberger Ltd	SLB	0.72%	1.61%	0.01%	17.00%	0.1227%
Scripps Networks Interactive Inc	SNI	0.05%	0.81%	0.00%	15.19%	0.0083%
Seagate Technology PLC	STX	0.08%	4.72%	0.00%	7.63%	0.0062%
Sealed Air Corp	SEE	0.03%	3.17%	0.00%	5.50%	0.0014%
Sempra Energy	SRE	0.13%	3.63%	0.00%	7.00%	0.0089%
Sherwin-Williams Co/The	SHW	0.12%	1.03%	0.00%	13.02%	0.0162%
Sigma-Aldrich Corp	SIAL	0.07%	1.15%	0.00%	7.11%	0.0047%
Simon Property Group Inc	SPG	0.36%	2.99%	0.01%	5.68%	0.0206%
SLM Corp	SLM	0.06%	2.99%	0.00%	-4.30%	-0.0026%
Snap-on Inc	SNA	0.03%	2.03%	0.00%	10.00%	0.0035%
Southern Co/The	SO	0.30%	4.59%	0.01%	5.28%	0.0157%
Southwest Airlines Co	LUV	0.05%	0.45%	0.00%	15.75%	0.0083%
Southwestern Energy Co	SWN	0.10%	n/a	n/a	n/a	n/a
Spectra Energy Corp	SE	0.14%	4.41%	0.01%	5.00%	0.0072%
Sprint Nextel Corp	S	0.13%	n/a	n/a	5.00%	0.0066%
St Jude Medical Inc	STJ	0.09%	2.63%	0.00%	10.00%	0.0086%
Stanley Black & Decker Inc	SWK	0.09%	2.91%	0.00%	8.00%	0.0073%
Staples Inc	SPLS	0.06%	3.75%	0.00%	5.53%	0.0035%
Starbucks Corp	SBUX	0.29%	1.72%	0.01%	17.43%	0.0507%
Starwood Hotels & Resorts Worldwide Inc	HOT	0.08%	2.43%	0.00%	15.19%	0.0122%
State Street Corp	STT	0.16%	2.17%	0.00%	5.75%	0.0094%
Stericycle Inc	SRCL	0.06%	n/a	n/a	16.00%	0.0099%
Stryker Corp	SYK	0.16%	1.63%	0.00%	9.50%	0.0150%
SunTrust Banks Inc	STI	0.11%	0.77%	0.00%	14.36%	0.0160%
Symantec Corp	SYMC	0.10%	n/a	n/a	6.60%	0.0066%
Sysco Corp	SYY	0.14%	3.73%	0.01%	10.00%	0.0141%
T Rowe Price Group Inc	TROW	0.13%	2.15%	0.00%	14.00%	0.0180%
Target Corp	TGT	0.33%	2.30%	0.01%	12.09%	0.0394%
TE Connectivity Ltd	TEL	0.11%	2.46%	0.00%	15.00%	0.0172%
TECO Energy Inc	TE	0.03%	5.33%	0.00%	3.67%	0.0010%
Tenet Healthcare Corp	THC	0.02%	n/a	n/a	11.00%	0.0025%
Teradata Corp	TDC	0.08%	n/a	n/a	16.00%	0.0134%
Teradyne Inc	TER	0.02%	n/a	n/a	11.75%	0.0026%
Tesoro Corp	TSO	0.04%	1.58%	0.00%	34.10%	0.0145%
Texas Instruments Inc	TXN	0.25%	2.97%	0.01%	9.50%	0.0240%
Textron Inc	TXT	0.05%	0.35%	0.00%	31.50%	0.0164%
Thermo Fisher Scientific Inc	TMO	0.17%	0.99%	0.00%	10.94%	0.0190%

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.
Tiffany & Co	TIF	0.06%	2.15%	0.00%	13.73%	0.0082%
Time Warner Cable Inc	TWC	0.22%	2.48%	0.01%	15.33%	0.0333%
Time Warner Inc	TWX	0.34%	2.33%	0.01%	12.72%	0.0429%
Titanium Metals Corp	TIE	0.02%	1.81%	0.00%	15.00%	0.0035%
TJX Cos Inc	TJX	0.25%	1.08%	0.00%	11.68%	0.0291%
Torchmark Corp	TMK	0.04%	1.19%	0.00%	9.00%	0.0034%
Total System Services Inc	TSS	0.03%	1.87%	0.00%	9.71%	0.0031%
Travelers Cos Inc/The	TRV	0.21%	2.68%	0.01%	7.75%	0.0162%
TripAdvisor Inc	TRIP	0.04%	n/a	n/a	16.34%	0.0064%
Tyco International Ltd	TYC	0.10%	2.24%	0.00%	13.00%	0.0129%
Tyson Foods Inc	TSN	0.04%	1.18%	0.00%	n/a	n/a
Union Pacific Corp	UNP	0.44%	2.35%	0.01%	13.20%	0.0581%
United Parcel Service Inc	UPS	0.40%	3.26%	0.01%	9.58%	0.0387%
United States Steel Corp	X	0.02%	1.00%	0.00%	6.50%	0.0015%
United Technologies Corp	UTX	0.55%	2.84%	0.02%	12.96%	0.0712%
UnitedHealth Group Inc	UNH	0.42%	1.64%	0.01%	10.25%	0.0433%
Unum Group	UNM	0.04%	2.67%	0.00%	10.00%	0.0043%
Urban Outfitters Inc	URBN	0.04%	n/a	n/a	18.44%	0.0075%
US Bancorp	USB	0.47%	2.47%	0.01%	7.57%	0.0358%
Valero Energy Corp	VLO	0.13%	2.38%	0.00%	6.30%	0.0082%
Varian Medical Systems Inc	VAR	0.06%	n/a	n/a	11.50%	0.0069%
Ventas Inc	VTR	0.15%	3.89%	0.01%	4.77%	0.0072%
VeriSign Inc	VRSN	0.05%	n/a	n/a	15.50%	0.0078%
Verizon Communications Inc	VZ	0.94%	4.98%	0.05%	6.43%	0.0605%
VF Corp	VFC	0.14%	2.23%	0.00%	12.40%	0.0170%
Viacom Inc	VIAB	0.18%	2.22%	0.00%	12.28%	0.0218%
Visa Inc	V	0.61%	0.93%	0.01%	18.71%	0.1140%
Vornado Realty Trust	VNO	0.11%	3.77%	0.00%	-2.91%	-0.0032%
Vulcan Materials Co	VMC	0.05%	0.09%	0.00%	9.67%	0.0046%
Wal-Mart Stores Inc	WMT	1.82%	2.34%	0.04%	10.22%	0.1863%
Walgreen Co	WAG	0.24%	3.42%	0.01%	12.83%	0.0311%
Walt Disney Co/The	DIS	0.68%	1.27%	0.01%	10.89%	0.0739%
Washington Post Co/The	WPO	0.02%	2.86%	0.00%	n/a	n/a
Waste Management Inc	WM	0.12%	4.52%	0.01%	2.80%	0.0033%
Waters Corp	WAT	0.06%	n/a	n/a	9.08%	0.0051%
Watson Pharmaceuticals Inc	WPI	0.08%	n/a	n/a	12.29%	0.0104%
WellPoint Inc	WLP	0.13%	2.09%	0.00%	11.00%	0.0147%
Wells Fargo & Co	WFC	1.34%	2.76%	0.04%	11.13%	0.1491%
Western Digital Corp	WDC	0.07%	2.89%	0.00%	2.13%	0.0014%
Western Union Co/The	WU	0.06%	3.93%	0.00%	10.41%	0.0063%
Weyerhaeuser Co	WY	0.11%	2.68%	0.00%	5.00%	0.0055%
Whirlpool Corp	WHR	0.06%	2.08%	0.00%	n/a	n/a
Whole Foods Market Inc	WFM	0.13%	0.88%	0.00%	18.86%	0.0252%
Williams Cos Inc/The	WMB	0.16%	4.10%	0.01%	12.00%	0.0190%
Windstream Corp	WIN	0.04%	12.12%	0.00%	-3.41%	-0.0013%
Wisconsin Energy Corp	WEC	0.07%	3.30%	0.00%	4.75%	0.0032%
WPX Energy Inc	WPX	0.02%	n/a	n/a	n/a	n/a
WW Grainger Inc	GWW	0.10%	1.70%	0.00%	14.18%	0.0147%
Wyndham Worldwide Corp	WYN	0.05%	1.88%	0.00%	18.60%	0.0102%
Wynn Resorts Ltd	WYNN	0.08%	1.92%	0.00%	8.00%	0.0067%
Xcel Energy Inc	XEL	0.10%	4.11%	0.00%	5.17%	0.0053%
Xerox Corp	XRX	0.06%	3.69%	0.00%	n/a	n/a
Xilinx Inc	XLNX	0.07%	2.71%	0.00%	14.00%	0.0095%
XL Group PLC	XL	0.06%	1.86%	0.00%	8.33%	0.0047%
Xylem Inc/NY	XYL	0.04%	1.67%	0.00%	7.00%	0.0025%
Yahoo! Inc	YHOO	0.17%	n/a	n/a	12.67%	0.0213%
Yum! Brands Inc	YUM	0.26%	1.86%	0.00%	12.00%	0.0311%
Zimmer Holdings Inc	ZMH	0.09%	1.12%	0.00%	9.56%	0.0085%
Zions Bancorporation	ZION	0.03%	0.20%	0.00%	7.75%	0.0022%

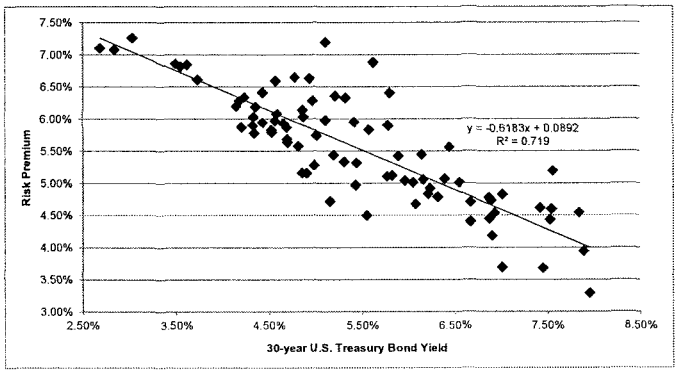
Notes:
[8] Equals sum of [15]
[9] Equals sum of Col. [17]
[10] Equals ([8] x (1 + (0.5 x [9]))) + [9]
[11] Source: Exhibit AEB-[X], at 1
[12] Equals [10] − [11]
[13] Equals weight in S&P 500 based on market capitalization
[14] Source: Bloomberg Professional
[15] Equals [13] x [14]
[16] Source: Bloomberg 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%	7.84%	4.55%
1992.2	11.83%	7.88%	3.94%
1992.3	12.03%	7.42%	4.62%
1992.4	12.14%	7.54%	4.60%
1993.1	11.84%	7.01%	4.83%
1993.2	11.64%	6.86%	4.78%
1993.3	11.15%	6.23%	4.92%
1993.4	11.04%	6.21%	4.84%
1994.1	11.07%	6.66%	4.40%
1994.2	11.13%	7.45%	3.68%
1994.3	12.75%	7.55%	5.20%
1994.4	11.24%	7.95%	3.29%
1995.1	11.96%	7.52%	4.44%
1995.2	11.32%	6.87%	4.45%
1995.3	11.37%	6.66%	4.71%
1995.4	11.58%	6.14%	5.45%
1996.1	11.46%	6.39%	5.07%
1996.2	11.46%	6.92%	4.54%
1996.3	10.70%	7.00%	3.70%
1996.4	11.56%	6.54%	5.02%
1997.1	11.08%	6.90%	4.18%
1997.2	11.62%	6.88%	4.73%
1997.3	12.00%	6.44%	5.56%
1997.4	11.06%	6.04%	5.02%
1998.1	11.31%	5.89%	5.43%
1998.2	12.20%	5.79%	6.41%
1998.3	11.65%	5.32%	6.33%
1998.4	12.30%	5.11%	7.20%
1999.1	10.40%	5.43%	4.97%
1999.2	10.94%	5.82%	5.12%
1999.3	10.75%	6.07%	4.68%
1999.4	11.10%	6.31%	4.79%
2000.1	11.21%	6.15%	5.06%
2000.2	11.00%	5.95%	5.05%
2000.3	11.68%	5.78%	5.90%
2000.4	12.50%	5.62%	6.88%
2001.1	11.38%	5.42%	5.96%
2001.2	10.88%	5.77%	5.11%
2001.3	10.76%	5.44%	5.32%
2001.4	11.57%	5.21%	6.36%
2002.1	10.05%	5.55%	4.50%
2002.2	11.41%	5.57%	5.83%
2002.3	11.25%	4.96%	6.29%
2002.4	11.57%	4.93%	6.63%
2003.1	11.43%	4.78%	6.65%
2003.2	11.16%	4.57%	6.60%
2003.3	9.88%	5.15%	4.72%
2003.4	11.09%	5.11%	5.98%
2004.1	11.00%	4.86%	6.14%
2004.2	10.64%	5.31%	5.33%
2004.3	10.75%	5.01%	5.74%
2004.4	10.91%	4.87%	6.04%
2005.1	10.56%	4.69%	5.87%
2005.2	10.13%	4.34%	5.78%
2005.3	10.85%	4.43%	6.41%
2005.4	10.59%	4.66%	5.93%
2006.1	10.38%	4.69%	5.69%
2006.2	10.63%	5.19%	5.44%
2006.3	10.06%	4.90%	5.16%
2006.4	10.33%	4.70%	5.64%
2007.1	10.39%	4.81%	5.58%
2007.2	10.27%	4.98%	5.28%
2007.3	10.02%	4.85%	5.16%
2007.4	10.36%	4.53%	5.83%
2008.1	10.37%	4.34%	6.03%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.95%
2008.4	10.36%	3.49%	6.86%
2009.1	10.46%	3.62%	6.85%
2009.2	10.58%	4.23%	6.34%
2009.3	10.46%	4.18%	6.28%
2009.4	10.54%	4.35%	6.19%
2010.1	10.66%	4.59%	6.08%
2010.2	10.08%	4.20%	5.87%
2010.3	10.34%	3.73%	6.61%
2010.4	10.34%	4.14%	6.20%
2011.1	10.32%	4.53%	5.80%
2011.2	10.23%	4.33%	5.90%
2011.3	10.36%	3.54%	6.82%
2011.4	10.29%	3.03%	7.26%
2012.1	10.84%	3.12%	7.72%
2012.2	9.92%	2.84%	7.08%
2012.3	9.78%	2.68%	7.10%
AVERAGE	10.98%	5.41%	5.57%
MEDIAN	10.94%	5.21%	5.64%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.847945
R Square	0.719010
Adjusted R Square	0.715541
Standard Error	0.004847
Observations	83

ANOVA

	df	*SS*	*MS*	*F*	*Sig. F*
Regression	1	0.004869	0.004869	207.266595	0.000000
Residual	81	0.001903	0.000023		
Total	82	0.006771			

	Coefficients	*Std. Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.089161	0.002385	37.383584	0.000000	0.084415	0.093906	0.084415	0.093906
30-year U.S. Treasury Bond	-0.618273	0.042945	-14.396756	0.000000	-0.703720	-0.532825	-0.703720	-0.532825

	[7] 30-year U.S. Treasury	[8] Risk Premium	[9] ROE
Current 30-Day Average [4]	2.87%	7.14%	10.01%
Blue Chip Consensus Forecast (Q4 2012 - Q1 2014) [5]	3.15%	6.97%	10.12%
Blue Chip Consensus Forecast (2014 - 2018) [6]	*5.10%*	*5.76%*	*10.86%*
AVERAGE			10.33%

Notes:
[1] Source: Regulatory Research Associates
[2] Source: Bloomberg Professional, quarterly bond yields are the average of the last trading day of each month in the quarter
[3] Equals Column [1] – Column [2]
[4] Source: Bloomberg Professional
[5] Source: Blue Chip Financial Forecasts, Vol. 31, No. 11, November 1, 2012, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14
[7] *See notes [4], [5] & [6]*
[8] Equals 0.089161 + (-0.618273 x Column [7])
[9] Equals Column [7] + Column [8]

EXHIBIT

AEB-7

2013-2017 CAPITAL EXPENDITURES AS A PERCENT OF 2011 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2011	2013	2014	2015	2016	2017	2013-17 Cap. Ex. / 2011 Net Plant
ALLETE, Inc.	ALE							
Capital Spending per Share			$7.55	$5.40	$3.25	$3.25	$3.25	
Common Shares Outstanding			40.00	40.75	41.50	41.50	41.50	
Capital Expenditures			$302.0	$220.1	$134.9	$134.9	$134.9	46.74%
Net Plant		$1,982.7						
American Electric Power Company, Inc.	AEP							
Capital Spending per Share			$7.75	$7.63	$7.50	$7.50	$7.50	
Common Shares Outstanding			489.00	494.50	500.00	500.00	500.00	
Capital Expenditures			$3,789.8	$3,770.6	$3,750.0	$3,750.0	$3,750.0	50.88%
Net Plant		$36,971.0						
Cleco Corporation	CNL							
Capital Spending per Share			$2.15	$2.20	$2.25	$2.25	$2.25	
Common Shares Outstanding			61.00	61.00	61.00	61.00	61.00	
Capital Expenditures			$131.2	$134.2	$137.3	$137.3	$137.3	23.40%
Net Plant		$2,893.9						
Empire District Electric Company	EDE							
Capital Spending per Share			$3.75	$3.50	$3.25	$3.25	$3.25	
Common Shares Outstanding			42.50	42.88	43.25	43.25	43.25	
Capital Expenditures			$159.4	$150.1	$140.6	$140.6	$140.6	46.76%
Net Plant		$1,563.7						
FirstEnergy Corporation	FE							
Capital Spending per Share			$6.40	$6.20	$6.00	$6.00	$6.00	
Common Shares Outstanding			418.22	418.22	418.22	418.22	418.22	
Capital Expenditures			$2,676.6	$2,593.0	$2,509.3	$2,509.3	$2,509.3	42.18%
Net Plant		$30,337.0						
Great Plains Energy Inc.	GXP							
Capital Spending per Share			$5.15	$4.58	$4.00	$4.00	$4.00	
Common Shares Outstanding			153.50	153.50	153.50	153.50	153.50	
Capital Expenditures			$790.5	$702.3	$614.0	$614.0	$614.0	47.28%
Net Plant		$7,053.5						
Hawaiian Electric Industries, Inc.	HE							
Capital Spending per Share			$4.15	$5.83	$7.50	$7.50	$7.50	
Common Shares Outstanding			104.00	113.00	122.00	122.00	122.00	
Capital Expenditures			$431.6	$658.2	$915.0	$915.0	$915.0	115.00%
Net Plant		$3,334.5						
IDACORP, Inc.	IDA							
Capital Spending per Share			$5.00	$6.28	$7.55	$7.55	$7.55	
Common Shares Outstanding			50.00	51.50	53.00	53.00	53.00	
Capital Expenditures			$250.0	$323.2	$400.2	$400.2	$400.2	52.06%
Net Plant		$3,406.6						
Otter Tail Corporation	OTTR							
Capital Spending per Share			$4.20	$4.60	$5.00	$5.00	$5.00	
Common Shares Outstanding			37.00	38.50	40.00	40.00	40.00	
Capital Expenditures			$155.4	$177.1	$200.0	$200.0	$200.0	86.54%
Net Plant		$1,077.5						
Pepco Holdings, Inc.	POM							
Capital Spending per Share			$4.00	$3.95	$3.90	$3.90	$3.90	
Common Shares Outstanding			242.00	248.50	255.00	255.00	255.00	
Capital Expenditures			$968.0	$981.6	$994.5	$994.5	$994.5	60.01%
Net Plant		$8,220.0						
Pinnacle West Capital Corporation	PNW							
Capital Spending per Share			$9.60	$9.05	$8.50	$8.50	$8.50	
Common Shares Outstanding			111.00	114.75	118.50	118.50	118.50	
Capital Expenditures			$1,065.6	$1,038.5	$1,007.3	$1,007.3	$1,007.3	51.45%
Net Plant		$9,962.3						
Portland General Electric Company	POR							
Capital Spending per Share			$4.05	$4.40	$4.75	$4.75	$4.75	

2013-2017 CAPITAL EXPENDITURES AS A PERCENT OF 2011 NET PLANT
($ Millions)

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		2011	2013	2014	2015	2016	2017	2013-17 Cap. Ex. / 2011 Net Plant
Common Shares Outstanding			75.75	76.13	76.50	76.50	76.50	
Capital Expenditures			$306.8	$335.0	$363.4	$363.4	$363.4	40.42%
Net Plant		$4,285.0						
Southern Company	SO							
Capital Spending per Share			$5.65	$6.20	$6.75	$6.75	$6.75	
Common Shares Outstanding			870.00	892.50	915.00	915.00	915.00	
Capital Expenditures			$4,915.5	$5,533.5	$6,176.3	$6,176.3	$6,176.3	64.38%
Net Plant		$45,010.0						
Westar Energy, Inc.	WR							
Capital Spending per Share			$7.05	$7.45	$7.85	$7.85	$7.85	
Common Shares Outstanding			128.00	131.00	134.00	134.00	134.00	
Capital Expenditures			$902.4	$976.0	$1,051.9	$1,051.9	$1,051.9	74.63%
Net Plant		$6,745.4						
UNS Electric, Inc.								
Capital Expenditures [8]			$55.9	$27.4	$32.7	$29.2	$36.9	64.85%
Net Plant [9]		$280.7						

Notes:
[1]-[7] Source: Value Line
[8] Source: Data provided by UNS Electric, Inc.
[9] Source: UNS Electric, Inc., FERC Form 1 for the year ended December 31, 2011, at 110

EXHIBIT

AEB-8

SIZE PREMIUM CALCULATION

Proxy Group Market Capitalization and Market-to-Book Ratio

Company	Ticker	[1] Customers	[2] Market Capitalization ($ Billions)	[3] Market-to-Book Ratio
ALLETE, Inc.	ALE	171,250	$ 1.579	1.37
American Electric Power Company, Inc.	AEP	5,206,000	21.141	1.38
Cleco Corporation	CNL	279,259	2.520	1.67
Empire District Electric Company	EDE	210,965	0.900	1.26
FirstEnergy Corporation	FE	5,810,687	18.504	1.38
Great Plains Energy Inc.	GXP	824,300	3.364	1.00
Hawaiian Electric Industries, Inc.	HE	445,566	2.503	1.56
IDACORP, Inc.	IDA	493,209	2.188	1.24
Otter Tail Corporation	OTTR	129,064	0.864	1.63
Pepco Holdings, Inc.	POM	1,959,000	4.457	1.00
Pinnacle West Capital Corporation	PNW	1,119,174	5.710	1.41
Portland General Electric Company	POR	823,027	2.040	1.19
Southern Company	SO	4,403,625	39.482	2.12
Westar Energy, Inc.	WR	687,375	3.698	1.28
MEAN		1,611,607	$ 7.782	1.39
MEDIAN		755,201	$ 2.942	1.38

UNS Electric, Inc.	
Rate Base ($ Millions) [4]	$ 216.6
Common Equity Ratio [5]	52.60%
Rate Base x Common Equity Ratio [6]	113.9
Implied Market Capitalization [7]	156.7
As a percent of Proxy Group Median Market Capitalization	5.33%

Ibbotson SBBI 2012 Valuation Yearbook -- Size Premium

Breakdown of Deciles 1-10	[8] Market Capitalization of Smallest Company ($ millions)	[9] Market Capitalization of Largest Company ($ millions)	[10] Size Premium
1-Largest	15,484.940	354,351.912	-0.38%
2	6,927.557	15,408.314	0.78%
3	3,596.535	6,896.389	0.94%
4	2,366.464	3,577.774	1.17%
5	1,621.096	2,362.532	1.74%
6	1,090.652	1,620.860	1.75%
7	683.059	1,090.515	1.77%
8	422.999	682.750	2.51%
9	206.802	422.811	2.80%
10-Smallest	1.028	206.795	6.10%
Proxy Group Median		2,942.051	1.17%
UNS Electric, Inc. Implied Market Capitalization		156.707	6.10%
Size Premium [11]			4.93%

Notes:
[1] Source: SNL Financial
[2] Source: Bloomberg Professional; equals 30-day average as of November 16, 2012
[3] Source: Bloomberg Professional; equals 30-day average as of November 16, 2012
[4] Source: Direct Testimony of Dallas J. Dukes, Schedule A-1
[5] Source: Direct Testimony of Kentton C. Grant
[6] Equals [4] x [5]
[7] Equals [6] x proxy group median market-to-book ratio
[8] Source: Ibbotson SBBI 2012 Valuation Yearbook, at 202
[9] Source: Ibbotson SBBI 2012 Valuation Yearbook, at 202
[10] Source: Ibbotson SBBI 2012 Valuation Yearbook, at 202
[11] Equals 6.10% – 1.17%

EXHIBIT

AEB-9

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO

Company	Ticker	2012 Q3	2012 Q2	2012 Q1	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	Average
ALLETE, Inc.	ALE	54.41%	57.43%	59.36%	58.41%	57.75%	58.92%	58.73%	58.00%	57.87%
American Electric Power Company, Inc.	AEP	52.83%	52.18%	51.46%	52.94%	52.71%	50.85%	50.07%	49.98%	51.63%
Cleco Corporation	CNL	49.77%	50.38%	48.38%	48.29%	47.52%	47.75%	46.98%	47.33%	48.30%
Empire District Electric Company	EDE	53.11%	52.50%	52.91%	52.29%	51.95%	50.96%	51.03%	50.93%	51.96%
FirstEnergy Corporation	FE	48.93%	48.14%	47.85%	47.65%	48.13%	47.13%	47.81%	50.07%	48.21%
Great Plains Energy Inc.	GXP	55.33%	49.49%	51.86%	51.93%	51.13%	53.00%	53.59%	52.23%	52.32%
Hawaiian Electric Industries, Inc.	HE	55.70%	55.36%	58.58%	57.06%	56.22%	55.85%	55.86%	55.83%	56.31%
IDACORP, Inc.	IDA	51.53%	50.37%	50.91%	50.59%	50.44%	48.95%	48.84%	46.61%	49.78%
Otter Tail Corporation	OTTR	50.35%	50.23%	50.48%	50.28%	53.36%	53.17%	53.24%	53.16%	51.78%
Pepco Holdings, Inc.	POM	46.48%	45.28%	47.12%	46.68%	46.69%	45.95%	46.41%	45.92%	46.32%
Pinnacle West Capital Corporation	PNW	56.30%	54.60%	54.36%	54.46%	52.06%	52.44%	52.57%	52.97%	53.72%
Portland General Electric Company	POR	49.74%	49.47%	49.37%	48.94%	47.90%	47.78%	47.74%	46.83%	48.47%
Southern Company	SO	48.01%	47.22%	46.48%	47.43%	51.14%	50.22%	50.59%	49.27%	48.79%
Westar Energy, Inc.	WR	60.30%	59.38%	60.05%	61.36%	60.66%	59.62%	59.24%	59.37%	60.00%
MEAN		52.34%	51.57%	52.08%	52.02%	51.98%	51.61%	51.62%	51.32%	51.82%
MEDIAN		52.18%	50.38%	51.18%	51.26%	51.54%	50.90%	50.81%	50.50%	51.71%
LOW		46.48%	45.28%	46.48%	46.68%	46.69%	45.95%	46.41%	45.92%	46.32%
HIGH		60.30%	59.38%	60.05%	61.36%	60.66%	59.62%	59.24%	59.37%	60.00%

OPERATING COMPANIES

Company	Ticker	2012 Q3	2012 Q2	2012 Q1	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	Average
ALLETE (Minnesota Power)	ALE	54.41%	57.43%	57.69%	56.92%	56.28%	58.10%	57.49%	56.82%	56.89%
Superior Water, Light and Power Company	ALE			61.03%	59.89%	59.22%	59.74%	59.97%	59.17%	59.84%
AEP Texas Central Company	AEP	50.05%	48.91%	45.78%	63.77%	60.84%	47.26%	44.99%	44.85%	50.81%
AEP Texas North Company	AEP	47.55%	47.24%	47.29%	46.93%	46.35%	46.08%	45.88%	45.52%	46.61%
Appalachian Power Company	AEP	44.82%	44.73%	44.62%	44.07%	44.19%	43.14%	41.53%	44.21%	43.91%
Indiana Michigan Power Company	AEP	49.61%	49.42%	49.55%	49.13%	49.10%	49.06%	48.86%	48.47%	49.15%
Kentucky Power Company	AEP	46.46%	46.12%	45.76%	45.61%	45.62%	45.42%	45.50%	44.84%	45.67%
Kingsport Power Company	AEP	59.92%	59.94%	60.35%	59.56%	58.67%	59.00%	59.12%	57.96%	59.31%
Ohio Power Company	AEP	54.38%	53.94%	53.49%	52.12%	53.92%	54.34%	54.52%	53.43%	53.77%
Public Service Company of Oklahoma	AEP	49.69%	48.93%	48.40%	48.52%	48.56%	47.51%	45.21%	46.45%	47.91%
Southwestern Electric Power Company	AEP	50.42%	49.27%	48.55%	51.85%	51.99%	50.32%	49.58%	49.15%	50.14%
Wheeling Power Company	AEP	75.36%	73.26%	70.78%	67.87%	67.88%	66.34%	65.53%	64.89%	68.99%
Cleco Power LLC	CNL	49.77%	50.38%	48.38%	48.29%	47.52%	47.75%	46.98%	47.33%	48.30%
Empire District Electric Company	EDE	53.11%	52.50%	52.91%	52.29%	51.95%	50.96%	51.03%	50.93%	51.96%
Cleveland Electric Illuminating Company	FE	39.87%	39.44%	40.47%	42.30%	42.84%	42.26%	42.07%	42.72%	41.50%
Jersey Central Power & Light Company	FE	61.16%	60.81%	60.94%	60.71%	60.36%	59.42%	63.89%	63.70%	61.37%
Metropolitan Edison Company	FE	53.40%	53.37%	53.03%	52.55%	51.60%	50.71%	55.76%	59.42%	53.73%
Monongahela Power Company	FE	47.87%	46.13%	45.29%	43.96%	45.76%	41.18%	40.41%	45.45%	44.51%
Ohio Edison Company	FE	42.65%	42.09%	41.67%	40.81%	42.58%	40.91%	44.90%	46.83%	42.81%
Pennsylvania Electric Company	FE	44.99%	44.56%	44.17%	45.72%	44.20%	43.60%	44.55%	44.60%	44.55%
Pennsylvania Power Company	FE	60.92%	60.25%	59.48%	58.75%	59.55%	62.36%	61.57%	60.75%	60.45%
Potomac Edison Company	FE	47.78%	46.41%	45.22%	43.97%	43.69%	42.38%	39.50%	44.17%	44.14%
Toledo Edison Company	FE	38.93%	38.20%	37.78%	38.13%	39.73%	38.84%	39.24%	39.71%	38.82%
West Penn Power Company	FE	51.70%	50.15%	50.49%	49.61%	50.98%	49.68%	46.19%	53.34%	50.27%
Kansas City Power & Light Company	GXP	52.56%	51.73%	51.48%	51.59%	49.84%	54.41%	52.66%	52.90%	52.15%
KCP&L Greater Missouri Operations Company	GXP	58.09%	47.26%	52.24%	52.28%	52.42%	51.59%	54.52%	51.55%	52.49%
Hawaii Electric Light Company, Inc.	HE									
Hawaiian Electric Company, Inc.	HE	55.70%	55.36%	58.58%	57.06%	56.22%	55.85%	55.86%	55.83%	56.31%
Maui Electric Company, Limited	HE									
Idaho Power Co.	IDA	51.53%	50.37%	50.91%	50.59%	50.44%	48.95%	48.84%	46.61%	49.78%
Otter Tail Power Company	OTTR	50.35%	50.23%	50.48%	50.28%	53.36%	53.17%	53.24%	53.16%	51.78%
Arizona Public Service Company	PNW	56.30%	54.60%	54.36%	54.46%	52.06%	52.44%	52.57%	52.97%	53.72%
Atlantic City Electric Company	POM	42.49%	42.14%	41.99%	41.72%	41.71%	38.97%	41.55%	41.08%	41.46%
Delmarva Power & Light Company	POM	48.19%	45.19%	49.57%	48.93%	48.76%	49.89%	49.26%	48.56%	48.54%
Potomac Electric Power Company	POM	48.77%	48.52%	49.79%	49.39%	49.61%	48.98%	48.43%	48.12%	48.95%
Portland General Electric Company	POR	49.74%	49.47%	49.37%	48.94%	47.90%	47.78%	47.74%	46.83%	48.47%
Alabama Power Company	SO	47.52%	46.81%	45.57%	46.53%	47.29%	46.71%	46.46%	46.54%	46.68%
Georgia Power Company	SO	49.61%	47.90%	50.17%	51.73%	51.94%	50.73%	51.17%	51.32%	50.57%
Gulf Power Company	SO	48.73%	48.31%	48.35%	47.61%	47.79%	47.45%	47.52%	46.71%	47.81%
Mississippi Power Company	SO	46.17%	45.88%	41.82%	43.83%	57.54%	55.99%	57.21%	52.51%	50.12%
Kansas Gas and Electric Company	WR	59.27%	58.30%	57.85%	57.55%	57.70%	56.77%	56.52%	57.00%	57.62%
Westar Energy (KPL)	WR	61.32%	60.46%	62.26%	65.18%	63.63%	62.47%	61.96%	61.74%	62.38%

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO

Company	Ticker	2012 Q3	2012 Q2	2012 Q1	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	Average
ALLETE, Inc.	ALE	45.59%	42.57%	40.64%	41.59%	42.25%	41.08%	41.27%	42.00%	42.13%
American Electric Power Company, Inc.	AEP	47.17%	47.82%	48.54%	47.06%	47.29%	49.15%	49.93%	50.02%	48.37%
Cleco Corporation	CNL	50.23%	49.62%	51.62%	51.71%	52.48%	52.25%	53.02%	52.67%	51.70%
Empire District Electric Company	EDE	46.89%	47.50%	47.09%	47.71%	48.05%	49.04%	48.97%	49.07%	48.04%
FirstEnergy Corporation	FE	51.07%	51.86%	52.15%	52.35%	51.87%	52.87%	52.19%	49.93%	51.79%
Great Plains Energy Inc.	GXP	44.67%	50.51%	48.14%	48.07%	48.87%	47.00%	46.41%	47.77%	47.68%
Hawaiian Electric Industries, Inc.	HE	44.30%	44.64%	41.42%	42.94%	43.78%	44.15%	44.14%	44.17%	43.69%
IDACORP, Inc.	IDA	48.47%	49.63%	49.09%	49.41%	49.56%	51.05%	51.16%	53.39%	50.22%
Otter Tail Corporation	OTTR	49.65%	49.77%	49.52%	49.72%	46.64%	46.83%	46.76%	46.84%	48.22%
Pepco Holdings, Inc.	POM	53.52%	54.72%	52.88%	53.32%	53.31%	54.05%	53.59%	54.08%	53.68%
Pinnacle West Capital Corporation	PNW	43.70%	45.40%	45.64%	45.54%	47.94%	47.56%	47.43%	47.03%	46.28%
Portland General Electric Company	POR	50.26%	50.53%	50.63%	51.06%	52.10%	52.22%	52.26%	53.17%	51.53%
Southern Company	SO	51.99%	52.78%	53.52%	52.57%	48.86%	49.78%	49.41%	50.73%	51.21%
Westar Energy, Inc.	WR	39.70%	40.62%	39.95%	38.64%	39.34%	40.38%	40.76%	40.63%	40.00%
MEAN		47.66%	48.43%	47.92%	47.98%	48.02%	48.39%	48.38%	48.68%	48.18%
MEDIAN		47.82%	49.62%	48.82%	48.74%	48.46%	49.10%	49.19%	49.50%	48.29%
LOW		39.70%	40.62%	39.95%	38.64%	39.34%	40.38%	40.76%	40.63%	40.00%
HIGH		53.52%	54.72%	53.52%	53.32%	53.31%	54.05%	53.59%	54.08%	53.68%

OPERATING COMPANIES

Company	Ticker	2012 Q3	2012 Q2	2012 Q1	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Q4	Average
ALLETE (Minnesota Power)	ALE	45.59%	42.57%	42.31%	43.08%	43.72%	41.90%	42.51%	43.18%	43.11%
Superior Water, Light and Power Company	ALE			38.97%	40.11%	40.78%	40.26%	40.03%	40.83%	40.16%
AEP Texas Central Company	AEP	49.95%	51.09%	54.22%	36.23%	39.16%	52.74%	55.01%	55.15%	49.19%
AEP Texas North Company	AEP	52.45%	52.76%	52.71%	53.07%	53.65%	53.92%	54.12%	54.48%	53.39%
Appalachian Power Company	AEP	55.18%	55.27%	55.38%	55.93%	55.81%	56.86%	58.47%	55.79%	56.09%
Indiana Michigan Power Company	AEP	50.39%	50.58%	50.45%	50.87%	50.90%	50.94%	51.14%	51.53%	50.85%
Kentucky Power Company	AEP	53.54%	53.88%	54.24%	54.39%	54.38%	54.58%	54.50%	55.16%	54.33%
Kingsport Power Company	AEP	40.08%	40.06%	39.65%	40.44%	41.33%	41.00%	40.88%	42.04%	40.69%
Ohio Power Company	AEP	45.62%	46.06%	46.51%	47.88%	46.08%	45.66%	45.48%	46.57%	46.23%
Public Service Company of Oklahoma	AEP	50.31%	51.07%	51.60%	51.48%	51.44%	52.49%	54.79%	53.55%	52.09%
Southwestern Electric Power Company	AEP	49.58%	50.73%	51.45%	48.15%	48.01%	49.68%	50.42%	50.85%	49.86%
Wheeling Power Company	AEP	24.64%	26.74%	29.22%	32.13%	32.12%	33.66%	34.47%	35.11%	31.01%
Cleco Power LLC	CNL	50.23%	49.62%	51.62%	51.71%	52.48%	52.25%	53.02%	52.67%	51.70%
Empire District Electric Company	EDE	46.89%	47.50%	47.09%	47.71%	48.05%	49.04%	48.97%	49.07%	48.04%
Cleveland Electric Illuminating Company	FE	60.13%	60.56%	59.53%	57.70%	57.16%	57.74%	57.93%	57.28%	58.50%
Jersey Central Power & Light Company	FE	38.84%	39.19%	39.06%	39.29%	39.64%	40.58%	36.11%	36.30%	38.63%
Metropolitan Edison Company	FE	46.60%	46.63%	46.97%	47.45%	48.40%	49.29%	44.24%	40.58%	46.27%
Monongahela Power Company	FE	52.13%	53.87%	54.71%	56.04%	54.24%	58.82%	59.59%	54.55%	55.49%
Ohio Edison Company	FE	57.35%	57.91%	58.33%	59.19%	57.42%	59.09%	55.10%	53.17%	57.19%
Pennsylvania Electric Company	FE	55.01%	55.44%	55.83%	54.28%	55.80%	56.40%	55.45%	55.40%	55.45%
Pennsylvania Power Company	FE	39.08%	39.75%	40.52%	41.25%	40.45%	37.64%	38.43%	39.25%	39.55%
Potomac Edison Company	FE	52.22%	53.59%	54.78%	56.03%	56.31%	57.62%	60.50%	55.83%	55.86%
Toledo Edison Company	FE	61.07%	61.80%	62.22%	61.87%	60.27%	61.16%	60.76%	60.29%	61.18%
West Penn Power Company	FE	48.30%	49.85%	49.51%	50.39%	49.02%	50.32%	53.81%	46.66%	49.73%
Kansas City Power & Light Company	GXP	47.44%	48.27%	48.52%	48.41%	50.16%	45.59%	47.34%	47.10%	47.85%
KCP&L Greater Missouri Operations Company	GXP	41.91%	52.74%	47.76%	47.72%	47.58%	48.41%	45.48%	48.45%	47.51%
Hawaii Electric Light Company, Inc.	HE									
Hawaiian Electric Company, Inc.	HE	44.30%	44.64%	41.42%	42.94%	43.78%	44.15%	44.14%	44.17%	43.69%
Maui Electric Company, Limited	HE									
Idaho Power Co.	IDA	48.47%	49.63%	49.09%	49.41%	49.56%	51.05%	51.16%	53.39%	50.22%
Otter Tail Power Company	OTTR	49.65%	49.77%	49.52%	49.72%	46.64%	46.83%	46.76%	46.84%	48.22%
Arizona Public Service Company	PNW	43.70%	45.40%	45.64%	45.54%	47.94%	47.56%	47.43%	47.03%	46.28%
Atlantic City Electric Company	POM	57.51%	57.86%	58.01%	58.28%	58.29%	61.03%	58.45%	58.92%	58.54%
Delmarva Power & Light Company	POM	51.81%	54.81%	50.43%	51.07%	51.24%	50.11%	50.74%	51.44%	51.46%
Potomac Electric Power Company	POM	51.23%	51.48%	50.21%	50.61%	50.39%	51.02%	51.57%	51.88%	51.05%
Portland General Electric Company	POR	50.26%	50.53%	50.63%	51.06%	52.10%	52.22%	52.26%	53.17%	51.53%
Alabama Power Company	SO	52.48%	53.19%	54.43%	53.47%	52.71%	53.29%	53.54%	53.46%	53.32%
Georgia Power Company	SO	50.39%	52.10%	49.83%	48.27%	48.06%	49.27%	48.83%	48.68%	49.43%
Gulf Power Company	SO	51.27%	51.69%	51.65%	52.39%	52.21%	52.55%	52.48%	53.29%	52.19%
Mississippi Power Company	SO	53.83%	54.12%	58.18%	56.17%	42.46%	44.01%	42.79%	47.49%	49.88%
Kansas Gas and Electric Company	WR	40.73%	41.70%	42.15%	42.45%	42.30%	43.23%	43.48%	43.00%	42.38%
Westar Energy (KPL)	WR	38.68%	39.54%	37.74%	34.82%	36.37%	37.53%	38.04%	38.26%	37.62%

EXHIBIT

AEB-10

PROXY GROUP DECOUPLING MECHANISMS

	State	Decoupling	Total Electric Customers (2011)	Notes
ALLETE, Inc.				
ALLETE (Minnesota Power)	MN	None	143,688	
Superior Water, Light and Power Company	WI	None	14,648	
American Electric Power Company, Inc.				
AEP Texas Central Company	TX	None	787,000	
AEP Texas North Company	TX	None	186,000	
Appalachian Power Company	VA	None	521,923	
	WV	None	439,206	
Indiana Michigan Power Company	IN	Partial	454,952	[1]
	MI	None	127,844	
Kentucky Power Company	KY	Partial	173,642	[2]
Kingsport Power Company	TN	None	47,436	
Ohio Power Company	OH	Full	1,459,876	[3]
Public Service Company of Oklahoma	OK	Partial	532,395	[4]
Southwestern Electric Power Company	AR	Partial	113,656	[5]
	LA	Full	227,287	[6]
	TX	None	180,658	
Wheeling Power Company	WV	None	41,099	
Cleco Corporation				
Cleco Power LLC	LA	None	280,857	
Empire District Electric Company	AR	None	4,333	
	KS	None	9,927	
	MO	None	147,219	
	OK	Partial	4,727	[7]
FirstEnergy Corp.				
Cleveland Electric Illuminating Company	OH	Partial	748,935	[8]
Jersey Central Power & Light Company	NJ	None	1,099,194	
Metropolitan Edison Company	PA	None	552,631	
Monongahela Power Company	WV	None	386,819	
Ohio Edison Company	OH	Partial	1,034,534	[8]
Pennsylvania Electric Company	NY	None	3,780	
	PA	None	582,091	
Pennsylvania Power Company	PA	None	160,250	
Potomac Edison Company	MD	None	252,769	
	WV	None	136,045	
Toledo Edison Company	OH	Partial	309,020	[8]
West Penn Power Company	PA	None	717,269	
Great Plains Energy Inc.				
Kansas City Power & Light Company	KS	None	240,636	
	MO	None	271,446	
KCP&L Greater Missouri Operations Company	MO	Partial	312,684	*Pending* [9]
Hawaiian Electric Industries, Inc.				
Hawaii Electric Light Company, Inc.	HI	Full	80,807	[10]
Hawaiian Electric Company, Inc.	HI	Full	296,800	[11]
Maui Electric Company, Limited	HI	Full	67,993	[12]
IDACORP, Inc.				
Idaho Power Co.	ID	Full	475,147	[13]
	OR	None	18,385	
Otter Tail Corporation				
Otter Tail Power Company	MN	None	59,486	
	ND	None	57,050	
	SD	None	11,452	
Pepco Holdings, Inc.				
Atlantic City Electric Company	NJ	None	547,762	
Delmarva Power & Light Company	DE	Full	301,542	[14]

PROXY GROUP DECOUPLING MECHANISMS

	State	Decoupling	Total Electric Customers (2011)	Notes
	MD	Full	199,456	[15]
Potomac Electric Power Company	DC	Full	255,948	[16]
	MD	Full	531,189	[15]
Pinnacle West Capital Corporation				
Arizona Public Service Company	AZ	Partial	1,120,236	[17]
Portland General Electric Company	OR	Partial	823,171	[18]
Southern Company				
Alabama Power Company	AL	Full	1,434,487	[19]
Georgia Power Company	GA	Partial	2,360,487	[20]
Gulf Power Company	FL	None	432,401	
Mississippi Power Company	MS	Full	185,768	[21]
Westar Energy, Inc.				
Kansas Gas and Electric Company	KS	Partial	317,580	[22]
Westar Energy (KPL)	KS	Partial	369,106	[22]

Operating Companies with Decoupling:	14,191,425
Total:	22,652,729
	62.6%

Notes:

[1] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 14
[2] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 16
[3] Public Utilities Commission of Ohio, Case No. 11-351-EL-AIR et al, Opinion and Order, December 14, 201
[4] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 22
[5] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 11
[6] Southwestern Electric Power Company, Louisiana Tariff, Formula Rate Plan;
adjusts rates annually to maintain earned ROE between 10.015% and 11.115% (extension pending)
[7] Empire District Electric Company, Oklahoma Tariff, Demand Side Management Cost Recovery Rider
[8] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 21
[9] KCP&L Greater Missouri Operations Company, Case No. EO-2012-0009, Application for Approval of Dem
Side Programs and for Authority to Establish a Demand-Side Programs Investment Mechanism, Decembe
[10] Public Utilities Commission of Hawaii, Docket No. 2009-0164, Decision and Order No. 30168, February 8
[11] Public Utilities Commission of Hawaii, Docket No. 2008-0083, Final Decision and Order, December 29, 2
[12] Public Utilities Commission of Hawaii, Docket No. 2009-0163, Decision and Order No. 30365, May 2, 201
[13] IDACORP, Inc., Form 10-K for the fiscal year ended December 31, 2011, at 18
[14] Pepco Holdings, Inc., Form 10-K for the fiscal year ended December 31, 2011, at 158
[15] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 5
[16] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 3
[17] Arizona Corporation Commission, Docket No. E-01345A-11-0224, Decision No. 73183, May 24, 2012
[18] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 23
[19] Alabama Power Company, Tariff, Rate RSE - Rate Stabilization and Equalization Factor;
adjusts rates annually to maintain earned ROE between 13.00% and 14.50%
[20] Georgia Public Service Commission, Docket No. 31958, Final Order, December 21, 2010, at 11;
if the company projects that its earned ROE will be less than 10.25%, it may petition the Commission for
implementation of an Interim Cost Recovery tariff which will adjust the company's earnings back to 10.25
[21] Mississippi Power Company, Tariff, Performance Evaluation Plan - Rate Schedule "PEP-5";
adjusts rates annually to maintain earned ROE within range of no change determined by ROE formula an
[22] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 15

PROXY GROUP CAPITAL TRACKER MECHANISMS

	State	Capital Tracker	Total Electric Customers (2011)	Notes
ALLETE, Inc.				
ALLETE (Minnesota Power)	MN	Rider For Transmission Cost Recovery	143,688	[1]
Superior Water, Light and Power Company	WI	None	14,648	
American Electric Power Company, Inc.				
AEP Texas Central Company	TX	Schedule TCRF - Transmission Cost Recovery Factor	787,000	[2]
AEP Texas North Company	TX	Schedule TCRF - Transmission Cost Recovery Factor - ERCOT System	186,000	[3]
Appalachian Power Company	VA	Transmission Rate Adjustment Clause Rider; Environmental & Reliability Cost Recovery Surcharge	521,923	[4]
	WV	Construction/765 kV Surcharge	439,206	[5]
Indiana Michigan Power Company	IN	Environmental Compliance Cost Rider	454,952	[6]
	MI	None	127,844	
Kentucky Power Company	KY	Environmental Surcharge	173,642	[7]
Kingsport Power Company	TN	None	47,436	
Ohio Power Company	OH	Transmission Cost Recovery Rider	1,459,876	[8]
Public Service Company of Oklahoma	OK	Southwest Power Pool Transmission Cost Tariff	532,395	[9]
Southwestern Electric Power Company	AR	Alternative Generation Recovery Rider	113,656	[10]
	LA	None	227,287	
	TX	Transmission Cost of Service Mechanism	180,658	[11]
Wheeling Power Company	WV	Construction/765 kV Surcharge	41,099	[12]
Cleco Corporation				
Cleco Power LLC	LA	Infrastructure and Incremental Costs Recovery	280,857	[13]
El Paso Electric Company	NM	None	91,031	
	TX	Transmission Cost of Service Mechanism	287,516	[11]
Empire District Electric Company	AR	Transmission Cost Recovery Rider	4,333	[14]
	KS	None	9,927	
	MO	None	147,219	
	OK	Transmission Cost Recovery	4,727	[15]
FirstEnergy Corp.				
Cleveland Electric Illuminating Company	OH	Transmission and Ancillary Services Rider; Advanced Metering Infrastructure / Modern Grid Rider; Delivery Service Improvement Rider; Delivery Capital Recovery Rider	748,935	[16]
Jersey Central Power & Light Company	NJ	None	1,099,194	[17]
Metropolitan Edison Company	PA	Transmission Service Charge; Smart Meter Technologies Charge Rider	552,631	[18]
Monongahela Power Company	WV	None	386,819	
Ohio Edison Company	OH	Transmission and Ancillary Services Rider; Advanced Metering Infrastructure / Modern Grid Rider; Delivery Service Improvement Rider; Delivery Capital Recovery Rider	1,034,534	[19]
Pennsylvania Electric Company	NY	None	3,780	
	PA	Transmission Service Charge; Smart Meter Technologies Charge Rider	582,091	[20]
Pennsylvania Power Company	PA	MTEP and MISO Exit Fees and PJM Integration Charges; PJM RTEP Charges; Smart Meter Technologies Charge Rider	160,250	[21]
Potomac Edison Company	MD	None	252,769	
	WV	Environmental Control Charge	136,045	[22]
Toledo Edison Company	OH	Transmission and Ancillary Services Rider; Advanced Metering Infrastructure / Modern Grid Rider; Delivery Service Improvement Rider; Delivery Capital Recovery Rider	309,020	[23]
West Penn Power Company	PA	Transmission Service Charge Rider; Smart Meter Technologies Surcharge	717,269	[24]
Great Plains Energy Inc.				
Kansas City Power & Light Company	KS	None	240,636	
	MO	None	271,446	
KCP&L Greater Missouri Operations Company	MO	None	312,684	
Hawaiian Electric Industries, Inc.				
Hawaii Electric Light Company, Inc.	HI	Renewable Energy Infrastructure Program Surcharge	80,807	[25]
Hawaiian Electric Company, Inc.	HI	Renewable Energy Infrastructure Program Surcharge	296,800	[25]
Maui Electric Company, Limited	HI	Renewable Energy Infrastructure Program Surcharge	67,993	[25]
IDACORP, Inc.				
Idaho Power Co.	ID	None	475,147	
	OR	None	18,385	
Otter Tail Corporation				
Otter Tail Power Company	MN	Transmission Cost Recovery Rider	59,486	[26]
	ND	Transmission Cost Recovery Rider	57,050	[26]
	SD	Transmission Cost Recovery Rider	11,452	[26]
Pepco Holdings, Inc.				
Atlantic City Electric Company	NJ	Infrastructure Investment Surcharge	547,762	[27]
Delmarva Power & Light Company	DE	Transmission Service Charge	301,542	[28]
	MD	None	199,456	
Potomac Electric Power Company	DC	None	255,948	
	MD	None	531,189	
Pinnacle West Capital Corporation				
Arizona Public Service Company	AZ	Transmission Cost Adjustment; Environmental Improvement Surcharge	1,120,236	[29]
Portland General Electric Company	OR	Renewable Resources Automatic Adjustment Clause	823,171	[30]

PROXY GROUP CAPITAL TRACKER MECHANISMS

	State	Capital Tracker	Total Electric Customers (2011)	Notes
Southern Company				
Alabama Power Company	AL	Adjustment for Commercial Operation of Certificated New Plant	1,434,487	[31]
Georgia Power Company	GA	Environmental Compliance Cost Recovery Schedule; Nuclear Construction Cost Recovery	2,360,487	[32]
Gulf Power Company	FL	Environmental Cost Recovery Clause	432,401	[33]
Mississippi Power Company	MS	Environmental Compliance Overview Plan	185,768	[34]
Westar Energy, Inc.				
Kansas Gas and Electric Company	KS	Transmission Delivery Charge; Environmental Cost Recovery Rider	317,580	[35]
Westar Energy (KPL)	KS	Transmission Delivery Charge; Environmental Cost Recovery Rider	369,106	[35]
		Operating Companies with Capital Trackers:	18,318,431	
		Total:	23,031,276	
			79.5%	

Notes:

[1] Minnesota Power, Electric Rate Book, Rider for Transmission Cost Recovery
[2] AEP Texas Central Company, Tariff for Retail Delivery Service, Schedule TCRF - Transmission Cost Recovery Factor
[3] AEP Texas North Company, Tariff for Retail Delivery Service, Schedule TCRF - Transmission Cost Recovery Factor
[4] Appalachian Power Company, Virginia S.C.C. Tariff No. 24, Environmental and Reliability Cost Recovery Surcharge and Transmission Rate Adjustment Clause Rider
Virginia State Corporation Commission, Case No. PUE-2009-00031, Final Order, October 6, 2009
[5] Appalachian Power Company, P.S.C. W.VA. Tariff No. 13, Construction Surcharge
[6] Indiana Michigan Power Company, I.U.R.C. NO. 15 Tariff, Environmental Compliance Cost Rider
[7] Kentucky Power Company, Schedule of Tariffs, Environmental Surcharge
[8] Ohio Power Company, P.U.C.O. No. 20, Transmission Cost Recovery Rider
[9] Public Service Company of Oklahoma, Riders Schedules, Southwest Pool Transmission Cost Tariff
[10] Southwestern Electric Power Company, Arkansas P.S.C. Tariff, Alternative Generation Recovery Rider
[11] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 26
[12] Wheeling Power Company, P.S.C. W.VA. Tariff No. 18, Construction Surcharge
[13] Louisiana Public Service Commission, Docket No. U-30689, Order, October 28, 2010, at 12
[14] Empire District Electric Company, Arkansas P.S.C. Tariff, Transmission Cost Recovery Rider
[15] Empire District Electric Company, Oklahoma Tariff, Residential Service - Schedule RG
[16] Cleveland Electric Illuminating Company, Schedule of Rates for Electric Service, Transmission and Ancillary Services Rider;
Advanced Metering Infrastructure / Modern Grid Rider; Delivery Service Improvement Rider; Delivery Capital Recovery Rider
[17] Regulatory Research Associates, "Adjustment Clauses and Rate Riders", March 21, 2012, at 20
[18] Metropolitan Edison Company, PA P.U.C. Electric Service Tariff, Transmission Service Charge and Smart Meter Technologies Charge Rider
[19] Ohio Edison Company, P.U.C.O. No. 11, Schedule of Rates for Electric Service, Transmission and Ancillary Services Rider;
Advanced Metering Infrastructure / Modern Grid Rider; Delivery Service Improvement Rider; Delivery Capital Recovery Rider
[20] Pennsylvania Electric Company, Electric Service Tariff, Transmission Service Charge and Smart Meter Technologies Charge Rider
[21] Pennsylvania Power Company, Schedule of Rates, Rules and Regulations for Electric Service, MTEP and MISO Exit Fees and PJM Integration Charges;
PJM RTEP Charges; Smart Meter Technologies Charge Rider
[22] Public Service Commission of West Virginia, Case No. 05-0780-E-PC, Commission Order, September 30, 2009
[23] Toledo Edison Company, Schedule of Rates for Electric Service, Transmission and Ancillary Services Rider;
Advanced Metering Infrastructure / Modern Grid Rider; Delivery Service Improvement Rider; Delivery Capital Recovery Rider
[24] West Penn Power Company, Rate Schedules and Rules and Regulations for Electric Service, Transmission Service Charge Rider and Smart Meter Technologies S
[25] Public Utilities Commission of Hawaii, Docket No. 2007-0416, Decision and Order, December 30, 2009
[26] Otter Tail Power Company, Electric Rate Schedule, Transmission Cost Recovery Rider
[27] Atlantic City Electric Company, Tariff for Electric Service, Infrastructure Investment Surcharge
[28] Delaware Public Service Commission, PSC Docket No. 12-284, Order No. 8193, July 17, 2012
[29] Arizona Public Service Company, Tariff, Transmission Cost Adjustment and Adjustment Schedule EIS - Environmental Improvement Surcharge
Arizona Corporation Commission, Docket No. E-01345A-12-0175, Decision No. 73262, July 30, 2012
[30] Portland General Electric Company, Tariff, Schedule 122 - Renewable Resources Automatic Adjustment Clause
[31] Alabama Power Company, Tariff, Rate CNP - Adjustment for Commercial Operation of Certificated New Plant
[32] Georgia Power Company, Tariff, Environmental Compliance Cost Recovery Schedule "ECCR-2" and Nuclear Construction Cost Recovery Schedule "NCCR-2"
[33] Gulf Power Company, Tariff, Rate Schedule ECR - Environmental Cost Recovery Clause
[34] Mississippi Power Company, Tariff, Environmental Compliance Overview Plan - Rate Schedule "ECO-2"
[35] Westar Energy, Tariff, Transmission Delivery Charge and Environmental Cost Recovery Rider

EXHIBIT

AEB-11

UNS ELECTRIC
FAIR VALUE RATE OF RETURN
ARIZONA STAFF METHODOLOGY

	Amount ($M)	Weighting	Weighted Amount ($M)	
Original Cost Rate Base (OCRB)	$ 216.6	50.00%	$ 108.3	[1]
Replacement Cost New, Depreciated Rate Base (RCND)	356.1	50.00%	178.0	[2]
Fair Value Rate Base (FVRB)			286.3	[3]
Appreciation Above OCRB			$ 69.8	[4]
FVRB / OCRB Multiple			1.32	

Capital	Amount ($M)	Percent	Cost Rate		Weighted Cost Rate	
Long-Term Debt	$ 102.7	35.85%	5.97%	[5]	2.14%	
Common Equity	113.9	39.79%	10.50%	[6]	4.18%	
Capital Financing OCRB	$ 216.6	75.64%			6.32%	
Appreciation Above OCRB Not Recognized on Utility's Books	69.8	24.36%	1.61%		0.39%	
Total	$ 286.3	100.00%			6.71%	[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]	
2014-2018	2.40%
2019-2023	2.40%
Average	2.40%
Consumer Price Index (All-Urban) [2]	
2012	2.28
2023	2.83
Compound Annual Growth Rate	1.98%
GDP Chain-type Price Index (2005=1.000) [2]	
2012	1.148
2023	1.373
Compound Annual Growth Rate	1.64%
Average Inflation Forecast	**2.01%**
Step 2	
Nominal U.S. Treasury Bond Yield, 30-year [1]	
2014-2018	5.10%
2019-2023	5.50%
	5.30%
Real Risk-Free Rate [3]	**3.23%**
50.0% of Real Risk-Free Rate [4]	**1.61%**

Notes:

[1] Blue Chip Financial Forecasts, Vol. 31, No. 6, June 1, 2012, at 14.
[2] Energy Information Administration, Annual Energy Outlook 2012, Table 20
[3] Equals (5.30% + 1) / (1 + 2.01%) − 1
[4] Equals [3] x 50.0%

EXHIBIT

AEB-12

Comparable Transactions Analysis

Calculation of Transaction Premium over Corporate Value

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 UNSE Valuation ($M)
Central Vermont Public Service Corporation	Gaz Métro LP	06/23/11	$20.59	$35.25	71.20%	61.29%	43.64%	$311.1
Constellation Energy Group Inc.	Exelon Corporation	04/28/11	$39.65	$38.59	-2.68%	65.30%	-1.75%	$212.8
DPL Inc.	AES Corporation	04/19/11	$10.52	$30.00	185.18%	63.13%	116.90%	$469.7
Progress Energy Inc.	Duke Energy Corporation	01/10/11	$34.21	$46.47	35.86%	46.68%	16.74%	$252.8
NSTAR	Northeast Utilities	10/18/10	$18.60	$40.28	116.51%	51.31%	59.79%	$346.1
Allegheny Energy, Inc.	FirstEnergy Corporation	02/11/10	$18.36	$27.65	50.62%	42.53%	21.53%	$263.2
Florida Public Utilities Company	Chesapeake Utilities Corporation	04/17/09	$8.14	$12.47	53.23%	53.38%	28.41%	$278.1
Puget Energy, Inc.	Investor Consortium	10/25/07	$18.45	$30.00	62.63%	50.35%	31.54%	$284.9
Energy East Corporation	Iberdrola, S.A.	06/25/07	$20.21	$28.50	41.01%	48.37%	19.83%	$259.5
Aquila, Inc.	Great Plains Energy, Inc.	02/06/07	$3.49	$4.54	30.18%	48.89%	14.76%	$248.5
Duquesne Light Holdings, Inc	Macquarie Consortium	07/05/06	$8.41	$20.00	137.82%	46.83%	64.55%	$356.4
Green Mountain Power Corporation	Gaz Métro LP	06/21/06	$22.79	$35.00	53.60%	61.71%	33.08%	$288.2
KeySpan Corp.	National Grid Group PLC	02/25/06	$25.60	$42.00	64.05%	56.78%	36.37%	$295.3
Cinergy Corp.	Duke Energy Corporation	05/08/05	$22.71	$45.80	101.69%	55.23%	56.16%	$338.2
RGS Energy Group, Inc.	Energy East Corporation	02/16/01	$22.19	$39.50	78.04%	55.15%	43.04%	$309.8
Conectiv	Potomac Electric Power Company	02/12/01	$13.10	$25.00	90.91%	54.41%	49.46%	$323.7
Montana Power Company	NorthWestern Corporation	09/28/00	$9.86	$10.50	6.53%	77.59%	5.06%	$227.5
Niagara Mohawk Holdings, Inc.	National Grid Group PLC	09/04/00	$16.90	$19.00	12.39%	43.41%	5.38%	$228.2
GPU, Inc.	FirstEnergy Corporation	08/08/00	$27.01	$36.50	35.12%	54.35%	19.09%	$257.9
IPALCO Enterprises, Inc.	AES Corporation	07/15/00	$7.76	$25.00	222.03%	49.21%	109.27%	$453.2
Bangor Hydro-Electric Company	NS Power Holdings Inc.	06/29/00	$18.34	$26.50	44.46%	46.73%	20.77%	$261.6
LG&E Energy Corp.	Powergen PLC	02/27/00	$8.80	$24.85	182.35%	63.37%	115.56%	$466.8
MidAmerican Energy Holdings Company	Investor group	10/24/99	$15.59	$35.05	124.81%	20.58%	25.69%	$272.2
Unicom Corporation	PECO Energy Company	09/22/99	$23.51	$34.40	46.36%	49.01%	22.72%	$265.8
Florida Progress Corporation	Carolina Power & Light Company	08/22/99	$19.70	$54.00	174.08%	51.35%	89.39%	$410.2
CMP Group, Inc.	Energy East Corporation	06/14/99	$16.79	$29.50	75.72%	78.19%	59.20%	$344.8
TNP Enterprises, Inc.	Investor Group	05/24/99	$23.21	$44.00	89.59%	40.00%	35.84%	$294.2
Eastern Utilities Associates	National Grid Group PLC	02/01/99	$18.29	$31.46	72.05%	61.42%	44.25%	$312.4
New England Electric System	National Grid Group PLC	12/11/98	$29.30	$53.75	83.48%	62.49%	52.16%	$329.5
PacifiCorp	Scottish Power PLC	12/06/98	$13.47	$25.13	86.56%	54.51%	47.19%	$318.8
Commonwealth Energy System	BEC Energy	12/05/98	$20.75	$44.10	112.58%	54.79%	61.68%	$350.2
CILCORP Inc	AES Corporation	11/23/98	$26.24	$65.00	147.71%	62.91%	92.92%	$417.8
MidAmerican Energy Holdings Company	CalEnergy Company, Inc.	08/11/98	$12.99	$27.15	109.07%	25.20%	27.49%	$276.1
Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.	05/10/98	$27.92	$58.50	109.52%	60.21%	65.94%	$359.4
Nevada Power Company	Sierra Pacific Resources	04/29/98	$16.33	$26.00	59.20%	52.88%	31.30%	$284.4
KU Energy Corporation	LG&E Energy Corporation	05/20/97	$17.29	$40.71	135.48%	56.38%	76.39%	$382.0
						Min:	**-1.75%**	**$212.8**
						Max:	**116.90%**	**$469.7**
						Mean:	**45.59%**	**$315.3**
						Median:	**39.70%**	**$302.6**
						Std. Dev.:	**30.22%**	**$65.4**
						Count:	**36**	**36**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional
[3] Source: SEC Filings
[4] Equals ([3] - [2]) / [2]
[5] Source: Bloomberg Professional
[6] Equals [4] x [5]
[7] Equals UNS Electric's OCRB x (1 + [6])

AEB

ATTACHMENT A

Ann E. Bulkley
Vice President

Ms. Bulkley has over 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 worked on acquisition teams with investors seeking to acquire utility assets, providing valuation services including an understanding of regulation, market expected returns, and the assessment of utility risk factors. In addition, Ms. Bulkley has over 15 years of valuation experience assisting clients with valuations of public utility and industrial properties for ratemaking, purchase and sale considerations, ad valorem tax assessments, and accounting and financial purposes.

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 been instrumental in developing Concentric's cost of capital practice including developing the analytical foundation, providing strategic advice to expert witnesses, counsel and company staff and providing expert testimony. Ms. Bulkley has prepared cost of capital testimony and supporting analysis for at least forty Federal and State regulatory proceedings over the past five years. Representative projects have included:

- 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.
- CenterPoint Energy: Provided analytical support and testimony development for Concentric expert witnesses in seven rate proceedings for electric and natural gas operations in Arkansas, Minnesota, Oklahoma and Texas.
- Ameren: Provided analytical support and testimony development for Concentric expert witnesses in four rate proceedings for electric and natural gas operations in Illinois and Missouri.
- Potomac Edison Power Company: Provided analytical support and testimony development for Concentric expert witnesses in six rate proceedings in Delaware, Maryland, New Jersey, and Washington DC.

- 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.

- Portland Natural Gas Transmission: Provided testimony strategy as well as analytical support for cost of capital testimony before the Federal Energy Regulatory Commission.

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. In these assignments, Ms. Bulkley has relied on the traditional approaches to valuation including income, cost and comparable market transactions analyses as well as other simulation based valuation methodologies.

Representative projects/clients have included:

- 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.

- 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.

- Confidential Utility Client: Prepared valuation of fossil and nuclear generation assets for financing purposes for regulated utility client.

- Prepared a valuation of numerous 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. Assisted clients in implementing generation divestiture programs. Acted as a liaison between the bidders and the seller in the divestiture process. Provided documentation, detailed due diligence and marketing support. Participated in site tour development, training and implementation.

- Prepared a valuation of numerous 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 VAR for the selling utility.

- Prepared a valuation of several FirstEnergy generating facilities using the income, cost, and comparable sales approaches as well as risk analysis. Prepared an independent report.

- Prepared valuation of fossil generating assets 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 across with analysis to support investor-owned and municipal utility clients in the preparation of rate cases.

- 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

EXPERT TESTIMONY OF ANN E. BULKLEY

SPONSOR	DATE	CASE/APPLICANT	DOCKET /CASE NO.	SUBJECT
Indiana Utility Regulatory Commission				
Kokomo Gas And Fuel Company	09/10	Kokomo Gas And Fuel Company	Docket No. 43942	Fair Value
Northern Indiana Fuel And Light Company, Inc.	09/10	Northern Indiana Fuel And Light Company, Inc.	Docket No. 43943	Fair Value
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
North Dakota Public Service Commission				
Northern States Power Company-MN	12/12	Northern States Power Company-MN	C-PU-12-813	Return on Equity
Northern States Power Company-MN	12/10	Northern States Power Company-MN	C-PU-10-657	Return on Equity

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	DOCKET NO. E-04204A-12-____

Direct Testimony of

Dallas J Dukes

on Behalf of

UNS Electric, Inc.

December 31, 2012

TABLE OF CONTENTS

I. Introduction 1

II. Pro Forma Adjustments 4

III. Rate Base Adjustments 6

- A. Acquisition Discount 6
- B. Post-Test Year Plant 8
- C. Asset Retirement Obligation 9
- D. Working Capital 9

IV. Operating Income Adjustments 13

- A. American Recovery and Reinvestment Act 13
- B. Non-Retail Revenue and Purchased Power 13
- C. Purchased Power and Fuel Adjustment Clause 14
- D. Renewable Energy Standard & Tariff and Demand-Side Management 15
- E. Payroll Expense 15
- F. Payroll Tax Expense 16
- G. Pension and Benefits 16
- H. Post-Retirement Medical 17
- I. Rate Case Expense 17
- J. Bad Debt Expense 17
- K. Depreciation and Amortization Expense Annualization 18
- L. Incentive Compensation 22
- M. Long-Term Incentive Compensation and Supplemental Executive Retirement Plan 28
- N. Injuries and Damages 29
- O. Membership Dues 29
- P. Building Allocation 29
- Q. Post-Test Year Depreciation Expense 30
- R. Remediation Expense 30

V. Proposed Changes to UNS Electric's Line Extension Policy – Section 7, Rules and Regulations 31

VI. Summary of Schedules 36

- A. "A" Schedules 36
- B. "B" Schedules 37
- C. "C" Schedules 40
- D. "E" Schedules 41

Exhibits:

Exhibit DJD-1 Summary of Interim NNS Rates

Exhibit DJD-2 Audited Financial Statements for 2011 and 2010

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am the Senior Director of Pricing and Economic Forecasting for Tucson Electric Power Company ("TEP"). I am responsible for monitoring and determining revenue requirements, customer pricing and rates structures for all the regulated subsidiaries of UNS Energy Corporation ("UNS Energy"), including UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Please describe your background and work experience.

A. I hold a Bachelors of Science degree with a concentration in Accounting from Indiana University and a Master of Business Administration degree from Anderson University. I am also a Certified Public Accountant. I have over 20 years experience within the utility industry. Before assuming my current position, I was employed as the Director of Accounting for TEP.

Prior to working for TEP, I was employed by Citizens Gas & Coke Utility ("Citizens Gas"), for approximately five years. Citizens Gas serves approximately 265,000 customers in the Indianapolis, Indiana area. The majority of my time at Citizens Gas was spent as the Controller.

Before then, I was the Controller and Director of Regulatory Affairs for Fountaintown Natural Gas Company, and Southeastern Indiana Natural Gas Company. Prior to that, I

was employed by the Indiana Office of Utility Consumer Counselor ("OUCC") for approximately seven years. The majority of my time at the OUCC was spent as a Principal Accountant. My primary duties at the OUCC were to perform professional investigative audits and to represent the public's interest as an expert witness in proceedings before the Indiana Utility Regulatory Commission.

Q. Could you please summarize your Direct Testimony?

A. I am supporting the Company's request for a rate increase by sponsoring Schedules A-1, A-2, and A-5, Schedules B-1, B-2, B-3, B-4 and B-5, and the pro forma accounting adjustments on Schedule B listed below:

- Acquisition Discount
- Post Test Year Plant
- Asset Retirement Obligation; and
- Working Capital.

Schedules C-1, C-2 and C-3, and the pro forma accounting adjustments reflected on Schedules C listed below:

- American Recovery and Reinvestment Act;
- Non-Retail Revenue and Purchased Power;
- PPFAC Adjustment;
- REST and DSM;
- Payroll Expense;
- Payroll Tax Expense;
- Pension and Benefits;
- Post Retirement Medical;
- Rate Case Expense;
- Bad Debt Expense;

- Depreciation & Amortization Expense Annualization;
- Incentive Compensation;
- Injuries and Damages;
- Membership Dues;
- Building Allocation;
- Post Test Year Depreciation;
- Remediation Expense; and
- Current Income Taxes.

I am also sponsoring UNS Electric's proposed changes to its line extension policy.

Q. Please describe the information contained in summary Schedule A-1.

A. Schedule A-1 provides a summary of the increase in revenue requirement that UNS Electric as is seeking through a rate increase in this case. Lines 1 through 8 of Schedule A-1 present the data utilized in determining the Company's revenue requirement. The data presented pursuant to three valuation methodologies: (1) original cost rate base ("OCRB"); (2) reconstruction cost new less depreciation ("RCND"); and (3) fair value rate base ("FVRB"). FVRB is determined by adding together the original cost and RCND rate base amounts and dividing that total by two. This gives equal weight to both methods when determining the fair value amount. This method of determining the fair value is consistent with prior Commission practice.

The test year that the Company utilized for this rate case is the twelve months ending June 30, 2012. As set forth in Schedule A-1, the OCRB is $216.6 million and the RCND rate base is $356.1 million. Under standard Arizona Corporation Commission ("Commission") practice, the fair value rate base is considered to be $286.3 million.

Schedule A-1 supports a finding that UNS Electric presently has an operating income deficiency of $4.6 million and is requesting an increase in base rates of $7.5 million. This is an increase of 4.5% over test year retail revenues.

II. PRO FORMA ADJUSTMENTS.

Q. Please explain the consideration of pro forma adjustments in the rate case process.

A. Public utility rates are based on the prudently incurred costs of providing safe, reliable service. The revenue requirement is based on a test year that reflects a level of operating revenues, expenses and net plant investment that is representative of normal conditions that are expected to exist during the time that resulting rates will be in effect. The revenue requirement calculation also contains a component to afford the utility a reasonable opportunity to achieve a fair rate of return.

Pro forma adjustments are made to recorded test-year amounts that are not required for the provision of service or that are not representative of the levels expected to occur during the period in which the new rates will be in effect. Such adjustments may be made in the form of eliminations, annualizations, or normalizations.

Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service; thus, not eligible for reflection in revenue requirements.

Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. They are typically computed using end-of-test-year quantities and the most current known and measurable prices and rates. Examples in this case include restating test year operating revenues to reflect customer

levels at the end of the test year, adjusting payroll expense to reflect current salary rates and changes in employee levels during the test year, and adjusting recorded depreciation expense to reflect the full effect of plant additions and retirements during the test year.

Normalization adjustments reflect that the recorded test year operating revenues and expenses may not be representative of a normal level for ratemaking purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions eligible for reflection in revenue requirements are incurred at intervals less frequently than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the test year may not be viewed as "normal," thus requiring a restatement for ratemaking purposes. Normalization adjustments are made in such instances when a test year level of revenues or expenses is not representative of what would be expected on an on-going basis. Examples in this case include the adjustment for bad debt expense, the overtime factor implicit in the payroll adjustment, and the adjustment to normalize the level of outside legal expense.

Q. Were the pro forma adjustments that you are sponsoring in your Direct Testimony prepared by you or under your supervision?

A. Yes, they were.

III. RATE BASE ADUSTMENTS.

A. Acquisition Discount.

Q. Please explain the Acquisition Discount adjustment.

A. Effective August 11, 2003, UniSource Energy acquired from Citizens Communications Company ("Citizens") its remaining electric utility assets located in Arizona. The Commission approved a Settlement Agreement regarding this acquisition ("Settlement Agreement") in Decision No. 66028 (July 3, 2003) subject to the conditions set forth in the Decision. This adjustment is necessary in order to properly reflect the discount, or negative acquisition premium, authorized by the Commission. Decision No. 66028 calls for the use of a $93.6 million "negative acquisition premium" (see page 8, line 20) in the calculation of rate base for ratemaking purposes to reflect this lower purchase price.

Q. Is an acquisition adjustment normally recognized?

A. No, the Commission has not generally recognized acquisition adjustments. Under Commission rules, the original cost of utility property is the cost "at the time it is first devoted to pubic service." Arizona Administrative Code ("AAC") R14-2-102.A.6. In the case of an asset sale of a utility, the assets will have been devoted to service before the sale. Thus, the sale does not affect the original cost of the assets, either positively or negatively. In other words, the relevant cost is the "cost of [the] property to the person first devoting it to public service." AAC R14-2-103.A.3.e. Thus, an acquisition adjustment is normally not appropriate. However, UniSource Energy and the Commission did agree to the specific negative acquisition adjustment noted above. This pro forma adjustment is necessary so that the acquisition adjustment is limited for ratemaking purposes to the specific value agreed to by the Company and approved by the Commission.

Q. Please explain further.

A. UniSource Energy actually paid $104.3 million less than the original cost for the electric assets that it acquired from Citizens. In accordance with United States Generally Accepted Accounting Principles ("GAAP"), this amount had to be shown on the Company's books as a negative acquisition adjustment. This GAAP acquisition discount is larger than the acquisition discount approved by the Commission as described above. Normally, an acquisition discount would not be considered for ratemaking purposes at all. However, in this case, the discount agreed to by the Company must be recognized. Essentially, this pro forma adjustment takes the GAAP discount and reduces it to the value of the discount authorized by the Commission. Put another way, the GAAP discount must be eliminated for ratemaking purposes, thus increasing its original cost rate base. This increased rate base must then be reduced by the value of the agreed upon discount. Overall, this adjustment results in a net increase to rate base.

Q. Please explain the accounting details further.

A. When I refer to the "value" of the agreed upon discount, I mean the $93.6 million figure stated in the Settlement Agreement, less amortization. The amortization has been calculated through June 30, 2012. Amortization reflects the fact that the assets which were purchased do not have an infinite life. Pursuant to the Settlement Agreement approved by the Commission, the amortization rate is the same as the depreciation rate for corresponding plant accounts. (Settlement Agreement at page 18.) According to Commission and the Federal Energy Regulatory Commission ("FERC") directives, the acquisition adjustment was a credit to accumulated depreciation. (Settlement Agreement at page 17.)

Q. Is the Acquisition Discount adjustment consistent with the last UNS Electric rate case, Docket No. E-04204A-06-0783?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Electric rate case order, Decision No. 71914 (September 30, 2010)("the last UNS Electric Rate Order").

B. <u>Post Test-Year Plant.</u>

Q. Please describe your proposal for including Post Test-Year Plant.

A. UNS Electric has adjusted its ACC jurisdictional rate base to include approximately $13.1 million of used and useful solar projects and other plant additions that have been, or are expected to be, placed in service between July 1, 2012 and June 30, 2013. These projects will be benefiting customers by the time new rates are effective.

Q. What are the benefits of including Post Test-Year Plant in rate base?

A. It more closely aligns the recovery of costs with the benefits that are currently being provided to existing customers. It also lowers the cost to customers by limiting the amount of AFUDC charged to the assets, thereby reducing the future depreciation and carrying costs associated with this plant. Additionally, the timely recovery of costs necessary to maintain a safe, reliable electric system is necessary to mitigate larger rate impacts that result from the use of historic test years combined with little to no increase in sales.

Q. Has the Commission allowed the use of Post Test-Year Plant before?

A. Yes. In the recent rate case settlement for Arizona Public Service Company ("APS"), the Commission approved the inclusion of Post-Test Year Plant, including renewable energy projects, in rate base for a period of fifteen months after the test year. See Decision No.

73183 (May 24, 2012). The Commission has also allowed Post-Test Year Plant in numerous other cases, including: Rio Rico Utilities, Inc., Decision No. 67279 (October 5, 2004); Arizona Water Co., Decision No. 66849 (March 19, 2004); and Bella Vista Water Co., Inc., Decision No. 65350 (November 1, 2002).

C. <u>Asset Retirement Obligation.</u>

Q. Please explain the Asset Retirement Obligation ("ARO") Adjustment.

A. The adjustment is necessary to remove the balances of ARO assets reported in Plant in Service. ARO assets exist only for those assets where there is a *legal* obligation to physically remove the assets at the end of their useful lives. In this rate case, the expected costs to remove the assets from Plant in Service in rate base are implicit in the Negative Net Salvage component of our depreciation rates, and used in the preparation of the depreciation annualization adjustment.

D. <u>Working Capital.</u>

Q. What is Working Capital?

A. Working Capital is generally viewed as investor funding in excess of the balance of net utility plant reflected in rate base that is required for the provision of utility service.

Q. What are the items of Working Capital for which the Company requests a return?

A. The components of Working Capital that the Company is requesting be included in rate base are:

(i) Materials and Supplies;

(ii) Prepayments; and

(iii) Cash Working Capital.

The amounts requested for rate base inclusion for the materials and supplies and prepayments are based on test-year recorded balances, adjusted to reflect normal levels. The cash working capital component was determined by the use of the Lead-Lag Study Methodology, to be covered in-depth later herein.

Q. What is Cash Working Capital?

A. The receipt of customer revenues for the provision of service, and the disbursement of cash for the payment of the various costs of providing service rarely occur simultaneously. This is the fundamental consideration underlying the concept of Cash Working Capital. Cash Working Capital is generally viewed as the component of working capital that represents the amount of invested cash required to pay day-to-day operating expenses incurred in rendering service to customers. It may either increase or decrease rate base. If the computation of Cash Working Capital produces a positive result, it is indicative that there is an additional investment for which a return is warranted, and thus, the amount is added to rate base. If the computation produces a negative result, there is an implicit non-investor funding of Cash Working Capital, requiring a rate base deduction.

Q. Please explain the Working Capital adjustment.

A. The Working Capital adjustment was computed in two pieces. First, as indicated on page 2 of Schedule B-5, the recorded end-of-test-year balances for Materials and Supplies, and Prepayments are adjusted to reflect the 13-month average monthly balances, in recognition of the variability in the monthly balances of the accounts. This is consistent with the treatment of such accounts in prior rate cases.

Second, Working Capital is adjusted for the reflection in rate base of a measure of Cash Working Capital, developed through the preparation of a comprehensive lead-lag study.

Q. What is a lead-lag study?

A. A lead-lag study is a detailed analysis of the dynamic movement of funds throughout the organization, between the receivable and payable balance sheet accounts and related revenues and expenses that are reflected in the operating income component of revenue requirements. The method is generally viewed as the most accurate measure of Cash Working Capital. The Commission has stated a clear preference for the use of lead-lag studies in support of requested working capital amounts in rate cases.

The focal point of all lead-lag studies is the "point of service." That is the instant in time at which customers receive service and, coincident therewith, the utility incurs the cost of providing that service. A lead-lag study measures the average length of time between the provision of service and the ultimate receipt of payment from the customer ("revenue lag"). The result is compared with the average length of time between the point at which the utility incurs a cost of providing that service and the date upon which it makes the related cash disbursement ("payment lead" if payment precedes the cost benefit, or "payment lag" if the payment occurs after the cost benefit). Cash Working Capital reflects the effect on costs of service of the difference between the revenue lag and payment leads or lags.

As may be seen on page 3 of Schedule B-5, a lead-lag study computes the Cash Working Capital associated with each component of cost of service. The revenue lag is constant for all cost categories. The various major expenses are analyzed separately for purposes of developing a specific payment lead or lag. Once the applicable expense lead or lag is known, it is compared with the revenue lag to determine the net lead or lag for that study category. After dividing the net lead or lag by 365 days to arrive at an annual percentage factor, the result is multiplied by the corresponding adjusted test year expense amount to quantify the Cash Working Capital requirement associated with that cost of service item.

Consistent with past Commission policy, the effect of non-cash expenses such as depreciation and deferred income taxes are reflected in the study at a zero requirement.

Q. How was the average revenue lag computed?

A. The revenue lag is comprised of three distinct parts: the service lag, the billing lag, and the customer payment lag.

The service lag is measured from the midpoint of the period of service to the end of the period, the date upon which meters are read. A key underlying assumption is that service is taken uniformly throughout the period. With each customer being billed under twelve monthly billing cycles during the year, the average service lag is computed as 15.21 days [365 days / (12 X 2)].

The billing lag is typically measured from the meter read date to the date customer bills are prepared and balances entered into accounts receivable. The billing lag was computed based on actual meter read dates and bill mailing schedules used by UNS Electric during the test year.

The customer payment lag is measured from the point at which the customer bill enters accounts receivable to the date that either a payment is received or the account is written off as uncollectible. That lag was determined by computing the average accounts receivable turnover for six months during the test year. The accounts receivable turnover measures the average time during which a balance remains in accounts receivable and is computed by dividing the sum of the daily ending balances of accounts receivable by the sum of revenues billed and charged to accounts receivable during the study month.

Q. How were the payment leads and lags computed?

A. The payment leads and lags were developed based on analyses of actual payment history, contractual and statutory payment dates, and samples of expenditures.

Q. What was the overall result of the lead-lag study?

A. The study showed that there was negative cash working capital and a corresponding decrease was made as a pro forma adjustment to rate base.

IV. OPERATING INCOME ADJUSTMENTS.

A. American Recovery and Reinvestment Act ("ARRA").

Q. Please explain the ARRA Adjustment.

A. This adjustment is necessary to eliminate the impact of a "non-recurring" Federal grant and the associated expenses incurred within the test year.

B. Non Retail Revenue and Purchased Power.

Q. Please explain the Non Retail Revenue and Purchased Power Adjustment.

A. This adjustment is necessary because the revenue associated with wholesale sales is recorded and 100% of that is also booked as a PPFAC regulatory liability (ultimately to credit customers through the PPFAC). There are also expenses associated with producing those revenues and those are expensed as incurred. Without adjustment the profit on those sales would flow through the income statement. Therefore an adjustment is made to the Company's actual books to bring the expenses up to the revenue level.

By making that adjustment, there is no operating income from wholesale transactions. That "profit" is maintained in the PPFAC regulatory liability, which is then credited to customers through the PPFAC process. So, the PPFAC rate reflects any profit in wholesale transactions and reduces the ultimate cost to customers. Therefore, we take the cost and the revenue out of the test year (which zero themselves out) because the profit on wholesale transactions is already reflected in the PPFAC rates, and the total average cost of PPFAC eligible expenses being passed along to customers.

C. <u>Purchased Power and Fuel Adjustment Clause ("PPFAC") Adjustment.</u>

Q. Please explain the PPFAC Adjustment.

A. The adjusted test-year fuel revenue and expenses that are reconciled through the PPFAC process do not reflect the most update cost estimates. The test year ending June 30, 2012, has primarily the PPFAC cost projections filed in April of 2011 as reflected in the PPFAC rate in effect June 2011 through May 2012.

This adjustment is necessary so that the adjusted test-year cost of service reflects the Company's most recent estimation of fuel, purchased power and purchased transmission expense to be recovered from our customers when the rates established in this proceeding are anticipated to be in effect. Therefore a cost estimate for the 2014 PPFAC rate effective period was used.

D. Renewable Energy Standard & Tariff ("REST") and Demand-Side Management ("DSM").

Q. Please explain the REST and DSM Adjustment.

A. This adjustment excludes from test year revenue and expense activity directly related to the REST and DSM adjustor programs. These programs have funding mechanisms separate from revenue requirements, and should thus be excluded from test year revenue and expenses.

E. Payroll Expense.

Q. Please explain the Payroll Expense Adjustment.

A. The Payroll Expense Adjustment is intended to reflect a normal level of salaries and wages in test year operating expenses. The Payroll Expense Adjustment was computed based on an average of operations and maintenance ("O&M") wages for the 12 month periods ended June 2011 and 2012, and reflects the known and measurable wage increase for 2013 and the estimated wage increase for 2014 - which will precede the anticipated date rates established in this proceeding will go into effect. Therefore, allowing for the adjustment to be revised to reflect the known and measurable payroll increase that will be in effect during the first year of the new rates.

Q. Is the Payroll Expense Adjustment consistent with the last UNS Electric rate case, Docket No. E-04204A-09-0206?

A. No. It's a simplified approach that was approved by the Commission in the last TEP and UNS Gas, Inc. ("UNS Gas") Rate Orders.

F. Payroll Tax Expense.

Q. Please explain the Payroll Tax Expense Adjustment.

A. The Payroll Tax Expense Adjustment reflects the employer's taxes (Social Security and Medicare) that correspondingly increase as a result of the increased expense from the Payroll Expense Adjustment. UNS Electric's effective employer's tax rate for 2012 was applied to the increased payroll expense reflected in the Payroll Expense Adjustment.

G. Pension and Benefits.

Q. Please explain the Pension and Benefits adjustment.

A. The Pension and Benefits adjustment is intended to reflect in operating expenses a level of pension and benefits expense reflecting the end-of-test-year work force, current pension and benefit actuarial expense level, and a normal level of business activity. The employee benefits covered by this adjustment include pensions, the Company's share of contributions to the employees' 401(k) plan, and current medical costs.

Q. Is the Pension and Benefits adjustment consistent with the last UNS Electric rate case, Docket No. E-04204A-09-0206?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Electric Rate Order.

H. Post Retirement Medical.

Q. Please explain the Post Retirement Medical adjustment.

A. The Post Retirement Medical adjustment is intended to reflect in operating expenses a level of post retirement medical payments reflecting the end-of-test-year work force level.

Q. Is the Post Retirement Medical adjustment consistent with the last UNS Electric rate case, Docket No. E-04204A-09-0206?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Electric Rate Order.

I. Rate Case Expense.

Q. Please explain the Rate Case Expense adjustment.

A. The Rate Case Expense adjustment addresses the outside costs already incurred, and expected to be incurred, in connection with this rate case. This amount is an estimate of the anticipated final cost and may be updated before this proceeding concludes. The adjustment amortizes the estimated expense over two and one half years. This is the approximate time period between when UNS Electric filed this rate case and when the next rate case will likely occur.

J. Bad Debt Expense.

Q. Please explain the Bad Debt Expense adjustment.

A. Bad Debt Expense is adjusted to a level reflective of final, pro forma weather-normalized, customer-annualized test year operating revenues, and the average

percentage of actual account write-offs experienced during the past three years. This method of calculating bad debt expense is consistent with past Commission accepted practice.

Q. Is the Bad Debt Expense adjustment consistent with the last UNS Electric rate case, Docket No. E-04204A-09-0206?

A. Yes. The adjustment was prepared and calculated in the same manner as was approved by the Commission in the last UNS Electric Rate Order.

K. <u>Depreciation and Amortization Expense Annualization.</u>

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

A. The depreciation adjustment is intended to reflect in cost of service an annualized level of depreciation expense based on the depreciable plant in rate base at the end of the test year, using current approved rates, except for generation assets, for which the Company is requesting approval to begin accruing net cost of removal as a component of depreciation expense, and for UNS Electric's investments in solar assets.

Q. Why is this adjustment necessary?

A. The amount of depreciation expense recorded on the UNS Electric books during the test year reflects less than a full year of depreciation for assets placed in service during the period and that are included in rate base. Moreover, it includes depreciation computed on assets retired during the test year, and thus, not included in rate base. Finally, the depreciation computed for generation assets does not reflect any amounts associated with the costs of removing them at the end of their useful service lives, or for the cost of new solar technology being deployed. This adjustment produces an annual depreciation expense

consistent with the level of depreciable plant in rate base, and meets the definition of being known and measurable.

Q. How was the adjustment computed?

A. The adjustment was calculated by first computing the pro forma annualized depreciation expense and then deducting test year recorded depreciation expense. For generation assets pro forma annual depreciation was computed by multiplying the end-of-test-year plant balance in rate base at each generating location and related depreciable FERC plant account, by the respective current or proposed depreciation rate. For other accounts, annual depreciation was computed using the end-of-test-year balance in the respective accounts multiplied by the approved current depreciation or amortization rate. For certain assets, a portion of depreciation is capitalized as part of the cost of constructing new assets; thus, such amounts were excluded from the calculation.

Commission – Decision No. 66028 – requires the Company to account for the resulting acquisition discount as a subaccount of Account 108, Accumulated Depreciation, and that it be amortized as a reduction of depreciation expense using the same lives being used to depreciate the corresponding acquired assets. Annualizing the amortization of the acquisition discount is a part of, and was computed in the same manner as other elements of, the depreciation annualization adjustment.

Q. Please describe the depreciation rates currently being used by UNS Electric.

A. The current depreciation rates were developed by Company consultant Dr. Ronald White of Foster & Associates and submitted as part of the last UNS Electric rate case filing. Dr. White's study reflected the net investment in utility plant in service as of December 31, 2008. The Commission approved them in Decision No. 71914 (September 30, 2010) – from UNS Electric's last rate case. As directed by the Commission in Decision No. 70360

(May 27, 2008) (UNS Electric's first rate case order), depreciation expense and accumulated depreciation are recorded on a bifurcated basis with capital recovery and negative net salvage ("NNS") (which is the difference between accrued and realized costs of removal and salvage proceeds) tracked separately.

Q. Is the Company submitting a new depreciation study in connection with this rate case?

A. No, it is not. As of the end of the test year, only three years have passed since the last study, and except for the two changes for which approval of which is being sought in this case, an analysis of plant transactions occurring since the last study indicated that an new study would likely not produce significantly different depreciation rates, thereby making a new study unnecessary at this time.

Q. What changes affecting depreciation have occurred since the last UNS Electric rate case?

A. One change relates to the expected cost of decommissioning the Company's generation assets at Valencia Generating Station ("Valencia") and at Black Mountain Generating Station ("BMGS"). Neither UNS Electric, nor the previous owner Citizens Communications had ever conducted a study to estimate the cost of dismantling the facilities at Valencia. Moreover, at the time of the last rate case, BMGS had just been placed in service and was then owned by affiliate Unisource Energy Development. Accordingly, there was no basis upon which a cost of removal factor could have been included in current or previous UNS Electric depreciation rates. Depreciation rates should reflect the original cost of plant assets plus the estimated cost of removing them at the end of their useful service lives.

The other change reflects the commencement of UNS Electric investment in solar projects under Arizona's Renewable Energy Standard Tariff Rules requirements. At the time of the last depreciation study, no such investments had yet been made. The Company is seeking approval of a proposed rate for depreciating such assets.

Q. What removal cost estimates did the decommissioning studies produce?

A. As more fully explained in the testimony of Company witness Mr. DeConcini, the estimates were $1,133,000 for Valencia and $1,771,000 for BMGS, in 2011 dollars.

Q. What is your proposal for reflecting the decommissioning cost estimates in the rates used to depreciate UNS Electric's generation assets?

A. Typically, in a study to develop new depreciation rates for generation assets, current decommissioning cost estimates are escalated to the expected removal date using projected level of inflation, and then adjusted to reflect the effect of interim retirements. In this instance, where no depreciation study is being performed, UNS Electric is requesting approval to implement an interim NNS rate to begin using with the existing approved capital recovery rates now being used to depreciate Valencia and BMGS generation assets. This is with the expectation that the rate will be revisited in the next full depreciation study prepared for submission in a future UNS Electric rate case. The interim NNS rates currently being requested are summarized on **Exhibit DJD-1**.

Q. How did you propose to compute the new, proposed NNS depreciation rates?

A. Using the decommissioning cost estimates, the expected remaining lives at the time of the last study (December 31, 2008) less three years, and the recorded original cost of the Valencia and BMGS generation assets as of the end of the test year, the computation would be as follows:

$$\frac{\text{Decommissioning Estimate}}{\text{Remaining Life at 12/31/11}} = \text{Required Annual Recovery}$$

$$\frac{\text{Required Annual Recovery}}{\text{Original Cost at 12/31/11}} = \text{Annual Depreciation Rate}$$

Q. What rate are you requesting for use with the Company's investment in solar assets?

A. The investment in solar assets is being recorded in Account No. 344, Other Production, Generators. A total rate of 2.33% for Valencia and 2.62% for BMGS was approved in the last UNS Electric rate case; however, no solar assets were in service at the time. The Company is requesting that Account 344 be bifurcated such that existing and new non-solar assets continue to be depreciated at the currently approved rates, and that solar assets be segregated and depreciated at a rate of 5.00% with no NNS, reflecting a 20-year expected service life and the fact that no retirement data exists upon which a NNS factor could be developed. That is the rate at which solar investments made by affiliate TEP have been depreciated and are included in the depreciation study filed in the TEP rate case now in progress.

L. <u>Incentive Compensation</u>.

Q. What is Short-Term Incentive Compensation?

A. Short-Term Incentive (cash-based) Compensation is an integral part of UNS Electric's compensation and benefits program. Incentive compensation may be viewed as a "lump-sum salary payment" because it is simply a core piece of compensation based on the benchmarked total compensation needed to attract and retain qualified personnel. The Short-Term Incentive Compensation is effectively withheld salary. As such, UNS Electric could either raise annual salaries or use this "at risk" compensation plan targeted

at achieving goals to benefit customers, and only pay the compensation upon completed performance.

Q. Which employees are eligible for the Short-Term Incentive Compensation program?

A. All non-union employees are eligible for the Short-Term Incentive Compensation program. Any form of compensation provided to the union work force must be collectively bargained. Currently, the union workforce is not comfortable with the "at risk" component of an incentive program or the ability to reward one employee more than another, as the incentive program is designed to do. Rather, the union has negotiated pay scales to increase base wages.

Q. What are the benefits to UNS Electric retail customers of having an "at risk" pay component of compensation as opposed to increasing an employee's annual salary amount?

A. The short-term incentive program benefits retail customers by enabling the entire organization to focus on key customer, operational and financial objectives. Having an "at risk" component of compensation allows a company to focus its effort toward achieving measurable, meaningful goals and only rewarding employees when those goals are met. For example, the goals of the 2012 program benefited the UNS Electric retail customers as follows:

Category	Goals	Benefit to Retail Customers
Customer	• Excellent operations • O&M cost containment	• Having goals that specifically target operations (system availability and reliability) and cost containment.
Community/ Environment	• Community volunteerism • Environmental focus: renewable energy and energy efficiency	• Partnering with the community helps to identify customer service needs and issues. • Meeting renewable goals established by the Commission.
Employee	• Safe work place • Improve processes	• Reducing injuries in the workplace reduces operating costs. • Making process improvements reduces operating costs.
Financial Strength	• Net income target • Incremental value	• Enhances the ability of the Company to conduct business. A financially strong company is better able to secure credit from vendors and lenders. This allows UNS Electric to timely procure goods and services for operations, which promotes a higher quality of service to customers and lower operational costs. This also benefits the retail customer because the company is able to raise capital at a lower cost to build the infrastructure needed to serve the retail customers.

Using an incentive compensation program is less costly than increasing base salaries because incentive compensation does not automatically drive increases in other employee costs that are included in "base compensation" such as: vacation pay; sick pay; long-term disability; 401(K) employer matching contributions; and pension expense. As a result, the incentive compensation program is less costly than increasing base salaries.

Q. What are other benefits to retail customers of the Short-Term Incentive Compensation program?

A. Even though this program creates "at-risk" compensation for employees, it contributes to the overall employment package offered by UNS Electric. This allows the Company to

be competitive in attracting and retaining highly qualified employees. Retention of employees helps to reduce costs by having a more experienced work force to provide safe, reliable service to the retail customers. Attracting and retaining a qualified work-force, in addition to the retail customer benefits described in the preceding table, demonstrates that the Short-Term Incentive Compensation costs are prudent.

Q. Please explain the Short-Term Incentive Compensation Expense Adjustment.

A. UNS Electric's Performance Enhancement Plan ("PEP") is based on specific, pre-established goals with awards measured on specific Company performance, and is designed to award non-union employees for their contributions to UNS Electric. The payout is determined based on year-end results and payments are made to employees the following year (usually in the first quarter).

The Adjustment produces a pro forma test year expense level reflecting 50% of officers and other senior management (collectively referred to as "Upper Management") costs allocate to UNS Electric and 100% of the average PEP for the past three years (2010-2012) for the remaining employees.

Q. Please explain why part of the PEP expense is at 50% and part is at 100%.

A. To be more aligned with past Commission decisions, the recovery of PEP for Upper Management is limited to 50%. The following Commission decisions appear to provide support for differentiating between recovery of officer and non-officer incentive compensation:

- **Southwest Gas Corporation ("SWG") – Decision No. 70665**: allowed recovery of 50% of SWG's Management Incentive Program ("MIP"). As set forth in the direct testimony of Staff witness Ralph C. Smith in that docket [pages 27-28], SWG's MIP only applied to upper management, specifically to: CEO, President,

Executive VP, Senior VP, Vice President and Director/Senior Manager (non-officers). Employees below these upper management levels were not eligible for MIP.

- **Arizona Public Service Company ("APS") – Decision No. 69663**: allowed recovery of 100% of APS' Cash-Based Incentive Compensation program. As set forth in the direct testimony of APS witness Mark K. Gordon (ay page 11), the APS plan applied to a wide spectrum of employees and not just upper management. Mr. Gordon further testified (also at page 11) that, the APS plan *"has five distinct organization levels of participation – PNW Chair/CEO, Officer (includes APS President, EVP and VP), Senior Management, Management and Broad-Based Employees."* In Decision No. 69663, page 37, the Commission adopted the Staff's position of not opposing inclusion of the program expense because the APS' "at risk" pay program ties employee performance to the customer's benefit:

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

Q. If APS received 100% rate recovery of short-term incentive compensation for Upper Management in Decision No. 69663, why is UNS Electric only asking for 50% recovery for short-term incentive compensation for Upper Management?

A. UNS Electric is proposing 50% recovery for Upper Management because UNS Electric's proposal is then consistent with both Decision Nos. 69663 and 70665. The underlying rationale for including 100% of APS' short-term incentive compensation expense in rates per APS' Decision No. 69663 appears applicable to UNS Electric. However, in Decision No. 70665, as well as Decision No. 70011 (regarding UNS Gas), the Commission allowed only 50% recovery of "at risk" pay based on balancing the interests of retail customers and shareholders. In consideration of the cost recovery rationale underlying the APS, SWG and UNS Gas decisions, UNS Electric believes it is appropriate to separate Upper Management (who may focus more on both retail customers and shareholders) from the remaining employees (who focus on daily operations and service to retail customers).

Q. Are there more recent rate case decisions for both SWG and APS?

A. Yes. However, both cases were settled and the treatment of the cash-based incentive compensation is not entirely clear.

Q. Does the cash-based Short-Term Incentive Compensation program result in salaries and wages that exceed the market?

A. No. When the Short-Term Incentive Compensation is combined with the employees' base salaries, the total cash compensation approximates the median of the market, based on the most recent benchmark studies. The benchmarking information demonstrates that the amounts are reasonable.

M. <u>Long-Term Incentive (Stock-Based) Compensation and Supplemental Executive Retirement Plan ("SERP").</u>

Q. Consistent with reducing Upper Management's short-term incentive expense by 50%, is it reasonable for UNS Electric to recover 50% of the allocated expenses from TEP's SERP and Officer Long-Term (Stock-Based) Incentive ("LTI") Compensation program?

A. Yes. The LTI Compensation program promotes the financial strength of UNS Energy and its subsidiaries, including UNS Electric, which benefits the retail customers by optimizing operational costs, providing access to capital needed to fund operations, and promotes employee retention. UNS Electric believes that equity awards encourage ownership of stock by executive officers and helps hold executive officers accountable for the long-term impact of their actions, which is in line with the interests of retail customers. The vesting provisions applicable to the awards encourage a focus on long-term operating performance, link compensation expense to the achievement of multi-year financial results, and help to retain executive officers.

The SERP expense is reasonable as it allows the Company to consistently provide benefits to all eligible employees without imposing limitations on select employees. The SERP expense is prudent as it is part of the compensation package needed to attract and retain highly qualified upper management.

Q. Is UNS Electric requesting any recovery of these expenses in this case?

A. No. While UNS Electric believes that 50% of the SERP and LTI Compensation programs are reasonable and prudent for recovery from retail customers, for purposes of this rate case, UNS Electric is not requesting recovery of these costs. UNS Electric reserves the right to request recovery of up to 100% of these costs in a future rate case. All cost

allocated to UNS Electric for LTI and SERP expense during the test year were recorded in FERC Account 426, below-the-line and UNS Electric is not proposing an adjustment to reflect any of those cost in this proceedings cost of service amount.

N. <u>Injuries and Damages.</u>

Q. Please explain the Injuries and Damages Expense Adjustment.

A. The Injuries and Damages Expense adjustment normalizes the test year expense to reflect the average annual expense for the 12 months periods ending June 2010, 2011 and 2012.

O. <u>Membership Dues.</u>

Q. Please explain the Membership Dues Expense adjustment.

A. This adjustment removes the portion of membership dues paid to Edison Electric Institute for legislative advocacy, and other dues paid to organizations that have been voluntarily excluded from pro forma operating expenses for purposes of this rate case.

P. <u>Building Allocation.</u>

Q. Please explain the Building Allocation Adjustment.

A. TEP allocates building expense, based on the level of services provided by TEP personnel to affiliates (including UNS Electric and UNS Gas). This cost allocation methodology has been accepted by the Commission in deriving the cost of service in the most recent rate cases for TEP, UNS Electric and UNS Gas.

The adjustment reflects a three-year average of hours of service provided by TEP personnel to UNS Electric times the most recent building allocation cost factor. The

adjustment results in an increase in cost being allocated to UNS Electric. This is because the test year only partially reflects the additional cost of a new office building owned by TEP.

Q. <u>Post Test-Year Depreciation Expense.</u>

Q. Please explain the Post Test-Year Depreciation Expense.

A. The Company annualized Post Test-Year Depreciation Expense based on the depreciable Post Test-Year plant addition to rate base.

R. <u>Remediation Expense.</u>

Q. Please explain the Remediation Adjustment.

A. As part of the acquisition of Valencia from Citizens, as approved by the Commission, UNS Electric accepted limited liability for remediation relating to pre-existing soil and groundwater contamination at the Valencia site. In December 2011, UNS Electric received a Remedial Alternatives Assessment for Valencia prepared by an outside consultant. Based on this assessment, UNS Electric recognized an expense of $231K in December 2011. UNS Electric has normalized the test year remediation expense to reflect a 36-month average level of recurring expense.

V. PROPOSED CHANGES TO UNS ELECTRIC'S LINE EXTENSION POLICY – SECTION 7, RULES AND REGULATIONS.

Q. Why has UNS Electric proposed changes to its Line Extension Policy?

A. UNS Electric is proposing changes to its Line Extension Policy ("Policy") to better align its Policy with TEP's line extension policy. Additionally, the Policy has been relocated from Section 9 to Section 7 of its Rules and Regulations ("Rules"). UNS Electric believes that the revised methodology will be easier for the Company to administer and for customers to understand. The revisions to the Policy are attached to the Direct Testimony of Lindy L. Sheehey as Exhibits LLS-1 (clean version) and LLS-2 (redlined version).

Q. What are the proposed changes to the general policy?

A. UNS Electric's general guidelines for the Policy, which apply to all applicants, remain largely unchanged. Subsection 7.C – "Line Extension Requirements" has been divided into seven new sections:

- Subsection C.1 applies to residential applicants for overhead facilities.
- Subsection C.2 applies to residential applicants for underground facilities.
- Subsection C.3 applies to extensions for non-residential applicants and is broken down into applicants under 21kV and 21kV to 69kV.
- Subsection C.4 applies to residential subdivision developers and Subsection C.5 applies to non-residential developers.

The Policy also has a new section for "Special Conditions" including:

- "Contracts";
- "Primary Service and Metering";
- "Advances under Previous Rules and Contracts";

- "Extensions for Temporary Service";
- "Exceptional Cases";
- "Special or Excess Facilities"; and "Unusual Loads".

Also, certain provisions were deleted from Subsection C.10 – "Other Conditions", because they are mentioned in other portions of the Rules. And finally, Subsection 7.D – "Construction/Facilities Related Income Taxes" has been revised as described below.

Q. How has the policy changed for Residential applicants, Subsection 7.C.1 and 2?

A. In the current Rules, residential customers are afforded three options on which to be evaluated: footage; revenue; and economic feasibility. The revised Rules now provides a residential applicant only with a line extension based on footage.

Previously, 400 feet of primary facilities for a line extension plus an additional 150 feet of a service line were considered "free footage". The revised Rule combines those distances to 550 feet to avoid any confusion and now explicitly states that the distance is calculated from the existing facility to the point-of-delivery. Consistent with the previous Rule, the cost for any facilities constructed in excess of 550 feet will be charged to the customer. The customer's cost is pro-rated and he or she may receive a refund if other permanent customers connect to the facilities constructed within five years, as shown in Subsection 7.C.1.c. Effectively, this is not a change from the current policy in how the customer is treated in regards to collecting or refunding his/her costs.

The revised Rules now show residential overhead and underground in their own separate sections. There is no change to how these applicants are treated under the Rules.

Q. What changes are being proposed for Non-Residential Customers (Subsection 7.C.3)?

A. In the current Rules, all non-residential customers are afforded three options on which to be evaluated: footage; revenue; and economic feasibility. Under the revenue option, when the cost of construction was less than $25,000, two years of estimated revenue was applied towards the cost of construction and the customer advanced the difference. The customer could receive a refund if their revenue was greater than what was estimated. The Company did not have any ability to collect additional dollars from the customer for over-estimated revenue. Under the economic feasibility option, when the cost of construction was over $25,000, five years of estimated revenue was applied to the cost of construction, maintenance, and ownership of the line and the customer advanced the difference. Similar to the revenue option, under the economic feasibility option, the customer could receive a refund, but over five years instead of two years. In addition, a construction true-up was performed for projects that cost over $25,000.

The new language has eliminated the $25,000 threshold for all non-residential customers and is using 50% instead of 100% of the estimated revenue initially to offset the cost of construction. The line extension will be designed and an estimated cost of construction on a per-customer basis. The Company then takes 50% of the estimated revenue for two years and applies that initially towards the cost of construction. After the construction is complete, a true-up calculation will be performed and the difference (still based upon 50% of revenue) will either be billed or refunded to the customer, making the Company or the customer whole with respect to the construction cost. After two years, the actual revenue will be compared to the original allowance calculation (which was 50% of the estimated revenue), and any difference will either be billed or refunded to the customer.

Q. How are Developers classified in the revised language?

A. With the new, revised Rule subsections, developers are classified as either residential (Subsection 7.C.4) or non-residential (Subsection 7.C.5) (*i.e.* commercial). In the current Rules all residential developers pay for the cost of construction and are then refunded per lot as customers are connected for service. At the end of five years, anything not refunded becomes a contribution-in-aid-of-construction ("Contribution"). The revised subsection provides similar treatment for residential developers and individual residential applicants by allowing them 550 feet for the line extension. If a residential developer requires facilities in excess of an average of 550 feet per new permanent lot, the excess portion will be treated as a non-refundable Contribution.

Non-residential developers are currently being served on an economic feasibility basis. The revised language allows non-residential developers to be treated similar to the individual non-residential applicant. The estimated cost of construction will be advanced by the developer less 50% of the estimated two-year revenue. After the construction is complete, a true-up calculation will be performed and the difference will either be billed or refunded, making the Company or the customer whole with respect to the construction cost. After two years, the actual revenue of all customers that have received service will be compared to the allowance (which was 50% of the estimated revenue), and any difference will either be billed or refunded to the customer.

Q. What changes did UNS Electric make to Subsections 7.C.6 and 7?

A. Subsection 7.C.6 – "Replacement of Overhead with Underground Distribution Facilities" and Subsection 7.C.7 – "Conversion from Single-Phase to Three-Phase Service" are new sections but do not add new rules. UNS Electric will still charge customers an overhead/underground differential if they request underground distribution

facilities and the Company will continue to charge customers for conversions from single-phase to three-phase.

Q. Why did UNS Electric create a new Subsection 7.C.8 – "Long Term Rental Mobile Home Park, Townhouses, Condominiums and Apartment Complexes"?

A. The new subsection is for clarification purposes. The new language merely qualifies this type of customer to be served under the terms of Subsection 7.C.1 and Subsection 7.C.2.

Q. Why did UNS Electric create a new Subsection 7.C.9 – "Special Conditions"?

A. Although there are minimal changes to this subsection from the existing UNS Electric Rules, the Company did revise the language regarding unusual loads to match TEP's language. UNS Electric presently addresses small loads on a revenue basis, collects the cost of construction with essentially no credit for revenue, but may enter into a contract with the customer that may provide for a refund to the customer. The revised language states that the cost of construction will be collected with no contract or refund. This revised language is consistent with current practices as the Company has not refunded any customer fitting this description.

Q. Did UNS Electric make changes to Section 7.C.10 – "Other Conditions?"

A. Yes. We propose to remove the following provisions from this Section: "Three Phase Service", "Request for Additional Facilities", "Primary Service and Metering", "Entering Customers Premises", "Resale of Energy", "Supply of Electricity", and "Power Factor". We propose these deletions because: (1) they were moved to more appropriate parts of the Rules; or (2) they were explained in other sections of the Rules.

Q. What about Subsection 7.D – "Construction / Facilities Related Income Taxes?"

A. The revisions to Subsection 7.D.1 and Subsection 7.D.2 were made to match the language in TEP's provisions regarding collection and refund of income tax gross up. The revisions to Subsection 7.D.3 – "Non-refundable Income Tax Gross Up", as well as the new calculation table in Subsection 7.D.1, includes the same revisions that were proposed in TEP's current rate case. These proposed revisions provide customers a Tax Gross Up ("TGU") option that has a lower up-front cost than the existing TGU requirement. This change will reduce the financial burden on customers and will reduce the Company's administrative costs of tracking and refunding the TGU.

VI. SUMMARY OF SCHEDULES.

A. "A" Schedules.

Q. Have you described Schedule A-1 earlier in your Direct Testimony?

A. Yes. Again, Schedule A-1 is a summary of the increase in revenue requirement that UNS Electric is seeking as a rate increase in this case.

Q. Please describe the information contained in Schedule A-2.

A. Schedule A-2 presents a summary of the results of operations for the test year and two prior calendar years, compared with the projected year. Lines 1-16 of Schedule A-2 set forth the summary of operations for the years ending June 30, 2010 and June 30, 2011, and the test year ending June 30, 2012. Schedule A-2 also presents projected results of operations for the year ending June 30, 2013 under the headings "present rates" and "proposed rates".

Q. Please describe the information contained in Schedule A-5.

A. Schedule A-5 presents statements of changes in financial position for the years ending June 30, 2010 and June 30, 2011, and the test year ending June 30, 2012 and the projected year ending June 30, 2013.

B. "B" Schedules.

Q. Please describe the information contained in Schedule B-1.

A. This schedule summarizes the elements of UNS Electric's rate base on both a net recorded original cost and RCND basis as of June 30, 2012, along with the pro forma adjustments to rate base. Rate base is comprised of net utility plant, certain regulatory assets, and working capital, with deductions from rate base for accumulated deferred income taxes ("ADIT"), customer advances for construction and customer deposits.

Q. What is shown on Schedules B-2, B-3 and B-4?

A. Schedule B-2 shows the pro forma adjustments to the original cost rate base. The information presented includes the actual per-books balances at the end of the test year, pro forma adjustments, and the adjusted balances. Schedule B-3 provides the same detail by functional account classifications as shown in Schedule B-2, except that it is shown on an RCND basis. Schedule B-4 shows the plant in service accounts on a reconstructed cost new ("RCN") and RCND basis.

Q. Please explain briefly the basis for the determination of the RCND rate base.

A. Plant in service and customer advances for construction reported at RCN are summarized from the results of a detailed plant cost trending study. The accumulated depreciation and ADIT reported on a RCN basis have been computed by multiplying the corresponding original cost balances by a ratio, the numerator of which is gross RCN of

depreciable plant, and the denominator of which is gross original cost of depreciable plant. All other rate base elements are reflected at original cost.

Q. Please describe the plant cost trending study.

A. The trending study was prepared to establish a measure of the cost to reconstruct utility plant in service at current cost levels. The June 30, 2012 recorded balance in each plant account was analyzed by vintage component and adjusted to current cost levels by applying trending factors to each vintage total. For example, the RCN value for 1984 vintage assets in Account No. 362, Distribution Plant – Station Equipment was computed as follows:

$$\text{Original Cost of 1984 vintage assets in Acct. 362} \times \frac{\text{2008 Cost Index for Acct 362}}{\text{1984 Cost Index for Acct. 362}}$$

For most accounts, the Handy-Whitman Index of Public Utility Construction Costs for the Plateau Region has been employed. For plant accounts 303, 391, 393, 394, and 398, the "Marshall Valuation Service Cost Index" was used. For plant accounts 392, 395, 396, and 397, the Bureau of Labor Statistics producer price index was used. Where the Handy-Whitman Index was used for the trend factors, they are based on the most recently available index numbers released by Handy-Whitman (at the time of preparation).

Q. What is the Handy-Whitman Index?

A. It is an index of public utility construction costs that has been published continuously since 1924 by Whitman, Requardt and Associates of Baltimore, Maryland. The Handy-Whitman Index is a well-recognized, widely used and generally accepted method for measuring differences in property values for insurance and other purpose, including the valuation of public utility property for rate case purposes. It has been used by UniSource

Energy's utilities and other companies in proceedings before the Commission for many years.

The Handy-Whitman Index is comprised of index numbers for various accounts prescribed by the FERC Uniform System of Accounts and for six geographical divisions of the country, including the Plateau Division, in which Arizona and New Mexico are located. These index numbers result from a comparison of the current prices of materials, labor, and equipment to prices in a base year. Index numbers are determined for each year as of January 1 and July 1.

The index numbers are used to determine cost trend factors, which are then applied to known original costs of like plant and property to determine the fluctuation in cost between the date of original installation and the date of valuation.

Q. What is the Marshall Index?

A. The Marshall Index, prepared by the firm of Marshall & Swift, is an index of construction cost trend valuations. It was used in development of costs reported in the RCND Study for those plant accounts not reported by Handy-Whitman. The Bureau of Labor producer price index was then used when neither the Handy-Whitman nor the Marshall indices were available.

Q. Please explain Schedule B-5.

A. This schedule summarizes the various elements of working capital that the Company is requesting for inclusion in rate base in this rate case.

Q. Why are the original costs and RCND costs of working capital the same in Schedule B-5?

A. They are the same because the original costs are at current prices or have been adjusted to current prices, meaning they have not been significantly affected by inflationary factors.

C. "C" Schedules.

Q. Please describe the Company's "C" Schedules in its filing.

A. Schedules C-1 through C-3 present the development of the net operating income component of revenue requirements submitted for Commission consideration in this rate case filing.

Q. Please explain Schedule C-1.

A. Schedule C-1 shows the actual Income Statement for the twelve months ending June 30, 2012, the test year in this case. It also summarizes the effect of the proposed pro forma adjustments to recorded operating revenues and expenses, and the resulting adjusted net operating income.

Q. What is the purpose of Schedule C-2?

A. Schedule C-2 presents the detailed pro forma adjustments that reflect the full annual impact of operating changes, annualizations, normalizations, and other adjustments made to revenues and expenses.

Q. What is the purpose of Schedule C-3?

A. Schedule C-3 contains the development of the Gross Revenue Conversion Factor. That factor is used to convert the computed test year return deficiency to an equivalent annual

revenue increase amount. It effectively recognizes that there will be additional bad debt expense and income taxes associated with any adjustment to annual revenue levels.

D. "E" Schedules.

Q. Please explain the Company's "E" Schedules.

A. The "E" Schedules were prepared in accordance with the filing requirements contained in AAC R14-2-103. They are comprised of Schedule Nos. E-1 through E-9, containing annual financial statements and key operating statistics and financial data extracted from the Company's regulatory books of account.

Q. On what basis are the regulatory books of account of UNS Electric maintained?

A. The Company's regulatory books of account are maintained in accordance with the FERC Uniform System of Accounts as required by A.A.C. R14-2-212.G.2.

Q. Have there been any significant changes to the Company's accounting policies or principles since UNS Electric's last test year, calendar year 2008?

A. No.

Q. Have the financial statements been audited?

A. Yes. The 2003 (from inception date) and calendar years 2004-2011 financial statements were audited by the firm of PricewaterhouseCoopers LLP (Independent Certified Public Accountants). The audited financial statements for 2011 and 2010 are provided as **Exhibit DJD-1**.

Q. Please describe Schedule E-1.

A. Schedule E-1 contains the comparative balance sheets of UNS Electric for the test year ending June 30, 2012, and the two prior calendar years ending December 31, 2010, and December 31, 2011.

Q. Please describe Schedule E-2.

A. This schedule sets forth comparative income statements for the test year ending June 30, 2012, and the two prior calendar years ending December 31, 2010, and December 31, 2011. The income statement for the test year supports the actual test period income statement shown on Schedules C-1 and C-2.

Q. Please describe Schedule E-3.

A. This Schedule presents the comparative statements of cash flows for the test year ending June 30, 2012, and the two prior calendar years ending December 31, 2010, and December 31, 2011.

Q. Please describe Schedule E-4.

A. This Schedule reports the changes that occurred in stockholders' equity (deficit) during the period beginning January 1, 2010 and ending June 30, 2012. Changes occurring each year in both the number of shares outstanding and in the amounts of the various elements of stockholders' equity are reflected.

Q. Please describe Schedule E-5.

A. Page 1 of Schedule E-5 presents a summary of the balances in the various electric utility plant account categories and accumulated depreciation at June 30, 2012 and December 31, 2011, and the net changes therein, with plant in service presented on a functional

basis. Pages 2 and 3 of Schedule E-5 present the same information on a more detailed basis, by individual electric plant account.

Q. Please describe Schedule E-6.

A. Schedule E-6 contains Operating Income Statements for the test year and two previous calendar years. Retail revenues are reported by rate class. Operating Expenses are reported by major category.

Q. Please describe Schedule E-7.

A. This Schedule reports key electric operating statistics, in a comparative format, for the June 30, 2012, and the two prior calendar years ending December 31, 2010, and December 31, 2011.

Q. Please describe Schedule E-8.

A. This Schedule shows the taxes charged to operating expenses by tax type for the test year ended June 30, 2012, and the two prior calendar years ending December 31, 2010, and December 31, 2011.

Q. Please describe Schedule E-9.

A. This Schedule is intended to disclose important facts required for a proper understanding of the financial statements. We have included here the Company's FERC Form 2Q for the quarter ended June 30, 2012 and the FERC Form 1 for the year ended December 31, 2011. The footnotes and other statistical data contained therein provide additional information to facilitate understanding of the remaining information contained in Schedules E.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT

DJD-1

UNSE Generating Facilities

Net Salvage Accrual Rates

Black Mountain	%
Other Production -	
Acct. 341, Structures and Improvements	.08
Acct. 342, Fuse Holders, Producers and Accessories	.08
Acct. 343, Prime Movers	.08
Acct. 344, Generators	.08
Acct. 345, Accessory Electric Equipment	.08
Acct. 346, Miscellaneous Power Plant Equipment	.08

Valencia	
Other Production -	
Acct. 341, Structures and Improvements	.11
Acct. 342, Fuse Holders, Producers and Accessories	.15
Acct. 343, Prime Movers	.17
Acct. 344, Generators	.12
Acct. 345, Accessory Electric Equipment	.15
Acct. 346, Miscellaneous Power Plant Equipment	.14

EXHIBIT

DJD-2

UNS Electric, Inc.

Financial Statements

Years Ended December 31, 2011 and 2010

UniSourceEnergy SERVICES

pwc

Report of Independent Auditors

To the Board of Directors and Stockholder of
UNS Electric, Inc.

In our opinion, the accompanying balance sheets and statements of capitalization and the related statements of income, cash flows, and changes in stockholder's equity and comprehensive income present fairly, in all material respects, the financial position of UNS Electric, Inc. (the "Company") at December 31, 2011 and December 31, 2010, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America and with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

March 30, 2012

PricewaterhouseCoopers LLP, 1850 N. Central Avenue, Suite 700 Phoenix, AZ 85004, www.pwc.com

UNS ELECTRIC, INC.
STATEMENTS OF INCOME

	Years Ended December 31, 2011	2010
	- Thousands of Dollars -	
Operating Revenues		**As Adjusted[1]**
Electric Retail Sales	$ **181,892**	$ 182,814
Electric Wholesale Sales	**37,556**	30,846
Other Revenues	**1,747**	1,707
Total Operating Revenues	**221,195**	215,367
Operating Expenses		
Fuel	**6,960**	11,658
Purchased Energy	**122,485**	120,711
Transmission	**11,899**	11,370
Decrease to Reflect PPFAC Recovery	**(4,075)**	(7,232)
Total Fuel and Purchased Energy	**137,269**	136,507
Other Operations and Maintenance	**26,641**	29,051
Depreciation	**20,071**	19,942
Amortization	**(3,111)**	(3,372)
Taxes Other than Income Taxes	**4,662**	4,270
Total Operating Expenses	**185,532**	186,398
Operating Income	**35,663**	28,969
Other Income		
Interest Income	**24**	34
Other Income	**659**	3,710
Other Expense	**(616)**	(727)
Total Other Income	**67**	3,017
Interest Expense		
Long-Term Debt	**7,534**	7,010
Capital Leases	**1**	6
Other Interest Expense	**281**	320
Interest Capitalized	**(397)**	(475)
Total Interest Expense	**7,419**	6,861
Income Before Income Taxes	**28,311**	25,125
Income Tax Expense	**10,634**	9,635
Net Income	$ **17,677**	$ 15,490

See Notes to Financial Statements.

[1]Adjusted to reflect Black Mountain Generating Station and UNS Electric combined. See Note 2.

UNS ELECTRIC, INC.
STATEMENTS OF CASH FLOWS

	Years Ended December 31, 2011	2010
	- Thousands of Dollars -	
Cash Flows from Operating Activities		**As Adjusted[1]**
Cash Receipts from Electric Retail Sales	**$ 200,290**	$ 194,866
Cash Receipts from Electric Wholesale Sales	**37,750**	28,923
Customer Deposits Received	**2,016**	2,111
Performance Deposits Received	**710**	7,780
Cash Receipts from Gas Wholesale Sales	**11**	62
Interest Received	**7**	9
Insurance Settlement Proceeds	**-**	3,605
Settlement Proceeds from Litigation	**-**	3,000
Income Tax Refunds Received	**-**	1,627
Other Cash Receipts	**827**	929
Purchased Energy Costs Paid	**(134,431)**	(130,323)
Taxes Paid, Net of Amounts Capitalized	**(20,272)**	(19,007)
Payment of Other Operations and Maintenance Costs	**(13,789)**	(14,676)
Fuel Costs Paid	**(7,326)**	(11,845)
Payment of Affiliate Charges	**(7,091)**	(6,176)
Interest Paid, Net of Amounts Capitalized	**(7,020)**	(6,651)
Wages Paid, Net of Amounts Capitalized	**(5,040)**	(5,463)
Income Taxes Paid	**(2,326)**	(1,035)
Performance Deposits Paid	**(710)**	(7,780)
Claim Settlement Payments	**-**	(4,500)
Other Cash Payments	**(902)**	(964)
Net Cash Flows - Operating Activities	**42,704**	34,492
Cash Flows from Investing Activities		
Contribution in Aid of Construction Receipts	**4,291**	1,069
Other Cash Receipts	**166**	144
Capital Expenditures	**(96,118)**	(23,909)
Purchase of Intangibles - Renewable Energy Credits	**(1,508)**	(443)
Other Cash Payments	**(20)**	-
Net Cash Flows - Investing Activities	**(93,189)**	**(23,139)**
Cash Flows from Financing Activities		
Proceeds from Issuance of Long-Term Debt	**30,000**	-
Proceeds from Borrowings under Revolving Credit Facility	**30,000**	1,000
Equity Investment from UES	**20,000**	-
Customer Advance Receipts	**904**	2,154
Repayment of Borrowings under Revolving Credit Facility	**(30,000)**	(1,000)
Payment to Affiliate Related to BMGS	**(6,353)**	(11,009)
Customer Advance Refunds	**(355)**	(710)
Payment of Debt Issue/Retirement Costs	**(218)**	(403)
Other Cash Payments	**(38)**	(108)
Net Cash Flows - Financing Activities	**43,940**	(10,076)
Net (Decrease) Increase in Cash and Cash Equivalents	**(6,545)**	1,277
Cash and Cash Equivalents, Beginning of Period	**11,468**	10,191
Cash and Cash Equivalents, End of Period	**$ 4,923**	$ 11,468

See Notes to Financial Statements.

[1]Adjusted to reflect Black Mountain Generating Station and UNS Electric combined. See Note 2.

UNS ELECTRIC, INC.
BALANCE SHEETS

	December 31, 2011	2010
	- Thousands of Dollars -	
ASSETS		**As Adjusted[1]**
Utility Plant		
Plant in Service	$ **365,999**	$ 330,320
Utility Plant under Capital Leases	**-**	706
Construction Work in Progress	**12,966**	25,205
Total Utility Plant	**378,965**	356,231
Less Accumulated Depreciation and Amortization	**(88,141)**	(73,798)
Less Accumulated Amortization of Capital Lease Assets	**-**	(675)
Total Utility Plant - Net	**290,824**	281,758
Investments and Other Property	**542**	522
Current Assets		
Cash and Cash Equivalents	**4,923**	11,468
Accounts Receivable - Customer	**12,232**	12,122
Unbilled Accounts Receivable	**7,144**	7,581
Allowance for Doubtful Accounts	**(953)**	(979)
Accounts Receivable - Due from Affiliates	**1,933**	344
Materials and Supplies	**9,911**	9,019
Regulatory Assets - Current	**17,988**	14,556
Derivative Instruments	**10,523**	3,891
Deferred Income Taxes - Current	**1,023**	-
Other	**1,097**	1,112
Total Current Assets	**65,821**	59,114
Other Assets		
Regulatory Assets - Noncurrent	**9,508**	5,473
Derivative Instruments	**558**	7,775
Other	**2,562**	1,572
Total Other Assets	**12,628**	14,820
Total Assets	$ **369,815**	$ 356,214

See Notes to Financial Statements.

[1]Adjusted to reflect Black Mountain Generating Station and UNS Electric combined. See Note 2.

(Balance Sheets Continued)

UNS ELECTRIC, INC.
BALANCE SHEETS

	December 31, 2011	December 31, 2010
	- Thousands of Dollars -	
CAPITALIZATION AND OTHER LIABILITIES		**As Adjusted[1]**
Capitalization		
Common Stock Equity	$ **136,127**	$ 163,878
Long-Term Debt	**130,000**	100,000
Total Capitalization	**266,127**	263,878
Current Liabilities		
Accounts Payable - Trade	**11,659**	12,774
Accounts Payable - Due to Affiliates	**2,782**	4,120
Derivative Instruments	**20,730**	15,455
Customer Deposits	**5,739**	5,474
Accrued Taxes Other than Income Taxes	**4,259**	4,045
Interest Accrued	**2,808**	2,713
Regulatory Liabilities - Current	**3,119**	870
Accrued Employee Expenses	**1,335**	1,154
Deferred Income Taxes - Current	**-**	657
Other	**144**	142
Total Current Liabilities	**52,575**	47,404
Deferred Credits and Other Liabilities		
Deferred Income Taxes - Noncurrent	**15,200**	5,837
Regulatory Liabilities - Noncurrent	**10,133**	9,223
Customer Advances for Construction	**10,380**	12,768
Pension and Other Postretirement Benefits	**4,332**	2,985
Derivative Instruments	**3,978**	9,285
Other	**7,090**	4,834
Total Deferred Credits and Other Liabilities	**51,113**	44,932
Commitments and Contingencies (Note 7)		
Total Capitalization and Liabilities	$ **369,815**	$ 356,214

See Notes to Financial Statements.

[1]Adjusted to reflect Black Mountain Generating Station and UNS Electric combined. See Note 2.

(Balance Sheets Concluded)

UNS ELECTRIC, INC.
STATEMENTS OF CAPITALIZATION

			December 31, 2011	December 31, 2010
			- Thousands of Dollars -	
COMMON STOCK EQUITY				**As Adjusted[1]**
Common Stock--No Par Value			**$ 78,887**	$ 121,916
	2011	**2010**		
Shares Authorized	**1,000**	1,000		
Shares Outstanding	**1,000**	1,000		
Accumulated Earnings			**57,278**	41,962
Accumulated Other Comprehensive Loss			**(38)**	-
Total Common Stock Equity			**136,127**	163,878

LONG-TERM DEBT				
Issue	**Maturity**	**Interest Rate**		
Senior Unsecured Notes - Series A	8/7/2015	6.50%	**50,000**	50,000
Senior Unsecured Notes - Series B	8/7/2023	7.10%	**50,000**	50,000
Senior Unsecured Note - Term Loan	8/10/2015	Variable	**30,000**	-
Total Long-Term Debt			**130,000**	100,000
Total Capitalization			**$ 266,127**	$ 263,878

See Notes to Financial Statements.

[1]Adjusted to reflect Black Mountain Generating Station and UNS Electric combined. See Note 2.

UNS ELECTRIC, INC.
STATEMENTS OF CHANGES IN STOCKHOLDER'S EQUITY AND COMPREHENSIVE INCOME

	Common Shares Outstanding	Common Stock	Accumulated Earnings	Accumulated Other Comprehensive Loss	Total Stockholder's Equity
		- Thousands of Dollars -			
Balances at December 31, 2009	**1,000**	**$ 58,887**	**$ 31,435**	**$ -**	**$ 90,322**
Comprehensive Income:					
2010 Net Income			15,490		15,490
Total Comprehensive Income					15,490
Adjustments to Retrospectively Reflect Inclusion of BMGS[1]:					
Non-Cash Contribution of BMGS Net Plant and Inventory		63,029			63,029
Non-Cash Distribution of BMGS Net Income			(4,963)		(4,963)
Balances at December 31, 2010	**1,000**	**$ 121,916**	**$ 41,962**	**$ -**	**$ 163,878**
Comprehensive Income:					
2011 Net Income			17,677		17,677
Unrealized Loss on Cash Flow Hedge (net of income taxes of $46)				(70)	(70)
Reclassification of Realized Losses on Cash Flow Hedge to Net Income (net of income taxes of $21)				32	32
Total Comprehensive Income					17,639
Cash Distribution for BMGS Net Plant and Inventory		(62,694)			(62,694)
Adjustments to Retrospectively Reflect Inclusion of BMGS[1]:					
Non-Cash Distribution of BMGS Net Plant and Inventory		(335)			(335)
Non-Cash Distribution of BMGS Net Income			(2,361)		(2,361)
Capital Contribution from UES for BMGS Purchase		20,000			20,000
Balances at December 31, 2011	**1,000**	**$ 78,887**	**$ 57,278**	**$ (38)**	**$ 136,127**

See Notes to Financial Statements.

[1]Adjusted to reflect Black Mountain Generating Station and UNS Electric combined. See Note 2.

NOTE 1. NATURE OF OPERATIONS

UNS Electric, Inc. (UNS Electric) is a regulated public utility, which generates, transmits and distributes electricity to approximately 91,000 retail customers in Mohave and Santa Cruz counties in Arizona. UniSource Energy Services, Inc. (UES), an intermediate holding company, owns all of the common stock of UNS Electric and UNS Gas, Inc. (UNS Gas). UniSource Energy Corporation (UniSource Energy) owns all of the common stock of UES.

References to "we" and "our" are to UNS Electric.

NOTE 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

RETROSPECTIVE APPLICATION OF TRANSFER OF A BUSINESS HELD UNDER COMMON CONTROL

UNS Electric purchased Black Mountain Generating Station (BMGS) from UniSource Energy Development Company (UED), a UniSource Energy affiliate, in July 2011. In accordance with accounting rules related to the transfer of a business held under common control, we reflect UNS Electric's purchase of BMGS as if it occurred on January 1, 2010. See Note 3.

REVISION OF PRIOR PERIOD FINANCIAL STATEMENTS

In 2011, UniSource Energy identified errors in the calculation of income tax expense, in prior years, arising from not treating Allowance for Equity Funds Used During Construction (AFUDC) as a permanent book to tax difference. UniSource Energy assessed the materiality of these errors on prior period financial statements and concluded they were not material to any prior periods, but the cumulative impact, if recognized in 2011, could be material to the annual period ended December 31, 2011. As a result, in accordance with Securities and Exchange Commission Staff Accounting Bulletin 108, UniSource Energy revised its prior period financial statements to correct these errors. UNS Electric, as a consolidated subsidiary, concurrently revised its separate financial statements. The income tax adjustment impacted fiscal years 2006 through 2010. The revision increased net income for UNS Electric by $0.2 million in 2010. Prior period revisions increased Accumulated Earnings by $0.7 million at December 31, 2009. Additionally, UNS Electric revised the prior year Statements of Cash Flows to correctly classify the Equity portion of AFUDC as a non-cash investing activity rather than an Operating cash outflow ($0.6 million), and a gross reduction of Capital Expenditures.

RECLASSIFICATIONS

To conform to the current year presentation and correctly account for the regulatory treatment of certain expenses, UNS Electric reclassified Other Operations and Maintenance costs of $0.6 million in 2010 to Other Expense.

BASIS OF PRESENTATION

Our accounting policies conform to accounting principles generally accepted in the United States of America (GAAP), including the accounting principles for rate-regulated enterprises.

USE OF ACCOUNTING ESTIMATES

Management makes estimates and assumptions when preparing financial statements under GAAP. These estimates and assumptions affect:

- Assets and liabilities in our balance sheet at the dates of the financial statements;
- Our disclosures about contingent assets and liabilities at the dates of the financial statements; and
- Our revenues and expenses in our income statement during the periods presented.

Because these estimates involve judgments based upon our evaluation of relevant facts and circumstances, actual amounts may differ from the estimates.

ACCOUNTING FOR RATE REGULATION

UNS Electric generally uses the same accounting policies and practices used by unregulated companies. However, sometimes regulatory accounting requires that rate-regulated companies apply special accounting treatment to show the effect of rate regulation. For example, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer Retail Rates (rates designed to allow a regulated utility an opportunity to recover its reasonable operating and capital costs and earn a return on its utility plant in service). Regulatory liabilities generally represent expected future costs that have already been collected from customers or items that are expected to be returned to customers through billing reductions. UNS Electric evaluates regulatory assets each period and believes recovery is probable. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

We apply regulatory accounting as the following conditions exist:

- An independent regulator sets rates;
- The regulator sets the rates to recover the specific enterprise's costs of providing service; and
- Rates are set at levels that will recover the entity's costs and can be charged to and collected from customers.

CASH AND CASH EQUIVALENTS

UNS Electric defines Cash and Cash Equivalents as cash (unrestricted demand deposits) and all highly liquid investments purchased with an original maturity of three months or less.

UTILITY PLANT

Utility Plant is a term we use to describe the business property and equipment that supports electric services, consisting primarily of generation, transmission and or distribution facilities. Utility plant is recorded at original cost. Original cost includes materials and labor, contractor services, construction overhead (where applicable), and AFUDC.

We record the cost of repairs and maintenance, including planned major overhauls to Other Operations and Maintenance Expense on the income statement as the costs are incurred.

When a unit of regulated property is retired, the original cost plus removal costs less any salvage value is credited or charged to accumulated depreciation.

AFUDC

AFUDC reflects the cost of debt or equity funds used to finance construction and is capitalized as part of the cost of regulated utility plant. AFUDC amounts capitalized are included in rate base for establishing Retail Rates. The interest capitalized that relates to debt reduces Other Interest Expense on the income statement. The cost capitalized for equity funds is recorded as Other Income.

	2011	2010
Average AFUDC Rate on Construction Expenditures	8.18%	8.22%

Depreciation

We compute depreciation for owned utility plant on a group method straight-line basis at depreciation

rates based on the economic lives of the assets. The Arizona Corporation Commission (ACC) approves depreciation rates for all utility plant. See Note 5. Depreciation rates are based on average useful lives and reflect estimated removal costs, net of estimated salvage value for interim retirements. Below are the summarized average annual depreciation rates for UNS Electric.

	2011	2010
Average Annual Depreciation Rates	4.31%	4.35%

Computer Software Costs

UNS Electric capitalizes costs incurred to purchase and develop computer software for internal use and amortizes those costs over the estimated economic life of the product. If the software is no longer useful, UNS Electric immediately charges capitalized computer software costs to expense.

ASSET RETIREMENT OBLIGATIONS

UNS Electric records a liability for the estimated present value of a conditional asset retirement obligation as follows:

- When it is able to reasonably estimate the fair value of any future obligation to retire as a result of an existing or enacted law, statute, ordinance or contract; or
- If it can reasonably estimate the fair value.

When the liability is initially recorded at net present value, UNS Electric capitalizes the cost by increasing the carrying amount of the related long-lived asset. UNS Electric adjusts the liability to its present value by recognizing accretion expense in Other Operations and Maintenance expense, and the capitalized cost is depreciated in Depreciation and Amortization expense over the useful life of the related asset.

UNS Electric records cost of removal for transmission and distribution assets through depreciation rates and recovers those amounts in Retail Rates charged to customers. There are no legal obligations associated with these assets. We have recorded an obligation for estimated costs of removal as regulatory liabilities. See Note 4.

EVALUATION OF ASSETS FOR IMPAIRMENT

UNS Electric evaluates long-lived assets for impairment whenever events or circumstances indicate the carrying value of the assets may be impaired. If the undiscounted expected future cash flows are less than the carrying value of the asset, an impairment loss is recognized, and the asset is written down to its fair value if the costs are not recoverable through rates.

DEFERRED FINANCING COSTS

UNS Electric defers the costs to issue debt and amortizes such costs to interest expense on a straight-line basis over the life of the debt as this approximates the effective interest method. These costs include underwriters' commissions, discounts or premiums, and other costs such as legal, accounting, regulatory fees and printing costs.

UTILITY OPERATING REVENUES

UNS Electric records utility operating revenues when services or commodities are delivered to customers. Operating revenues include an estimate for unbilled revenues from service that has been provided but not billed by the end of an accounting period.

We determine amounts delivered through periodic readings of customer meters. At the end of the month, the usage since the last meter reading is estimated and the corresponding unbilled revenue is calculated.

Unbilled revenue is estimated based on daily generation or purchased volumes, estimated customer usage by class, estimated line losses and estimated average customer Retail Rates. Accrued unbilled revenues are reversed the following month when actual billings occur. The accuracy of the unbilled revenue estimate is affected by factors that include fluctuations in energy demands, weather, line losses, customer Retail Rates and changes in the composition of customer classes.

UNS Electric is authorized a rate-adjustment mechanism that provides for the recovery of actual fuel, transmission and purchased power/energy cost. The revenue surcharge or surcredit adjusts the customers' rate for delivered electricity to collect or return under- or over- recovered energy costs. The ACC revises these rate-adjustment mechanisms annually and may increase or decrease the level of costs recovered through Retail Rates for any difference between the total amount collected under the clause and the recoverable costs incurred. See Note 4.

Arizona's mandatory Renewable Energy Standard (RES) requires UNS Electric to increase its use of renewable energy and allows recovery of RES compliance costs through a surcharge to customers. We charge customers a Demand Side Management (DSM) surcharge to recover the cost of ACC-approved energy efficiency programs. We defer differences between actual RES or DSM qualified costs incurred and the recovery of such costs through the RES and DSM surcharges. Cost over-recoveries (the excess of cost recoveries through the RES and DSM surcharges over actual qualified costs incurred) are deferred as regulatory liabilities and cost under-recoveries (the excess of actual qualified costs incurred over cost recoveries through the RES and DSM surcharges) are deferred as regulatory assets. The surcharges are reset annually and incorporate an adjustor mechanism that, upon approval of the ACC, allows UNS Electric to apply any shortage or surplus in the prior year's program expenses to the subsequent year's RES or DSM surcharge. See Note 4.

We record an Allowance for Doubtful Accounts to reduce accounts receivable for amounts estimated to be uncollectible. The allowance is determined based on historical bad debt patterns, retail sales and economic conditions. UNS Electric refers uncollected accounts to external collection agencies after 90 days.

INVENTORY

Materials and supplies consist of transmission, distribution and generation construction and repair materials. UNS Electric records fuel, materials and supply inventories at the lower of weighted average cost or market prices. We capitalize handling and procurement costs (such as materials, labor, overhead costs and transportation costs) as part of the cost of inventory.

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE (PPFAC)

UNS Electric defers differences between actual fuel, transmission and purchased power costs and current PPFAC costs incurred and the recovery of such costs in base rates. Base Rates are defined as the portion of UNS Electric's Retail Rates attributed to generation, transmission, distribution costs, and customer charge. Cost over-recoveries (the excess of fuel costs recoveries in Base Rates over actual costs incurred) are deferred as regulatory liabilities and cost under-recoveries (the excess of actual costs incurred over fuel costs recovered in Base Rates) are deferred as regulatory assets. See Note 4.

RENEWABLE ENERGY CREDITS (RECs)

The ACC uses Renewable Energy Credits (RECs) to measure compliance with the RES requirements. A REC equals one kWh generated from renewable resources. The cost of REC purchases are qualified renewable expenditures recoverable through the RES surcharge. When UNS Electric purchases renewable energy, the premium paid above conventional power is the REC cost, a qualified cost recoverable through the RES surcharge, and the remaining cost is recoverable through the PPFAC.

When RECs are purchased, UNS Electric records the cost of the RECs as Other Assets, and a corresponding regulatory liability, to reflect the obligation to use the RECs for future RES compliance.

Unretired RECs are recorded as Other Assets on the balance sheet. RECs are expensed to the income statement when the RECs are reported to the ACC for compliance with the RES requirements. See Note 4.

RELATED PARTY TRANSACTIONS

Tucson Electric Power Company (TEP), a regulated public utility serving retail electric customers in southern Arizona, is UniSource Energy's largest operating subsidiary. UNS Electric receives all corporate services (finance, accounting, tax, information technology services, etc.) from TEP. Corporate services from TEP totaled $5.6 million in 2011 and $5.3 million in 2010. TEP also allocates common costs (systems, facilities, etc.) on a cost-causative basis to UNS Electric. Common costs from TEP for UNS Electric were $4.0 million in 2011 and $3.7 million in 2010.

TEP and UNS Electric sell power to each other at prices based on the Dow Jones Four Corners Daily Index. TEP had wholesale power sales to UNS Electric of $2.1 million in 2011 and $17.8 million in 2010. UNS Electric had wholesale power sales of $2.2 million to TEP in 2011 and 2010.

TEP charged UNS Electric $2.9 million in 2011 and $2.8 million in 2010 for control area services based on a Federal Energy Regulatory Commission (FERC) approved tariff.

Southwest Energy Solutions, Inc., another UniSource Energy affiliate, charged UNS Electric $0.8 million in 2011 and 2010 for meter reading services.

UED provided energy from BMGS to UNS Electric through a power purchase agreement prior to July 1, 2011. In July, 2011, UNS Electric purchased BMGS from UED. See Note 3.

UNS Gas charged UNS Electric $3.3 million for gas and transportation used by BMGS in 2011 and $5.3 million in 2010. Corporate and administrative services provided by UNS Gas totaled $0.5 million in 2011 and $0.2 million in 2010. Corporate and administrative services provided to UNS Gas totaled $0.8 million in 2011 and $0.9 million in 2010.

Balances arising from transactions with affiliates are recorded on the balance sheets as Accounts Receivable – Due from Affiliates or Accounts Payable – Due to Affiliates.

INCOME TAXES

Due to the difference between GAAP and income tax laws, many transactions are treated differently for income tax purposes than they are in the financial statements. Temporary differences are accounted for by recording deferred income tax assets and liabilities on our balance sheets. These assets and liabilities are recorded using income tax rates expected to be in effect when the deferred tax assets and liabilities are realized or settled. We record a valuation allowance to reduce deferred tax assets when we believe it is more likely than not that the deferred asset will not be realized.

Tax benefits are recognized in the financial statements when it is more likely than not that a tax position will be sustained upon examination by the tax authorities based on the technical merits of the position. The tax benefit recorded is the largest amount that is more than 50% likely to be realized upon ultimate settlement with the tax authority, assuming full knowledge of the position and all relevant facts. Interest Expense includes interest accrued by UNS Electric on tax positions taken on tax returns which have not been reflected in the financial statements.

UNS Electric is a member of the UniSource Energy consolidated income tax filing. UNS Electric is allocated income taxes based on its taxable income and deductions as reported in the UniSource Energy consolidated and/or combined tax return filings. As a result, the regular and AMT tax liability of UNS Electric is calculated on a separate return basis and the liability is then paid to UniSource Energy through intercompany accounts. UniSource Energy has the ultimate responsibility for payment of consolidated tax liabilities to taxing authorities and maintaining intercompany tax accounts with its subsidiaries.

TAXES OTHER THAN INCOME TAXES

UNS Electric acts as a conduit or collection agent for sales tax, utility taxes, franchise fees and regulatory assessments. As we bill customers for these taxes and assessments, we record trade receivables. At the same time, we record liabilities payable to governmental agencies for these taxes and assessments. These amounts are not reflected in the income statement.

DERIVATIVE FINANCIAL INSTRUMENTS

Risks and Overview

UNS Electric is exposed to energy price risk associated with gas and purchased power requirements, volumetric risk associated with seasonal load and operational risk associated with power plants, transmission and distribution systems. We reduce our energy price risk through a variety of derivative and non-derivative instruments. The objectives for entering into such contracts include: creating price stability; ensuring we can meet load and reserve requirements; and reducing exposure to price volatility that may result from delayed recovery under the PPFAC. See Note 4.

We consider the effect of counterparty credit risk in determining the fair value of derivative instruments that are in a net asset position after incorporating collateral posted by counterparties and allocate the credit risk adjustment to individual contracts. We also consider the impact of our own credit risk after considering collateral posted on instruments that are in a net liability position and allocate the credit risk adjustment to all individual contracts.

We present cash collateral and derivative assets and liabilities associated with the same counterparty separately in our financial statements, and we bifurcate all derivatives into current and long-term portions on the balance sheet.

Cash Flow Hedges

UNS Electric accounts for cash flow hedges as follows:

- The effective portion of the change in the fair value of cash flow hedges is recorded in Accumulated Other Comprehensive Income (AOCI) and the ineffective portion, if any, is recognized in earnings; and

- When UNS Electric determines a contract is no longer effective in offsetting the changes in cash flow of a hedged item, it recognizes the changes in fair value in earnings. The unrealized gains and losses at that time remain in AOCI and are reclassified into earnings as the underlying hedged transaction occurs.

We formally assess, both at the hedge's inception and on an ongoing basis, whether the derivatives have been and are expected to remain highly effective in offsetting changes in the cash flows of hedged items. We discontinue hedge accounting when: (1) the derivative is no longer effective in offsetting changes in the fair value or cash flows of a hedged item; (2) the derivative expires or is sold, terminated, or exercised; (3) it is no longer probable that the forecasted transaction will occur; or (4) we determine that designating the derivative as a hedging instrument is no longer appropriate.

Mark-to-Market

UNS Electric enters into derivative agreements to economically hedge a portion of its purchased power exposure to fixed price and natural gas-indexed contracts with forward power purchases, financial gas swaps, and call and put options. Unrealized gains and losses are recorded as either a regulatory asset or regulatory liability, as the UNS Electric PPFAC mechanism allows recovery of the prudent costs of contracts for economically hedging fuel and purchased power costs.

Normal Purchase and Normal Sale

UNS Electric enters into forward energy purchase and sales contracts, including call options, to support its current load forecasts, with counterparties for load serving requirements or with counterparties with generating capacity. These contracts are not required to be marked-to-market and are accounted for on an accrual basis as they qualify for the normal purchase, normal sales exception. We evaluate our counterparties on an ongoing basis for non-performance risk to ensure it does not impact our ability to obtain the normal scope exception.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

The following recently issued accounting standards are not yet reflected in the financial statements:

- The Financial Accounting Standards Board (FASB) issued authoritative guidance that will eliminate the current option to report other comprehensive income in the statement of changes in equity. An entity can elect to present items of net income and other comprehensive income in one continuous statement, or in two separate but consecutive statements. We plan to present a separate statement of other comprehensive income to comply with this new standard in our 2012 financial statements.

- The FASB issued authoritative guidance that changed some fair value measurement principles and disclosure requirements. The most significant disclosure change is expansion of required information for unobservable inputs. We will be required to comply with this standard in our 2012 financial statements, and we do not expect this pronouncement to have a material impact on the valuation techniques used to estimate the fair value of assets and liabilities.

- The FASB issued authoritative guidance that will require entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting arrangement. In addition, the standard requires disclosure of collateral received and posted in connection with master netting arrangements. We will be required to comply with this standard in our 2013 financial statements.

NOTE 3. PURCHASE OF BLACK MOUNTAIN GENERATING STATION

In July 2011, UNS Electric purchased BMGS's utility plant and inventory from UED, an affiliate, at a net book value of $62.7 million. The facility in northwestern Arizona consists of two natural gas-fired combustion turbines. Prior to July 2011, UNS Electric received energy from BMGS through a power purchase agreement with UED. In accordance with accounting rules related to the transfer of a business held under common control, we reflect UNS Electric's purchase as if it occurred on January 1, 2010.

The following adjustments were made to UNS Electric's Statements of Income:

- Elimination of Purchased Energy expense related to the BMGS power purchase agreement with UED;
- Elimination of Other Revenues related to the BMGS ground lease agreement with UED; and
- Incorporation of BMGS Operating Expenses, including O&M, depreciation, taxes, and capitalized interest.

These adjustments increased UNS Electric's Net Income by $5.0 million for the year ended December 31, 2010 and by $2.4 million for the year ended December 31, 2011.

The following adjustments were made to UNS Electric's Statements of Cash Flows:

- Purchased Energy Costs Paid related to the BMGS power purchase agreement with UED are

now being reflected as a financing activity under Payment to Affiliate; and
- Other Operating Cash Receipts and Payments related to the ground lease agreement with UED are now being reflected as a financing activity under Payment to Affiliate.

These adjustments increased UNS Electric's Net Cash Flows – Operating Activities, and decreased Net Cash Flows – Financing Activities, by $11 million for the year ended December 31, 2010 and by $6.4 million for the year ended December 31, 2011.

The following adjustments were made to UNS Electric's December 31, 2010 Balance Sheet:

- Total Utility Plant – Net increased $62.2 million;
- Materials and Supplies increased $0.8 million; and
- Common Stock Equity increased by $63 million.

UNS Electric purchased BMGS net utility plant and inventory in July 2011. The December 31, 2011 Balance Sheet includes an adjustment to Common Stock Equity of $0.3 million to reflect the net decrease in book value of transferred Plant and Inventory from the retrospective application date to the purchase date.

NOTE 4. REGULATORY MATTERS

ACCOUNTING FOR RATE REGULATION

The ACC and the FERC each regulate portions of the utility accounting practices and rates used by UNS Electric. The ACC regulates rates charged to retail customers, the siting of generation and transmission facilities, the issuance of securities, and transactions with affiliated parties. The FERC regulates terms and prices of transmission services and wholesale electricity sales.

2010 UNS Electric Rate Order

In September 2010, the ACC approved a base rate increase of 4% ($7 million), including an 8% authorized rate of return on original cost rate base, effective October 1, 2010. The ACC approved new depreciation rates effective October 2010.

Effective July 2011, after UNS Electric purchased BMGS, the ACC allowed UNS Electric to recover BMGS in base rates as part of rate base rather than from base power supply rates. This reclassification of approximately 0.7 cents per kWh has no effect on revenue.

COST RECOVERY MECHANISMS

Purchased Power and Fuel Adjustment Clause (PPFAC)

UNS Electric's PPFAC provides for the adjustment of Retail Rates to reflect variations in retail fuel, transmission and purchased power costs, including demand charges, and the prudent costs of contracts for hedging fuel. UNS Electric records deferrals for recovery or refund to the extent actual retail fuel, transmission and purchased power costs vary from the fuel rate and current PPFAC rates. UNS Electric's PPFAC rate adjustment is made annually each June 1st, effective for the subsequent 12-month period.

The PPFAC rate includes (a) a "Forward Component," under which UNS Electric recovers or refunds differences between forecasted fuel, transmission and purchased power costs for the upcoming calendar year and those embedded in the fuel rate and the current PPFAC rates; and (b) a "True-up Component," which reconciles differences between actual fuel, transmission and purchased power costs and those recovered through the combination of the fuel rate and the forward component for the preceding 12-month period.

The chart below summarizes the PPFAC rates in cents per kWh for the prior two years:

	January 2010 to May 2010	June 2010 to September 2010	October 2010 to May 2011	June 2011	July 2011 to December 2011
Charge (Credit)	(1.06)	(0.28)	0.08	(0.88)	(0.88)
Base Rate	7.10	7.10	6.77	6.77	6.11

RES and Energy Efficiency Standards

The ACC adopted a mandatory RES that requires UNS Electric to expand its use of renewable energy through efforts funded by customer surcharges. UNS Electric is required to file a five-year implementation plan with the ACC and annually seek approval for the upcoming year's RES funding amount. Similarly, UNS Electric recovers the cost of ACC-approved energy efficiency programs through DSM surcharges established by the ACC.

The following table shows RES and DSM tariffs collected:

	RES	DSM
	-Thousands of Dollars-	
2011	$6,951	$1,753
2010	7,232	1,596

Renewable Energy Standard

In 2010, the ACC approved a funding mechanism for UNS Electric to invest approximately $5 million in UNS Electric owned solar projects per year between 2011 and 2014. The funding mechanism allows UNS Electric to use RES funds to recover operating costs, depreciation, and property taxes. The funding mechanism provides UNS Electric with a return on its investment until these costs can be incorporated in UNS Electric's base rates.

In 2009, UNS Electric entered into a long-term purchase power agreement with a company developing a renewable energy generation facility. The ACC approved the agreement in April 2010. UNS Electric is required to purchase the full output of the facility for 20 years. UNS Electric is authorized to recover a portion of the cost of renewable energy through the PPFAC with the balance of cost recoverable through the RES tariff.

Electric Energy Efficiency Standards

In 2010, the ACC approved new Electric Energy Efficiency (EE) Standards designed to require UNS Electric to implement cost-effective DSM programs, effective in 2011. In 2011, the EE Standards targeted total retail kWh savings of 1.25% of 2010 sales increasing to 22% by 2020. The EE Standards provide for a DSM surcharge to recover the costs to implement DSM programs.

In January 2012, the ACC granted UNS Electric a waiver from complying with the 2011 and 2012 EE Standards.

Renewable Energy Credits

In 2011, UNS Electric purchased $1.5 million of RECs bundled with renewable energy and expensed $0.5 million to purchased power. The cost of REC purchases are qualified renewable expenditures and are offset by customer collections through the RES tariff. At December 31, 2011, UNS Electric had $1.2 million in RECs recorded as Other Assets on the balance sheet.

Regulatory Assets and Liabilities

UNS Electric has the following regulatory assets and liabilities:

	December 31, 2011	December 31, 2010
	-Thousands of Dollars-	
Current Regulatory Assets		
Derivative Instruments (Note 13)	$ 10,207	$ 11,564
PPFAC - Under-Recovered Purchased Power Costs [1]	6,593	2,502
DSM Assets [1]	821	266
Self-Insured Medical and Short-Term Disability Assets [2]	245	102
Other Current Regulatory Assets [3]	122	122
Other Regulatory Assets		
Pension and Other Postretirement Benefits (Note 9)	4,160	2,212
Derivative Instruments (Note 13)	3,358	1,510
Income Taxes Recoverable through Future Revenues[4]	1,889	1,536
Other Regulatory Assets [3]	101	215
Current Regulatory Liabilities		
RES Liabilities [1]	(3,119)	(870)
Other Regulatory Liabilities		
Net Cost of Removal for Interim Retirements [5]	(10,126)	(9,223)
Income Taxes Refundable through Future Revenues[4]	(7)	-
Total Net Regulatory Assets (Liabilities)	$ 14,244	$ 9,936

Regulatory assets are either being collected in Retail Rates or are expected to be collected through Retail Rates in a future period. We describe regulatory assets and state when we earn a return below:

(1) See Cost Recovery Mechanisms discussion.

(2) Self-Insured Medical and Short-Term Disability assets are recorded based on historical ratemaking treatment allowing UNS Electric to recover self-insured medical costs and short-term disability costs on a pay-as-you-go or cash basis. UNS Electric records a liability to reflect the accrual for financial reporting purposes and an offsetting regulatory asset to reflect recovery for regulatory purposes. While these assets do not earn a return, they are fully recovered in rates over an approximate one-year period.

(3) These assets represent rate case costs approved for recovery over periods of three years in the 2008 and 2010 Rate Orders. UNS Electric does not earn a return on these costs.

Regulatory liabilities represent items that UNS Electric expects to pay to customers through billing reductions in future periods or use for the purpose for which they were collected from customers, as described below:

(4) Income Taxes Recoverable/Refundable through Future Revenues are primarily related to plant assets and are amortized over the life of the assets.

(5) Net Cost of Removal for Interim Retirements represents an estimate of the cost of future asset retirement obligations net of salvage value. These are amounts collected through revenue for the net cost of removal of interim retirements for which removal costs have not yet been expended.

Income Statement Impact of Applying Regulatory Accounting

If UNS Electric had not applied regulatory accounting, net income would have been $3 million higher in 2011 and $7 million lower in 2010 as UNS Electric would have recognized higher purchased energy and unrealized losses on its commodity derivative instruments as an expense to its income statement, rather than as either regulatory assets or a reduction to its regulatory liabilities.

Future Implications of Discontinuing Application of Regulatory Accounting

UNS Electric regularly assesses whether it can continue to apply regulatory accounting to regulated operations, and concluded regulatory accounting is applicable. If we stopped applying regulatory accounting to our regulated operations the following would occur:

- Regulatory pension assets would be reflected in AOCI;
- UNS Electric would write-off remaining regulatory assets as an expense and regulatory liabilities as income on the income statement; and
- At December 31, 2011, based on the regulatory asset balances, net of regulatory liabilities, we would have recorded an extraordinary after-tax loss of $6 million and an after-tax loss in AOCI of $3 million.

While future regulatory orders and market conditions may affect cash flows, UNS Electric's cash flows would not be affected by discontinuing application of regulatory accounting.

NOTE 5. UTILITY PLANT

The following table shows Utility Plant in Service and depreciable lives by major class at:

	December 31, 2011	December 31, 2010	Depreciable Lives
	-Thousands of Dollars-		
Plant in Service:			
Electric Generation Plant[1]	$ 84,157	$ 81,919	38 – 49 years
Electric Distribution Plant	218,676	200,110	23 – 50 years
Electric Transmission Plant	43,790	31,138	20 – 50 years
General Plant	13,622	12,100	5 – 40 years
Intangible Plant	4,318	4,304	15 – 32 years
Computer Software	512	-	5 years
Electric Plant Held for Future Use	924	749	
Total Plant in Service	$ 365,999	$ 330,320	
Utility Plant under Capital Leases	$ -	$ 706	

Intangible Plant is principally comprised of transmission access rights.

[1] Electric Generation Plant includes adjustments in 2010 to reflect the transfer of BMGS. See Note 3.

NOTE 6. DEBT, CREDIT FACILITIES, AND CAPITAL LEASE OBLIGATIONS

UNS ELECTRIC TERM LOAN CREDIT AGREEMENT AND INTEREST RATE SWAP

In August 2011, UNS Electric entered into a four-year $30 million variable rate term loan credit agreement. UNS Electric used the $30 million in proceeds to repay borrowings under its revolving credit facility. The interest rate currently in effect is three-month LIBOR plus 1.25%. At the same time, UNS Electric entered into a fixed-for-floating interest rate swap in which UNS Electric will pay a fixed rate of 0.97% and receive a three-month LIBOR rate on a $30 million notional amount over a four-year period ending August 10, 2015. The UNS Electric term loan credit agreement, included in Long-Term Debt on the balance sheet, is guaranteed by UES.

The term loan credit agreement contains certain restrictive covenants for UNS Electric and UES. The covenants include restrictions on transactions with affiliates, restricted payments, additional indebtedness, liens and mergers. UNS Electric must meet an interest coverage ratio to issue additional debt. However, UNS Electric may, without meeting these tests, refinance indebtedness and incur short-term debt in an amount not to exceed $5 million. The credit agreement also requires UNS Electric to

maintain a maximum leverage ratio, and allows UNS Electric to pay dividends so long as it maintains compliance with the credit agreement.

UNS ELECTRIC SENIOR UNSECURED NOTES

UNS Electric has $100 million of senior unsecured notes outstanding, consisting of $50 million at 6.5%, due 2015 and $50 million at 7.1%, due 2023. The notes may be prepaid with a make-whole call premium reflecting a discount rate equal to an equivalent maturity U.S. Treasury security yield plus 50 basis points. UES guarantees the notes.

UNS Electric's long-term notes contain certain restrictive covenants, including restrictions on transactions with affiliates, mergers, liens to secure indebtedness, restricted payments and incurrence of indebtedness.

UNS GAS/UNS ELECTRIC CREDIT AGREEMENT

In November 2011, UNS Gas and UNS Electric amended their existing unsecured credit agreement to extend the expiration date from November 2014 to November 2016.

In November 2010, UNS Gas and UNS Electric amended and restated their existing unsecured credit agreement. As amended, the UNS Gas/UNS Electric Credit Agreement consists of a $100 million revolving credit and revolving letter of credit facility. The maximum borrowings outstanding at any one time for UNS Gas or UNS Electric under the agreement may not exceed $70 million. UNS Gas and UNS Electric each are liable for only their own individual borrowings under the UNS Gas/UNS Electric Credit Agreement. UES guarantees the obligations of both UNS Gas and UNS Electric. The UNS Gas/UNS Electric Credit Agreement may be used to issue letters of credit, as well as for revolver borrowings. UNS Gas and UNS Electric issue letters of credit, which are off-balance sheet obligations, to support power and gas purchases and hedges.

UNS Electric capitalized approximately $0.1 million of costs related to the 2011 credit agreement amendment and $0.4 million of costs related to the 2010 credit agreement amendment and restatement. UNS Electric will amortize these costs through November 2016.

Interest rates and fees under the UNS Gas/UNS Electric Credit Agreement are based on a pricing grid tied to their credit ratings. The interest rate currently in effect on borrowings is LIBOR plus 1.5% for Eurodollar loans or Alternate Base Rate plus 0.5% for Alternate Base Rate loans.

The UNS Gas/UNS Electric Credit Agreement contains a number of covenants which impose restrictions on UNS Gas, UNS Electric and UES, including restrictions on additional indebtedness, liens, and mergers. The UNS Gas/UNS Electric Credit Agreement also stipulates a maximum leverage ratio. Under the terms of the UNS Gas/UNS Electric Credit Agreement, UNS Gas and UNS Electric may pay dividends so long as they maintain compliance with the agreement.

UNS Electric did not have any revolver borrowings under the UNS Gas/UNS Electric Credit Agreement at December 31, 2011, or 2010. UNS Electric had $6 million of outstanding Letters of Credit at December 31, 2011, and $13 million of outstanding Letters of Credit at December 31, 2010, which are not shown on the balance sheet.

NOTE 7. COMMITMENTS AND CONTINGENCIES

FIRM PURCHASE COMMITMENTS

At December 31, 2011, UNS Electric had the following firm non-cancelable purchase commitments (minimum purchase obligations) and operating leases:

	2012	2013	2014	2015	2016	Thereafter	Total
Purchased Power	$ 53,511	$39,843	$31,120	$2,957	$2,957	$ 43,369	$ 173,757
Transmission	4,248	1,764	1,764	1,764	882	-	10,422
Operating Leases	91	74	25	-	-	-	190
Total Unrecognized Firm Commitments	$ 57,850	$41,681	$32,909	$4,721	$3,839	$ 43,369	$ 184,369

UNS Electric enters into agreements with various energy suppliers for purchased power at market prices to meet energy requirements. In general, these contracts provide for capacity payments and energy payments based on actual power taken under the contracts. These contracts expire in various years through 2014. Certain of these contracts are at a fixed price per MW and others are indexed to natural gas prices. The commitment amounts included in the table above are based on market prices as of December 31, 2011. Purchased power commitments also include one 20-year PPA with a renewable energy generation facility that achieved commercial operation in September 2011. UNS Electric is obligated to purchase 100% of the output from this facility.

UNS Electric imports the power it purchases over the Western Area Power Administration's (WAPA) transmission lines. UNS Electric's transmission capacity agreements with WAPA provide for annual rate adjustments and expire in 2012 and 2016. However, the effects of both purchased power and transmission cost adjustments are mitigated through a purchased power rate-adjustment mechanism.

Operating Leases

UNS Electric has operating leases, primarily for office facilities and office equipment, with varying terms, provisions, and expiration dates. UNS Electric's operating lease expense was $0.2 million in 2011 and in 2010.
Following the purchase of BMGS from UED in July 2011, UNS Electric terminated its purchased power agreement with UED, which was accounted for as an operating lease. See Note 3.

Gas Supply and Transportation Agreement

In 2008, to supply gas to the BMGS, UNS Electric entered into a gas supply and a transportation agreement with UNS Gas. These contracts expire in 2028. Additionally, UNS Electric contracted to pay monthly pipeline capacity charges to UNS Gas through February 2020. At December 31, 2011, UNS Electric's commitments under these contracts were as follows:

	2012	2013	2014	2015	2016	Thereafter	Total
	-Thousands of Dollars-						
Transportation Agreement	$ 569	$ 569	$ 569	$ 569	$ 569	$ 6,347	$ 9,192
Capacity Charges	768	766	766	766	768	2,379	6,213
Firm Commitments to UNS Gas	$1,337	$1,335	$1,335	$1,335	$1,337	$ 8,726	$ 15,405

UNS Electric's expense for transportation and capacity charges under the above agreements was $1.3 million in each of 2011 and 2010.

ENVIRONMENTAL CONTINGENCY

UNS Electric records liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties and other sources when it is probable that a liability has been incurred and the amount of the assessment can be reasonably estimated.

UNS Electric owns and operates the Valencia Power Plant (Valencia), located in Nogales, Arizona. The Valencia plant consists of four gas and diesel-fueled combustion turbine units. UNS Electric has continued efforts initiated by the site's previous owner to remediate the soil and groundwater contamination at its Valencia facility. In December 2011, based on the results of a new study, UNS Electric recognized an additional $0.2 million for estimated remediation costs. Remediation costs incurred through December 31, 2011, total $1.1 million.

RESOLUTION OF CALIFORNIA ENERGY MARKET ISSUE

In March 2010, based on settlement discussions with parties involved in various legal proceedings related to wholesale power prices charged during the California Energy Crisis in 2001 and 2000, UNS Electric reached a settlement with Arizona Public Service Company (APS) and recorded Other Income of $3 million for cash received in 2010.

NOTE 8. INCOME TAXES

Management believes that based on the historical pattern of taxable income, UNS Electric will produce sufficient taxable income in the future to realize its deferred tax assets. As a result, no valuation allowance has been recorded on the deferred income tax assets in 2011 and 2010.

The deferred income tax assets and liabilities consist of the following:

	December 31,	
	2011	2010
	-Thousands of Dollars-	
Gross Deferred Income Tax Liabilities		
Plant	$(28,857)	$(17,597)
Purchased Power and Fuel Adjustment Clause (PPFAC)	(2,605)	(986)
Other	(496)	(326)
Total Gross Deferred Income Tax Liabilities	(31,958)	(18,909)
Gross Deferred Income Tax Assets		
Customer Advances	3,587	4,564
Contributions in Aid of Construction	4,157	3,492
Net Operating Loss	3,580	-
Compensation and Benefits	773	962
Renewable Energy Credit Up Front Incentives	4,032	2,843
Other	1,652	554
Total Gross Deferred Income Tax Assets	17,781	12,415
Net Deferred Income Tax Liabilities	$(14,177)	$ (6,494)

The balance sheet displays the net deferred income tax liability as follows:

	December 31, 2011	December 31, 2010
	-Thousands of Dollars-	
Deferred Income Taxes – Current Assets	$ 1,023	$ -
Deferred Income Taxes – Current Liabilities	-	(657)
Deferred Income Taxes – Noncurrent Liabilities	(15,200)	(5,837)
Net Deferred Income Tax Liabilities	$(14,177)	$ (6,494)

Income tax expense included in the income statement consists of the following:

	Years Ended December 31, 2011	Years Ended December 31, 2010
	-Thousands of Dollars-	
Current Tax Expense		
Federal	$ 1,585	$ 2,847
State	1,263	1,412
Deferred Tax Expense (Benefit)		
Federal	7,343	5,120
State	443	256
Total Federal and State Income Tax Expense	$ 10,634	$ 9,635

For December 31, 2011 and December 31, 2010, the effective tax rate differed from the Federal statutory rate as a result of state income tax expenses.

Included in Accounts Receivable - Due from Affiliates and Accounts Payable – Due to Affiliates on the balance sheet are current income taxes payable and receivable. UNS Electric's net intercompany income taxes were a receivable of $1.5 million at December 31, 2011, and a payable of $0.9 million at December 31, 2010.

State Tax Rate Change

We record deferred tax assets and liabilities using the income tax rates expected to be in effect when the deferred tax assets and liabilities are realized or settled. In the first quarter of 2011, the Arizona legislature passed a bill reducing the corporate income tax rate from the current rate of 6.968%. The tax rate reduction will be phased in beginning in 2014, with a reduction of approximately 0.5% per year until the income tax rate reaches 4.9% for 2017 and later years. As a result of these tax rate reductions, we increased the net deferred tax liabilities at UNS Electric by $0.1 million, offset entirely by adjustments to regulatory assets and liabilities. The income tax rate change did not have an impact on UNS Electric's effective tax rate for 2011.

Uncertain Tax Positions

Accounting guidance requires us to determine whether it is "more likely than not" that we will sustain a tax position under examination. Each uncertain tax position is measured to determine the amount of benefit to recognize in the financial statements.

The following table shows the changes in unrecognized tax benefits:

	December 31, 2011	December 31, 2010
	-Thousands of Dollars-	
Unrecognized Tax Benefits, beginning of year	$ 4,455	$ -
Additions based on tax positions taken in the current year	1,296	2,088
Additions based on tax positions taken in the prior year	518	2,367
Reductions based on settlements with tax authorities	(1,438)	-
Unrecognized Tax Benefits, end of year	$ 4,831	$ 4,455

The effective tax rate would not be impacted if the balance of unrecognized tax benefits at December 31, 2010, was recognized. The entire balance relates to positions where uncertainty is due to the timing of tax deductions. Included in reductions based on settlements with authorities is $1.4 million for UNS Electric related to a change in accounting method filed with the Internal Revenue Service (IRS) in 2011. The remaining balance in unrecognized tax benefits could change in the next twelve months as a result of ongoing IRS audits, but we are unable to determine the amount of the change.

UNS Electric recognizes interest accrued related to unrecognized tax benefits in Other Interest Expense on the income statement. UNS Electric recorded no change to interest expense in 2011 and an increase to interest expense in 2010 of $0.1 million. The balance of interest payable was $0.1 million at December 31, 2011 and December 31, 2010. No penalties have been accrued in the years presented.

UNS Electric has been audited by the IRS through tax year 2006 and is currently under audit by the IRS for 2008 through 2010. Tax Year 2007 was not selected for audit. We are unable to determine when the audits will be completed. UNS Electric is not currently under audit by any state tax agencies.

NOTE 9. EMPLOYEE BENEFIT PLANS

UNS Electric does not maintain a separate pension plan or other postretirement benefit plan for its employees. All regular employees are eligible to participate in the pension plan maintained by our parent, UES. UES allocates net periodic benefit cost based on service cost for participating employees. UNS Electric provides postretirement medical benefits for current retirees. Retirees contribute a portion of the cost of their medical benefits. UNS Electric active employees do not participate in the postretirement medical plan.

PENSION PLAN

The noncontributory, defined benefit pension plan (the Plan) provides benefits based on years of service and the employee's average compensation. UNS Electric recognizes its share of the underfunded status of the UES defined benefit pension plan as a liability on its balance sheets. The underfunded status is measured as the difference between the fair value of the Plan's assets and the projected benefit obligation. UNS Electric recognizes a regulatory asset to the extent these future costs are probable of recovery in Retail Rates, and expects to recover these costs over the estimated service lives of employees.

Pension Contributions

The Pension Protection Act of 2006 (The Pension Act) established minimum funding targets for pension plans. A plan's funding target is the present value of all benefits accrued or earned as of the beginning of the plan year. While the annual targets are not legally required, benefit payment options are limited for plans that do not meet the targets, and a funding deficiency notice must be sent to all plan participants. The UES pension plan is in compliance with The Pension Act.

In 2012, UNS Electric expects to contribute $1.4 million to the pension plan.

We record changes in our other postretirement obligation, not yet reflected in net periodic benefit cost, as a regulatory asset, as such amounts are probable of future recovery in Retail Rates.

The pension and other postretirement benefit related amounts included on UNS Electric's balance sheet are:

	Pension Benefits		Other Postretirement Benefits	
	December 31,			
	2011	2010	2011	2010
	-Thousands of Dollars-			
Regulatory Pension Asset included in Regulatory Assets - Noncurrent	$ 3,722	$ 2,034	$ 438	$ 177
Accrued Benefit Liability included in Accrued Employee Expenses	-	-	(61)	(81)
Accrued Benefit Liability included in Pension and Other Postretirement Benefits	(3,749)	(2,502)	(583)	(482)
Net Amount Recognized	$ (27)	$ (468)	$ (206)	$ (386)

OBLIGATIONS AND FUNDED STATUS

UNS Electric measured the actuarial present values of all pension benefit obligations and other postretirement benefit plans at December 31, 2011 and December 31, 2010.

The tables below reflect UES' plan information as a whole. The change in projected benefit obligation and plan assets and reconciliation of the funded status are as follows:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
	2011	2010	2011	2010
	-Thousands of Dollars-			
Change in Projected Benefit Obligation				
Benefit Obligation at Beginning of Year	$14,295	$11,444	$ 1,148	$ 1,143
Actuarial Loss	2,222	1,336	313	136
Interest Cost	767	709	57	65
Service Cost	1,381	1,209	-	-
Benefits Paid	(886)	(403)	(312)	(196)
Projected Benefit Obligation at End of Year	17,779	14,295	1,206	1,148
Change in Plan Assets				
Fair Value of Plan Assets at Beginning of Year	8,561	6,141	2	7
Actual Return on Plan Assets	(96)	957	-	-
Benefits Paid	(886)	(403)	(358)	(239)
Employer Contributions	2,633	1,866	312	191
Participant Contributions	-	-	46	43
Fair Value of Plan Assets at End of Year	10,212	8,561	2	2
Funded Status at End of Year	$ (7,567)	$ (5,734)	$ (1,204)	$ (1,146)

At December 31, 2011, UNS Electric's proportionate share of the Plan's funded status is approximately 50%.

The following table provides the components of UES' regulatory assets that have not been recognized as components of periodic benefit cost as of the dates presented:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
	2011	2010	2011	2010
	-Thousands of Dollars-			
Net Loss	$ 5,690	$ 2,836	$ 667	$ 365
Prior Service Cost (Benefit)	1,229	1,486	(27)	(30)

At December 31, 2011 and December 31, 2010, the UES defined benefit pension plan had accumulated benefit obligations in excess of plan assets as follows:

	December 31,	
	2011	2010
	-Thousands of Dollars-	
Projected Benefit Obligation at End of Year	$17,779	$14,295
Accumulated Benefit Obligation at End of Year	13,054	9,841
Fair Value of Plan Assets at End of Year	10,212	8,561

The components of UES' net periodic benefit costs are as follows:

	Pension Benefits		Other Postretirement Benefits	
	Years Ended December 31,			
	2011	2010	2011	2010
	-Thousands of Dollars-			
Service Cost	$ 1,381	$ 1,209	$ -	$ -
Interest Cost	766	709	57	65
Expected Return on Plan Assets	(651)	(503)	-	-
Prior Service Cost (Benefit) Amortization	258	258	(3)	(3)
Recognized Actuarial Loss	116	75	11	10
Net Periodic Benefit Costs	$ 1,870	$ 1,748	$ 65	$ 72

In 2011, UNS Electric recognized 47% of total net periodic pension benefit costs and 59% of other postretirement benefit costs based on relative employee participation.

Approximately 39% of the net periodic benefit cost was capitalized as a cost of construction and the remainder was included in Other Operating and Maintenance costs.

The changes in UES' plan assets and benefit obligations recognized as regulatory assets are as follows:

	Pension Benefits	
	2011	2010
	-Thousands of Dollars-	
Current Year Actuarial Loss	$2,970	$ 882
Amortization of Actuarial (Loss)	(116)	(75)
Prior Service (Cost) Amortization	(258)	(258)
Total Recognized as Regulatory Asset	$2,596	$ 549

	Other Postretirement Benefits	
	2011	2010
	-Thousands of Dollars-	
Current Year Actuarial Loss	$ 313	$ 136
Amortization of Actuarial (Loss)	(11)	(10)
Prior Service Benefit Amortization	3	3
Total Recognized as Regulatory Asset	$ 305	$ 129

For the Plan, we amortize prior service costs on a straight-line basis over the average remaining service period of employees expected to receive benefits under the Plan. UES will amortize $0.3 million of prior service cost and $0.4 million of net loss from regulatory assets into net periodic benefit cost in 2012. The estimated net loss and prior service benefit for the defined benefit postretirement plans that will be amortized from regulatory assets into net periodic benefit cost in 2012 are each less than $0.1 million.

Weighted-Average Assumptions Used to Determine Benefit Obligations as of the Measurement Date	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
Discount Rate	4.9%	5.5%	4.7%	5.2%
Rate of Compensation Increase	3.0%	3.0 – 4.0%	N/A	N/A

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs for Years Ended December 31	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
Discount Rate	5.5%	6.3%	5.2%	6.0%
Rate of Compensation Increase	3.0 – 4.0%	3.0 – 4.0%	N/A	N/A
Expected Return on Plan Assets	7.0%	7.5%	N/A	N/A

Net periodic benefit cost is subject to various assumptions and determinations, such as the discount rate, the rate of compensation increase, and the expected return on plan assets. UES uses a combination of sources in selecting the expected long-term rate-of-return-on-assets assumption, including an investment return model. The model used provides a "best estimate" range over 20 years from the 25th percentile to the 75th percentile. The model used as a guideline for selecting the overall rate-of-return-on-assets assumption is based on forward looking return expectations only. The above method is used for all asset classes.

Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as net periodic benefit cost.

	December 31,	
	2011	2010
Assumed Health Care Cost Trend Rates		
Health Care Cost Trend Rate Assumed for Next Year	6.9%	7.9%
Ultimate Health Care Cost Trend Rate Assumed	4.5%	4.5%
Year that the Rate Reaches the Ultimate Trend Rate	2027	2027

A one-percentage-point change in assumed health care cost trend rates would have an impact of less than $0.1 million on the December 31, 2011, UES benefit obligation.

Pension Plan Assets

UES calculates the market-related value of plan assets using the fair value of plan assets on the measurement date. The pension plan asset allocations by asset category are as follows:

	December 31,	
	2011	2010
Asset Category		
Equity Securities	55%	57%
Fixed Income Securities	34	32
Real Estate	11	11
Total	100%	100%

The following tables set forth the fair value measurements of pension plan assets, by level within the fair value hierarchy:

	Fair Value Measurements of Pension Assets December 31, 2011			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Asset Category		-Thousands of Dollars-		
Cash Equivalents	$ 3	$ -	$ -	$ 3
Equity Securities:				
U.S. Large Cap	-	2,879	-	2,879
U.S. Small Cap	-	573	-	573
Non-U.S.	-	2,192	-	2,192
Fixed Income	-	3,446	-	3,446
Real Estate	-	1,119	-	1,119
Total	$ 3	$ 10,209	$ -	$ 10,212

	Fair Value Measurements of Pension Assets December 31, 2010			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Asset Category		-Thousands of Dollars-		
Cash Equivalents	$ 3	$ -	$ -	$ 3
Equity Securities:				
U.S. Large Cap	-	2,490	-	2,490
U.S. Small Cap	-	514	-	514
Non-U.S.	-	1,875	-	1,875
Fixed Income	-	2,751	-	2,751
Real Estate	-	928	-	928
Total	$ 3	$ 8,558	$ -	$ 8,561

Level 1 cash equivalents are based on observable market prices and are comprised of the fair value of commercial paper, money market funds, and certificates of deposit.

Level 2 investments comprise amounts held in commingled equity funds, US bond and real estate funds. Valuations are based on active market quoted prices for assets held by each respective fund.

Pension Plan Investments

Investment Goals

Strategic asset allocation is the principal method for achieving the Plan's investment objective, while maintaining an appropriate level of risk. We consider the projected impact on benefit security of any proposed changes to the current asset allocation policy. The expected long-term returns and implications for pension plan sponsor funding will be reviewed in selecting policies to ensure that current asset pools are projected to be adequate to meet the expected liabilities of the Plan. We expect to use asset allocation policies weighted most heavily to equity and fixed income funds, while maintaining some exposure to real estate and opportunistic funds. Within the fixed income allocation, long-duration funds may be used to partially hedge interest rate risk.

Risk Management

We recognize the difficulty of achieving investment objectives in light of the uncertainties and complexities of the investment markets. We also recognize some risk must be assumed to achieve a plan's long-term investment objectives. In establishing risk tolerances, the following factors affecting risk tolerance and risk objectives will be considered: 1) Plan status; 2) UES' financial status and profitability; 3) Plan features; and 4) workforce characteristics. We have determined that the Plan can tolerate some interim fluctuations in market value and rates of return in order to achieve long-term objectives. We track the Plan's portfolio relative to the benchmark through quarterly investment reviews. The reviews consist of a performance and risk assessment of all investment categories and on the portfolio as a whole. Investment managers for the Plan may use derivative financial instruments for risk management purposes or as part of their investment strategy. Currency hedges have also been used for defensive purposes.

Relationship between Plan Assets and Benefit Obligations

The overall health of the Plan will be monitored by comparing the value of Plan obligations (both Accumulated Benefit Obligation and Projected Benefit Obligation) against the market value of assets and tracking the changes in each. The frequency of this monitoring will depend on the availability of Plan data, but will be no less frequent than annually via annual actuarial valuation.

The current target allocation percentages for the major categories or plan assets follow. The Plan allows a variance of +/- 2% from these targets before funds are automatically rebalanced.

	UES Plan %
Fixed Income	33%
U.S. Large Cap	28
Non-US Developed	17
Real Estate	11
U. S. Small Cap	5
Non-US Emerging	6
Total	100%

Estimated Future Benefit Payments

UES expects the following benefit payments to be made by the defined benefit pension plan and postretirement plan, which reflect future service, as appropriate.

	Pension Benefits	Other Postretirement Benefits
	- Thousands of Dollars -	
2012	$ 884	$ 118
2013	1,155	117
2014	1,004	116
2015	1,358	113
2016	1,172	110
Years 2017-2021	8,165	486

DEFINED CONTRIBUTION PLAN

UNS Electric offers a defined contribution savings plan to all eligible employees. The Internal Revenue Code identifies the plan as a qualified 401(k) plan. Participants direct the investment of contributions to certain funds in their account. UNS Electric matches part of a participant's contributions to the plan. UNS Electric made matching contributions of less than $0.3 million in each of 2011 and 2010.

NOTE 10. FAIR VALUE MEASUREMENTS

Fair Value of Financial Instruments Carried at Fair Value

The following tables set forth, by level within the fair value hierarchy, UNS Electric's assets and liabilities accounted for at fair value on a recurring basis. These assets and liabilities are classified in their entirety based on the lowest level of input significant to the fair value measurement. There were no transfers between Levels 1, 2, or 3 for either reporting period.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		December 31, 2011 - Thousands of Dollars -		
Assets				
Cash Equivalents [1]	$ 15	$ -	$ -	$ 15
Energy Contracts [2]	-	42	11,039	11,081
Total Assets	15	42	11,039	11,096
Liabilities				
Interest Rate Swaps [3]	-	(62)	-	(62)
Energy Contracts [2]	-	(3,506)	(21,140)	(24,646)
Total Liabilities	-	(3,568)	(21,140)	(24,708)
Net Total Assets and (Liabilities)	$ 15	$ (3,526)	$ (10,101)	$ (13,612)

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		December 31, 2010 - Thousands of Dollars -		
Assets				
Cash Equivalents [1]	$ 2,012	$ -	$ -	$ 2,012
Energy Contracts [2]	-	60	11,606	11,666
Total Assets	2,012	60	11,606	13,678
Liabilities				
Energy Contracts [2]	-	(2,601)	(22,139)	(24,740)
Total Liabilities	-	(2,601)	(22,139)	(24,740)
Net Total Assets and (Liabilities)	$ 2,012	$ (2,541)	$ (10,533)	$ (11,062)

(1) Cash Equivalents are based on observable market prices and are comprised of the fair value of money market funds and certificates of deposit.

(2) Energy Contracts include natural gas swap agreements (Level 2), forward power purchase and sales contracts (Level 3), and forward power purchase contracts indexed to gas (Level 3), entered into to reduce exposure to energy price risk. These contracts are included in Derivative Instruments on the balance sheets. The valuation techniques are described below. See Note 13.

(3) Interest Rate Swaps are valued based on the 3-month LIBOR index. These interest rate swaps are included in Derivative Instruments on the balance sheets.

Energy Contracts

We primarily apply the market approach for recurring fair value measurements. When we have observable inputs for substantially the full term of the asset or liability – such as gas swap derivatives valued using New York Mercantile Exchange (NYMEX) pricing, adjusted for basis differences – we categorize the instrument in Level 2. We categorize derivatives in Level 3 using an aggregate pricing service or published prices that represent a consensus reporting of multiple brokers.

For both power and gas prices, UNS Electric obtains quotes from brokers, major market participants, exchanges or industry publications and relies on its own price experience from active transactions in the market. We primarily use one set of quotations each for power and for gas and then validate those prices using other sources. We believe that the market information provided is reflective of market conditions as of the time and date indicated.

Published prices for energy derivative contracts may not be available due to the nature of contract delivery terms including: delivery periods during non-standard time blocks, delivery during only a few months of a given year when prices are quoted only for the annual average, or delivery at illiquid delivery points. In these cases, we use percentage multipliers to value non-standard time blocks, we apply historical price curve relationships to calendar year quotes, and we include adjustments for transmission and line losses to value contracts at illiquid delivery points. We also consider the impact of counterparty credit risk using current and historical default and recovery rates as well as our own credit risk using market credit default swap data. We review these assumptions quarterly.

UNS Electric's assessments of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth a reconciliation of changes in the fair value of assets and liabilities classified as Level 3 in the fair value hierarchy:

	Year Ended December 31,	
	2011	2010
	-Thousands of Dollars-	
Balance, beginning of year	$(10,533)	$ (8,732)
Gains and (Losses) (Realized/Unrealized) Recorded to:		
Net Regulatory Assets-Derivative Instruments	(11,166)	(17,612)
Settlements	11,598	15,811
Balance, end of year	$(10,101)	$ (10,533)
Total gains (losses) attributable to the change in unrealized gains or losses relating to assets/liabilities held at the end of the period	$ (8,986)	$ (8,459)

Fair Value of Financial Instruments Not Carried at Fair Value

The market price received when selling an asset or paid to transfer a liability at the measurement date is the fair value of a financial instrument.

UNS Electric's outstanding senior unsecured notes of $100 million have estimated fair values of $119 million at December 31, 2011, and $112 million at December 31, 2010. UNS Electric uses quoted market prices, where available, or calculates the present value of remaining cash flows at the balance sheet date using current market rates for bonds with similar characteristics with respect to credit rating and time-to-maturity. We also incorporate the impact of our own credit risk using a credit default swap rate when determining the fair value of long-term debt.

The carrying value of UNS Electric's $30 million term loan approximates its fair value due to the short-term nature of the instrument.

The use of different estimation methods and/or market assumptions may yield different estimated fair value amounts.

NOTE 11. COMMON STOCK EQUITY

In July 2011, UniSource Energy contributed $20 million in capital through UES to help fund UNS Electric's purchase of BMGS from UED.

DIVIDEND LIMITATIONS

The terms of the senior unsecured note agreements and the UNS Gas/UNS Electric Credit Agreement contain dividend restrictions. See Note 6. UNS Electric made no dividend payments to UES in 2011 or 2010.

NOTE 12. SUPPLEMENTAL CASH FLOW INFORMATION

A reconciliation of net income to net cash flows from operating activities follows:

	Years Ended December 31,	
	2011	2010
	-Thousands of Dollars-	
Net Income	$17,677	$ 15,490
Adjustments to Reconcile Net Income to Net Cash Flows		
Depreciation Expense	20,071	19,942
Amortization Expense	(3,111)	(3,372)
Depreciation Recorded to Other Operations & Maintenance Expense	725	710
Amortization of Deferred Debt-Related Costs Included in Interest Expense	181	111
Provision for Retail Customer Bad Debts	399	706
Use of Renewable Energy Credits for Compliance	505	500
Deferred Income Taxes	7,786	5,376
Pension and Postretirement Expense	911	858
Pension and Postretirement Funding	(1,495)	(1,067)
Decrease to Reflect PPFAC Recovery	(4,075)	(7,232)
Allowance for Equity Funds Used During Construction	(640)	(649)
Purchase of Black Mountain Generating Station Retrospective Adjustment [1]	1,637	573
Changes in Assets and Liabilities which Provided (Used) Cash Exclusive of Changes Shown Separately		
Accounts Receivable	(98)	(5,229)
Materials and Supplies Inventory	(892)	1,467
Income Taxes	1,827	4,455
Accounts Payable	(198)	1,552
Interest Accrued	95	4
Taxes Accrued	214	446
Other	1,185	(149)
Net Cash Flows – Operating Activities	$42,704	$ 34,492

[1] Represents BMGS operating expenses for O&M, taxes other than deferred income taxes, and capitalized interest. See Note 3.

Other non-cash investing and financing activities that affected recognized assets and liabilities but did not

result in cash receipts or payments were as follows:

	Years Ended December 31, 2011	2010
	-Thousands of Dollars-	
(Decrease)/Increase to Utility Plant Accruals [1]	$ (917)	$ 1,241
Net Cost of Removal of Interim Retirements [2]	903	(2,747)
Purchase of Black Mountain Generating Station [3]	-	63,029

(1) The non-cash additions to Utility Plant represent accruals for capital expenditures.
(2) The non-cash net cost of removal of interim retirements represents an accrual for future asset retirement obligations that does not impact earnings.
(3) See Note 3.

NOTE 13. ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES

CASH FLOW HEDGES

At December 31, 2011, UNS Electric had liabilities related to cash flow hedges of $0.1 million. In 2011, UNS Electric had net after-tax unrealized losses on derivative activities reported in AOCI of $0.1 million. UNS Electric had no cash flow hedges in 2010.

REGULATORY TREATMENT OF COMMODITY DERIVATIVES

The following table discloses unrealized gains and losses on energy contracts that are recoverable through the PPFAC on the balance sheet as a regulatory asset or a regulatory liability rather than as a component of AOCI or in the income statement.

	Years Ended December 31, 2011	2010
	-Thousands of Dollars-	
Increase to Regulatory Assets	$ 491	$ 1,462

The fair value of derivative assets and liabilities were as follows:

	December 31, 2011	December 31, 2010
	-Thousands of Dollars-	
Assets	$ 11,081	$ 11,666
Liabilities	(24,646)	(24,740)
Net Assets (Liabilities)	$(13,565)	$(13,074)

The realized losses on settled gas swaps that are fully recovered through the PPFAC were as follows:

	Years Ended December 31, 2011	2010
	-Thousands of Dollars-	
Realized Losses on Gas Swaps	$ 2,668	$ 4,951

At December 31, 2011, UNS Electric had contracts that will settle through the fourth quarter of 2014.

DERIVATIVE VOLUMES

At December 31, 2011, UNS Electric had gas swaps totaling 2,758 Billion British thermal units (GBtu) and power contracts totaling 2,332 Gigawatt-hours (GWh). At December 31, 2010, UNS Electric had gas swaps totaling 2,445 GBtu and power contracts totaling 3,663 GWh. We account for gas swaps and power contracts as derivatives.

CREDIT RISK ADJUSTMENT

When the fair value of our derivative contracts is reflected as an asset, the counterparty owes us and this creates credit risk. We also consider the impact of our own credit risk on instruments that are in a net liability position. The impact of counterparty credit risk and our own credit risk on the fair value of derivative asset contracts was less than $0.2 million at December 31, 2011 and December 31, 2010.

CONCENTRATION OF CREDIT RISK

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of non-performance by counterparties pursuant to the terms of their contractual obligations. UNS Electric enters into contracts for the physical delivery of energy which contain remedies in the event of non-performance by the supply counterparties. In addition, volatile energy prices can create significant credit exposure from energy market receivables and mark-to-market valuations.

UNS Electric has contractual agreements for its energy procurement and hedging activities that contain certain provisions requiring it to post collateral under certain circumstances. These circumstances include: exposures in excess of unsecured credit limits provided to UNS Electric; credit rating downgrades; or a failure to meet certain financial ratios. In the event that such credit events were to occur, UNS Electric would have to provide certain credit enhancements in the form of cash or letters of credit to fully collateralize its exposure to these counterparties.

The following table shows the sum of the fair value of all derivative instruments under contracts with credit-risk related contingent features that are in a net liability position at December 31, 2011. It also shows cash collateral and letters of credit posted, and additional collateral to be posted if credit-risk related contingent features were triggered.

	December 31, 2011
	-Thousands of Dollars-
Net Liability Position	$ 21,426
Cash Collateral Posted	-
Letters of Credit	5,500
Additional Collateral to Post if Contingent Features Triggered	18,360

At December 31, 2011, UNS Electric had $1.3 million of credit exposure to other counterparties' creditworthiness related to its supply and hedging contracts. UNS Electric had one counterparty which individually comprised greater than 10% of UNS Electric's total credit exposure.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-01933A-12-____

Direct Testimony of

Jason J. Rademacher

on Behalf of

UNS Electric, Inc.

December 31, 2012

TABLE OF CONTENTS

I. Introduction 1

II. Pro Forma Adjustments 2

III. Rate Base Adjustments 4

A. Accumulated Deferred Income Tax ("ADIT") 4

B. Accumulated Deferred Investment Tax Credit ("ITC") 10

IV. Operating Income Adjustments 12

A. Property Tax Expense 12

B. Income Tax Expense 12

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Jason J. Rademacher and my business address is 88 East Broadway, Tucson, Arizona, 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP"), a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy"), as Manager of Tax Compliance and Regulatory Support. In my position I am responsible for the accounting and compliance filings related to income, sales and use and property tax and FERC Forms 1 and 3-Q for all the regulated subsidiaries of UNS Energy, including TEP, UNS Electric, Inc. ("UNS Electric" or the "Company") and UNS Gas, Inc.

Q. Would you please describe your education, background and experience?

A. I received a Bachelor of Science Degree in Accounting from the University of Buffalo in 1999 and I am a Certified Public Accountant licensed to practice in the state of Arizona. Since joining TEP in 2003, I have held various positions within the Tax Department with increasing leadership responsibility. I have been in my current role since 2011.

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

A. My direct testimony supports UNS Electric's rate request in this proceeding. I am the sponsoring witness for several pro forma adjustments.

Q. Please summarize your testimony.

A. In my testimony, I provide support for the following rate-base items:

- Accumulated Deferred Income Tax ("ADIT") adjustment; and
- Accumulated Deferred Investment Tax Credit ("ITC").

Further, I am the sponsoring witness for the following income statement pro forma accounting adjustments:

- Property Tax Expense; and
- Income Tax Expense.

II. PRO FORMA ADJUSTMENTS.

Q. Please explain the consideration of pro forma adjustments in the rate case process.

A. Public utility rates are based on the prudently-incurred costs of providing safe, reliable service. The revenue requirement underlying rates is developed on the basis of a test year that reflects a level of operating revenues and expenses and net plant investment that represents normal conditions that may be expected to exist during the time that resulting rates may be in effect. This affords the utility a reasonable opportunity to achieve a fair rate of return, as authorized by the respective regulatory authority.

Pro forma adjustments are made to recorded test year amounts that do not reflect the levels of expenses required for the provision of service, or that do not represent the levels expected to occur during the period when the new rates will be in effect. These adjustments may be made in the form of eliminations, annualizations, or normalizations.

Elimination adjustments are made to remove out-of-period or non-recurring transactions, or items that are not costs or revenues related to the provision of utility service. Thus, they are not eligible for reflection in the revenue requirement.

Annualization adjustments are made to reflect the full, 12-month revenue or expense level of certain components of operating income. Annualization adjustments are typically computed using end-of-test-year quantities, and the most current known and measurable prices and rates. Examples in this case include restating test-year operating revenues to reflect customer levels at the end of the test year, adjusting payroll expense to reflect current salary rates and changes in employee levels during the test year, and adjusting recorded depreciation expense to reflect the full effect of plant additions and retirements during the test year.

Normalization adjustments reflect that the recorded test year operating revenues and expenses may not represent a normal level for rate-making purposes. Certain events may have affected recorded transactions in an atypical manner. Moreover, some transactions – while eligible for reflection in the revenue requirement – are incurred at intervals less frequent than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amounts recorded in the test year may not be viewed as "normal", thus requiring a restatement for ratemaking purposes. Normalization adjustments are made in these instances when a test year level of revenues or expenses does not represent what would be expected on an on-going basis. Examples in this case include the adjustment for bad debt expense and the overtime factor implicit in the payroll adjustment.

Q. Were the pro forma adjustments that you are sponsoring in your testimony prepared by you or under your supervision?

A. Yes, they were.

Q. Have the pro forma adjustments for which you are responsible in this rate filing been computed in accordance with sound rate-making principles and applicable rules and policies of the Arizona Corporation Commission ("Commission")?

A. Yes. To the best of my knowledge, all of the adjustments that I am sponsoring have been so calculated.

III. RATE BASE ADJUSTMENTS.

A. Accumulated Deferred Income Tax ("ADIT").

Q. Please explain the ADIT Adjustment.

A. The adjustment reduces rate base for the computed balance of ADIT, a source of non-investor capital, based on adjusted test-year rate base, test-year operating results, and the Company's existing income tax ratemaking authority.

Q. What are deferred income taxes?

A. Deferred income taxes represent the tax effect of differences that arise between the time period when revenues and expenses are recognized for financial reporting purposes and when they are considered for income tax return purposes. For public utilities, the largest such difference is that which exists as a result of using accelerated methods and shorter lives in computing tax depreciation, as compared with the manner in which book and regulatory depreciation is computed. The process of apportioning income taxes among accounting periods is often referred to as "inter-period income tax allocation," or "normalization".

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

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

Timing/temporary differences represent differences between book income before income taxes and taxable income which originate in one or more periods, and reverse or turn around, in one or more subsequent periods. Because of their capital intensity, the difference between book and tax depreciation is typically the largest timing difference affecting public utilities.

For book purposes, utility plant is capitalized and depreciated over the estimated useful life in a systematic and rational manner, typically straight-line. For income tax purposes, depreciation is computed over shorter lives using one of the accelerated methods contained in the IRC. Depreciation is generally considered a timing/temporary difference because both book and tax depreciation amounts are limited, over time, to the cost of the utility plant. Thus, in the early years tax depreciation will exceed book depreciation, but in the later years, book depreciation will exceed tax depreciation.

Other examples of timing/temporary differences include: (i) expenses that are deducted by utilities currently for tax purposes, but deferred on the books as regulatory assets for future recognition in rates (such as rate case expense); and (ii) expenses that are recognized for book purposes ahead of when they are deductible for income tax purposes (such as accrued vacation expense).

Permanent differences also exist between book income and taxable income, and do not reverse in subsequent periods. Examples of permanent differences include non-taxable interest income from municipal bonds and non-deductible lobbying expenses. Both of these items are included when determining book income, but are never included in the determination of taxable income on the income tax return.

Q. How are the income tax components calculated?

A. Income taxes currently payable are calculated on the estimated amount that the Company will pay based on the current year's taxable income (using the rules under the IRC). Deferred income taxes are computed for timing/temporary differences, but not for permanent differences. Deferred income tax expense is calculated by multiplying timing/temporary difference by the income tax rate. It should be noted that the typical effect of timing/temporary differences is to reduce current income taxes and increase deferred income taxes, dollar for dollar with no "net" impact on the calculation of total income taxes.

Q. How do deferred income taxes affect public utility rate-making?

A. The reflection of deferred income taxes in rate-making is labeled "normalization." Some regulatory bodies permit utilities to recognize deferred income taxes associated with all timing/temporary differences in rate-making ("full normalization"), while others only permit the recognition of certain timing/temporary differences required by the IRC to be

recognized in utility ratemaking ("partial normalization"). To the extent that normalization is permitted in ratemaking, the resulting deferred income taxes are reflected as a component of income tax expense – with the corresponding balance sheet reserve for accumulated deferred taxes deducted from rate base as non-investor capital. This treatment reflects the availability of such amounts for plant investment or operating purposes between the time they are collected from customers and ultimately remitted to taxing authorities. In effect, the ADIT represents a cost-free or interest-free loan from the U.S. Treasury.

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

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

A. UNS Electric's assets were formerly owned by Citizens Communications Company, which operated various properties throughout the state of Arizona, with each having its separate designated service territory, rate schedules and service rules. For electric operations, Citizens operated separate divisions in northern Arizona and southern Arizona. The pro forma income tax expense calculations prepared in connection with the 1996 Citizens rate case, resulting in Decision No. 59951 (January 3, 1997) clearly

indicate the use of a full normalization of all book/tax-timing differences. For ratemaking purposes, both of the electric plant divisions acquired from Citizens have been permitted to provide deferred income taxes in rate making for all timing differences. In that rate case (which resulted in Decision No. 59951), the filing and resulting revenue requirement and rate structure were prepared on a combined basis, providing precedent for the consolidation of rate designs for Mohave and Santa Cruz County customers in UNS Electric's rate applications. This combined-division basis and use of full normalization was affirmed for use in Decision No. 66028 (July 3, 2003)(approving the acquisition of the systems by UNS Energy and the organization where electric assets would be owned by UNS Electric) and again in UNS Electric's most recent rate case order, Decision No. 71914 (September 30, 2010).

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

A. Yes. UNS Electric's last rate case used a test year ending December 31, 2008. While there are not many new book/tax differences, since then the ADIT relating to accelerated depreciation has increased. This is a result of the bonus depreciation legislation included in the "Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010," under which the difference between book and tax depreciation is much larger than in prior years. This legislation extended the 50% bonus provisions to include assets placed in service prior to January 1, 2013. The bill also provided for 100% bonus depreciation in the case of qualifying property placed in service after September 8, 2010 and before January 1, 2012. 100% bonus depreciation allows the entire cost of qualifying assets to be deducted, at the taxpayer's election, at the time the asset is placed in service.

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

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

Q. Did the bonus depreciation deductions result in a net operating loss ("NOL") carryforward?

A. Yes. UNS Electric generated a net operating loss carryforward in 2011. However, the carryforward was fully utilized by June 30, 2012. As a result, UNS Electric has not included any NOL ADIT in this case.

Q. Are there circumstances that would cause UNS Electric to change its determination that the NOL carryforward was fully utilized by June 30, 2012?

A. Yes. UNS Electric assumed that current tax law which allows 50% bonus depreciation in 2012 would remain in effect. If Congress were to retroactively reinstate 100% bonus depreciation for 2012 (or enact some other modification to this provision of the current tax law), the Company may not use all of its NOL carryforward by June 30, 2012 and the ADIT amount included in rate base may need to be updated to include the NOL carryforward ADIT.

Q. Have there been any changes in the Arizona corporate income tax rate since UNS Electric's last rate case?

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

Q. What impact does the Arizona rate change have on UNS Electric's ratemaking ADIT?

A. None. For purposes of ADIT included in this case, the balance of Arizona deferred income taxes is at the rates in effect at the end of the test year, or 6.968%. The rate change does have an impact of deferred income tax expense discussed later in my testimony.

B. <u>Accumulated Deferred Investment Tax Credit ("ITC").</u>

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

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

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

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

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

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

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

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

A. UNS Electric amortizes the ITC over the tax life of the assets that generated the ITC. In the case of solar generating facilities, the property is classified for depreciation purposes in IRC §168(e)(3)(B)(vi) and qualifies for a five-year life for tax depreciation purposes. As the book life of the solar generating assets is 20 years, the use of the shorter life is in compliance with the normalization provisions of IRC §46(f)(1).

Q. How was the ITC rate base reduction calculated in this case?

A. The ITC rate base reduction is calculated by taking the ITC claimed by UNS Electric less amortization over the five-year tax life of the qualifying property. Since the five-year tax depreciation recovery period is spread over six years, UNS Electric uses a straight-line amortization period of six years with a half-year of amortization in the first and last years.

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

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

IV. OPERATING INCOME ADJUSTMENTS.

A. Property Tax Expense.

Q. Please explain the Property Tax adjustment.

A. The Property Tax adjustment is a pro forma adjustment to test-year operating expense to reflect the final, adjusted plant in service at the end of the test year, using the 2013 statutory assessment ratio of 19.5%, and average property tax rates based on the 2012 property tax bills.

B. Income Tax Expense.

Q. Please explain the Income Tax Expense adjustment.

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

base and the weighted cost of debt in the capital structure. The Commission has traditionally used this synchronization methodology - and most recently approved its use for UNS Electric's sister company, UNS Gas in Decision No. 73142 (May 1, 2012).

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

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

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

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

Q. Are there any adjustments to deferred income tax expense as a result of the Arizona income tax rate change discussed earlier?

A. Yes. When timing/temporary differences reverse at an income tax rate that is lower than the rate that was in effect when the timing/temporary differences originate excess

deferred income taxes are created. UNS Electric proposes that the excess deferred taxes be used to reduce retail customer rates on the same schedule that the taxes would have been paid to the state of Arizona, if the income tax rates had not been reduced. In other words, the excess deferred income taxes will be amortized as a reduction to deferred income tax expense as the underlying timing differences reverse. These timing differences will start to reverse with the lower tax rate beginning in 2014. Since there was no amortization during the test year UNS Electric has included the projected average amortization for 2014-2016 as a reduction to deferred income tax expense.

Q. Does this conclude your Direct Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	DOCKET NO. E-04204A-12-____

Direct Testimony of

Denise A. Smith

on Behalf of

UNS Electric, Inc.

December 31, 2012

TABLE OF CONTENTS

I. Introduction.....1

Exhibits:

Exhibit DAS-1 Plan of Administration for the Energy Efficiency Resource Plan
Exhibit DAS-2 Monthly Residential Customer Impact

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Denise Smith. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. What is your position with UNS Electric, Inc. ("UNS Electric" or the "Company")?

A. I am the Director of Demand Side Resources at Tucson Electric Power Company ("TEP") UNS Gas, Inc. ("UNS Gas") and UNS Electric, Inc. ("UNS Electric" or "Company").

Q. Please describe your education and experience.

A. I graduated from Northern Arizona University ("NAU"), earning a Bachelor of Science degree, in Mathematics with an extended major in Statistics, and then completed graduate work in Statistics at NAU. During my tenure at TEP, I completed a Masters of Business Administration at the University of Phoenix. After leaving NAU, I was hired by Pima Association of Governments in the Travel Reduction Program, which reduces vehicle emissions by targeting major employers to reduce employees' travel to and from work.

I was hired in 1996 by TEP as a Demand-Side Management ("DSM") Analyst, developing, analyzing and researching new DSM and energy-related market programs. In addition, I implemented and reported progress of existing DSM programs and then transitioned them into market-transformation programs. In 1999, I moved into the Pricing and Rates Department, where I developed cost-of-service and revenue requirement models. In 2002, I was promoted to the Director of the Pricing and Rates Department. I then accepted the position of Director of Conservation and Renewable Programs. During my tenure as Director of Conservation and Renewable Programs, and

more recently as Director of Demand Side Resources, I have overseen the implementation and management of 29 new DSM programs. I also managed the successful design and implementation of several renewable energy programs for TEP and UNS Electric.

Q. What is the purpose of your Direct Testimony?

A. I discuss UNS Electric's proposed Energy Efficiency Resource Plan ("EE Resource Plan"). This is a three-year pilot program that allows UNS Electric to invest in and deliver cost-effective energy efficiency programs to our customers – while also being a way to better align cost and benefits and moderate future bill impacts for the DSM/EE programs.

Q. What is the EE Resource Plan?

A. UNS Electric's EE Resource Plan provides an alternate and improved approach to compliance with the Energy Efficiency Standard ("EES"). It is a three-year pilot program that allows UNS Electric to invest in and deliver cost-effective EE programs to our customers and to moderate future rate impacts for DSM/EE programs. As a part of this proposal, the Company would recover the cost of its EE investments, including a return, through UNS Electric's existing Demand Side Management Surcharge ("DSMS").

Q. Please explain why UNS Electric is proposing its EE Resource Plan as part of its rate application?

A. The adoption of cost-effective energy efficiency measures plays an important role in the Company's ability to develop a diverse and least-cost resource portfolio. Our goal is to develop and deploy measures that provide the greatest operating efficiencies to UNS Electric's generation, transmission and distribution system – while reducing reliance on more costly traditional generating resources and providing more rate stability and more

program certainty to customers, contractors and the Company. Allowing UNS Electric to invest and recover capital spent on energy efficiency measures in a timely manner, similar to investments in conventional and renewable resources, more closely aligns costs and benefits and eliminates the need for a performance incentive.

Further, the adoption of a three-year program provides our customers, the EE market and local contractors with some predictability, allows UNS Electric to adequately plan and budget for EE programs, and affords UNS Electric and Commission Staff easier administration of the Company's EE Implementation Plan. All of these benefits should ultimately reduce the total cost of providing EE resources to UNS Electric customers, compared to the current method for acquiring annual approval of an EE Implementation Plan. The EE Resource Plan is the most cost-effective way to achieve the desired energy savings levels set forth in the EE Rules by establishing a moderate, gradually inclining rate for the DSMS.

Q. Does UNS Electric believe that DSM/EE can be a cost-effective supply-side resource?

A. Yes. Based on analysis performed in conjunction with UNS Electric's Integrated Resource Plan ("IRP") efforts, the savings produced by certain EE measures will cost less than traditional supply-side resources, help reduce peak load requirements and, in the future, may reduce the need for investment in new generation resources. Further, the deployment of cost-effective EE also has less environmental impact (to the water, air and land) than other generation resources.

Q. What costs are to be included in the EE Resource Plan and recovered through the DSMS?

A. The EE Resource Plan will include the same type of program-related costs that are

currently being recovered through the DSMS. This includes the costs of developing, implementing and administering DSM/EE measures and programs. A return on UNS Electric's investments in DSM/EE will also be recovered through the DSMS. The Plan of Administration ("POA") for the EE Resource Plan details the costs UNS Electric proposes to recover through the DSMS and is attached as **Exhibit DAS-1**.

Q. Does the EE Resource Plan include a performance incentive?

A. No.

Q. Please describe the challenges UNS Electric has faced in its efforts to comply with the EES.

A. The EES compels utilities to pursue ambitious energy sales reductions through customer-oriented conservation programs. While UNS Electric supports the underlying principles, the Company has continuously asserted that the EES goals may not be reasonably achievable and, as a result, may create unintended consequences for utilities and customers. For instance, EES compliance costs increase significantly each year as utilities are required to meet ever increasing annual and cumulative savings goals. Costs will escalate further as utilities exhaust the potential of the simplest and most cost-effective measures and are forced to invest in less productive and more expensive programs.

Q. How would UNS Electric's EE Resource Plan improve the current regulatory framework for complying with the EE Rules?

A. UNS Electric's proposal provides an alternative solution for financing the cost of complying with the EE Rules that would reduce and stabilize the rate impacts to our customers, better synchronize the benefits of EE with their associated costs, provide a

base level of certainty to program offerings and eliminate the need to provide a performance incentive.

The EE Resource Plan would establish a three-year planning horizon for the Company's EE programs and the associated DSMS. The DSMS rate would be established in advance and would include moderate, predictable year-over-year increases to ease customers into the increasing costs of EES compliance.

The proceeds of the DSMS would be used to recover the costs of UNS Electric's investments in EE programs. The Company believes the most efficient way to provide cost-effective EE is to treat it like any other resource in the IRP process. Under UNS Electric's proposal, the Company would determine the most cost-effective EE option appropriate for its particular system, invest its capital to procure that resource, and recover the associated costs – including the amortization expense and an appropriate return on investment – through the DSMS. This capital investment and recovery model is similar to that used for any other supply-side resource except that, due to the nature of EE measures, the capital invested in such programs will be considered a regulatory asset and amortized over a four-year term.

Q. Please describe the benefits of the EE Resource Plan's multi-year planning and investment cycle compared with the current annual DSMS approval process.

A. UNS Electric's EE Resource Plan is a win-win proposition for all stakeholders. Customers would benefit from a predictable DSMS that allows them to plan for their energy expenses while gaining greater assurance that UNS Electric's EE programs will be available over a multi-year timeframe. The local contractors who manage such programs will enjoy greater certainty regarding program funding levels. The Commission and its Staff would benefit from a reduction in the administrative burden

associated with annual reviews of UNS Electric's EE Implementation Plans. Finally, UNS Electric will have more certainty about the energy savings to incorporate into its resource and system planning and will realize a reasonable return from its EE investments.

Q. What rate of return on EE investments is UNS Electric requesting?

A. The Company believes the Weighted Average Cost of Capital used to calculate the return on UNS Electric's EE investments should be based on the capital structure and cost of debt approved by the Commission in this proceeding. The ROE component, however, should be increased by 200 basis points to reflect the nature of the investment. Unlike its investments in power plants, buildings, computers and other assets with independent market value, UNS Electric's EE expenditures produce only intangible assets with no value to UNS Electric outside of the Commission's rules. That is why the creation of a regulatory asset – the value of which is derived solely from the Commission's authorization – is required to allow UNS Electric to recover and earn a return on its EE investment. The nature of this investment justifies this higher rate of return, since intangible assets do not necessarily provide UNS Electric with the same financial benefits as tangible, saleable assets.

Q. Please explain how the EE Resource Plan works?

A. In this plan, the Company is submitting a three-year DSM/EE budget that totals $23,027,120. That budget is broken into annual budget amounts to be used for DSM/EE from January 1, 2014 (coincident with anticipated date of the rate case approval) through December 31, 2016 (approximately three years). Rather than adding the recovery of this DSM/EE investment to base rates, the Company proposes that the EE Resource Plan use the DSMS for recovery of the approved DSM/EE program budgets.

Q. Please break the $23,027,120 into annual budgets through December 2016.

A. The Company's EE Resource Plan proposes the following:

- January 1, 2014 through December 31, 2014 –$7,279,921.
- January 1, 2015 through December 31, 2015 –$7,697,093.
- January 1, 2016 through December 31, 2016 –$8,050,105

The recovery schedule for the EE Resource Plan will continue for an additional three years due to the four-year amortization schedule. As shown in **Exhibit DAS-2**, the monthly residential customer impact, with the four-year amortization of costs, for the DSM/EE investment is reduced when compared to the existing cost recovery model through 2016. However, the recovery period would extend another three years as a result of the amortization.

Exhibit DAS-1, the EE Resource Plan POA, fully describes the plan associated revenue requirement and the DSMS calculations. It also outlines the procedure for implementing new programs and measures using proposed inputs and methodologies to determine cost-effectiveness similar to Commission Staff's cost-effectiveness template.

Q. Please show detail of the actual costs that will be included in the DSMS if the EE Resource Plan is approved.

A. The total three-year plan amount would be $23,027,120 but the only costs recovered through the EE Resource Plan will be the revenue requirements resulting from carrying costs and regulatory asset amortization.

Table 1: Costs included in DSMS with EE Resource Plan

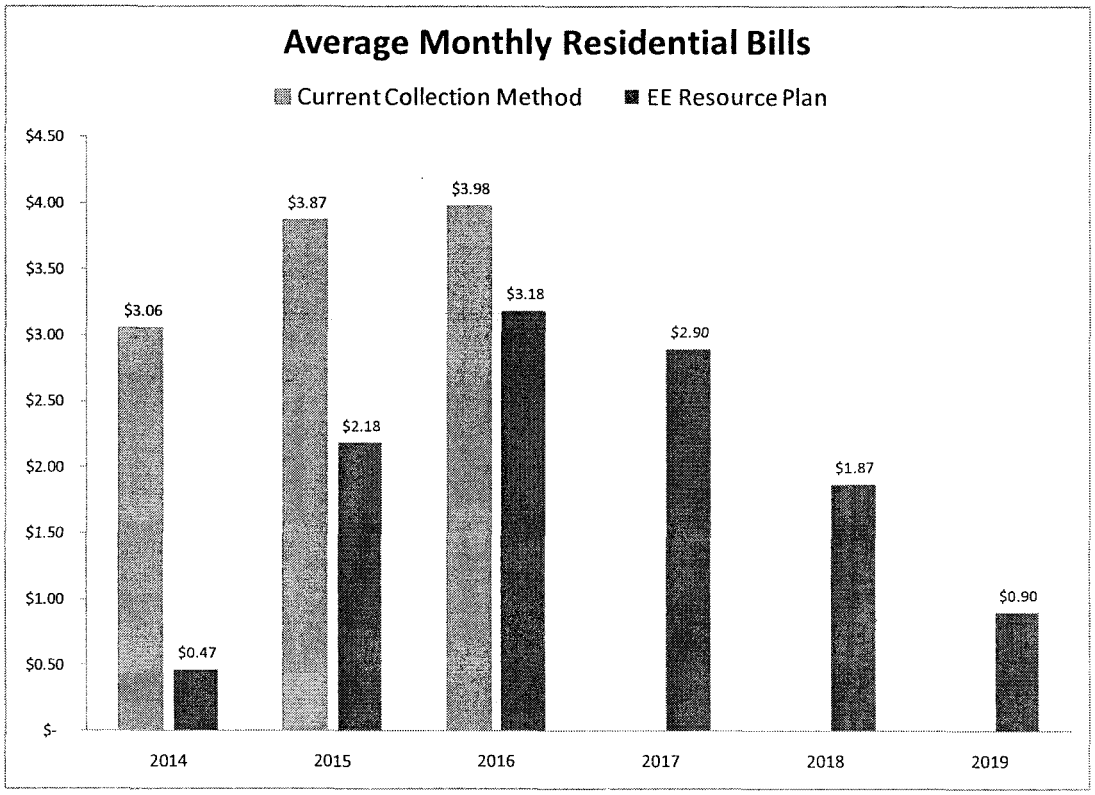
Year	Investment	Revenue Requirements					
2014 Budget	$ 7,279,921	2014	2015	2016	2017	2018	2019
Revenue Requirements (2014 includes true-up)		$996,302	$2,198,224	$2,046,926	$1,895,629		
2015 Budget	$7,697,093						
Revenue Requirements			$2,534,394	$2,324,192	$2,164,225	$2,004,257	
2016 Budget	$8,050,105						
Revenue Requirements				$2,650,629	$2,430,786	$2,263,482	$2,096,178
Total	**$23,027,120**	$996,302	$4,732,617	$7,021,747	$6,490,640	$4,267,739	$2,096,178

Q. **Would UNS Electric's proposal reduce the EE costs reflected on customers' bills?**

A. Yes. Because UNS Electric would amortize its EE costs over a four-year period, the EE Resource Plan would allow DSM surcharges to be significantly lower from 2014 through 2016 than they would be compared to the status quo where the annual expenses are fully recovered each year. If the program is extended past its initial pilot period, the DSM surcharges reflected on customers' bills would moderately step up each year, but UNS Electric analysis indicates DSM surcharges using the EE Resource Plan will remain lower than DSM surcharges compared to the status quo where annual expenses are fully recovered each year.

The EE programs UNS Electric intends to offer in 2014 through 2016 would be funded under the EE Resource Plan with a DSMS that would create an average monthly residential bill impact of $0.47 in 2014, $2.18 in 2015, and $3.18 in 2016. By comparison, UNS Electric estimates that the average monthly residential bill impact of funding the same level of EE programs under the current pay-as-you-go system would be

$3.06 in 2014, $3.87 in 2015, and $3.98 in 2016. The comparison of the two alternatives is shown in the chart below.



The calculation of the DSMS is included in the EE Resource Plan POA.

Q. Will the Company continue to file annual adjustments to the DSMS?

A. No. The budgets and DSMS will have been determined in advance in this rate case based on the scheduled investment by the Company from January 2014 through December 2016.

Q. Will the Company continue to request annual 'true-up' of under-recovered costs?

A. Not for this three-year period. An adjustment for the DSM/EE surcharge balance from prior years will be added to the calculation for the DSMS to begin with the effective date of the Commission Order in this rate case. However, with the EE Resource Plan,

any additional true-up of under-recovered costs will be recovered through the continuing collection of the DSMS or settled in the next general rate case, or in a second EE Resource Plan filing.

Q. Is this type of DSM/EE cost recovery allowed under the EE Rules?

A. Yes. Alternative recovery mechanisms were discussed in the EE workshops and are specifically allowed in the rules. R14-2-2406 (A) (1) states:

> An affected utility's DSM tariff filing shall include the following:
>
> 1) A detailed <u>description of each method proposed</u> by the affected utility <u>to recover the reasonable and prudent costs</u> associated with implementing the affected utility's intended DSM programs (emphasis added)

UNS Electric's alternative recovery method, as described in the proposed EE Resource Plan, provides the Commission an opportunity to implement a three-year pilot program to determine if this is a superior approach for utilities like UNS Electric to meet the EES. If the Commission determines that UNS Electric's pilot program provides greater benefits for all stakeholders and is in the public interest, then the Commission may consider continuing the program beyond the initial three-year term.

Q. What are the accounting implications of treating such amounts as regulatory assets?

A. Accounting rules governing alternative revenue programs (ASC 980-605-25-4) prescribe specific criteria permitting recognition of revenue-related regulatory asset associated with our EE Resource Plan. One such criterion is that "[t]he amount of additional revenues for the period is objectively determinable and is probable of recovery."

Q. Why is a four-year amortization period appropriate for recovering Company investments in EE programs and measures?

A. First, cost recovery as proposed by UNS Electric's EE Resource Plan requires a balance

between the need for timely cost recovery and customers' desire for more moderate rate increases. A four-year amortization provides an appropriate balance.

Second, accounting rules governing recognition of a regulatory asset provide criteria for deferring costs that would otherwise be immediately expensed. ASC 980-340-25-1 allows the deferral of costs as long as it is probable that those specific costs are subject to recovery in future revenues. The term *probable* is defined as "the future event or events are likely to occur." In addition, as acknowledged by rules that govern accounting for regulatory assets, the risk associated with full recovery of a regulatory asset increases as the corresponding recovery period expands. The Company believes that a four-year period is short enough to meet the probable recovery determination.

Third, UNS Electric believes that a recovery period of four years is reasonable and appropriate in order to maintain a moderately-sized regulatory asset over time. Longer amortization periods will produce larger regulatory assets.

Q. How will cost effectiveness of EE measures or programs be determined under the EE Resource Plan?

A. The Societal Cost Test ("SCT"), as defined in the UNS Electric's POA for the EE Resource Plan, will determine if a program or measure is cost-effective for recovery through the DSMS. This is set forth in more detail in the EE Resource Plan POA.

Q. What standard industry cost-benefit methodology will be used to determine cost effectiveness?

A. The determination of cost effectiveness of UNS Electric's DSM/EE programs will be the societal cost test based upon the methodology sanctioned by the EPA in 2008. The EPA's methodology is the most widely used approach by utilities and regulatory agencies

to determine cost effectiveness.

Q. Why should the Societal Cost Test be used to determine the cost effectiveness of an EE measure or program?

A. In accordance with A.A.C. R14-2-2412(B), the Commission requires the SCT be used to determine cost effectiveness. The EE Rules define the SCT and the Total Resource Cost Test ("TRC") (which is contained within the SCT definition) as follows:

For the SCT:

> A cost-effectiveness test of the net benefits of DSM programs that starts with the Total Resource Cost Test, but includes non-market benefits and costs to society.

For the TRC:

> A cost-effectiveness test that measures the net benefits of a DSM/EE programs as a resource option, including incremental measure costs, incremental affected utility costs, and carrying costs as a component of avoided capacity cost, but excluding incentives paid by affected utilities and non-market benefits to society.

Q. Will UNS Electric invest its capital as proposed in the EE Resource Plan without an acceptable definition of "cost effective"?

A. No. If the definition of cost effectiveness and the standardized measurements that are embedded in the calculation are not acceptable, then we must withdraw our proposal to invest the Company's capital in EE programs and measures. If that happens, we will simply continue to fund these costs on an annual basis – based on Commission approval of UNS Electric's EE Implementation Plans. The most critical component included in the determination of cost effectiveness is agreement on inputs and methodology. If, however, the existing annual funding method is maintained, UNS Electric will request a performance incentive and propose changes to the methodology currently in place for calculating the utility performance incentive as allowed under the EE Rules.

Q. Will the Commission and other interested parties have opportunities to review projects included in the EE Resource Plan?

A. Yes. The Commission and other interested parties may review the costs related to the EE investment with the annual DSM/EE compliance filing and within the context of a rate case to determine prudency. The IRP process also provides the Commission with proceedings to review the cost of UNS Electric's overall resource portfolio including the costs related to the EE investment.

Q. Can the pilot program for the EE Resource Plan be extended?

A. Yes. UNS Electric is proposing the EE Resource Plan as a pilot program that could then be extended beyond December 31, 2016 – as a part of the next rate case or in a separate proceeding if the Commission determines it is necessary to establish an additional docket.

In the next rate case, the remaining dollars in the regulatory asset account could either be moved into rate base (thus clearing the regulatory asset in the DSMS) or remain as a regulatory asset in the DSMS. Since the Company would be amortizing recovery of the DSM/EE cost over four years, unless the regulatory asset account is cleared and the cost rolled into rate base, the first year of the second three-year EE Resource Plan period will reflect a slightly higher rate but it thereafter will flatten out assuming annual expenditures stay relatively constant.

Q. Do you have any concluding comments regarding the proposed EE Resource Plan?

A. Yes. UNS Electric is undertaking an innovative departure from the way in which we traditionally finance and implement EE programs and measures, because we believe that the adoption of cost-effective EE measures significantly enhances the Company's ability to develop a balanced and low cost resource portfolio. This is certainly in the best

interest of our customers. Our goal is to develop and deploy measures that provide the greatest operating efficiencies to UNS Electric's generation, transmission and distribution systems; reduce reliance on more costly generating resources; and provide customers with the most cost-effective DSM/EE programs.

By "putting our skin in the game" the Company is taking on additional risk by investing in a regulatory asset that derives value *only* as a result of an order of the Commission authorizing UNS Electric to recover its costs from customers.

As discussed above, we believe that implementation of the EE Resource Plan will not only eliminate the need for a performance incentive, but will also result in:

- lower costs;
- more stable rates and more predictable program availability for customers;
- greater stability for local EE contractors; and
- less administrative burden on the Commission and its Staff.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT

DAS-1

UNS Electric, Inc.
Energy Efficiency Resource Plan
Plan of Administration

Table of Contents

1. General Description *1*
2. Definitions *1*
3. Annual Energy Efficiency (EE) Investment *3*
4. Cost-effectiveness *3*
5. EE Standard Credits *4*
A. Demand Response *4*
B. Codes and Standards *4*
C. Combined Heat and Power *4*
6. Revenue Requirement *4*
A. Program Investment Base *4*
B. Capital Structure and Cost of Capital *5*
7. Demand Side Management Surcharge *5*
A. Rate Schedule Applicability *5*
B. Allowable Costs *5*
C. Determination of True-up *6*
D. Determination of the Surcharge *6*
E. Review Process *8*
8. DSM/EE Reports *8*

Attachments

Attachment A – Cost-Effectiveness and Savings Assessment
Attachment B – Societal Cost Test Template
Attachment C – Societal Cost Test Template Example
Attachment D – Revenue Requirements (2014, 2015, 2016)
Attachment E – DSMS Backup
Attachment F – Proposed DSMS Tariff

1. General Description

This document describes the Plan of Administration ("POA") for the Energy Efficiency Resource Plan ("EERP") approved for UNS Electric, Inc. ("UNS Electric" or "Company") by the Arizona Corporation Commission ("Commission") on XXXX, 2014 in Decision No. XXXX ("Decision"). The EERP mechanism provides for the recovery of allowable costs related to Demand Side Management/Energy Efficiency Programs ("DSM/EE") as a capital investment, setting recovery of the asset over a four-year term where UNS Electric recovers the revenue requirements from carrying costs, regulatory asset amortization and return on its investments in cost-effective DSM/EE programs through the Demand Side Management Surcharge ("DSMS"), as described within this POA.

2. Definitions

Amortize – The process of ratably distributing a previously capitalized cost to expense over a designated period.

Avoided Cost – The avoided cost is the marginal cost to produce one more unit of energy. The avoided cost consist of two components: avoided cost of energy and avoided cost of capacity.

> UNS Electric's avoided cost of energy or marginal energy cost is determined using the Resource Planning Hourly Economic Dispatch Model.
>
> UNS Electric's avoided cost of capacity is determined through UNS Electric's long-term planning modeling of capacity. The plan for meeting capacity needs is determined on both economics and reliability. Future capacity costs include market purchase power capacity, transmission upgrades and capacity build options.

Carrying Cost (Weighted Average Cost of Capital) – Cost of the company's debt and equity as approved by the Commission in UNS Electric's most recent Rate Order.

Cost-Effective – The result of an action or series of actions where the total incremental benefits from a DSM/EE measure or DSM/EE program exceed total incremental costs over the life of the DSM/EE measure, as determined under A.A.C.R14-2-2412.[1]

Demand Savings – The load reduction, measured in KW, occurring during a relevant peak period or periods as a direct result of energy efficiency and demand response programs.

DSM – A Company program defined by the implementation and maintenance of one or more Demand Side Management ("DSM") measures or Demand Side Management program.

DSM Measure – Any material, device, technology, educational program, pricing option, practice, or facility alteration designed to result in reduced peak demand, increased energy efficiency, or shifting of electricity consumption to off-peak periods and includes Combined Heat and Power used to displace space heating, water heating, or another load.

DSM Program – One or more DSM measures provided as part of a single offering to customers.

[1] As may be amended from time to time.

DSMS – A Commission-approved provision in UNS Electric rate schedules allowing UNS Electric to change certain rates through a surcharge, in an established manner, when changes in specific costs and charges are incurred by UNS Electric.

DSM Tariff – A Commission-approved schedule of rates designed to recover the allowable and prudent costs of complying with the EE Rule.

Energy Efficiency ("EE") – The production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers.

Energy Efficiency Programs – Any program approved by the Commission that is specifically designed to reduce kWh energy use and also provide some non-coincident and coincident peak demand savings.

Energy Savings – The reduction in a customer's energy consumption directly resulting from a DSM/EE program, expressed in kWh, at the generator.

Energy Efficiency Standard ("EE Rule") – The Arizona Electric Energy Efficiency Standards, Title 14, Chapter 2, Article 24 of the Arizona Administrative Code.

Incentives – Financial payments, goods, or services offered by a utility to promote energy and related cost savings including, but not limited to, cash rebates or financial payments, advanced financing of project costs, design and implementation of utility related projects, energy management services, facilities alterations, installation of technologies and Energy Savings devices, or water conservation devices.

Incremental Cost – As defined by the Commission in A.A.C. R14-2-2401, the additional expenses of DSM/EE measures, relative to baseline.

Measurement, Evaluation, and Research ("MER") – The performance of studies and activities aimed at determining the effects of an energy efficiency program, which may include data collection, monitoring, and analysis associated with the calculation of energy and demand savings from measures or projects, and including research necessary to inform the evaluation of existing EE programs and the design of new EE programs.

Non-Energy Benefits – As stated in A.A.C. R14-2-2401, non-market benefits (or non- energy benefits) are the improvements in societal welfare that are not bought or sold. These benefits are any program implementation or participation effect that is other than the direct Energy Savings effects associated with an energy efficiency, resource acquisition, or resource procurement program. Some examples may include: reduced water consumption, reduced emission and environmental benefits in a building, secondary economic impacts from low income programs, health and safety, job creation, improved comfort, indoor air quality, longevity of equipment, improved worker productivity, and worker retention.

Program Costs – The expenses, including but not limited to those incurred as a result of developing, marketing, implementing, administering, and evaluating Commission-approved DSM/EE programs.

Regulatory Asset – A capitalized cost that would otherwise be accounted for as an expense, but for its inclusion in a regulator-approved cost recovery mechanism providing for such costs to be

deferred and then transferred to expense and recovered via basic service rates or a specific surcharge in effect for a designated period.

Societal Cost Test– As defined by the Commission in A.A.C. R14-2-2401, a cost-effectiveness test of the net benefits of DSM/EE programs that starts with the Total Resource Cost Test, but includes non-market benefits and costs to society.

Staff – Individuals working for the Commission's Utilities Division, whether as employees or through contract.

Technical Reference Manual - A resource document that includes information used in program planning and reporting of Energy Efficiency Programs. It can include savings values for measures, engineering algorithms to calculate savings, source documentation, specified assumptions, and other relevant material to support the calculation of measure and program savings.

Total Resource Cost Test – As defined by the Commission in A.A.C. R14-2-2401, a cost-effectiveness test that measures the net benefits of a DSM/EE program as a resource, including incremental measure costs, incremental affected utility costs, and carrying costs as a component of avoided capacity cost, but excluding incentives paid by affected utilities and non-market benefits to society.

3. Annual Energy Efficiency (EE) Investment

UNS Electric's planned investment for its DSM/EE programs for years 2014 through 2016 are as follows:

Program Year	Annual Budget
2014	$7,279,921
2015	$7,697,093
2016	$8,050,105

Program investments will be the sum of all costs for all DSM/EE programs, as defined in the planning stage (ex-ante or expected), plus allowable costs outlined in A.A.C. R14-2-2410. These investments will be deemed to be allowable expenses for recovery. After 2016, the annual budget and EE Resource Plan shall remain in effect at 2016 levels until further order of the Commission.

4. Cost-effectiveness

UNS Electric will invest in existing DSM/EE programs and measures that have been previously approved by the Commission and implemented by UNS Electric. In addition, UNS Electric will invest in and implement new EE measures and programs that produce a benefit/cost ratio greater than one, resulting from UNS Electric's analysis, using the Societal Cost Test, which is the

required test per A.A.C. R14-2-2412.B. UNS Electric's analysis of cost-effectiveness utilizes industry best practices for the SCT.[2]

The methodology and inputs regarding the Societal Cost Test are included in Attachment A. UNS Electric's Societal Cost Test template and an example of its implementation are included as Attachments B and C. Any EE measure or program that passes the Societal Cost Test is determined to be cost-effective and all costs will be fully recoverable.

5. EE Standard Credits

A. Demand Response

UNS Electric will convert peak demand reductions resulting from Demand Response programs to equivalent annual energy savings based on an assumed 50% annual load factor to apply towards achieving up to two percentage points of the 22% energy efficiency standard. In addition, the Demand Response credit will not exceed 10% of the energy efficiency standard requirement for any year.

B. Codes and Standards

UNS Electric will count toward meeting the standard up to one third of the energy savings, resulting from codes and standards, which are quantified and reported through MER.

C. Combined Heat and Power

UNS Electric will count toward meeting the standard the energy savings from combined heat and power installations that do not qualify under the Renewable Energy Standard.

6. Revenue Requirement

The following discussion provides inputs and methodologies for each of the terms in the capitalization model. The revenue requirement will be determined by applying a 4-year amortization schedule. Attachment D includes the revenue requirement worksheets for 2014, 2015 and 2016.

A. Program Investment Base

Program Investment Base (asset cost) from the effective date of the order through December 2016 will be equivalent to the Commission approved budget as referenced in Section 3. For purposes of computing the amortization expense and the return components of the program revenue requirement that will underlie the DSMS, an investment base will be established comprised of a Regulatory Asset in which the approved program spending will be accumulated. Upon implementation of the program, all actual program costs will be charged to the regulatory

[2] As defined in the *Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects.* http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

asset. Deducted therefrom will be the accumulated amortizations based on recovery of all budgeted program costs at a rate of 25% during the current program year and 25% for each of the three succeeding years. In addition, the net program investment will be reduced by Accumulated Deferred Income Taxes reflecting the book-tax timing difference created by all program expenditures being currently deducted for tax, but deferred and amortized over four years for accounting purposes. Based on authorized program budget as approved in this plan the prior program spending plus budgeted spending for the then current year, UNS Electric will record each year's amortization expense. The expense will be recorded throughout the year based on each month's retail sales volumes, as will the program revenues. Variances between budgeted program costs and those actually incurred in a program year will be reflected in the Commission filing for the next funding cycle.

Should the EE Resource Plan be discontinued, UNS Electric will be permitted to recover the balance remaining in the regulatory asset through continued use of the DSMS in existence at the time, until the entire balance is collected. In connection therewith, UNS Electric will provide final documentation reconciling all differences between program budgets and actual costs incurred producing any unrecovered balance remaining in the regulatory assets at the end of the last funding cycle.

B. Capital Structure and Cost of Capital

The return on the EE Resource Plan investments will be based on UNS Electric's weighted average cost of capital ("WACC") and capital structure approved by the Commission in Decision No. XXX, adjusted to reflect a 200 basis point increase in UNS Electric's return on equity.

7. Demand Side Management Surcharge

A. Rate Schedule Applicability

The DSMS shall be applied monthly to every rate schedule. A DSMS schedule is included in Attachment E and shall be updated with Commission order.

A self-direction option exists for qualifying customers of sufficient size in which the amount of money paid by each qualifying customer toward DSM costs is tracked for the customer and made available for use by the customer for approved DSM investments.

B. Allowable Costs

Allowable expenses include, but are not limited to: program implementation; rebates and incentives; training and technical assistance; consumer education; marketing; planning and administration; measurement, evaluation and research; new program development and analysis; any software development required for tracking and reporting of EE and Demand Response programs; and any other expenses required to design and implement cost-effective EE and Demand Response programs. All program costs will initially be charged to the regulatory asset previously described. As such amounts are amortized, they will be charged to Account 908,

Customer Assistance Expense or other appropriate accounts as required by the FERC Uniform System of Accounts.

C. Determination of True-up

The initial true-up of over or under collections for the first year will be determined by subtracting the actual allowable expenses (including Performance Incentives accrued to the effective date of this order) for approved DSM/EE programs per Decision 70360 starting June 1, 2008 through the effective date of this order, from the actual revenue collected by the Company through the DSMS starting June 1, 2008 through the effective date of this order.

During the next funding cycle, the DSMS will include a true-up for any revenue requirement differences from the planned revenue requirement to actual revenue requirement collected during the previous funding cycle. The next funding cycle will occur in a future filing or during the next rate case, whichever comes first.

D. Determination of the Surcharge

Projected revenue requirements determined by the sum of carrying costs and regulatory asset amortization for each time period will be divided by the forecasted energy sales for the same time period to determine the $/kWh DSMS. The table below shows the schedule for determining the total annual revenue requirements used for calculating the DSMS for the first funding cycle.

Table 1: First Funding Cycle Revenue Requirement Schedule

Year	Investment	Revenue Requirements					
2014 Budget	$7,279,921	2014	2015	2016	2017	2018	2019
Revenue Requirements (2014 includes true-up)		$996,302	$2,198,224	$2,046,926	$1,895,629	$0.00	$0.00
2015 Budget	$7,697,093						
Revenue Requirements		$0.00	$2,534,394	$2,324,192	$2,164,225	$2,004,257	$0.00
2016 Budget	$8,050,105						
Revenue Requirements		$0.00	$0.00	$2,650,629	$2,430,786	$2,263,482	$2,096,178
Total	$23,027,120	$996,302	$4,732,617	$7,021,747	$6,490,640	$4,267,739	$2,096,178

The DSMS for purposes of recovering expenses from the effective date of this order through December 31, 2014 will be calculated based upon the following formula:

$$DSMS = \frac{RR1+TU}{Sales}$$

Where:

RR1	=	First year of 2014 revenue requirement (to be calculated from the effective date of this order through December 31, 2014).
TU	=	An adjustment for the DSM/EE surcharge balance as determined according to Section 7C above.
Sales	=	Forecasted energy (kWh) sales under applicable rate schedules during the period in which the DSMS will be effective.

All customers will be billed on a per kWh basis.

The DSMS for purposes of recovering expenses for 2015 will be calculated based upon the following formula:

$$DSMS = \frac{RR2}{Sales}$$

Where:

RR2	=	First year of 2015 revenue requirement plus the second year of 2014 revenue requirement.
Sales	=	Forecasted energy (kWh) sales under applicable rate schedules (as defined above) during the period in which the DSMS will be effective.

All customers will be billed on a per kWh basis.

The DSMS for purposes of recovering expenses for 2016 will be calculated based upon the following formula:

$$DSMS = \frac{RR3}{Sales}$$

Where:

RR3	=	First year of 2016 revenue requirement plus the second year of 2015 revenue requirement plus the third year of 2014 revenue requirement.
Sales	=	Forecasted energy (kWh) sales under applicable rate schedules (as defined above) during the period in which the DSMS will be effective.

All customers will be billed on a per kWh basis.

The proposed DSMS Tariff is provided in Attachment F.

E. Review Process

The proposed DSMS for use during a specific period will be calculated as shown in Section 7.D. The DSMS will remain in effect until further order of the Commission.

8. DSM/EE Reports

In accordance with A.A.C. R14-2-2409, the Company will provide a previous year progress report to Commission Staff by March 1st and a current mid-year status report by September 1st. UNS Electric will include any new cost-effective measures or programs implemented or planned for implementation in the March 1st report.

Cost-Effectiveness and Savings Assessment

UNS Electric will invest in existing DSM/EE programs that have been previously approved by the Commission and new programs/measures determined to be cost-effective with a benefit/cost ratio greater than one using the methodology as defined below. This document outlines the methodologies and inputs utilized in UNS Electric's cost effectiveness test.

1. Cost-effectiveness using Societal Cost Test

UNS Electric will invest in and implement new EE measures and programs that produce a ratio greater than one, resulting from UNS Electric's analysis, using the Societal Cost Test ("SCT"), which is the required test per A.A.C. R14-2-2412.B.

UNS Electric will utilize A.A.C. R14-2-2412.D-H to further clarify cost-effectiveness calculations for non-traditional programs as shown below:

> D. An affected utility shall make a good faith effort to quantify water consumption savings and air emission reductions, while other environmental costs or the value of environmental improvements shall be estimated in physical terms when practical but may be expressed qualitatively.
>
> E. Market transformation programs shall be analyzed for cost-effectiveness by measuring market effects compared to program costs;
>
> F. Educational programs shall be analyzed for cost-effectiveness based on estimated energy and peak demand savings resulting from increased awareness about energy use and opportunities for saving energy;
>
> G. Research and development and pilot programs are not required to demonstrate cost-effectiveness; and
>
> H. An affected utility's low-income customer program portfolio shall be cost-effective, but costs attributable to necessary health and safety measures shall not be used in the calculation.

When expressed in terms of net present value, the cost effectiveness of EE is the ratio of the discounted total benefits of the program to the discounted total costs over some specified time period. The equation and terms of the SCT are defined as follows:

$$BCR_{SCT} = (UAC_{NPV} + NEB_{NPV}) \div (PAC_{NPV} + PCN_{NPV} + UIC_{NPV})$$

Where:

BCR_{SCT} = *Societal Benefit/Cost Ratio*

UAC_{NPV} = *Net Present Value of Utility Avoided Cost*

NEB_{NPV} = *Net Present Value of Non-Energy Benefits*

PAC_{NPV} = *Net Present Value of Program Administrative Costs*

PCN_{NPV} = Net Present Value of Net Participant Costs

UIC_{NPV} = Net Present Value of Utility Increased Supply Costs (i.e., the increase in supply costs for the utility providing the fuel chosen as a result of fuel substitution programs)

Utility avoided costs ("UAC") are defined as follows:

$$UAC = \Delta E_N \text{ x } ACE + \Delta D_N \text{ x } ACC + AEC$$

Where:

ΔE_N = Net lifetime energy savings

ACE = Avoided cost of energy

ΔD_N = Net demand savings

ACC = Avoided cost of capacity

AEC = Utility avoided environmental costs

2. Societal Cost Test Inputs and Methodologies

The following discussion provides inputs and methodologies for each of the terms in the SCT as defined above. Inputs and values will be provided in a Technical Reference Manual referenced in Section 3.

A. Discount Rate

The discount rate for the SCT is typically a societal discount rate, based upon the long-term Treasury Bill Rate. However for the purposes of UNS Electric's SCT the after-tax weighted average cost of capital approved in the most recent rate case will be used as the discount rate applied to the SCT.

B. Utility Avoided Cost (UAC)

The avoided cost is the marginal cost to produce one more unit of energy. The avoided cost consist of two components: avoided cost of energy and avoided cost of capacity.

UNS Electric's avoided cost of energy or marginal energy cost is determined using the Resource Planning Hourly Economic Dispatch Model. The avoided cost of energy is determined on an 8,760 hourly resolution, which will be applied to the 8,760 hourly savings load shapes of measures in a program. This helps to ensure that the avoided cost of the energy savings that result from the programs are being applied appropriately with respect to the lifetime energy UNS Electric's avoided cost of capacity is determined through UNS Electric's long-term planning modeling of capacity. The plan for meeting capacity needs is determined on both economics and reliability. Future capacity costs include market purchase power capacity, transmission upgrades and capacity build options. UNS Electric applies the avoided cost of capacity to the coincident demand savings of the measures in a program.

UNS Electric will use the avoided cost developed from the most recent Integrated Resource Plan (IRP) filing. The avoided cost from the IRP will be assigned for a program year and remain consistent from the onset of a program year through completion and reporting of that program.

Net Lifetime Energy Savings (ΔE_N)

Net Lifetime Energy Savings will be defined by the following equation utilizing the Effective Useful Life ("EUL") as defined for each measure in the TRM:

$$\Delta E_N = \Delta E_G \text{ x } (1 + ELLF) \text{ x } NTGR$$

Where:

ΔE_N = *Net lifetime energy savings*

ΔE_G = *Gross lifetime energy savings (at the meter)*

NTGR = Net To Gross Ratio

The value for the energy line loss factor ("ELLF") will be determined by the rate case.

The NTGR is defined as 1.

Net Demand Savings (ΔD_N)

Net Demand Savings will be defined by the following equation:

$$\Delta D_N = \Delta D_G \text{ x } (1 + DLLF) \text{ x } (1 + CRF) \text{ x } NTGR$$

Where:

ΔD_N = *Net demand savings*

ΔD_G = *Gross demand savings (at the meter)*

NTGR = Net To Gross Ratio

The value for the line capacity reserve factor ("CRF") will be determined by the rate case.

The value for the demand line loss factor ("DLLF") will be determined by the rate case.

The NTGR is defined as 1.

Avoided Environmental Costs (AEC)

An SCT includes monetization of environmental factors. UNS Electric is supplying the avoided cost of SO_2, H_2O, NOx, and PM10 as determined per Commission Decision No. 72024 in table format and these values may be utilized in cost-effectiveness tests.

	Avoided Externalities ($/MWh)				
Year	**SO_2**	**H_2O**	**NOx**	**PM10**	**Total**
2014	$0.02	$0.72	$0.04	$0.00	$0.78
2015	$0.02	$0.72	$0.04	$0.00	0$.78
2016	$0.02	$0.72	$0.04	$0.00	0$.78
2017	$0.02	$0.72	$0.04	$0.00	0$.78
2018	$0.02	$0.72	$0.04	$0.00	$0.78
2019	$0.02	$0.72	$0.04	$0.00	$0.78
2020	$0.02	$0.72	$0.04	$0.00	$0.78

C. Program Administrative Costs (PAC)

Program administrative costs are all non-incentive costs incurred by the utility in the process of operating and delivering DSM/EE programs. These costs include management, administration, marketing, training, implementation services, and measurement and evaluation.

For the purposes of cost-effectiveness analysis of DSM/EE programs, UNS Electric will utilize the SCT and apply the program administrative costs at the program level.

D. Non-Energy Benefits (NEB)

The SCT allows for the inclusion of 'non-energy benefits to society.' Non-energy benefits may include: reduced water consumption, reduced emission and environmental benefits in building, secondary economic impacts from low income programs, health and safety, job creation, improved comfort, indoor air quality, longevity of equipment, improved worker productivity, and worker retention. These non-energy benefits will be monetized when supporting research is available.

E. Net Participant Costs (PCN)

The net participant costs typically include all equipment costs, installation, operation and maintenance, and cost of removal (less salvage value) paid by participants.

The majority of participant costs are typically the incremental costs or full installed costs incurred by customers in the process of installing the DSM/EE measure. The term 'net' implies that all relevant customer costs are included in this value, and generally includes either one of two types of costs:

1. Incremental costs are determined from various industry standard resources such as ENERGY STAR®, the California Energy Commission and California Public Utilities Commission sponsored Database for Energy Efficiency Resources (DEER), American Council for an Energy-Efficient Economy (ACEEE), primary research projects, or actual

historical project details collected by the utility and verified through the Measurement, Evaluation, and Research ("MER") process.

2. Full installed costs are typically defined as the cost of replacing a working system with a higher-efficiency system. In general full installed costs include the full cost of the material being installed, the cost of the labor to install the measure minus the incremental operational and maintenance costs.

All incremental costs, including other expenses such as additional costs for designing a more efficient building, will be considered on a case by case basis as part of the measure screening process.

F. Effective Useful Life (EUL)

The EUL of each measure varies widely but is used to determine the lifetime energy savings for each measure. The EUL for each measure are determined from industry standard resources such as ENERGY STAR, DEER, ACEEE, primary research projects, or actual historical project details collected by the utility and verified through the MER process.

G. Demand Response

In accordance with A.A.C. R14-2-2404.C, UNS Electric will convert peak demand reductions resulting from demand response programs to equivalent annual energy savings based on an assumed 50% annual load factor to apply towards achieving up to two percentage points of the 22% energy efficiency standard. Demand response programs will be valued as a dispatchable resource. The monetized resource value to UNS Electric may include: emergency dispatch value, avoided T&D, energy displacement, demand displacement, reserve margin value, risk avoidance value, fuel savings, and avoided plant maintenance.

The evaluation of cost effectiveness for demand response programs may include the demand response energy credit and the avoided costs of capacity and energy at the time the program was submitted. The effective useful life is defined as the submitted program life or contract period if applicable. The evaluation of capacity and energy savings for Demand Response programs will take place during the MER process.

3. Technical Reference Manual

The Company will compile and make available to Commission Staff and interested stakeholders a Technical Reference Manual ('TRM') that will outline measure savings assumptions and incremental costs. The TRM will be filed each year with the March 1st DSM progress report and be updated based upon the results of previous year's MER reports and will go into effect the following program year. UNS Electric will use the values as defined by UNS Electric's TRM for a specific year as the input values for determining the cost-effectiveness ratio for the same year.

4. Variance between program ex-ante (expected) and ex-post (verified) savings

Program planning assumptions (i.e. ex-ante estimates) will be used for the purpose of recovering costs incurred within each funding year. MER activities will be conducted each year to assess

the previous year's asset performance (i.e. ex-post estimates), and be used to adjust performance estimates for the next funding year. In this way, the performance of the asset will be reviewed and adjusted each year such that benefits are maximized while costs are controlled in a way that reflects prudent management decisions.

There are various market conditions that may occasionally hinder a DSM/EE program from successfully achieving program savings or cost-effectiveness targets. Natural market conditions that may precipitate this occurrence include slow ramp-up periods of new DSM/EE programs that require significant market development. As outlined in the California Evaluation Framework[1], "Many information and market transformation programs take time to work due to significant market inertia. The timing of the effects evaluation needs to consider the likely response time of the market to the program intervention. Market effects evaluations may need to be conducted after multiple program cycles to provide enough time for the programs to overcome inertia in markets in which they operate." Once a proper infrastructure is established, these programs can produce years of cost-effective savings. UNS Electric will not be precluded from recovering costs of programs that are determined to be in a ramp-up stage. If after a sufficient time a program is evaluated to not be cost-effective, then UNS Electric will either refine the program measures or discontinue the program entirely.

5. Measurement, Evaluation, and Research

MER is conducted based on industry best practices as outlined by the International Performance Measurement and Evaluation Protocol (IPMVP).[2]

6. Measure-level Review and Update

Inputs and algorithms in the TRM are to be based on best available and applicable data pertaining to UNS Electric's programs. Any need to update inputs and algorithms would be reflected on a prospective basis as a result of the MER process.

As a result of the MER savings verification process, DSM/EE delivered savings may vary from initial planning estimates. For instance, MER results may identify different measure operating conditions than planned, baseline conditions for measures may have shifted based on code/appliance updates or standard practice changes, the estimated effective useful life of measures may have changed based on the availability of certain EE measures/products, incremental costs may have changed, or other market factors effecting delivered savings may have changed.

7. Program-level Tracking and Review

UNS Electric has engaged a third party provider to create a program tracking database to help enable timely and accurate tracking and recording of project-specific data from program application forms. To help ensure the quality of data received from its implementation contractors, UNS Electric will provide database access to its MER contractor, who will verify savings claims. Continuous review of DSM/EE program tracking datasets throughout the

[1] http://www.tecmarket.net/documents/California%20Evaluation%20Framework%20Jan%202006.pdf
[2] www.evo-world.org

program year ensures that measure characteristics accurately reflect measure savings achieved by each program and helps inform TRM updates and process improvements for future program delivery.

Cost Test

Program Name	ABC	NPV of DSM benefits	$-----.--
		NPV of DSM costs	$-----.--
		NPV of DSM net societal benefits	$-----.--
		Benefit Cost Ratio	--.--
year DSM installed	YYYY		
capital cost of DSM program (base yr $)	$-----.--	First Year Measure Avoided Cost of Energy ($/kWh)	-.-----
societal discount rate	%	IOU actual average annual cost of generation escalation	-.-----

year	n	kW savings AT GENERATOR	kWh savings AT GENERATOR	DSM cap cost nom $	Avoided Cost of Energy nom $	Avoided Cost of Capacity nom $	Annual DSM Costs	Total Annual Avoided Costs
YYYY	1	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	2	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	3	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	4	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	5	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	6	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	7	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	8	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	9	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	10	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	11	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	12	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	13	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	14	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	15	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	16	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	17	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	18	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	19	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	20	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	21	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	22	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	23	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	24	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	25	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	26	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	27	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	28	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	29	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--
YYYY	30	--	--	$-----.--	$-.--	$-.--	$-----.--	$-.--

Program Summary

PROGRAM

Utility Name	AZ IOU
Program Year / Base Year	2013
Program Name	Example
Total Program Budget ($)	$100,000
Incentives	$60,000
Program Delivery	$30,000
Program Marketing	$5,000
Utility Administration	$2,000
Evaluation	$3,000
Total Incremental Costs	$110,000

Inputs

Line Loss Factor 10.00%

MEASURE

Measure Name	# Units	Incremental Cost per Unit ($)	Total Annual Savings per Unit (kWh) - AT METER	Total Annual Savings per Unit (kWh) - AT GENERATOR	Life of DSM (years)	Total Lifetime Energy Savings (kWh) - AT GENERATOR
Measure 1	50	400	500.0	550.0	5	137,500
Measure 2	100	500	2000.0	2200.0	10	2,200,000
Measure 3	25	800	7500.0	8250.0	15	3,093,750
Measure 4	40	500	150.0	165.0	20	132,000

Load Shape Summary

Measure Hourly Load Shapes								
Measure #					1	2	3	4
# Units					--	--	--	--
Annual Savings per Unit (kWh) - AT GENERATOR					---.-	---.-	---.-	---.-
Life of DSM (years)					--	--	--	--
Year	Year Hour	Month	Day	Hour				
YYYY	1	1	1	1	-.-------	-.-------	-.-------	-.-------
YYYY	2	1	1	2	-.-------	-.-------	-.-------	-.-------
YYYY	3	1	1	3	-.-------	-.-------	-.-------	-.-------
YYYY	4	1	1	4	-.-------	-.-------	-.-------	-.-------
YYYY	5	1	1	5	-.-------	-.-------	-.-------	-.-------
YYYY	6	1	1	6	-.-------	-.-------	-.-------	-.-------
YYYY	7	1	1	7	-.-------	-.-------	-.-------	-.-------
YYYY	8	1	1	8	-.-------	-.-------	-.-------	-.-------
YYYY	9	1	1	9	-.-------	-.-------	-.-------	-.-------
YYYY	10	1	1	10	-.-------	-.-------	-.-------	-.-------
YYYY	11	1	1	11	-.-------	-.-------	-.-------	-.-------
YYYY	12	1	1	12	-.-------	-.-------	-.-------	-.-------
YYYY	13	1	1	13	-.-------	-.-------	-.-------	-.-------
YYYY	14	1	1	14	-.-------	-.-------	-.-------	-.-------
YYYY	15	1	1	15	-.-------	-.-------	-.-------	-.-------
YYYY	16	1	1	16	-.-------	-.-------	-.-------	-.-------
YYYY	17	1	1	17	-.-------	-.-------	-.-------	-.-------
YYYY	18	1	1	18	-.-------	-.-------	-.-------	-.-------
YYYY	19	1	1	19	-.-------	-.-------	-.-------	-.-------
YYYY	20	1	1	20	-.-------	-.-------	-.-------	-.-------
YYYY	21	1	1	21	-.-------	-.-------	-.-------	-.-------
YYYY	22	1	1	22	-.-------	-.-------	-.-------	-.-------
YYYY	23	1	1	23	-.-------	-.-------	-.-------	-.-------
YYYY	24	1	1	24	-.-------	-.-------	-.-------	-.-------
YYYY	25	1	2	1	-.-------	-.-------	-.-------	-.-------
YYYY	26	1	2	2	-.-------	-.-------	-.-------	-.-------
YYYY	27	1	2	3	-.-------	-.-------	-.-------	-.-------
YYYY	28	1	2	4	-.-------	-.-------	-.-------	-.-------
YYYY	29	1	2	5	-.-------	-.-------	-.-------	-.-------
YYYY	30	1	2	6	-.-------	-.-------	-.-------	-.-------

Program Annual Avoided Costs			
	Total Program Annual Avoided Costs ($/kWh)	$-.------	
	Coincidence Peak Demand Factor	-.-------	
Year Hour	Program Annual Hourly Shape	YYYY Avoided Costs ($/kWh)	Total Program Avoided Costs ($/kWh)
1	-.-------	$-.---	$-.------
2	-.-------	$-.---	$-.------
3	-.-------	$-.---	$-.------
4	-.-------	$-.---	$-.------
5	-.-------	$-.---	$-.------
6	-.-------	$-.---	$-.------
7	-.-------	$-.---	$-.------
8	-.-------	$-.---	$-.------
9	-.-------	$-.---	$-.------
10	-.-------	$-.---	$-.------
11	-.-------	$-.---	$-.------
12	-.-------	$-.---	$-.------
13	-.-------	$-.---	$-.------
14	-.-------	$-.---	$-.------
15	-.-------	$-.---	$-.------
16	-.-------	$-.---	$-.------
17	-.-------	$-.---	$-.------
18	-.-------	$-.---	$-.------
19	-.-------	$-.---	$-.------
20	-.-------	$-.---	$-.------
21	-.-------	$-.---	$-.------
22	-.-------	$-.---	$-.------
23	-.-------	$-.---	$-.------
24	-.-------	$-.---	$-.------
25	-.-------	$-.---	$-.------
26	-.-------	$-.---	$-.------
27	-.-------	$-.---	$-.------
28	-.-------	$-.---	$-.------
29	-.-------	$-.---	$-.------
30	-.-------	$-.---	$-.------

Summary of Annual Program Energy and Demand Savings						
Measure #	1	2	3	4		
# Units	--	--	--	--		
Annual Savings per Unit (kWh) - AT GENERATOR	---.-	---.-	---.-	---.-		
Life of DSM (years)	--	--	--	--		
Year	kWh	kWh	kWh	kWh	Total Annual Program Savings (kWh) - AT GENERATOR	Total Program Coincident Peak Demand Savings (kW) - AT GENERATOR
1	-----	-----	-----	-----	-----	--.---
2	-----	-----	-----	-----	-----	--.---
3	-----	-----	-----	-----	-----	--.---
4	-----	-----	-----	-----	-----	--.---
5	-----	-----	-----	-----	-----	--.---
6	-----	-----	-----	-----	-----	--.---
7	-----	-----	-----	-----	-----	--.---
8	-----	-----	-----	-----	-----	--.---
9	-----	-----	-----	-----	-----	--.---
10	-----	-----	-----	-----	-----	--.---
11	-----	-----	-----	-----	-----	--.---
12	-----	-----	-----	-----	-----	--.---
13	-----	-----	-----	-----	-----	--.---
14	-----	-----	-----	-----	-----	--.---
15	-----	-----	-----	-----	-----	--.---
16	-----	-----	-----	-----	-----	--.---
17	-----	-----	-----	-----	-----	--.---
18	-----	-----	-----	-----	-----	--.---
19	-----	-----	-----	-----	-----	--.---
20	-----	-----	-----	-----	-----	--.---
21	-----	-----	-----	-----	-----	--.---
22	-----	-----	-----	-----	-----	--.---
23	-----	-----	-----	-----	-----	--.---
24	-----	-----	-----	-----	-----	--.---
25	-----	-----	-----	-----	-----	--.---
26	-----	-----	-----	-----	-----	--.---
27	-----	-----	-----	-----	-----	--.---
28	-----	-----	-----	-----	-----	--.---
29	-----	-----	-----	-----	-----	--.---
30	-----	-----	-----	-----	-----	--.---

Cost Test

Program Name	Example	NPV of DSM benefits	$264,844.43
		NPV of DSM costs	$150,000.00
		NPV of DSM net societal benefits	$114,844.43
		Benefit Cost Ratio	1.77
year DSM installed	2013		
capital cost of DSM program (base yr $)	$150,000	First Year Measure Avoided Cost of Energy ($/kWh)	0.042000
societal discount rate	0.04	IOU actual average annual cost of generation escalation	0.049905

year	n	kW savings AT GENERATOR	kWh savings AT GENERATOR	DSM cap cost nom $	Avoided Cost of Energy nom $	Avoided Cost of Capacity nom $	Annual DSM Costs	Total Annual Avoided Costs
2013	1	56.473	460,350	$150,000	$19,334.70	$181.32	$150,000.00	$19,516.02
2014	2	56.473	460,350	$0	$20,299.60	$307.65	$0.00	$20,607.25
2015	3	56.473	460,350	$0	$21,312.65	$1,986.73	$0.00	$23,299.38
2016	4	56.473	460,350	$0	$22,376.26	$2,307.82	$0.00	$24,684.09
2017	5	56.473	460,350	$0	$23,492.95	$2,659.28	$0.00	$26,152.24
2018	6	53.099	432,850	$0	$23,191.93	$3,037.35	$0.00	$26,229.28
2019	7	53.099	432,850	$0	$24,349.33	$3,281.19	$0.00	$27,630.52
2020	8	53.099	432,850	$0	$25,564.49	$3,428.20	$0.00	$28,992.69
2021	9	53.099	432,850	$0	$26,840.28	$3,667.53	$0.00	$30,507.81
2022	10	53.099	432,850	$0	$28,179.75	$3,740.88	$0.00	$31,920.63
2023	11	26.111	212,850	$0	$14,548.68	$1,846.85	$0.00	$16,395.53
2024	12	26.111	212,850	$0	$15,274.73	$1,879.06	$0.00	$17,153.79
2025	13	26.111	212,850	$0	$16,037.02	$3,164.91	$0.00	$19,201.93
2026	14	26.111	212,850	$0	$16,837.34	$3,154.47	$0.00	$19,991.81
2027	15	26.111	212,850	$0	$17,677.61	$3,141.21	$0.00	$20,818.82
2028	16	0.810	6,600	$0	$575.50	$97.45	$0.00	$672.95
2029	17	0.810	6,600	$0	$604.22	$97.50	$0.00	$701.72
2030	18	0.810	6,600	$0	$634.37	$97.55	$0.00	$731.92
2031	19	0.810	6,600	$0	$666.03	$97.59	$0.00	$763.62
2032	20	0.810	6,600	$0	$699.27	$97.64	$0.00	$796.91
2033	21	0.000	0	$0	$0.00	$0.00	$0.00	$0.00
2034	22	0.000	0	$0	$0.00	$0.00	$0.00	$0.00
2035	23	0.000	0	$0	$0.00	$0.00	$0.00	$0.00
2036	24	0.000	0	$0	$0.00	$0.00	$0.00	$0.00
2037	25	0.000	0	$0	$0.00	$0.00	$0.00	$0.00
2038	26	0.000	0	$0	$0.00	$0.00	$0.00	$0.00
2039	27	0.000	0	$0	$0.00	$0.00	$0.00	$0.00
2040	28	0.000	0	$0	$0.00	$0.00	$0.00	$0.00
2041	29	0.000	0	$0	$0.00	$0.00	$0.00	$0.00
2042	30	0.000	0	$0	$0.00	$0.00	$0.00	$0.00

Program Summary

PROGRAM

Utility Name	AZ IOU
Program Year / Base Year	2013
Program Name	Example
Total Program Budget ($)	$100,000
Incentives	$60,000
Program Delivery	$30,000
Program Marketing	$5,000
Utility Administration	$2,000
Evaluation	$3,000
Total Incremental Costs	$110,000

Inputs

Line Loss Factor 10.00%

MEASURE

Measure Name	# Units	Incremental Cost per Unit ($)	Total Annual Savings per Unit (kWh) - AT METER	Total Annual Savings per Unit (kWh) - AT GENERATOR	Life of DSM (years)	Total Lifetime Energy Savings (kWh) - AT GENERATOR
Measure 1	50	400	500.0	550.0	5	137,500
Measure 2	100	500	2000.0	2200.0	10	2,200,000
Measure 3	25	800	7500.0	8250.0	15	3,093,750
Measure 4	40	500	150.0	165.0	20	132,000

Load Shape Summary

Measure Hourly Load Shapes								
Measure #					1	2	3	4
# Units					50	100	25	40
Annual Savings per Unit (kWh) - AT GENERATOR					550.0	2200.0	8250.0	165.0
Life of DSM (years)					5	10	15	20
Year	Year Hour	Month	Day	Hour				
2013	1	1	1	1	0.000087	0.000096	0.000150	0.000095
2013	2	1	1	2	0.000052	0.000094	0.000084	0.000095
2013	3	1	1	3	0.000035	0.000092	0.000044	0.000095
2013	4	1	1	4	0.000035	0.000089	0.000006	0.000095
2013	5	1	1	5	0.000035	0.000085	0.000003	0.000098
2013	6	1	1	6	0.000038	0.000082	0.000003	0.000100
2013	7	1	1	7	0.000085	0.000082	0.000016	0.000100
2013	8	1	1	8	0.000180	0.000082	0.000031	0.000100
2013	9	1	1	9	0.000171	0.000085	0.000053	0.000100
2013	10	1	1	10	0.000086	0.000089	0.000075	0.000100
2013	11	1	1	11	0.000070	0.000092	0.000103	0.000095
2013	12	1	1	12	0.000069	0.000096	0.000131	0.000091
2013	13	1	1	13	0.000069	0.000096	0.000134	0.000091
2013	14	1	1	14	0.000069	0.000098	0.000137	0.000091
2013	15	1	1	15	0.000071	0.000101	0.000143	0.000091
2013	16	1	1	16	0.000080	0.000103	0.000150	0.000091
2013	17	1	1	17	0.000118	0.000105	0.000168	0.000093
2013	18	1	1	18	0.000214	0.000108	0.000187	0.000095
2013	19	1	1	19	0.000359	0.000105	0.000218	0.000095
2013	20	1	1	20	0.000464	0.000103	0.000252	0.000095
2013	21	1	1	21	0.000434	0.000103	0.000271	0.000095
2013	22	1	1	22	0.000334	0.000103	0.000290	0.000095
2013	23	1	1	23	0.000252	0.000101	0.000252	0.000095
2013	24	1	1	24	0.000175	0.000098	0.000215	0.000095
2013	25	1	2	1	0.000087	0.000096	0.000150	0.000095
2013	26	1	2	2	0.000052	0.000094	0.000084	0.000095
2013	27	1	2	3	0.000035	0.000092	0.000044	0.000095
2013	28	1	2	4	0.000035	0.000089	0.000006	0.000095
2013	29	1	2	5	0.000035	0.000085	0.000003	0.000098
2013	30	1	2	6	0.000038	0.000082	0.000003	0.000100

s

Program Annual Avoided Costs			
	Total Program Annual Avoided Costs ($/kWh)	$0.0420	
	Coincidence Peak Demand Factor	0.000123	
Year Hour	Program Annual Hourly Shape	2013 Avoided Costs ($/kWh)	Total Program Avoided Costs ($/kWh)
1	0.000126	0.042	$0.0000053
2	0.000087	0.042	$0.0000037
3	0.000064	0.042	$0.0000027
4	0.000042	0.042	$0.0000018
5	0.000038	0.042	$0.0000016
6	0.000038	0.042	$0.0000016
7	0.000046	0.042	$0.0000019
8	0.000057	0.042	$0.0000024
9	0.000070	0.042	$0.0000029
10	0.000081	0.042	$0.0000034
11	0.000097	0.042	$0.0000041
12	0.000115	0.042	$0.0000048
13	0.000116	0.042	$0.0000049
14	0.000119	0.042	$0.0000050
15	0.000123	0.042	$0.0000052
16	0.000128	0.042	$0.0000054
17	0.000140	0.042	$0.0000059
18	0.000154	0.042	$0.0000065
19	0.000174	0.042	$0.0000073
20	0.000195	0.042	$0.0000082
21	0.000205	0.042	$0.0000086
22	0.000212	0.042	$0.0000089
23	0.000189	0.042	$0.0000079
24	0.000165	0.042	$0.0000069
25	0.000126	0.042	$0.0000053
26	0.000087	0.042	$0.0000037
27	0.000064	0.042	$0.0000027
28	0.000042	0.042	$0.0000018
29	0.000038	0.042	$0.0000016
30	0.000038	0.042	$0.0000016

Summary of Annual Program Energy and Demand Savings						
Measure #	1	2	3	4		
# Units	50	100	25	40		
Annual Savings per Unit (kWh) - AT GENERATOR	550.0	2200.0	8250.0	165.0		
Life of DSM (years)	5	10	15	20		
Year	kWh	kWh	kWh	kWh	Total Annual Program Savings (kWh) - AT GENERATOR	Total Program Coincident Peak Demand Savings (kW) - AT GENERATOR
1	27,500	220,000	206,250	6,600	460,350	56.473
2	27,500	220,000	206,250	6,600	460,350	56.473
3	27,500	220,000	206,250	6,600	460,350	56.473
4	27,500	220,000	206,250	6,600	460,350	56.473
5	27,500	220,000	206,250	6,600	460,350	56.473
6	0	220,000	206,250	6,600	432,850	53.099
7	0	220,000	206,250	6,600	432,850	53.099
8	0	220,000	206,250	6,600	432,850	53.099
9	0	220,000	206,250	6,600	432,850	53.099
10	0	220,000	206,250	6,600	432,850	53.099
11	0	0	206,250	6,600	212,850	26.111
12	0	0	206,250	6,600	212,850	26.111
13	0	0	206,250	6,600	212,850	26.111
14	0	0	206,250	6,600	212,850	26.111
15	0	0	206,250	6,600	212,850	26.111
16	0	0	0	6,600	6,600	0.810
17	0	0	0	6,600	6,600	0.810
18	0	0	0	6,600	6,600	0.810
19	0	0	0	6,600	6,600	0.810
20	0	0	0	6,600	6,600	0.810
21	0	0	0	0	0	0.000
22	0	0	0	0	0	0.000
23	0	0	0	0	0	0.000
24	0	0	0	0	0	0.000
25	0	0	0	0	0	0.000
26	0	0	0	0	0	0.000
27	0	0	0	0	0	0.000
28	0	0	0	0	0	0.000
29	0	0	0	0	0	0.000
30	0	0	0	0	0	0.000

EERP POA - Attachment D – Revenue Requirements for 2014, 2015, and 2016

2014 Revenue Requirement

	Capitalization of EE Investments	
Year		
2014	$ 7,279,921	Original Cost
	4	Asset Life
	38.6%	Income Tax Rate
	9.40%	Nominal Return
	13.53%	Pre-tax Return
	8.31%	After-tax Return
		Capital Structure:
	47.40%	Debt
	52.60%	Equity
		Short-Term Debt
		Cost of Capital:
	5.97%	Debt
	12.50%	Equity (additional 200 basis points)
		Short-Term Debt

		2014	2015	2016	2017	2018	2019
	0	1	2	3	4	5	6
Regulatory Asset Amortization		$ 1,819,980	$ 1,819,980	$ 1,819,980	$ 1,819,980		$ -
Tax depreciation	$ -	$ 7,279,921	$ -	$ -	$ -	$ -	$ -
Net book basis (end of year)	$ -	$ 5,459,941	$ 3,639,960	$ 1,819,980	$ -	$ -	$ -
Tax basis (end of year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADIT (end of year) ((book basis minus tax basis) times tax rate)	$ -	$ 2,106,281	$ 1,404,188	$ 702,094	$ -	$ -	$ -
Long-term debt balance (end of year)	$ -	$ 1,589,635	$ 1,059,756	$ 529,878	$ -	$ -	$ -
LT Debt Interest		$ 120,652	$ 79,084	$ 47,451	$ 15,817	$ -	$ -
Rate Base, end of year							
Regulatory Asset	$ -	$ 7,279,921	$ 7,279,921	$ 7,279,921	$ 7,279,921	$ 7,279,921	$ 7,279,921
Accumulated Amortization		$ (1,819,980)	$ (3,639,960)	$ (5,459,941)	$ (7,279,921)	$ (7,279,921)	$ (7,279,921)
ADIT	$ -	$ (2,106,281)	$ (1,404,188)	$ (702,094)	$ -	$ -	$ -
Unamortized ITC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base, end of year	$ -	$ 3,353,659	$ 2,235,773	$ 1,117,886	$ -	$ -	$ -
Revenue Requirement							
Carrying Costs	$ -	$ 577,053	$ 378,244	$ 226,946	$ 75,649	$ -	$ -
Regulatory Asset Amortization	$ -	$ 1,819,980	$ 1,819,980	$ 1,819,980	$ 1,819,980	$ -	$ -
O & M	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Gross Revenue Requirement		$ 2,397,033	$ 2,198,224	$ 2,046,926	$ 1,895,629	$ -	$ -

EERP POA - Attachment D – Revenue Requirements for 2014, 2015, and 2016

2015 Revenue Requirement

Year	Capitalization of EE Investments	
2015	$ 7,697,093	Original Cost
	4	Asset Life
	38.6%	Income Tax Rate
	9.40%	Nominal Return
	13.53%	Pre-tax Return
	8.31%	After-tax Return
		Capital Structure:
	47.40%	Debt
	52.60%	Equity
		Short-Term Debt
		Cost of Capital:
	5.97%	Debt
	12.50%	Equity (additional 200 basis points)
		Short-Term Debt

		2015	2016	2017	2018	2019	2020
	0	1	2	3	4	5	6
Regulatory Asset Amortization		$ 1,924,273	$ 1,924,273	$ 1,924,273	$ 1,924,273	$ -	$ -
Tax depreciation	$ -	$ 7,697,093	$ -	$ -	$ -	$ -	$ -
Net book basis (end of year)	$ -	$ 5,772,820	$ 3,848,547	$ 1,924,273	$ -	$ -	$ -
Tax basis (end of year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADIT (end of year) ((book basis minus tax basis) times tax rate)	$ -	$ 2,226,981	$ 1,484,654	$ 742,327	$ -	$ -	$ -
Long-term debt balance (end of year)	$ -	$ 1,680,728	$ 1,120,485	$ 560,243	$ -	$ -	$ -
LT Debt Interest		$ 127,566	$ 83,616	$ 50,170	$ 16,723	$ -	$ -
Rate Base, end of year							
Regulatory Asset	$ -	$ 7,697,093	$ 7,697,093	$ 7,697,093	$ 7,697,093	$ 7,697,093	$ 7,697,093
Accumulated Amortization		$ (1,924,273)	$ (3,848,547)	$ (5,772,820)	$ (7,697,093)	$ (7,697,093)	$ (7,697,093)
ADIT	$ -	$ (2,226,981)	$ (1,484,654)	$ (742,327)	$ -	$ -	$ -
Unamortized ITC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base, end of year	$ -	$ 3,545,839	$ 2,363,893	$ 1,181,946	$ -	$ -	$ -
Revenue Requirement							
Carrying Costs		$ 610,120	$ 399,919	$ 239,951	$ 79,984	$ -	$ -
Regulatory Asset Amortization		$ 1,924,273	$ 1,924,273	$ 1,924,273	$ 1,924,273	$ -	$ -
O & M		NA	NA	NA	NA	NA	NA
Gross Revenue Requirement		$ 2,534,394	$ 2,324,192	$ 2,164,225	$ 2,004,257	$ -	$ -

EERP POA - Attachment D – Revenue Requirements for 2014, 2015, and 2016

2016 Revenue Requirement

	Capitalization of EE Investments	
Year		
2016	$ 8,050,105	Original Cost
	4	Asset Life
	38.6%	Income Tax Rate
	9.40%	Nominal Return
	13.53%	Pre-tax Return
	8.31%	After-tax Return
		Capital Structure:
	47.40%	Debt
	52.60%	Equity
		Short-Term Debt
		Cost of Capital:
	5.97%	Debt
	12.50%	Equity (additional 200 basis points)
		Short-Term Debt

		2016	2017	2018	2019	2020	2021
	0	1	2	3	4	5	6
Regulatory Asset Amortization		$ 2,012,526	$ 2,012,526	$ 2,012,526	$ 2,012,526	$ -	$ -
Tax depreciation	$ -	$ 8,050,105	$ -	$ -	$ -	$ -	$ -
Net book basis (end of year)	$ -	$ 6,037,579	$ 4,025,053	$ 2,012,526	$ -	$ -	$ -
Tax basis (end of year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADIT (end of year) ((book basis minus tax basis) times tax rate)	$ -	$ 2,329,117	$ 1,552,745	$ 776,372	$ -	$ -	$ -
Long-term debt balance (end of year)	$ -	$ 1,757,811	$ 1,171,874	$ 585,937	$ -	$ -	$ -
LT Debt Interest		$ 133,416	$ 87,451	$ 52,471	$ 17,490	$ -	$ -
Rate Base, end of year							
Regulatory Asset	$ -	$ 8,050,105	$ 8,050,105	$ 8,050,105	$ 8,050,105	$ 8,050,105	$ 8,050,105
Accumulated Amortization		$ (2,012,526)	$ (4,025,053)	$ (6,037,579)	$ (8,050,105)	$ (8,050,105)	$ (8,050,105)
ADIT	$ -	$ (2,329,117)	$ (1,552,745)	$ (776,372)	$ -	$ -	$ -
Unamortized ITC	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rate Base, end of year	$ -	$ 3,708,462	$ 2,472,308	$ 1,236,154	$ -	$ -	$ -
Revenue Requirement							
Carrying Costs		$ 638,102	$ 418,260	$ 250,956	$ 83,652	$ -	$ -
Regulatory Asset Amortization		$ 2,012,526	$ 2,012,526	$ 2,012,526	$ 2,012,526	$ -	$ -
Gross Revenue Requirement		**$ 2,650,629**	**$ 2,430,786**	**$ 2,263,482**	**$ 2,096,178**	**$ -**	**$ -**

2014 DSMS Collection

LINE NO.			(A)
1	UNSE DSM Revenue Requirement 2014		$2,397,033
2	UNSE DSM Unrecovered Expenses Through 2013		($1,400,731)
3	**DSM Expenses to be recovered in adjusted surcharge**		**$996,302**
4			
5	**Forecast Sales 2014 (kWh)**		**1,795,535,058**
6	**Rate per kWh for all Classes**	**(Ln.3A/Ln.5A)**	**$0.000555**
7	Current DSMS		$0.004382
8	Net Change		($0.003827)

2015 DSMS Collection

LINE NO.			(A)
1	UNSE DSM Revenue Requirement 2015		$4,732,617
2	**DSM Expenses to be recovered in adjusted surcharge**		**$4,732,617**
3			
4	**Forecast Sales 2015 (kWh)**		**1,820,846,281**
5	**Rate per kWh for all Classes**	**(Ln.2A/Ln.4A)**	**$0.002599**
6	2014 DSMS		$0.000555
7	Net Change		$0.002044

2016 DSMS Collection

LINE NO.			(A)
1	UNSE DSM Revenue Requirement 2016		$7,021,747
2	**DSM Expenses to be recovered in adjusted surcharge**		**$7,021,747**
3			
4	**Forecast Sales 2016 (kWh)**		**1,852,127,008**
5	**Rate per kWh for all Classes**	**(Ln.2A/Ln.4A)**	**$0.003791**
6	2015 DSMS		$0.002599
7	Net Change		$0.001192

Rider R-2
Demand Side Management Surcharge (DSMS)

APPLICABILITY
The Demand Side Management Surcharge (DSMS) applies to all Customersin the entire territory served by the Company as mandated by the Arizona Corporation Commission (ACC), unless otherwise specified.

RATE
The DSMS shall be applied to all monthly bills. The rates for 2014, 2015 and 2016 are shown in the UNS Electric Statement of Charges.

REQUIREMENTS
The 2014 UNS Electric DSMS is effective XXXXXX XX, 2014, and will remain in effect until December 31, 2014. The 2015 DSMS is effective January 1, 2015, and will remain in effect until December 31, 2015. The 2016 DSMS is effective January 1, 2016, and remain in effect until further order of the ACC.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company, and/or the price of, or revenue from, gas sales or service sold and/or the volume of gas sales generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file from time to time with the ACC shall apply where not inconsistent with this Rate.

EXHIBIT

DAS-2

DAS-2 - UNSE Energy Efficiency Resource Plan Comparison – funding through 2016

			NPV	2014	2015	2016	2017	2018	2019
1									
	a	*Total DSM Program Expenses*	$ 19,730,118	$ 7,279,921	$ 7,697,093	$ 8,050,105			
	b	Retail Sales Forecast		1,795,535	1,820,846	1,852,127	1,881,522	1,914,142	1,949,514
2		**Current Method: Program Expenses + Performance Incentive @ 10% of net benefits capped at 10% of expenses**							
	c	Recovery of Expenses	$ 19,730,118	$ 7,279,921	$ 7,697,093	$ 8,050,105			
	d	Performance Incentive "PI" (Pre-tax)	$ 1,775,711	$ 655,193	$ 692,738	$ 724,509			
	e	True-up of Un-recovered Costs		$ (1,400,731)	$ -	$ -			
	f	Customer Costs	$ 20,208,855	$ 6,534,383	$ 8,389,832	$ 8,774,615			
	g	DSM Rate		$ 0.003639	$ 0.004608	$ 0.004738			
	h	Average monthly residential bill		$ 3.06	$ 3.87	$ 3.98			
3		**Proposed Method: Capitalization of DSM Expenses (100%) + 200 basis points**							
	j	TEP Investment	$ 19,730,118	$ 7,279,921	$ 7,697,093	$ 8,050,105	$ -	$ -	$ -
	j	Carrying Costs (+200 basis points)	$ 3,203,198	$ 577,053	$ 988,364	$ 1,264,967	$ 733,860	$ 330,940	$ 83,652
	k	Book Depreciation	$ 17,644,136	$ 1,819,980	$ 3,744,254	$ 5,756,780	$ 5,756,780	$ 3,936,800	$ 2,012,526
	l	True-up of Un-recovered Costs		$ (1,400,731)	$ -	$ -			
	m	Customer Costs (Rev Req)	$ 19,550,361	$ 996,302	$ 4,732,617	$ 7,021,747	$ 6,490,640	$ 4,267,739	$ 2,096,178
	n	DSM Rate		$ 0.000555	$ 0.002599	$ 0.003791	$ 0.003450	$ 0.002230	$ 0.001075
	o	Average monthly residential bill		$ 0.47	$ 2.18	$ 3.18	$ 2.90	$ 1.87	$ 0.90

Effective date is assumed 1/1/14. DSM balance over collection of $1.4 million.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	DOCKET NO. E-04204A-12-____

UNS ELECTRIC, INC.

APPLICATION

TESTIMONY AND EXHIBITS

VOLUME 2 of 3

December 31, 2012

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
GARY PIERCE- CHAIRMAN
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	)	DOCKET NO. E-04204A-12-____

Direct Testimony of

Craig A. Jones

on Behalf of

UNS Electric, Inc.

December 31, 2012

TABLE OF CONTENTS

I. Introduction 1

II. Weather Normalization Adjustment 6

III. Customer Annualization Adjustment 9

IV. Jurisdictional Allocation of Costs 12

A. Transmission Allocation 12

V. Class Cost-of-Service Study 13

VI. Rate Design 20

A. Overall Objectives of Updated Rate Design 20

B. Specific Rate Design Changes 23

1. Residential Rates 28

a. Monthly Charge 28

b. Volumetric Rate 30

2. Non-Residential Rates 31

a. Monthly Charges 32

b. Volumetric Rates 33

c. Demand Charges 34

3. Time of Use Rates 37

4. Lighting Rates 37

5. Partial Requirement and Qualified Facility Rates 38

6. GreenWatts 39

C. Bill Impacts 41

VII. Purchased Power & Fuel Adjustment Clause 42

A. Elimination of Base Fuel Rates 43

B. Creation of Multiple PPFAC Components 44

VIII. Adjustor Mechanisms 46

A. Lost Fixed Cost Recovery Mechanism 46

B. Transmission Cost Adjustor 51

IX. CARES Rates 52

X. Miscellaneous Service Fees 54

XI. Proposed Tariffs 55

XII. Electric Load Curtailment Tariff 56

XIII. Elimination or Modification of Certain Compliance Filings and Programs 56

A. Request for Elimination of Reporting Requirement 57

B. Request for Modification of Reporting Requirement 58

Exhibits:

Exhibit CAJ-1 Bill Impact Summary
Exhibit CAJ-2 PPFAC - Plan of Administration
Exhibit CAJ-3 PPFAC Components
Exhibit CAJ-4 LFCR - Plan of Administration
Exhibit CAJ-5 Calculation of Initial LFCR Adjustment
Exhibit CAJ-6 TCA - Plan of Administration
Exhibit CAJ-7 Statement of Charges
Exhibit CAJ-8 Clean version of Tariffs
Exhibit CAJ-9 Redlined version of Tariffs

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Craig A. Jones. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP"), a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy") as the Manager of Pricing. UNS Energy was known as UniSource Energy Corporation before a name change that took effect on May 4, 2012. As the Manager of Pricing, I am responsible for various rate-related matters including monitoring and coordinating the determination of revenue requirements, customer pricing options and support and the rate structures for all the regulated subsidiaries of UNS Energy, including TEP, UNS Electric, Inc. ("UNS Electric" or the "Company") and UNS Gas, Inc. ("UNS Gas"). This includes overseeing the development of the cost-of-service analysis and rate design in general rate cases.

Q. Please describe your educational background.

A. I graduated from the University of Missouri - Columbia in December 1980 with a Bachelor of Science Degree in Agricultural Engineering. In May 1981, I received a Bachelor of Science Degree in Agricultural Mechanization. I have completed much of the course work required for a Master's Degree in Agricultural Engineering at the University of Missouri – Columbia. I am qualified as an Engineer-in-Training under the laws of the State of Missouri.

Q. Please describe your professional background and experience.

A. In February 1983, I joined the Staff of the Missouri Public Service Commission as a Rate Engineer. My responsibilities included analyzing and making recommendations relating to purchased gas adjustment filings, actual cost adjustment filings, rate cases, certificate of service applications, intrastate pipeline applications and applications to establish new local distribution systems. I left the Missouri Public Service Commission in December 1994 to take a position with the New York State Electric and Gas Corporation ("NYSEG"). My responsibilities at NYSEG included establishing prices to be used in "repackaged" contract offerings, training co-workers and end-users with respect to the application of new rates and service concepts, and complying with Commission filing requirements, including the calculation and filing of the monthly gas cost adjustment filings with the New York Public Service Commission.

I left NYSEG in April 1998 to take a position as Rates Manager with Citizens Energy Group (formerly Citizens Gas & Coke Utility) ("Citizens") in Indianapolis, Indiana. In March 2004, I was promoted to Manager - Rates and Regulatory Affairs. I was responsible for various rate-related matters associated with both the natural gas and steam utilities operated by Citizens, including the annual filings for approval of a fuel cost adjustment for the steam utility and the development of the monthly gas cost adjustment filings, various miscellaneous tariff filings, special contracts, and numerous other rate-related activities for the gas and steam utilities, including cost of service and rate design in general rate cases.

In November 2009, I left my position at Citizens and joined TEP as the Manager of Pricing. Since joining TEP, I have provided pre-filed direct testimony and live testimony in the UNS Gas 2011 general rate case (Docket No. G-04204A-11-0158, Decision No. 73142) and pre-filed testimony in TEP's pending general rate case (Docket No. E-

01933A-12-0291). I have actively participated in the Arizona Corporation Commission's ("Commission") Decoupling Workshops, line extension reviews, oversaw UNS Electric's compliance filings relating to its most recent rate case (Docket No. E-04204A-09-0206, Decision Nos. 71914 and 72213), the filing of TEP's Community Solar tariff and other pricing and regulatory activities. I also have pre-filed direct testimony in the pending TEP rate case in Docket No. E-01933A-12-0291.

Q Have you previously testified before any other regulatory agencies?

A. Yes. I testified before Indiana Public Service Commission on numerous occasions, including in Cause Nos. 41969-FAC01-FAC15, 41969-FAC03(S1), 41969-FAC06(S1), 41605, 41824, 42578, 42726, 42767, 43025, 43463 37399-GCA68, 37399-GCA68(S1), 37399-GCA69, and 37399-GCA77. I also testified before the Missouri Public Service Commission on several occasions regarding rates, tariffs, and certificate applications.

Q. Are you sponsoring any schedules?

A. I am sponsoring the "G" and "H" Schedules, which summarize the class cost-of-service study ("CCOSS"), rate design, and proof of revenue in this proceeding.

Q. Could you please summarize your Direct Testimony?

A. First, I address the weather normalization and customer annualization adjustments. Both of these adjustments reflect test year billing determinants under normal weather and year-end customer levels, respectively. The methodology employed for both was approved by this Commission in the last UNS Electric and TEP rate cases.

Second, I discuss the Company's jurisdictional allocation of both wholesale and transmission costs. For wholesale generation related demand and expenses, UNS Electric is requesting the utilization of the four coincident peak methodology ("4CP"). The

Company is also requesting that its transmission revenue requirement be calculated using the Open Access Transmission Tariff ("OATT") rates approved by Federal Energy Regulatory Commission ("FERC") an approach approved by the Commission in other electric utility rate cases.

Third, I address the CCOSS. This study is necessary in order to determine an appropriate total cost to serve each class. The Company's study utilized both external and internal allocation factors, as well as the Average and Peaks Methodology. It shows that most all customers are being subsidized by the Large General Service class. While my testimony and rate design recognizes this result, the proposed rate design does not fully resolve the disparity in cost of service in this case; rather the Company proposes an initial step towards a more equitable cost allocation between classes.

Fourth, I describe the Company's proposed rate design, including the proposal to simplify and modernize rates to not only better meet its customer's needs, but also to align it more with similarly situated electric utilities and to better reflect recent regulatory requirements such as Energy Efficiency ("EE") and Renewable Energy Standard Tariff ("REST").

In light of the CCOSS results, UNS Electric proposes moving its rates towards actual cost of service; primarily through the simplification and some consolidation of rates. My testimony explains the Company's need to reduce the existing cross-subsidies between customer classes by lowering the percentage increase for customers currently paying more than their cost of service, and increasing the percentage increase for customers currently paying less than their cost of service. I also set forth the bill impacts of these changes.

My rate design testimony further addresses: changes to the demand charge for certain classes, the time of use ("TOU") rates, the monthly customer charge and the existing Qualified Facility ("QF") rates.

Fifth, I propose two changes to the Purchased Power and Fuel Adjustment Clause ("PPFAC"). The Company is proposing to move all fuel and purchase power costs from base rates and to recover them entirely through the PPFAC. UNS Electric is also proposing multiple PPFAC components that are differentiated on the basis of on-peak and off-peak and some shift in fuel costs to moderate fuel-related bill impacts. I also sponsor a revised Plan of Administration ("POA") for the PPFAC to reflect the Company's proposed changes. While this proposal creates multiple PPFAC components, it will not add to the PPFAC rates any single customer will pay.

Sixth, I sponsor the POA for the Lost Fixed Cost Recovery ("LFCR") mechanism. I further describe how the cost recovery mechanism will work and the costs the adjustor will recover.

Seventh, I sponsor the POA for the Transmission Cost Adjustment mechanism ("TCA"), which provides an opportunity to timely collect FERC-approved transmission costs that are incurred by retail customers.

Eighth, I address Customer Assistance Residential Energy Support Program ("CARES") rates. The Company proposes modifications to its CARES rates in order to simplify the rates to more effectively serve the Company's low income customers. The modifications would reduce the two existing tariffs which contains six multi-leveled percentage discount variations and two fixed discount variations of CARES rates down to a single tariff with a flat $13.00 per-month discount (limited to a reduction of the bill down to

zero dollars.) UNS Electric also proposes to eliminate the exclusion of CARES rates from the Demand Side Management ("DSM") surcharges, and eliminate the separate discount rates for CARES-medical.

Finally, I address several other miscellaneous changes – including changes to the Company's miscellaneous service fees, sponsoring the rate tariffs and the tariff sheet changes, and describing the Company's request to eliminate or modify certain compliance filings and programs.

II. WEATHER NORMALIZATION ADJUSTMENT.

Q. What is the purpose of a weather normalization adjustment?

A. Weather normalization is a standard adjustment commonly performed in rate cases. It is performed to provide a best estimate of test year sales, revenues, and costs as they would have been under normal weather conditions. Energy consumption for some of UNS Electric's customer classes are weather sensitive. For instance, a significant portion of energy usage in the summer comes from air conditioning load. Some summers, however, are warmer than normal and result in the Company selling more kilowatt hours ("kWhs") and receiving more revenues than in a "normal" year. The reverse of this occurs when cooler than normal summer weather is experienced. The purpose of weather normalization is to "average" out these differences, so one can get a better sense as to what the Company is likely to receive in revenues during a normalized year. In other words, the weather normalization adjustment attempts to quantify the change in kWh sales and the related revenues that would have occurred if the weather in the test year had been typical.

Q. How is annual usage normalized based on the weather in order to make this adjustment?

A. A typical industry practice and the method approved by this Commission in prior UNS Electric rate cases is to use a variable known as heating degree days ("HDD") to measure heating load and another variable known as cooling degree days ("CDD") to measure cooling load. Electric heating requirements are small when average daily temperatures are greater than 65 degrees Fahrenheit, and cooling requirements are small when the average daily temperatures are less than 65 degrees Fahrenheit. In other words, customers will generally have no need for heating when average daily temperatures are at or above 65 degrees Fahrenheit, and customers will have no need for cooling when average daily temperatures are at or below 65 degrees Fahrenheit. Therefore, a HDD is measured by subtracting 65 degrees from the average of the maximum and minimum temperature for that day. For UNS Electric a CDD is measured by subtracting 65 degrees from the average of the maximum and minimum temperature for that day. Negative results for both CDD and HDD calculations are set to zero.

The normal weather for each calendar month is the average HDDs and CDDs that have been recorded over the last ten years and reported by the National Oceanic and Atmospheric Administration ("NOAA"). Actual monthly CDD and HDD for the UNS Electric service area are then compared with the normal weather.

Q. Please explain further the weather normalization calculation.

A. The method I have used is consistent with the method used in prior electric cases and has been accepted and approved by this Commission. To quantify how much electric usage changes in response to weather deviating from normal, the statistical technique of linear regression analysis is used. Regression analysis is used to estimate how much a

dependent variable "y" (*e.g.*, average use-per-customer ("UPC")) changes in response to a change in an independent variable "x" (*e.g.*, CDD). This estimate, the slope coefficient (rise over run), represents the change in "y" divided by the change in "x." Specifically, the analysis focuses on the average monthly UPC. Regression models estimate how much electric UPC changed in response to a change of one CDD. This analysis is conducted by month and by customer class. A monthly analysis recognizes that the impact on UPC of CDD variations by month.

When regression is used for weather adjustments, one multiplies the slope coefficient (change in UPC/change in CDD) by the deviation from normal weather (*i.e.*, the difference in normal CDD ("CDDN") and actual CDD ("CDDA") (which is: CDDN – CDDA)). Note that when actual CDD is more than normal CDD, the calculated difference is negative, which is indicative of a warmer than normal month. To normalize UPC, a negative adjustment is added to actual UPC and a normalized UPC lower than the actual UPC results. In this case, we can say that weather was more extreme than normal (*i.e.*, a hotter summer).

Likewise, when CDDA is less than CDDN, the calculated difference is positive, which is indicative of a cooler than normal month. To normalize UPC, a positive adjustment is added to actual UPC and a normalized UPC higher than the actual UPC results. In this case, we can say that weather was less extreme than normal (*i.e.,* a cooler summer). The result of this calculation is the weather adjustment in kWh per customer. To obtain the total monthly weather adjustment, the weather adjustment per customer is simply multiplied by the annualized number of customers by month.

Q. Was the weather normalization adjustment performed for all classes?

A. No. Weather normalization calculations were performed only for weather-sensitive classes, as identified through regression analysis. The weather-sensitive classes for UNS Electric are the residential and commercial classes. Regression analysis revealed no statistically significant relationship between usage and weather for the industrial, mining, or street lighting classes; therefore, no weather adjustment is proposed for these classes.

Q. What did your calculations show?

A. Overall, weather was more extreme than normal during the test year (*i.e.,* warmer in the summer, on average). Therefore, sales were slightly higher than normal resulting in a "negative" adjustment to sales volumes.

Q. What was the effect of weather adjustments on test year revenues?

A. Because sales during the test year were slightly higher than normal due to the weather, it is necessary to make negative adjustments to reflect a "normalized" level of sales. The net result of these weather normalization adjustments was to adjust the total actual revenues downward. The weather adjustment is a negative $1,141,834.

III. CUSTOMER ANNUALIZATION ADJUSTMENT.

Q. Please describe the customer annualization adjustment.

A. The customer annualization adjustment restates the number of test year bills and related energy consumption to be consistent with the number of customers on the system at the end of the test year. The method the Company is proposing to use is the same method that has been approved by this Commission in prior electric rate cases. The early months of the test year typically reflect more adjustment in the number of customers.

For instance, the first month of the test year must be adjusted for 11 months of growth to reach adjusted test year end levels, whereas the eleventh month of the test year only requires one month of adjustment. Adjustments to the monthly volumes were made by multiplying the monthly customer differences by the normalized UPC for the month.

Q. Why is your customer annualization adjustment reflective of test year-end customer values, as opposed to some other adjusting point?

A. The customer annualization adjustment – when added to normalized billing determinants – should result in adjusted billing determinants that will accurately reflect the bills and volumes during the time rates will be in effect. Even when a small positive growth in the number of customers is experienced in the test year, and if the last month of the test year reflects a customer count at or close to the test year maximum, then making adjustments to reflect values at test-year end is appropriate. Under the conditions described above and existing in this case, there is a nominal positive growth rate in the number of customers, and the last month of the test year reflects a customer count at or statistically close to the test year maximum. Therefore, the year-end adjustment technique results are the most accurate method to determine what sales will be for the time rates are in effect. Also, adjusting to year-end values provides a larger reduction in the rate increase versus adjusting to other test year levels, such as a mid-year level. Accordingly, the year-end technique therefore is most effective in mitigating the rate increase UNS Electric is requesting in this application.

Q. What is the effect of the customer annualization adjustment on test year sales volumes?

A. The customer adjustment is a negative 63,260,736 kWh. This is approximately (3.5)% of the test year sales.

Q. Why does the customer annualization adjustment have an impact on test year revenue and costs?

A. As I mentioned above, even small positive customer annualization adjustments affect the number of customers, kWh consumed, and can also affect kW demand. Any increase, even a small one, means that adjusted billing determinants will be adjusted upward. So, increasing these billing determinants increases both adjusted revenues and expenses. More specifically, incremental customer growth will increase revenue and certain expenses. In this case, incremental net margin (the difference in revenue and expenses) is positive. Therefore, because the incremental net margin is positive, that will increase the total operating income and reduce the total revenue requirement. The reduction in the revenue requirement associated with the customer annualization adjustment is $7,279,584 (*i.e.*, the added customers and associated revenues add to the test year revenues thereby reducing the overall revenue deficiency and the resulting increase in rates the Company has requested). Additionally, the Company included adjustments for known losses in load resulting from a large customer adding self generation and any large customers substantially reducing their load or shutting down their operations.

The net effect of the weather normalization and the customer annualization is a reduction to test year revenues of $8,421,419.

IV. JURISDICTIONAL ALLOCATION OF COSTS.

A. Transmission Allocation.

Q. Please describe the OATT and the Company's proposal regarding how to allocate transmission costs.

A. The Company's OATT is approved by FERC and provides an annual formula rate that is applicable to UNS Electric's transmission services. It is divided into FERC authorized charges that differ between the Mohave and Santa Cruz service areas. These charges are weighted and blended together for purposes of determining the OATT expense included in rates. UNS Electric's Commission-jurisdictional retail customers use both service areas to bring energy from the source to the UNS Electric distribution system. The Company proposes that retail customers pay transmission costs based on the FERC-approved OATT rates. Accordingly, transmission expenses in base rates have been calculated based on the current OATT rates and the retail jurisdiction's demand billing determinants. Future changes to the OATT rate will be recovered through the TCA.

Q. If the Company is including the FERC approved rates for purposes of allocating Transmission costs to retail customers, doesn't that mean they are paying for these facilities twice?

A. Absolutely not. To make sure that doesn't happen, the Company has removed all Transmission-related expenses and Plant as well as any other Transmission-related cost from its calculation of revenue requirement. This prevents the customers from paying any more or less than provided for by the OATT rates for Transmission-related services.

Q. Will the OATT rate be included in the customers' bills?

A. Yes. For each class of service, a simple rate per kWh is calculated and included in the base rate in the same manner that is currently in place and approved by the Commission in the Company's last rate case. These energy rates are based on the demand rates in the OATT, but are applied to the customers as part of their bill when demand billing determinants are not available on a customer by customer basis. As the formula based OATT rate changes over time, those changes with be reflected on the customer's bill through the proposed TCA. The TCA is addressed in more detail in Company witness Mr. Michael J. DeConcini's Direct Testimony and in the discussion of the TCA POA below.

V. CLASS COST OF SERVICE STUDY.

Q. What is the purpose of a CCOSS?

A. The purpose of a CCOSS is to assign each cost component to the respective classes in order to determine an appropriate total cost to serve each class. A cost component may be one of three things: (1) an individual rate base or expense account as defined in the FERC Uniform System of Accounts; (2) a portion of a single FERC account (e.g., the "coincident peak demand-related" portion of an account), or (3) some composite of accounts. An example of a single FERC account is Account 364, which is a rate base account for distribution and overhead lines (aptly named Distribution - Overhead Lines).

Q. What are the steps in designing a CCOSS?

A. There are three basic steps involved in developing a CCOSS. Those steps are: functionalization, classification, and allocation. Functionalization involves grouping cost components by purpose or function. Some examples of functions include

transmission, distribution-primary lines, metering, and meter-reading. The CCOSS presented by the Company in this proceeding identifies over twenty different functions. The next step, classification, involves identifying each function as demand-related, energy-related or customer-related. The final step, allocation, involves apportioning each cost component to the classes of service (e.g., residential, commercial and industrial). However, the Company for this rate case has identified the costs associated with each primary rate class, not each of the sub-classes. This was done because the Company intends to simplify and consolidate rates and did not attempt to distinguish the minor differences between the sub-classes where customer usage profiles were similar.

Q. Please describe how cost components are classified for purposes of the CCOSS.

A. Costs classified as demand are most affected by the level of kW by class. Demand-classified costs are either coincident, meaning that they occur at the same time, or non-coincident, meaning at times that may vary. Coincident demands tend to be more correlated with cost at the production level. In other words, coincident demands address whether there is purchased power and generation capacity for UNS Electric's entire system needs. Consequently, non-coincident demands become more correlated with cost as we move downstream though the distribution system to the end-users.

Costs classified as energy are most affected by kWh by class. The energy classification can be either time-of-day (e.g., on-peak and off-peak) or non-time-differentiated. Finally, costs classified as customer are based on class customer counts – either non-weighted counts or weighted counts. Weighted counts take into account not just the number of customers but the level of costs imposed by the customers. In dealing with billing costs, for example, a residential customer may defined as one "weighted

customer" and an industrial customer that costs twenty times as much to meter would count as twenty "weighted customers."

Q. Please describe the allocation step in designing a CCOSS.

A. As I stated above, allocation involves assigning each cost component to the different classes of service, including residential, commercial and industrial. Each function has a single allocation factor that applies to all cost components in that function. The allocation factor should be based upon an equitable method that harmonizes the cost-causation with the functional cost being considered. In other words, the allocation should be done in a way where the cost-causation for the functional cost considered is properly identified.

Q. Please describe the CCOSS model used in this proceeding.

A. The model, created in Microsoft Excel, starts with sorting cost components by function, known as functionalized costs. The model presents functionalized and classified costs vertically (*i.e.*, in rows down the spreadsheet) and the allocation of costs to rate classes horizontally (*i.e.*, in columns across the spreadsheet). Each functionalized and classified cost is then fully allocated to the customer classes. The percentage of a given cost allocated to a specific class will depend on the function and its associated allocation factor. A cost associated with billing customers, for example, should be allocated so that it reasonably approximates the cost of billing the customers by class. As mentioned above, a weighted customer basis would be used to derive a factor that reflects both the number of customers by class and the level of costs each customer class imposes.

Q. Are there different types of allocation factors?

A. Yes. Some allocation factors used are "external" allocation factors. External allocation factors are determined independent of the magnitude of specific costs in the CCOSS. That is, the external allocation factor is developed in an analysis separate from the CCOSS. An example of an external allocation factor is the distribution substations – demand sub-transmission allocation factor, which is the factor used for the allocation of distribution substations component of distribution plant. This factor is further functionalized as demand sub-transmission and is based on class non-coincident peak demands.

Another external allocation factor – the Demand Production allocation factor - is based on the Average and Peaks Method. This method is also described in more detail below.

Q. Are there also internal allocation factors?

A. Yes, an internal allocation factor is calculated within the CCOSS model and is dependent on the cost components found therein. For example, Deferred Taxes and Tax Credits are allocated based on Total Plant in Service. Total Plant in Service is a composite of different plant categories (e.g., transmission, distribution). To the extent that plant categories are allocated differently, the Total Plant in Service allocator will vary based on the level of different plant types of net plant. Total Plant in Service, like all internal allocation factors, is a weighted average of other allocation factors. The relative sizes of cost components determine the weights in the weighted average.

Q. Is there a listing of allocation factors?

A. Yes. Allocation factors are listed in Schedule G-7. As shown, some factors are "customer-related." Studies on metering, services, meter reading, customer service and billing provide the basis for the customer-related factors. Additionally, there are factors

based on labor costs, throughput, or internal factors based on individual or aggregate costs.

Q. Please describe the Average and Peaks Method.

A. The Average and Peaks Method provides the basis of allocating for the largest cost component – production and transmission-related costs. This method has also been approved by the Commission in previous UNS Electric rate cases. The Average and Peaks 4CP factor is made up of two components: an average demand component (with a percentage weight of the system load factor) and a peak demand component (with a percentage weight of one minus the system load factor). The average demand component was calculated by dividing the number of hours in the test year into the loss-adjusted energy. The peak demand component was calculated as a combination of coincident peak demands (time of system peak) from July, August, and September 2011 and June 2012, of the test year. The system peak during a period of 12 consecutive months occurs with greatest likelihood in these four summer months.

Q. Does this methodology recognize differences in base-load versus other types of capacity?

A. Yes. This is because the allocator includes the peak component to recognize that the system must have adequate capacity to satisfy demand at the time of the peak, and that classes of customers should receive some allocation of costs reflecting contribution to this peak. But the allocator also includes the average demand component to recognize that different types of capacity – base-load, intermediate and peaking capacity – are installed depending on energy use and the duration of load. Base-load capacity has a relatively high capital cost, but a relatively low running (incremental operation and maintenance, and fuel) cost. Consequently, the average total cost per kWh, which is the

sum of capital cost and running cost, from base-load capacity falls as the utilization of the base-load capacity increases.

Peaking capacity, on the other hand, has relatively low capital costs and relatively high running costs. As a general rule, a system with a low load factor (peak demand high relative to average demand) will have more peaking units, and a higher load factor system will have more base-load units, other things equal. Typically, higher load factor customers' energy use helps support the addition of base-load capacity. The average demand component of the production allocator reflects the impact of energy use on the mix of capacity and its cost.

Q. Is the Company's overall allocation approach consistent with past approaches approved by the Commission?

A. Yes. Allocations for the production and transmission functions, and the use of weighted customers for billing, metering and meter reading match the approach approved by the Commission in UNS Electric's last general rate case.

Q. What is the final objective of the CCOSS?

A. Based on allocated costs, the goal is to confirm the extent to which present and proposed rates generate revenue that recovers costs and provides for a reasonable return on investment per customer class. The term "cost" covers both expenses (including taxes) and the return on investment. The total cost to serve a particular class varies depending on its customers' individual and combined consumption characteristics, installed facilities, labor, and other capital needed to reliably and safely serve customers in the class.

If the proposed rates produce class revenues resulting in each class earning its required return on invested capital, we say that "parity" has been reached. This is typically characterized as a "return index" (actual return/ required return) of one (100%) for each class. The CCOSS is designed to clearly present the costs and the allocation factors applied to the costs. The cost model also includes sections summarizing costs, a list of the allocation factors, and a revenue requirements summary. The "G" Schedules of the filing are assembled using the results of the CCOSS.

Q. During the rate design process, did you achieve parity?

A. No. The Company strives to achieve parity where possible, but due to the principle of gradualism, we had to make some reasonable adjustments. The impact on customers must be compared with the benefits of moving to fully cost-based rates. This approach moderates what would otherwise be even larger percentage differences in the rate increases some classes would experience. In other words, we balanced the future need to move each class towards rates that are more reflective of cost of service while recognizing that such a move must be tempered with other factors like gradualism, and the avoidance of "rate shock". Some classes will be affected more than other classes because those classes have been paying rates that are currently being subsidized by other customers. The Company is attempting to move in the general direction of parity between classes, but to truly achieve this worthy goal will likely take a few more rate cases. Because this problem has occurred over a very long period of time, the Company is not suggesting that the solution be implemented overnight.

VI. RATE DESIGN.

A. Overall Objectives of Updated Rate Design.

Q. What are the Company's objectives in rate design?

A. The Company's primary objective is to simplify the rates where possible and modernize its overall rate design.

The Company does have a few rates that it wishes to eliminate due to a lack of participation, and the Company would like to simplify a few of the existing rates and add consistency. For some of the larger classes, the minimum demand amounts and maximums demands established in some of the rates add to customer confusion and frequently results in switching from one rate to another and back. The Company is proposing changes designed to help minimize that situation. Additionally, while five additional TOU rates were added in the Company's last rate case, UNS Electric experienced an increase of zero TOU customers as of the end of the current test year in these new TOU rates. The over-abundance of choices might have resulted in significant customer confusion – enough to prevent greater participation in TOU. By simplifying the tariffs, UNS Electric hopes to reduce the customer confusion and encourage customers to more effectively consider their rate options and possibly be more encouraged to choose the more efficient options like TOU rates.

Q. Are there other reasons justifying the need for UNS Electric to update and modernize its rate schedules?

A. Yes. In addition to the reasons outlined above, UNS Electric's proposed rate design has two secondary objectives: (1) to better align the Commission's policies with Company's need for fixed cost recovery; and (2) to reduce existing cross-subsidies

between customer classes. To meet these objectives, the Company proposes: (1) a lower percentage rate increase for classes paying significantly more than the system average return on plant; and (2) a higher percentage rate increase for classes paying significantly less than the system average return on plant where the resulting bill impact is reasonable. **Exhibit CAJ-1**, which I discuss in more detail below, sets forth average annual bill impacts for each of the rate classes.

Q. What was the primary concern in developing the Company's rate design proposals?

A. As we analyzed each of the proposed rate design changes and evaluated their potential impacts on customers, we had to develop a full understanding of how these changes would affect revenues. Our concerns focused on: (i) billing determinants; (ii) ratchets; and (iii) consistency. First, to best determine the true impact on the customer and Company revenues, we went to great lengths to determine the appropriate levels of billing determinants.[1] It was essential that we had a complete understanding of the billing determinants as we modified provisions within the tariffs. For the Demand Charge, we evaluated how the billing determinants would change as the ratchet[2] was changed from an amount that could vary by month in some rate classes to an amount that would be set for 12 billing months. The Company is proposing to create provisions for all rates with Demand Charges that results in an application that is consistent for all rates with Demand Charges.

[1] Billing determinants are number of units on which each of the billing components would apply to generate the Company's Revenue Requirement. By class, this would include the number of customers on which the customer charge applies, the number of total Demand units on which the Demand Charges apply and the number of kWh on which the volumetric charges apply.

[2] A ratchet is a billing provision under which the Demand Charge for each month is based on the highest measured or billed demand over a period of time in the previous year. This mechanism minimizes risk of not recovering fixed costs and properly compensates for the year-round expenses incurred to provide service to a customer.

Q. What must be considered with respect to whether the ratchet and billing determinants result in just and reasonable rates?

A. First, in developing these proposed modifications, a thorough analysis must be performed to best ensure that the impacts on the customer are understood and the proposals are fair and equitable. Second, in the event even one of the design parameters is changed by settlement or Commission Order, the billing determinants and ratchets must be reevaluated.

For example, if the Commission wanted to modify the Demand ratchet that the Company is proposing in this proceeding but does not adjust the rate proportionately, then the Company could experience a significant revenue shortfall resulting in the rates not being just or reasonable. The Company has proposed a 100% ratchet be applied to the measured demand for classes with a demand charge (one-half of the measured demand if it occurs off-peak in a TOU rate) and has proposed an appropriate rate based on the determinants that are generated under that assumption. While changing from a monthly demand amount to a 100% ratchet (demand does not decrease for 12 months) will not necessarily double the actual billed demand units, the impact can be illustrated by this overly simple assumption. If proposed rates are designed to capture a $1,000 in total revenue and the determinants are cut in half without increasing the rate proportionally, the Company may only realize $500 of revenues. Applied to a large segment of customers, this would deny the Company any reasonable opportunity of earning its Commission-approved rate of return.

In summary, if any change is made to a rate design component, an equivalent review and modification of an appropriate change in billing determinants must be made to the revenue proof to assure the revenue proof reflects the appropriate recovery of revenues.

B. Specific Rate Design Changes.

Q. Please provide an overview of the changes that the Company is proposing that are not rate specific before moving to the individual rate classes?

A. First, the Company is proposing to increase all monthly customer charges in a manner consistent with the results of the COSS. UNS Electric proposes an increase in monthly customer charges to levels that better match the true customer-related costs, as indicated by the CCOSS. The need to ensure that service is available (including having the distribution infrastructure in place) does not change if the customer decides not to use energy on a given day. This is why the majority of UNS Electric's costs are fixed in nature.

Second, the Company is proposing to move all fuel out of base rates and into the PPFAC. This will be discussed more thoroughly later in my testimony.

Third, for TOU customers, the Company is proposing to create more uniform provisions for all classes. The shoulder periods will be eliminated for all classes and the peak period will be expanded to include the hours that were formerly shoulder hours (except for the School TOU rates – the shoulder period will be considered off-peak for this class only). The rates will be adjusted downward for the peak period in a proportional manner. The Super Peak rates will be eliminated since they have been in place over two years and not a single customer has elected to participate in these classes. There are billing system and accounting costs associated with maintaining every rate and to continue to offer rates that no one appears to have an interest in simply costs the other customers without receiving anything in return.

Fourth, for firm classes with a Demand Charge, the Company proposes to establish minimum demand amounts (minimum billing demand levels) in order for a customer become and remain eligible on those classes. This should make it easier for customers to stay on a particular rate schedule and eliminate the confusion and added cost associated with tracking and regularly changing a customer from one class to another.

Fifth, The Company's current Large General Service ("LGS") and Large Power Service ("LPS") rates have different ways of calculating the billing demand. One has the demand amount changing monthly and the other is a 12-month ratchet. The Company proposes to change how the demand charge is calculated for each of these firm rate classes that currently have a demand charge. This will allow for a common interpretation of what the demand charges will be based on, which will make it less confusing for both the customer and the Company.

For these firm classes the billed demand amount will be based on the higher of:)1) the current months measured demand; (2) the highest measured demand in the prior 11 months; or (3) the contract demand amount or the specified minimum demand amount whichever is greater. For the TOU classes with a demand rate, a fourth option will be considered if the measured off-peak demand is higher than two times the measured on-peak demand amount. If this occurs the Billed Demand will be the greater of one-half of the highest off-peak demand unless the next season's on-peak demand is higher. This is designed to encourage the customer to shift load to off-peak periods at a lower cost. It will only be available to TOU classes. The above criteria are already in place for the LPS rate class therefore it will only result in a change to the customers in the LGS rate class.

Q. Does the existing rate design, which recovers a significant portion of the fixed costs through volumetric energy charges for most rate classes, create problems other than revenue instability?

A. Yes. First, the collection of significant fixed costs through energy charges places a disproportionate burden on the larger energy users within a rate class that, on average, pay more than their share of fixed costs. Even though a higher load factor customer is using the system more efficiently (and therefore more cost effectively) than a low load factor customer, having a larger proportion of the fixed costs in the energy rate will result in that higher load factor customer paying a disproportionate amount of the system cost. If the Company can shift revenue collection away from energy charges, it can reduce the cross-subsidization that occurs when usage within customer classes varies significantly.

Second, an over-dependence on fixed cost recovery through volumetric energy charges creates an economic disincentive for the utility to promote conservation, EE, and distributed generation ("DG"). If margin is collected primarily through volumetric charges and is dependent on usage, the associated reduction in sales significantly erodes a utility's ability to earn its Commission-authorized rate of return.

Q. Can this disparity be resolved solely through modification of the monthly customer charges?

A. No. The basic customer-related charges are a good starting point to identify what should be included in the monthly customer charge for each class, but does not tell the whole story. These basic charges are limited to metering, meter-reading, service (service drop) to the specific customer, and customer service and billing. While these costs should be included in the customer charge and may be used as the guide to what

the customer charge should be for classes with Demand Charges, they are not sufficient for classes without a Demand Charge.

Q. Why is it necessary for demand-related costs to be included in monthly customer charges for classes with rates that do not include a Demand Charge?

A, Without some level of demand-related cost being included in the customer charge for classes without a Demand Charge, a disproportionate amount of the Company's fixed costs must be recovered in the energy charges. Consequently, if customer energy usage falls, the Company will not have a reasonable opportunity to earn its Commission-authorized rate of return. This will only be exacerbated as EE becomes more prevalent in the future. The rates must be modified accordingly to include fixed costs in the monthly customer charges in order for the Company to encourage EE and DG. Specifically, because the residential and small general service classes currently do not have a Demand Charge, the cost of at least some of the demand-related items (such as transformers and distribution conductors) should be included in the monthly customer charge.

Q. Why does UNS Electric prefer increasing the monthly customer charges over further increasing the energy (per kWh) charges to recover fixed costs?

A. For many of the rate classes, UNS Electric currently collects the bulk of its fixed costs through an energy charge, which is a conceptually flawed rate design. This is because the bulk of a utility's costs are fixed and do not vary with the quantity of energy the customer uses on a given day. The Company is in the business of providing safe and reliable energy service. This means that facilities and personnel must be in place to ensure that customer demand is met – 365 days a year, no matter where the service is requested in the Company's service territory. In short, the Company earns a regulated rate of return on infrastructure necessary to provide reliable electrical service to its

customers. The obligation to provide safe, adequate, and reliable service does not change, regardless of whether or to what extent the customer consumes energy. This is why the majority of UNS Electric's costs are fixed.

Periodic variation in energy consumption has limited impact on the true, non-fuel cost of serving customers. Most non-fuel costs are fixed and will ultimately produce a mismatch between costs and revenues when a substantial portion of the revenues are recovered through weather-sensitive sales. Increasing customer charges helps to address this disparity. When customer charges are increased, energy charges are decreased (holding revenue requirement and other factors constant). Customer charge revenue stays relatively constant within a given month – despite weather variations, conservation efforts or (in the short run) economic activity. Consequently, customer charges provide a relatively stable and predictable source for funding fixed costs, which constitute the bulk of a utility's margin costs.

Additionally, as discussed in the Commission's decoupling workshops, an increase in customer charges will have the effect of minimizing any adjustment that will be passed through a decoupling mechanism such as the LFCR the Company is proposing in this case. This has the effect of stabilizing rates for all customers. Further, the Commission policy of EE is at odds with the current rate design for UNS Electric as the Company currently depends significantly on increased consumption to recover its fixed costs.

Q. Mr. Jones, will the Company's proposed rate designs guarantee it the ability to earn its authorized rate-of-return?

A. Absolutely not. The Company's rate design hardly guarantees achieving its Commission-authorized rate-of-return ("ROR"). For the majority of UNS Electric's customers, a significant percentage of *margin* (non-fuel revenue) recovery will still be

collected through the energy charges (volumetric or per kWh). For example, UNS Electric's residential rate R-01 (which is the rate responsible for approximately 42% of the system margin revenue) collects nearly 73% of classes' margin currently through energy charges. This is reflective of the small general service class as well, and the small general service class accounts for another 8% of the Company's marginal revenues. This large allocation of fixed cost to an energy charge potentially causes large swings in the amount of revenue collected to capture the Company's authorized ROR. Warmer than normal summer weather could result in over-recovery and cool summer weather will result in under-recovery of margin revenues. Of course, any conservation effort or decreased use per customer will, by design, result in under earnings for the utility. Further, even with a three-year rate-case cycle, factors such as operating costs, material costs, and plant expansions have consistently increased. These factors work against the Company's ability to earn its authorized ROR.

While not guaranteeing a ROR, the Company's proposal to gradually increase monthly customer charges mitigates the impacts caused by these factors.

1. <u>Residential Rates</u>.

a. <u>Monthly Charge</u>.

Q. How do UNS Electric's current residential monthly customer charges compare to other Arizona electric utilities?

A. The Company's residential customer charge covers a smaller portion of fixed costs than the residential customer charges of other electric utilities in Arizona. UNS Electric's residential customer charge is only $8.00 per month ($3.50 if currently on a CARES rate). In contrast, Arizona Public Service Company ("APS"), Trico Electric

Cooperative, Inc. and Salt River Project ("SRP") have customer charges ranging from $8.50 to $19.00 per month, with TOU customer charges consistently greater than $15.00 per month. APS also has a Demand Charge that applies in addition to the customer charge. Considering that all electric utilities incur similar fixed costs to serve residential customers, and that those fixed costs typically exceed the higher customer charges approved, for those utilities, UNS Electric's current monthly service charge should be raised significantly. While it is imperative to start addressing the issue of moving customer charges towards reflecting actual fixed costs incurred, the Company realizes the difference cannot be fully addressed in a single rate case. Therefore, UNS Electric is proposing a significantly smaller increase in the monthly customer service charge.

Q. Mr. Jones, with that background in mind, what increase is UNS Electric proposing to the residential monthly customer charge?

A. In an effort to gradually move towards more appropriate monthly customer charges for the residential and small general service rate classes, UNS Electric proposes to increase residential customer charges from the current $8.00 per month to $10.50 per month for the standard residential customer and $12.00 for all residential TOU customers when new rates are implemented. The proposed customer charge is still only approximately 25% of the $42.00 in customer (*e.g.* meter reading, billing, etc.) and demand charges identified by the CCOSS for the residential customer and the charge is still below monthly customer charges that this Commission has previously approved for other electric utilities.

Q. Will the gradual increases in the monthly customer charges also smooth out the amount of revenues that will be recovered through the Company's proposed LFCR mechanism?

A. Yes. Besides reflecting sound rate design principles, increasing these customer charges will also help to mitigate the amount of lost revenues to be recovered in the proposed LFCR described below. This is because as the fixed charges are increased, the volumetric charges are proportionally decreased for each rate class. Further, because the energy rate is lower, the total lost margin will be smaller for each kWh lost as the result of EE and DG programs.

b. <u>Volumetric Rate.</u>

Q. What volumetric rate is UNS Electric proposing for the residential rate classes?

A. Schedule H-3 shows the various rates and rate components for each of the Company's proposed rates. For the Residential R-01 rate class, UNS Electric proposes an average overall volumetric rate of $0.0319 per kWh (exclusive of purchased power and fuel costs) for the standard residential class, resulting in a $0.0021 per kWh increase on the average volumetric rate for the R-01 rate. This rate is identified as the "Delivery Rate" on the tariffs and is designed to recover the portion of fixed costs not covered by the monthly customer charge.

Q. Describe the change for Rate R-01.

A. For Rate R-01, which is the residential rate for nearly 79% of our customers, the Company has not proposed any substantial rate design changes other than to move all of the fuel costs into the PPFAC.

Q. Describe the changes to the two R-01 TOU rates.

A. In addition to moving all of the fuel costs to the PPFAC, the Company has proposed to eliminate the shoulder period and only have an on-peak and off-peak period for the standard TOU rate. The peak period will be expanded to include the hours that were formerly the shoulder period with the rates adjusted accordingly. The Company is proposing to eliminate the Super Peak rate.

Q. Will UNS Electric offer an opt-out option for those customers that do not want an Automated Meter Reading ("AMR") meter that uses radio frequency for meter readings?

A. Yes. The Company is proposing to add language to the R-01 rate that sets forth the charges if a customer chooses to have an AMR meter replaced.

2. <u>Non-residential Rates.</u>

Q. What changes is the Company proposing for the general service customers and the large power service customers?

A. Much like what the Company is proposing for the residential customers, the changes for general service and large power service customers also are designed to simplify and consolidate rates. Customer charges for the non-residential classes also need to be increased to amounts closer to levels indicated by the CCOSS. In addition to the increases to the customer charges, UNS Electric is proposing: (i) uniform application of the demand charges; (ii) the movement of fuel from base rates to the PPFAC, (iii) the creation of a minimum billing demand for the LGS rate and the LPS rate. Additionally, the small general service rate will have a third tier established.

a. **Monthly Charges.**

Q. What monthly charges is UNS Electric proposing for non-residential customer classes?

A. For SGS customers, UNS Electric is proposing an increase to the customer charges for the same reasons as discussed for the residential class, because no Demand Charge is in place for this class of customers. The proposed customer charge will reflect an increase from the current $12.50 per month to the proposed $14.50 per month; the TOU classes will be $2.00 per month higher at $16.50 per month. This class will be restricted to only those customers having an imputed maximum demand that does not calculate to greater than 500 kW.

For the LGS class, the customer charge will reflect an increase from the current $16.00 and $20.90 per month, to the proposed $50.00 per month. The TOU classes will be $2.00 per month higher. As set forth in Schedule G-6-1, line 38, the proposed general service charges are still well below the true costs of providing service. Additionally, the LGS class will have a minimum billing demand applied to all customers within the class. The minimum demand will be 20kW and the existing cap of 1,000 kW will be eliminated.

The LPS class currently has two customer charges. For service that is taken at less than 69 kV service, the customer charge is $372.00 per month and for service that is taken at 69 kV or higher, the charge is $407.00. The Company is proposing to establish one customer charge for the class that will be set at $1,500.00 per month. The metering cost data the Company reviewed indicated there is no significant difference in cost to service the different levels. For the LPS class, a minimum billing demand will be applied to all customers within the class. The class currently has a 500 kW minimum demand which

will be maintained, but it will also be the minimum billing demand for any participant in the class.

The Company believes these increased customer charges are just and reasonable as they will help mitigate existing intra-class subsidies and allow the Company to recover more of its fixed costs through a fixed charge.

b. <u>Volumetric Rates.</u>

Q. What is the Company proposing for the non-residential volumetric rates?

A. Any remaining authorized revenue requirement allocated to these classes will be recovered through an adjustment to the per-kWh delivery rate or demand rate for the specific class. The volumetric rates vary by class and can be found in Schedule H-3.

Q. Why is the Company proposing a third tier of rates in the SGS rate class?

A. Currently, the SGS tariff states that any time a customer exceeds 7,500 kWh of consumption in two consecutive months they are automatically moved to the LGS rate. The tariff requires that once the customer changes to another rate schedule, they must stay on that schedule for 12 months. The customer can request to be moved to the LGS rate schedule any time they choose, but either way, once they move they must stay for 12 months. The Company's proposal is designed to create a more expensive rate for customers in the SGS rate schedule that exceed 7,500 kWh in any month. The Company believes that rates should be designed to encourage those customers with that level of consumption to be on the larger demand-based rate. Nonetheless, some customers may believe they will only exceed the 7,500 kWh level for a short time and may prefer to pay the higher rate to remain on the SGS rate schedule.

The third tier will also encourage energy conservation by providing an economic incentive to use less than 7,500 kWh per month.

Q. Currently the tariffs include a charge for some of large customers if they fall below a certain power factor. What change is the Company proposing to this provision in the tariffs?

A. The Company is proposing to change the way the power factor is applied and billed for in the two large power service tariffs (Rate LPS and LPS-TOU). Currently, a customer who does not operate at a power factor that is at least 85% will have an adjustment made to their bill. Section 9.D.6.n of the Company's current Rules and Regulations provides that the Company may require a customer who is operating with a low power factor to install power factor correcting equipment at the customer's expense. In this proceeding the Company is proposing to modify the power factor related charges to be based on 95% power factor instead of 85% as provided for in the current tariffs. The proposed tariffs reflect wording that will effect this change. Also, the Company will start applying the provision in its Rules and Regulations that allows the Company to require installation of power factor correcting equipment on a regular basis, if the change to the tariffs does not encourage the customers to operate at improved power factors.

c. <u>Demand Charges.</u>

Q. How is the Company proposing to calculate demand charges?

A. As discussed above, UNS Electric is proposing a change to the way it calculates the Demand Charges in those firm rate tariffs where a Demand Charge is part of the rate design. This would include the existing Rate LGS, LGS-TOU, LGS-TOU-S, LPS, and LPS-TOU rate tariffs. Currently the LGS rate class has its billing demand calculated

based on the highest measured 15-minute integrated reading of the demand meter during the billing month. The LGS-TOU rate is based on the highest of:

(i) the highest measured 15 minute integrated reading of the demand meter during the on-peak and shoulder hours of the billing period;

(ii) one-half the highest measured 15 minute integrated reading of the demand meter during the off-peak hours; or

(iii) the contract capacity.

The two LPS rates have language similar to the LGS-TOU, except that a fourth "higher of" option is added that also checks the higher demand for the prior 11 months to determine of the billing demand.

In the interest of consolidating and simplifying rates, the Company is proposing to apply one general method to all classes. In applying sound cost of service principles, the Company proposes to establish the billing demand based on the "ratchet" being set at: (i) 100% of the higher of the current month's 15-minute peak demand, (ii) the highest 15-minute demand occurring in the prior 11 months, or (iii) the contract demand or the specified minimum demand amount whichever is greater for both non-TOU classes (LGS and LPS). For the TOU classes (LGS-TOU, LGS-TOU-S and LPS-TOU) a fourth option would be used in the determination of the billing demand and would be based on one-half the highest measured 15 minute integrated reading of the demand meter during the off-peak hours. These provisions add consistency between the classes yet allows the TOU customer some recognition for moving load to off-peak periods.

Additionally, this change for the LGS customer allows higher load factor customers to benefit from their usage habits. It does shift some of the costs to the lower load factor customers, but that is consistent with sound rate making principles. This will also result

in some customers in the affected rate classes realizing an increase and some realizing a decrease. The rate-per-billing-demand unit would be changed to address the change in total billing determinants where applicable, but the net effect to the Company would be revenue neutral (before applying any approved increase in rates for the class). This is simply a proposal to create more equitable rates that are less complicated and easier to understand.

As a result of the design changes in the commercial and industrial classes the Company addressed the anticipated movement from one class to another by certain customers that will be necessary with the new minimum billing demands being established in the LGS and LPS Rates.

Q. You mentioned that the Company has modified the billing determinants used in its revenue proof to reflect that the 100% ratchet will generate more billing determinants in the LGS rate class, thereby reducing the rate the Company is requesting. If the 100% ratchet is not approved, will those billing determinants need to be reduced for purposes of calculating the revenue proof?

A. Yes and the rates will need to be increased proportionally. To not address this change could be devastating to the Company's revenues. The billing determinants must be changed if the 100% ratchet is not approved and the rates increased proportionally to generate the approved demand-related revenues authorized for each rate class. Although it will require substantial analysis, it should not be overlooked.

3. TOU Rates.

Q. Is the Company proposing changes to its TOU rates?

A. As discussed above, the Company is proposing to eliminate the shoulder period in its TOU rates. This will result in the Company having only on - off-peak time periods. This is more consistent with the way the Company incurs cost and will be easier for the customer to understand. The rates will be adjusted proportionally downward to reflect that additional peak period consumption may occur since the hours have been expanded.

With less complexity in the rate design and less customer confusion, all customers will benefit in the end. It is the Company's belief that the end result of simplifying and consolidating the TOU rates will result in greater participation, which should help all customers by avoiding some level of peak period purchases.

Q. Do you intend to make these changes to the TOU customers effective immediately with the approval of these rate tariffs?

A. Yes. The changes we are proposing in this proceeding can be implemented with the rates themselves and will not require an immediate reprogramming of the TOU meters.

4. Lighting Rates.

Q. What changes are being proposed for the Lighting Rates?

A. The Company is proposing to update the lighting rates. Lighting services are designed to be offered to private or public outside lighting conditions where no meter is installed. The prices vary by the wattage and type of light bulb. The service includes the recovery of the initial cost of the pole, wiring, and fixture, as well as a normalized cost to

maintain the light itself. The maintenance costs have continued to increase, however the rates have not kept up.

The lighting rates were substantially below the cost of service based levels in UNS Electric's last rate case and would have required a substantial increase to bring them up to the appropriate levels. The Company reviewed the lighting customers' rates and again determined substantial increases are warranted. The Company has decided rate impact should be considered as we attempt to move these rates toward the cost to serve them. It is still going to require a substantial increase just to make a dent in the current significantly subsidized rate. We have also proposed modified wording in the tariff that will assist us in the fair application of rules and procedures associated with lighting services.

5. <u>Partial Requirement and Qualified Facility Rates.</u>

Q. What changes is the Company proposing to make to the current Partial Requirement Service ("PRS") and the Qualified Facility ("QF") rates?

A. The Company is proposing to eliminate its current PRS tariff and all of its QF tariffs. In their place the Company is adding a partial requirement provision to the standard SGS, LGS and LPS rate tariffs. Any customer that does not wish to receive its full requirements from the Company will be able to receive service under these provisions of each of the rate tariffs. The rates charged for partial requirement service will be based on the existing retail rates (as proposed in this rate case); however they will be converted to a full demand charge. For the SGS rate this will have to be created and the customer would have to have a demand meter installed to receive service. The only other change would be that this demand charge would be based on the highest 24 month measured peak demand amount. This change is necessary since a partial requirements

customer may need the Company to provide service at some point. Equipment and capacity must be able to meet their load at that time and will need to be available going forward. Therefore, it is appropriate for the customer to pay the demand charge for 24 months in order to compensate the system for the capacity the customer utilized.

6. <u>GreenWatts</u>.

Q. What does the Company propose regarding the GreenWatts tariff?

A. The Company is also proposing to eliminate the GreenWatts tariff (Rider 17). The GreenWatts Program was a voluntary contribution program that allowed customers to support the development of solar resources. All revenues from GreenWatts are devoted to the cost of building, operating, and maintaining new solar power sources. This program was designed to support solar before the Commission approved the Renewable Energy Standard Tariff Rules ("REST Rules") in 2006. Since the REST Rules have in effect for over five years, the GreenWatts program is a redundant program requiring separate administration and accounting resulting in unnecessary additional costs to support solar development. Since Commission also approved UNS Electric's renewable energy adjustor that collects the costs to implement its programs in accordance with the REST Rules, the number of customers who voluntarily pay into GreenWatts has declined to 192 in UNS Electric's service territory, and that number continues to decline as our REST surcharge continues to increase. This represents approximately $750 per month. The cost burden to continue to this program outweighs its effectiveness in light of other programs available to our customers to support solar development.

Q. What other programs are available to GreenWatts customers if they want to continue to promote the development of solar energy?

A. Along with Commission-approved customer-sited DG incentive programs such as net-metering and renewable energy credit purchase programs, UNS Electric launched its Bright Arizona Community Solar Program in February 2012 ("Community Solar Program") designed specifically for customers who want to support solar development in the community without having to put a system on their personal residence. This program not only accomplishes all of the goals of the GreenWatts Program, but provides a number of benefits to the customer that the GreenWatts Program does not provide.

Q. Please explain the benefits of the Community Solar Program over the GreenWatts Program.

A. The Community Solar Program has numerous benefits, to both the Company and the Customer. The program offers our customers an opportunity to participate in the development of solar energy in their territory with no up-front equipment or installation expenses, no long term contracts or binding lease agreements, fixed energy rates for up to 20 years along with pro-rated reductions in the customers' fuel surcharge and renewable surcharge. The Company generates additional revenue which is then credited against the annual renewable energy budget reducing the amount the remaining ratepayers need to pay.

Q: Will the current GreenWatts customers be allowed to subscribe to the Community Solar Program?

A: Yes, all of the GreenWatts customers will be encouraged to participate in the Community Solar Program, which will allow them to continue to support solar energy

development while enjoying the benefits associated with the Community Solar Program.

Q. Will the Community Solar rate be changed?

A. Yes. The existing rate will be locked in place for the remainder of the customer's 20-year agreement. A new rate based on the revised fuel cost will be calculated and have the same $0.02 premium added to it and placed on the Community Solar tariff for use by any customer signing up after the effective date of the new rates.

C. <u>Bill Impacts.</u>

Q. What type of bill impacts will the UNS Electric's rate design have on the Company's customers?

A. The impact of any rate case on the Company's customers is always significant concern. A great deal of time and effort was put into creating a set of rates that would keep the impact on the customers within a reasonable range and generally consistent with other like situated customers. These impacts have been summarized in general based on comparing proposed rates to current rates and can be found in attached as **Exhibit CAJ-1.**

Additional bill impact data has been provided in Schedule H. The data in this schedule must be reviewed in context. For sufficiency purposes, the Company is required to submit the information in comparison to test year rates. However, this comparison will be misleading given the rate design changes and the updated fuel costs. That is why I prepared the comparison of current rates to proposed rates in **Exhibit CAJ-1** that is based on consistent fuel costs for both bill calculations.

With respect to the residential classes, the comparisons reflect a customer that uses 1,000 kWh per month in the summer months and 700 kWh per month in the winter months. Residential customers under our basic residential rate (R-01) will see just over a 4.4% increase which equates to just over $3.60 per month on average if the Company's full revenue requirement is approved. This impact also includes the Company's proposed fuel calculation in the before and after comparison so the impact is not exaggerated by the Company's proposed change in fuel cost which reflects forecasted fuel costs. The CARES customers' existing rates are lower; therefore, the percentage impact is larger. I discuss the details of the CARES rates later in my testimony.

The overall increase the SGS customers will see is an approximate 4.64% increase for the typical customer. The impact to the LGS customers will vary somewhat due to the change in the way the Demand charge will be calculated. In general, the LGS customer using a monthly average of approximately 22,500 kWh will see an approximate 5.21% increase. The impact to the LPS customer using a monthly average of approximately 900,000 kWh will see an approximate 5.09% increase.

VII. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE.

Q. How is UNS Electric proposing to modify its PPFAC?

A. The Company is proposing to: (1) eliminate the base fuel rate and recover all fuel and purchased power costs through the PPFAC; (2) develop multiple PPFAC rate components to differentiate between on-and off-peak fuel costs and to create rates that better reflect the cost of fuel for each class; and (3) add additional costs that should appropriately be recovered through the PPFAC. I discuss the first two modifications in more detail below and Mr. DeConcini discusses the third proposal in his Direct

Testimony. I am also sponsoring the POA for the PPFAC, which is set forth in **Exhibit CAJ-2**.

A. <u>Elimination of Base Fuel Rates.</u>

Q. Why is UNS Electric proposing to move all of the fuel and purchased power costs out of base rates and into the PPFAC?

A. Currently, UNS Electric recovers a portion of its fuel and purchased power costs through the "Base Power Supply Rate", while the PPFAC simply reflects how much the actual cost of fuel differs in the current year from what was recovered through the Base Power Supply Rate established in the last rate case. Further, existing customer rates contain base fuel and purchased power costs that vary between rate classes and within rate classes. The actual cost of fuel used to serve a particular customer within a class or in separate classes is not materially different. Currently there are 23 different Base Power Supply Rates included in the various tariffs. These rates vary from $0.006761 per kWh to $0.151771 per kWh even though the average cost of fuel and purchased power is approximately $0.052 per kWh.

Fuel and purchased power costs are simply passed through to the customer on a dollar-for-dollar basis. The Company makes nothing on the recovery of the fuel itself. There is no reason to separate it into a base fuel component and into an adjustor. Rolling the entire fuel and purchased power cost into the adjustor makes it easier for customers to understand the actual cost per kWh of fuel and purchased power for their usage (clearly distinguishing that expense from the cost of providing electric service). This separation also makes it easier for the Company's accounting department to track the different components of the bill. It will provide the customer with clearer price signals which will

allow the customer to affect purchasing behavior that is more conducive to efficiency and conservation.

B. <u>Creation of Multiple PPFAC Rate Components.</u>

Q. Why is UNS Electric proposing to create multiple PPFAC rate components when currently there is only one PPFAC rate applicable to all rate classes?

A. Unlike the current situation where there are 23 different base costs for fuel and purchased power embedded in base rates, the multiple PPFAC rate components that UNS Electric proposes here are based on sound cost-of-service principles that will send more accurate price signals regarding the true cost of power consumption. The overall change proposed by the Company will reduce the existing 24 fuel components to 13. Yet any individual customer will only pay one (two if TOU) PPFAC rate components in any billing month. The Company would like to minimize the actual number of PPFAC rate components further, but the fuel cost reflected in certain of the existing base rates is substantially below the average cost of the energy used by the customer. Additional PPFAC rate components had to be created for the LGS and LPS customers to moderate the bill impact that would have resulted from moving these customers to an average cost of fuel. In its next rate case, the Company would like to review the numbers and determine if more movement would be justified.

UNS Electric is proposing to further break down the PPFAC rate into on-peak versus off-peak components for TOU customers. Since the only true value brought to the system by TOU customers over the near-term is associated with the cost of fuel and purchased power, the Company decided to maintain most of the price differential between peak and off-peak usage on the cost of fuel. This is consistent with current TOU fuel pricing in the Company's existing rates that were approved by the Commission in its last rate case.

Q. Is UNS Electric proposing revisions to the existing PPFAC POA?

A. Yes. **Exhibit CAJ-2** is the proposed PPFAC POA and reflects my discussion of the PPFAC above and the other modifications to the PPFAC discussed in Mr. DeConcini's Direct Testimony.

Q. Since the Company is proposing to move all of the fuel and purchased power costs out of base rates and into the PPFAC, what will be done to determine the proposed fuel components when the new rates go into effect?

A. When the new rates go into effect a total cost of fuel and purchased power will have been used to generate the then effective PPFAC rate. As part of the resolution of this case a set of calculations will be approved if the Company's proposal is accepted. The attached **Exhibit CAJ-3** shows each of the proposed PPFAC components and the percentage adjustment from the average cost of fuel and purchased power. Once approved by this Commission these calculations will determine each of the 13 PPFAC components that will be created to recover the Company's total cost of fuel and purchased power each year when the PPFAC filing is made.

Each year, including when the new rates go into effect (and until the next rate case establishes new percentages) these percentage adjustments will be applied to the overall average cost of fuel and purchased power at the time the calculation is made. By applying the percentages created in this set of calculations and approved by the Commission to the total average cost of fuel and purchased power and existing forward component in the then effective PPFAC a new set of PPFAC components will be created. These new PPFAC components will recover the Company's total fuel and purchased power costs. Any over or under-recovery that may occur will be captured in the subsequent PPFAC filing and included in future rates.

VIII. ADJUSTOR MECHANISMS.

Q. Is UNS Electric requesting approval of new adjustors in this case?

A. Yes. We are proposing three new adjustors: the LFCR mechanism, the TCA mechanism and a new way to determine the energy efficiency programs costs that will be recovered through UNS Electric's existing DSMS. Mr. DeConcini discusses the TCA and Ms. Denise Smith describes the Energy Efficiency Resource Plan in their respective Direct Testimonies. I address the LFCR mechanism and related POA. I also sponsor the POA for the TCA.

A. Lost Fixed Cost Recovery Mechanism.

Q. Is UNS Electric proposing a revenue decoupling mechanism?

A. Yes, the Company is proposing a LFCR mechanism that is narrowly tailored to recover kWh sales that are lost as a direct result of complying with the Commission's EE Rules and REST Rules (specifically the DG requirement). The LFCR is designed to align the Commission's EE and REST policies with the Company's financial objectives and cost-effective programs that our customers desire. Thus, this mechanism is designed to help reduce the linkage between volumetric energy sales and margin revenues (non-fuel). The LFCR is very similar to the Commission-approved mechanisms in the APS and UNS Gas rate cases that were decided earlier this year, and currently proposed in the pending TEP rate case in Docket No. E01933A-12-0291.

Q. How will the LFCR work?

A. The LFCR POA is attached as **Exhibit CAJ-5**. The POA presents the detail of how the LFCR works. In summary, the LFCR works as follows:

1. Quantify the lost level of kWh sales by class from EE programs;

2. Quantify the lost level of kWh sales by class from DG and net metering programs;
3. Adjust for any residential customers who have chosen to contribute to the lost margins in the form of a fixed option;
4. Price the lost kWh sales in each class by the tail block margin rate if no Demand Charge is in place for that rate class, or the per kWh rate plus one half of the value of the Demand Charges for the class if Demand Charges are in place for that class;
5. Compare the total dollars recovered from the last year based on actual sales and determine if any over or under-collection has occurred;
6. Add any carry over from the prior year (amount the prior year's year-over-year increase was in excess of 2% of total revenues) and any over- or under-collection from the prior year;
7. Compare this total to the total estimated retail revenues for the Company;
8. Carry-over any amount the year-over-year increase amount is in excess of 2%;
9. Add in the prior year's allowed amount to the allowed amount for the current year and divide this amount by the forecasted total sales for the Company to determine the per kWh rate applicable for the subsequent year; and
10. Submit these calculations and the proposed tariffs to the Commission by May 15 of each year for an anticipated effective date of July 1.

Q. What time period is UNS Electric proposing regarding review of the LFCR charge each year?

A. The time period reviewed will be the most recent calendar year and a filing will be made annually on May 15 with a proposed July 1 effective date.

Q. Will there be a cap on the amount recovered through the LFCR each year?

A. Yes. In order to ensure rate predictability, the proposal includes an annual 2% year-over-year cap based on total Company revenues that will be applied to the adjustment. Any amount in excess of the 2% year-over-year cap will be deferred (with interest) for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 2% cap. The Company intends to calculate a per kWh rate that will be applied to all customer classes as an energy rate. Since the EE and DG related losses are cumulative, the prior year's accumulated losses will be added to the current year's allowed losses (amount not in excess of 2% year-over-year cap) for purposes of determining the allowed kWh rate. But no individual year's increase will exceed 2%.[3]

Q. Is there an option for residential customers to choose to contribute to the LFCR in the form of a fixed charge instead of the volumetric rate?

A. Residential customers will have the option of choosing between the volumetric recovery of the adjustment or a fixed charge per month, similar to the APS and UNS Gas mechanisms. This was referred to in those cases as an "opt out" provision. The customer choosing this option can elect to contribute through an optional customer charge. The residential rate tariffs reflect the proposed fixed charges. The Company also proposes to offer residential customers a fixed option of contributing to the LFCR. This fixed option is set at a fixed incremental increase to the monthly charge of $2.50 in months where usage is less than 2,000 kWh and will be an incremental increase of $6.50 for months when usage exceeds 2,000 kWh.

[3] The 2% cap may need to be exceeded in the initial recovery period, which includes lost revenues beginning on July1, 2012, as explained in my testimony below and in the LCFR POA.

Q. How do you propose to calculate the lost margins to be recovered in the LFCR?

A. For lost revenues resulting from EE Rules compliance, the Company will be proposing to utilize the Measurement, Evaluation and Research ("MER") generated in the annual DSM/EE filing as the source for identifying EE-related lost revenues to be recovered through the LFCR for EE. The DG-related losses will be quantified based on actual measured or estimated data for each class. Those figures will be combined to determine each year's lost revenue. As set forth in the LFCR POA, when the report is issued with the DSM/EE filing, the kWh identified as lost as the result of the effective implementation of the EE programs will be quantified for each rate class.

For lost revenues related to the REST DG requirements, actual kWh utilized by customer-installed DG and net metering equipment will be quantified by class. For classes without a demand rate, the lost margins will be quantified using the per-unit kWh tail-block rate for classes with blocked rates, at the per-kWh rate for classes without block rates and no demand rate and priced at the average rate plus the lost kW times 50% of the demand rate for those classes with a demand rate.

Q. Will the LFCR result in large surcharges to customers?

A. No. First, the annual 2% year-over-year cap reduces the impact of the LFCR on the customer. Any incremental adjustments resulting from revenue decoupling will be relatively small and will be reset during each rate case. This concept was discussed thoroughly at the Commission's decoupling workshops and was addressed in the conclusions expressed by Pamela G. Lesh in her comprehensive review of decoupling mechanisms.[4] Her conclusion was that "decoupling adjustments tend to be small, even miniscule." Our proposed increase to the fixed customer charges will also reduce the total dollars subject to adjustment in the LFCR.

[4] See Pamela G. Lesh, Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling, A Comprehensive Review (2009).

Although UNS Electric anticipates any LFCR-related adjustments to be small, as mentioned above, we are proposing an annual year-over-year cap of 2% of total revenues to provide for such predictability.

Q. What time period are you proposing to include in the initial LFCR adjustment?

A. To avoid the loss of margin associated with the current EE and DG programs, the Company is proposing that the calculations associated with this adjustment start immediately after the end of the test year, or July 1, 2012. The annualized and normalized level of sales used to generate the billing determinants in this case will adjust forward sales once the new rates become effective. Unless the lost revenues are tracked from the end of the test year, all margin lost as the result of current EE and DG programs will be lost forever and the utility will be denied the opportunity to earn its authorized return due to the mandates of the Commission. Such a result is not only inequitable, but results in revenue confiscation despite UNS Electric promoting EE programs in good faith but with the understanding that it would receive some opportunity to recover lost revenues. Starting with the end of the test year instead of the effective date of the rates approved in this case resolves both of these issues. Therefore, the first LFCR filing will include the quantification of the margin lost for the last six months of 2012 and all of 2013 and include that lost margin in the first LFCR filing, which is anticipated to be filed in May 2014.[5]

Q. Will the first LFCR adjustment result in a large surcharge to the customers?

A. No. The Company has estimated the lost margin directly attributable to EE and REST compliance for 2012 and 2013 to be approximately $2.5 million. Based on this lost margin amount and an estimated 1,740.6 MWh of annual sales, the LFCR results in an

[5] Again, this initial recovery period may produce a result that would exceed the 2% cap since it is more than a 12-month period and UNS Electric is requesting a waiver of the cap only in this instance.

estimated $0.001426 per kWh LFCR adjustment effective July 1, 2014. That adjustment covers one and one half years of lost revenues (assuming a January 1, 2014 effective date and a June 30, 2012 test year.) If just the year 2013 was calculated, the incremental rate would be $0.000585 per kWh, which would be less than the 2% cap, based on the $169.7 million of retail revenues requested by the Company in this proceeding. Please refer to **Exhibit CAJ-5** for the details of how the calculation has been performed and for an estimate of what future LFCR calculations might generate as an adjustment. The numbers in this document would be replaced with actual data once that data is available. This Exhibit is for informational purposes and is designed to provide a clear example of how the Company intends to make the calculations.

B. <u>Transmission Cost Adjustor.</u>

Q. You mentioned earlier in your testimony that you would be sponsoring the POA for the TCA which you have attached as Exhibit CAJ-6. Would you explain your exhibit?

A. Yes. My **Exhibit CAJ-6** is the POA that will be used to guide the Company in preparing its TCA filing. Under UNS Electric's OATT the formula rate provides for changes on an annual basis. Accordingly, the TCA will be used to recover those annual formula rate changes, which are outside of the Company's control. The attached exhibit describes what transmission costs will be included in the annual TCA calculation and what the timing and calculation process will be under the Company's proposal.

IX. CARES RATES.

Q. What concerns does the Company currently have with its existing CARES rates?

A. The Company's low income rates are referred to as CARES rates. The Company proposes to simplify the CARES rate by offering a single uniform discount. The modifications would reduce the two existing tariffs which contains six multi-leveled percentage discount variations and two fixed discount variations of CARES rates down to a single tariff with a flat $13.00 per month discount (limited to a reduction of the bill down to zero dollars.) UNS Electric also proposes to eliminate the exclusion of CARES rates from the DSM surcharges. Under the Company's proposal there will be no separate rate for low-income medical customers. They will receive the same discount as all other low-income customers.

Although the Company supports creating a way for customers in need of assistance to receive a discount on their bills, the existing design is overly burdensome and bears no resemblance to cost based rate design. Not only do UNS Electric's other customers have to pay for the subsidies created by these options, they also have to pay for the cost of administration. In fact, the complexities associated with the existing rates results in additional cost to serve these CARES customers. This is not fair to the remaining customers. Therefore, UNS Electric proposes to simplify and consolidate the existing CARES options. But because the costs to serve these customers are no less than the cost to serve an average residential customer, the Company's proposed CARES rate design also more accurately reflects the actual cost to serve customers, while reducing the administrative costs to implement CARES.

Q. Please describe the current CARES rate structures.

A. The currently available CARES options establish two types of customers. Both receive a reduction to the Customer Charge, when compared to residential customers. The CARES Customer Charge is discounted from $8.00 to $3.50/month or 56% on a monthly basis. The customer receives an additional discount to the energy and base fuel charges (depending on a customer's usage) that varies from 10% to 30% as usage drops. The standard CARES customer sees the percentage discount drop from 30% to 10% as usage approaches 1,000 kWh. For the CARES-medical customer the discount drops from 30% to 10% as usage approaches 2,000 kWh. This discount to the volumetric charges is applied to per kWh rates that are already 3.7% below the standard residential rate. When the customer's consumption exceeds the 2,000 kWh or 1,000 kWh cap, they receive a flat $8.00 discount to their already discounted bill.

Additionally, a separate determination has to be made by the billing system to allow for the additional discounts associated with the Commission's decision to allow CARES customers to be exempt from paying the DSM charges. The combination of these rate concessions totaled $686,980 during the test year for 7,436 CARES customers as of the end of the test year.

Q. What is UNS Electric proposing in this rate case?

A. First, the Company is proposing to modify the CARES discounts. The CARES customers formerly on the CARES rate will become standard R-01 customers and pay standard R-01 rates except that a flat $13.00 per month discount will be applied to the bill (with the discount limited to no more than the actual bill in order to prevent a bill from being below zero).

Second, CARES customers will no longer be exempt from DSMS charges. With respect to the DSMS, there are no cost-based reasons to exempt them from DSMS charges. Moreover, this will also reduce the costs of testing and tracking this exemption - costs that are imposed on other customers

Third, all CARES customers will be subject to annual re-qualification at the Company's request. Although the Company can currently require this re-qualification, it is not always performed each year. Actively requiring this re-qualification will ensure that discounts are only provided to those most in need and reduce instances of fraud to protect the Company and the remaining customers.

Fourth, as is currently done, CARES rates will be limited to customers who qualify as below 150% of the federally-defined poverty level. However, CARES customers currently in the "medical" category will no longer be a distinct group and will receive the same discount as other CARES customers.

X. MISCELLANEOUS SERVICE FEES.

Q. Please describe the proposed changes in charges listed in Section 18 - "Statement of Additional Charges".

A. The Company has reviewed the costs associated with providing other miscellaneous services to customers. This is being done during the rate case so any change in revenues resulting from changes to the rates can be accurately reflected in the Company's total revenue requirement. UNS Electric has calculated updated charges after quantifying the actual costs of providing these services. These charges were then applied to the actual number of units of each service occurring in the test year. The result of the new miscellaneous charges will be an increase in revenues totaling $181,900. This

incremental increase will reduce the overall revenue requirement allocated to general rates based on the weighted proportion each rate class contributes to the total miscellaneous revenues. Please refer to attached **Exhibit CAJ-7** to see the specific charges.

Also, the miscellaneous service fees will no longer be found in UNS Electric's Rules and Regulations. Instead, these fees will be consolidated into one place and contained in UNS Electric's tariffs under a separate tariff called "Statement of Charges." Additionally, we are proposing to place the charges that would otherwise be reflected on the various Riders in this "Statement of Charges." We believe this change will make these charges easier to locate for customers.

XI. PROPOSED TARIFFS.

Q. What tariffs are UNS Electric proposing in this rate case?

A. The proposed rate-related tariffs are attached to my Direct Testimony as **Exhibit CAJ-8** (clean copy) and **Exhibit CAJ-9** (redlined copy). In addition to updated rates, the tariff sheets reflect a change in appearance due to our returning the sheet number and the sheet being cancelled to the header of all tariff sheets. We also made presentation changes to the footers of tariff sheets. The changes will make it easier for the Company and the Commission to keep track of any future revisions to the tariff and the sheet numbers and will make it easier to find specific portions of the tariff in the future. Other changes to the rate tariff and tariff sheets include the elimination of the TOU Super Peak rates, the PRS and QF rates and the addition of the LFCR, TCA and EE Resource Plan. We are also proposing to eliminate the GreenWatts schedule tariff. All other changes not specifically discussed earlier in my testimony are minor and are reflected as a redlined change in **Exhibit CAJ-9** referenced above.

XII. ELECTRIC LOAD CURTAILMENT TARIFF.

Q. Why has UNS Electric added an Electric Load Curtailment Tariff?

A. UNS Electric is adding an Electric Load Curtailment Tariff as a formality to comply with the Arizona Administrative Code R14-2-208.E. UNS Electric currently has a detailed Electric Load Curtailment Plan that has been filed with the Utilities Division Director annually, except in years where no updates have been made to the Plan. This Tariff serves as a general outline of the much larger, more detailed plan that is filed. There are no changes to UNS Electric's curtailment policy and filing this tariff has no affect on the policy.

XIII. ELIMINATION OR MODIFICATION OF CERTAIN COMPLIANCE FILINGS AND PROGRAMS.

Q. Is UNS Electric requesting any relief from certain existing compliance reporting requirements?

A. Yes, there are certain existing compliance reports for which UNS Electric requests either: (1) a complete waiver; or (2) modification of the reporting requirement. These reporting requirements are no longer necessary, as detailed below. However, they remain in the Commission's database until they are formally waived or otherwise removed by Order of the Commission.

Q. What reports are UNS Electric requesting to eliminate?

A. There is one report related to competition in Arizona that the Company is required to file on an annual basis. UNS Electric also requests the elimination of one monthly report.

Q. What reporting requirement is UNS Electric requesting that the Commission modify?

A. There is a semi-annual report for UNS Electric's CARES Tariffs. Because UNS Electric is proposing significant changes to its CARES Tariffs, UNS Electric would like to simplify its reporting.

A. <u>Request for Elimination of Reporting Requirements.</u>

Q. Why is UNS Electric requesting a waiver from the monthly filing known as the "Generation Mix Data Report"?

A. This filing is no longer necessary because it was ordered in Commission decisions issued almost 35 years ago – regarding the Commission's investigation regarding then-existing fuel and purchase power escalation clauses. In Decision No. 49333 (September 13, 1978) the Commission's sought to "develop a fuller understanding of the range of benefits and detriments, both real and potential, to the consumer, the utility, and the regulatory agency" of the fuel escalation clause. In Decision No. 49438 (October 25, 1978) the Commission ordered monthly filings of fuel costs, purchased power and use of generating facilities. Since that time, there have been several Commission orders prescribing very specific reporting requirements for UNS Electric and its current PPFAC, as well as for other utilities. The Commission has also ordered several provisions to protect customers including reporting requirements independent of those ordered in Decision No. 49438. For these reasons, the "Generation Mix Data Report" is redundant and unnecessary. Further, the issues that prompted the Commission to require the specific report in Decision No. 49438 no longer apply. Therefore, UNS Electric requests that the Commission waive this report entirely. The information provided in the report is provided in rate cases and all fuel information is reported in the monthly PPFAC report.

Q. Please explain the waiver request for the Competition Rules.

A. Due to the inactivity of the Electric Competition Rules (Arizona Administrative Code R14-2-1601 through R14-2-1618) and that UNS Electric's service area has never been open to competition; UNS Electric requests a waiver from the reporting requirements as codified at A.A.C. R14-2-1613(A) if and when retail electric competition manifests in Arizona.

B. <u>Request for Modification/Consolidation of Reporting Requirement.</u>

Q. Why is UNS Electric requesting to modify its "Customer Assistance Residential Energy Support Program ("CARES") Reporting requirement?

A. Decision No. 66861 (March 24, 2004) required UNS Gas to file semi-annual reports with the Commission on January 30 and July 30 each year that document CARES program participation levels. That order *only* applies to UNS Gas. By contrast, in Decision No. 67434 (December 2, 2004) the Commission ordered both UNS Gas and UNS Electric to file semi-annual reports – and requires that the reports list by month; (1) the number of participants; (2) the total amount of discounts; (3) the average amount of discount per customer; and (4) the amount of administrative expenses. Currently, the Commission's database lists this reporting requirement for UNS Electric and UNS Gas under both Decision Nos. 66861 and 67434.

The Company is currently filing these reports pursuant to Decision No. 67434; by contrast, Decision No. 66861 only applies to UNS Gas (as also stated in Decision No. 70029 (December 4, 2007) at Findings of Fact 5 through 7). Therefore, the Company requests that the Commission's database remove the reference to Decision No. 66861 regarding CARES reporting for UNS Electric.

Further, UNS Electric believes that CARES semi-annual reports required by Decision No. 67434 and as modified by Decision Nos. 70029, and 70360 (May 27, 2008) (requiring UNS Electric only, to separately report CARES-Medical participation) – should be consolidated and reported pursuant to the decision resulting from this case. This will make it easier for the Company to submit, and for Commission Staff to track, CARES participation if this rate decision superseded all other decisions regarding the CARES program.

Q. Why is UNS Electric requesting to modify its TOU Reporting requirements?

A. Pursuant to Decision No. 70440 (July 28, 2008) UNS Electric is required to file an annual report on TOU showing how many customers are taking service under the RES-01 TOU-A, SGS-10 TOU, LGS-TOU, LPS-TOU-N and IPS-TOU tariffs, how much those customers have saved relative to its non-TOU rates for the same class of service, and how these tariffs have provided a benefit to UNS Electric. This report is due annually, on February 15th for the previous calendar year's results. Decision No. 73583 (December 21, 2012) requires UNS Electric to provide an annual report on April 1st summarizing the subscription and savings of its TOU customers on the LGS-TOU-S and SGS-TOU-S rates. UNS Electric requests that these reporting requirements be consolidated into one report due February 15th – together with any reporting requirements and including any tariff changes stemming from this rate case regarding TOU.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

EXHIBIT

CAJ-1

ANNUAL BILL IMPACTS PROPOSED COMPARED TO CURRENT RATES

Line No.	Class Description	Customer Counts To-date 10/2012	New Summer A	Summer Change B	Total Summer Change C=(B*6)	New Winter D	Winter Change E	Total Winter Change F=(E*6)	Annual Bill G=(A*6+D*6)	Annual Bill Change H=(C+F)	Percent Change to Total Bill With Fuel Increase
1	Residential R-01	72,783	$100.72	$3.85	$23.09	$71.58	$3.44	$20.62	$1,033.82	$43.71	4.41%
2	Residential CARES	457	$87.72	$7.46	$44.78	$58.58	$3.28	$19.67	$877.82	$64.45	7.92%
1	Residential TOU R-01	153	$107.46	$11.46	$68.77	$58.43	($8.06)	($48.35)	$995.37	$20.42	2.09%
2	General Service GS-10	8,068	$137.23	$5.89	$35.34	$115.90	$5.33	$31.96	$1,518.81	$67.30	4.64%
3	General Service TOU	5	$184.81	$22.55	$135.30	$124.99	($6.86)	($41.19)	$1,858.78	$94.11	5.33%
4	Interruptible Service	39	$2,286.94	$123.29	$739.72	$1,908.79	$103.08	$618.45	$25,174.41	$1,358.17	5.70%
5	Large General Service	1801	$2,106.51	$100.90	$605.41	$1,695.21	$87.52	$525.12	$22,810.35	$1,130.53	5.21%
6	Large Power Service	16	$78,118.84	$3,725.64	$22,353.85	$70,053.70	$3,452.21	$20,713.24	$889,035.29	$43,067.09	5.09%
7	Large Power Service TOU	4	$181,159.69	$5,069.40	$30,416.42	$178,036.15	$13,499.15	$80,994.92	$2,155,175.06	$111,411.34	5.45%
8	Large Power Service Mining	2	$768,117.63	$29,764.57	$178,587.43	$489,347.58	$19,338.55	$116,031.27	$7,544,791.23	$294,618.70	4.06%
9	Lighting Service	25,720	$6.89	$0.42	$2.51	$6.89	$0.42	$2.51	$82.63	$5.02	6.47%
10	**Overall Percent Increase with TY Fuel Increase**			**4.64%**							

Line No.	Class Description	Customer Counts To-date 10/2012	New Summer A	Summer Change B	Total Summer Change C=(B*6)	New Winter D	Winter Change E	Total Winter Change F=(E*6)	Annual Bill G=(A*6+D*6)	Annual Bill Change H=(C+F)	Percent Change to Total Bill to Test Year Rates
11	Residential R-01	72,783	$100.72	$5.05	$30.29	$71.58	$4.28	$25.66	$1,033.82	$55.95	5.72%
12	Residential CARES $10		$87.72	$8.55	$51.27	$58.58	$4.03	$24.20	$877.82	$75.47	9.41%
13	Residential TOU R-01	153	$107.46	$12.66	$75.97	$58.43	($7.22)	($43.31)	$995.37	$32.66	3.39%
14	General Service GS-10	8,068	$137.23	$7.33	$43.98	$115.90	$6.53	$39.16	$1,518.81	$83.14	5.79%
15	General Service TOU	5	$184.81	$24.47	$146.82	$124.99	($5.18)	($31.11)	$1,858.78	$115.71	6.64%
16	Interruptible Service	39	$2,286.95	$159.28	$955.71	$1,908.79	$133.07	$798.42	$25,174.49	$1,754.13	7.49%
17	Large General Service	1801	$2,106.51	$130.90	$785.37	$1,695.21	$111.52	$669.10	$22,810.35	$1,454.47	6.81%
18	Large Power Service	16	$78,118.84	$4,865.43	$29,192.59	$70,053.70	$4,472.02	$26,832.11	$889,035.29	$56,024.70	6.73%
19	Large Power Service TOU	4	$181,159.69	$8,668.74	$52,012.43	$178,036.15	$17,098.49	$102,590.94	$2,155,175.06	$154,603.37	7.73%
20	Large Power Service Mining	2	$768,117.63	$42,962.14	$257,772.83	$489,347.58	$27,737.00	$166,421.98	$7,544,791.23	$424,194.81	5.96%
21	Lighting Service	25,720	$6.89	#DIV/0!	#DIV/0!	$6.89	#DIV/0!	#DIV/0!	$82.63	#DIV/0!	#DIV/0!
22	**Overall Percent Increase without TY Fuel Increase**			**6.00%**							

C:\Documents and Settings\mippolito\Local Settings\Temporary Internet Files\Content.Outlook\CFBMUHIS\[Exhibit CAJ-1 - Annual Bill Impacts.xls]BILL IMPACTS

EXHIBIT

CAJ-2

UNS Electric, Inc.
Purchased Power and Fuel Adjustment Clause
Plan of Administration

Table of Contents

1. General Description 1
2. Definitions 1
3. PPFAC Components 3
4. Calculation of the PPFAC 4
5. Filing and Procedural Deadlines 4
6. Verification and Audit 5
7. Schedules 5
8. Compliance Reports 6
9. Allowable Costs 7

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 UNS Electric, Inc. ("UNS Electric") in Decision No. 70360 (May 27, 2008) and amended by the Commission in Decision No. xxx. The PPFAC provides for the recovery of fuel and purchased power costs from the date of Decision No. xxx forward.

The PPFAC described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs incurred. 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.

Average System PPFAC Rate – The Average System PPFAC Rate is the sum of the True-Up Component and Estimated F&PP Costs divided by forecasted Retail Native Load Energy Sales for the forecasted PPFAC year.

Brokerage Fees – The costs attributable to the use of brokers recorded in Federal Energy Regulatory Commission ("FERC") Account 557.

Credit Support Costs – The costs of obtaining and maintaining credit with trade counterparties for the purchase of fuel and purchased power. Credit Support Costs include prepayments, cash escrow accounts and standby letters of credit.

Estimated Fuel and Purchased Power Costs ("Estimated F&PP Costs") – Forecasted Fuel and Purchased Power Costs and all Allowable Costs set forth in Section 9 of this POA.

Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by UNS Electric to serve both Native Load Energy Sales and Short Term Sales. Fuel and Purchased Power Costs include all Allowable Costs set forth in Section 10 of this Plan of Administration.

Fuel Imbalance Tracking Account – An account that records on a monthly basis under or over collections. The account balance at the end of the PPFAC Year will be included in the calculation of the Average System PPFAC Rate for the following PPFAC Year. UNS Electric files the balances and supporting details underlying this Account with the Commission on a monthly basis (Schedule 4).

Greenhouse Gas Costs – The cost of any greenhouse gas regulations or taxes associated with providing fuel or purchased power for Total Native Load Energy Sales and Short Term Sales. Greenhouse gas costs include: (1) costs of complying with EPA rules regulating greenhouse gases; (2) costs of complying with any other regulatory requirements regarding greenhouse

gases; (3) carbon taxes; and (4) costs of any "cap and trade" program, or other similar program, for greenhouse gases.

Native Load Energy Sales – Retail Native Load Energy Sales and Wholesale Native Load Energy Sales in the UNS Electric control area for which UNS Electric has a generation service obligation.

PPFAC - The Purchased Power and Fuel Adjustment Clause approved by the Commission in Decision No. 70360 and amended by the Commission in Decision No. xxxx, is a combination of two primary rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced. This PPFAC also provides for 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 June 1 and lasting through May 31 the following year.

Preference Power - Power allocated to UNS Electric wholesale customers by federal power agencies such as the Western Area Power Administration.

Retail Native Load Energy Sales – The portion of load from Native Load Energy Sales retail customers that are served by UNS Electric.

Short Term Sales – Wholesale sales with a duration of less than one-year made to non-Native Load customers for the purpose of optimizing the UNS Electric system, using UNS Electric-owned or contracted generation and purchased power.

Short Term Sales Revenue - The revenue recorded from Short Term wholesale sales made to non-Native Load customers, for the purpose of optimizing the UNS Electric system, using UNS Electric-owned or contracted generation and purchased power.

Transition Component – An inter-PPFAC year amount of under or over collected Fuel and Purchased Power costs, as reflected in the Fuel Imbalance Tracking Account.

True-Up Component Tracking Account - Account that records on a monthly basis the account balance to be collected via the True-Up Component rate as compared to the actual Transition Component revenues, plus applicable interest. UNS Electric files the balances and supporting details underlying this account with the Commission on a monthly basis.

True-Up Component - An amount that is updated annually on June 1 of each year and effective with the first billing cycle in June. 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.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of UNS Electric's electricity over transmission facilities owned by others.

3. PPFAC COMPONENTS

On or before December 31 of each year, UNS Electric will submit an Average System PPFAC Rate filing, which shall include a proposed calculation of the components for the PPFAC Rate. This filing shall be accompanied by supporting information as Staff determines to be required. UNS Electric will supplement this filing with a True-Up Component filing on or before April 1 in order to replace estimated balances with actual balances, as explained below.

A. Estimated F&PP Cost Component

The Estimated F&PP Cost Component is intended to reflect the expected Fuel and Purchased Power Costs for the upcoming PPFAC Year. UNS Electric will submit, on or before xxx of each year, a forecast for the upcoming PPFAC Year of its Fuel and Purchase Power Costs. It will also submit a forecast of kWh sales for the same PPFAC Year to produce the cents per kWh unit rate required to collect those costs over those sales during the year.

All revenues from Short Term Sales will be credited against total Fuel and Purchased Power Costs before the individual components are calculated. UNS Electric shall maintain and report monthly the balances in a Fuel Imbalance Tracking Account, which will record UNS Electric's over/under-recovery of its actual costs of Fuel and Purchased Power as compared to the Estimated F&PP Cost Component revenue. This Account will track the sales by individual PPFAC component but will be accumulated to a total Fuel and Purchased Power recovery amount. This amount will be compared to the total system actual costs for purposes of calculating the True-up Component. This Account will operate on a PPFAC Year basis (i.e. June 1 to the following May 31), and its balances will be used to administer this PPFAC's True-Up Component, which is described immediately below Applicable Interest is included in the Fuel Imbalance Tracking Account.

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 Fuel Imbalance Tracking Account (described above) during the previous PPFAC Year.

Each annual UNS Electric filing on December 31 will include an accumulation of Fuel Imbalance Tracking Account balances for the preceding June through November and an estimate of the balances for December through May (the remaining six months of the current PPFAC Year). The UNS Electric filing shall use these balances to calculate a preliminary Average System PPFAC Rate for the coming PPFAC Year. On or before April 1, UNS Electric will submit a supplemental filing that recalculates the Average System PPFAC Rate. This recalculation shall replace estimated monthly balances with those actual monthly balances that have become available since the December 31 filing.

The December 31 filing's use of estimated balances for December through May (with supporting workpapers) is required to allow the PPFAC review process to begin in a way that will support its completion and allow the new PPFAC rate to go into effect on June 1 unless otherwise ordered by the Commission. The April 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 April 1 update filing, UNS Electric monthly filings (for the months of November through February) of actual Fuel Imbalance Tracking Account balance information (replacing the estimated balances in the December 1 filing) will adjust the True-Up Component for the next PPFAC Year.

C. Transition Component Description

The Transition Component will be used as the method for incorporating any future, approved mid-year changes to the Average System PPFAC Rate. UNS Electric may request implementation when the Fuel Imbalance Tracking Account reaches over or under-recovery of at least $10 million. Such request shall include a calculation of a Transition Component rate based on forecasted costs and sales.

After the review of such request, the Commission may provide for the refund or collection of such balance over such period as the Commission determines appropriate. A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. The Transition Tracking Component Account will also include Applicable Interest as determined by the Commission. UNS Electric shall file the amounts and supporting calculations and workpapers for this account each month.

4. CALCULATION OF THE PPFAC RATE

The Average System PPFAC Rate will be designed for application to peak and off-peak usage as well as to specific customer classes. The PPFAC rates will be split into a peak and off-peak rate consistent with the method approved in Docket No. XXXXX and attached as Schedule 2. The PPFAC rate shall be applicable to UNS Electric's retail electric rate schedules. The PPFAC rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge.

The new PPFAC rates shall be reset on June 1 of each year, and shall be effective with the first June billing cycle unless otherwise ordered by the Commission. The tariff effective on June 1 of each year will reflect the individual seasonal, TOU and class specific rates calculated above. The PPFAC rates are not prorated.

5. FILING AND PROCEDURAL DEADLINES

A. December 31 Filing

UNS Electric shall file the PPFAC rate with all Component calculations for the PPFAC year beginning on the next June 1, including all supporting data, with the Commission on or before December 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 Estimated F&PP Costs. The filing will also include the True-Up Component calculation for the year beginning on the next June 1, with all supporting data.

Those calculations will use the same forecast of sales used for the Estimated F&PP Costs calculations.

B. April 1 Filing

UNS Electric will update the December 31 filing by April 1. This update will replace estimated Fuel Imbalance Tracking Account balances with actual balances and with more current estimates for those months (March, April, and May) for which actual data are not available. The new PPFAC rate will go into effect on June 1 unless otherwise ordered by the Commission.

C. Additional Filings

UNS Electric will also file with the Commission any additional information that the Commission Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PPFAC.

D. Review Process

Commission Staff and interested parties will have an opportunity to review the December 31 and April 1 forecast, balances, and supporting data on which the calculations of the two PPFAC components have been based. Any objections to the December 31 calculations must be filed within 45 days of the UNS Electric filing. Any objections to the April 1 calculations must be filed within 15 days of the UNS Electric 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 June 1).

7. SCHEDULES

Samples of the following schedules are attached to this Plan of Administration:

Schedule 1	PPFAC Rate Calculation
Schedule 2	PPFAC Rate Calculation by Customer Classification
Schedule 3	PPFAC Fuel Imbalance Tracking Account
Schedule 4	PPFAC Transition Component Tracking Account

8. COMPLIANCE REPORTS

UNS Electric shall provide monthly reports to Commission Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A UNS Electric 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. 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); Rate Calculation by Customer Classification (Schedule 2); Fuel Imbalance Tracking Account (Schedule 3) as well as the Transition Amount Tracking Account if applicable (Schedule 4). Additional information will provide other relative inputs and outputs such as:
    a. Total Fuel and Purchased Power Costs (including Brokerage Fees, Greenhouse Gas Costs, and Credit Support 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.

2. Identification of a contact person and phone number from UNS Electric for questions.

UNS Electric 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 and treated as confidentially protected information.

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. UNS Electric 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 Total Fuel and Purchased Power cost reflected in the non-confidential filing (Section 8.1.a).
   4. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Workpapers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under a fully executed protective agreement. UNS Electric 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

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 FERC accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- All other costs referenced as allowable costs in Section 8.1.a

These accounts are subject to change if the FERC alters its accounting requirements or definitions.

B. Other Allowable Costs

- None without preapproval from the Commission in an Order.

Schedule 1

Purchased Power and Fuel Adjustment Clause (PPFAC) Rate Calculation Proposed Filing

($ in Thousands)

Line No.	PPFAC Rate Calculation	Current Month/Day/Year
1	True-Up Component Amount From Prior Year 1	
2	Current year Fuel and Purchased Power Costs [2]	
3	Transition Amount [3]	
4	Forecasted Sales [4]	
5	Average PPFAC Rate $kWh (L1 + L2 + L3) / (L4)	

Notes:

[1] Prior Year True-Up Amount as approved on Month/Day/Year

[2] Current year Forecasted Fuel And Purchased Power Costs net of wholesale sales revue as submitted on Month/Day/Year

[3] Transition amount applicable if threshold is reached

[4] Forecasted Sales includes all rated classes

Schedule 2

PPFAC Rate Calculation By Customer Classification Proposed Filing

(Rates in $/kWh)

Line No.	PPFAC Forward Component Rate - Calculation	A Current	B Multiplier for System Average
1	Average PPFAC Rate $kWh [1]	$0.000000	
2	Standard fuel (Column A, line 1 x Column B, line 2)	$0.000000	1.129552
3	School Fuel Summer On-Peak (Column A, line 1 x Column B, line 3)	$0.000000	2.352918
4	Standard Fuel Summer On-Peak (Column A, line 1 x Column B, line 4)	$0.000000	1.958833
5	Standard Fuel Summer Off-Peak (Column A, line 1 x Column B, line 5)	$0.000000	0.900831
6	Standard Fuel Winter On-Peak (Column A, line 1 x Column B, line 6)	$0.000000	1.599150
7	Standard Fuel Winter Off-Peak (Column A, line 1 x Column B, line 7)	$0.000000	0.398338
8	Large General Service Standard (Column A, line 1 x Column B, line 8)	$0.000000	1.000000
9	Interruptible Standard (Column A, line 1 x Column B, line 9)	$0.000000	0.686896
10	Industrial Standard (Column A, line 1 x Column B, line 10)	$0.000000	0.690762
11	Industrial Fuel Summer On-Peak (Column A, line 1 x Column B, line 11)	$0.000000	1.168535
12	Industrial Fuel Summer Off-Peak (Column A, line 1 x Column B, line1 2)	$0.000000	0.433707
13	Industrial Fuel Winter On-Peak (Column A, line 1 x Column B, line 13)	$0.000000	1.168535
14	Industrial Fuel Winter Off-Peak (Column A, line 1 x Column B, line 14)	$0.000000	0.395632

Notes:

[1] Average PPFAC Rate calculated in Schedule 1

UNS Electric, Inc.
Schedule 3
Fuel Imbalance Tracking Account - PPFAC Rate in effect Month/Day/Year
($ in thousands; Rates in $/kWh)

Line			Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
1	Prior Month Balance													
Energy Sales														
2	Retail Native Load Energy Sales (MWh)													
3	Retail Native Load Energy Sales including losses (MWh)													
4	Long Term Energy Sales (MWh)													
5	Long Term Energy Sales including losses (MWh)													
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													
9	Short Term Sales Revenue Credit													
10	Wholesale Trading Activities Credit													
11	Credit Costs													
12	SO_2 Allowance Sales Credit [7]													
13	Net Fuel and Purchased Power Costs													
PPFAC Recovery														
14	PPFAC Retail Power Supply Costs													
15	PPFAC Recovery													
(Over) / Under Collections and Accrued Interest														
16	(Over)/Under Collections													
17	Interest [1]													
18														

		Jan 13 - Dec 13
19	Average PPFAC Rate - $ per kWh	$0.000000
20	Interest Rate [1] as of 1/2/2010	0.0000%

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

UNS Electric, Inc.
Schedule 4
Transition Component Tracking Account
($ in thousands; rate in $/kWh)

Line No.		Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
1	Beginning Transition Component Amount [1]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transition Component Rate ($/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	Retail Native Load Energy Sales (MWh) [2]	-	-	-	-	-	-	-	-	-	-	-	-
4	Transition Component Amount ($/kWh) (L1 x L2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Monthly Interest (Line1 * Int Rate/12) [3]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Ending Transition Component Amount; (L1 - L4 + L5)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

1 Transition Component Amount of $ ###,###,### approved for recovery on Month/Day/Year

2 Forecasted sales based on data submitted on Month/Day/Year

3 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 $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rates/kWh roundup to $0.000000/kWh

EXHIBIT

CAJ-3

UNS ELECTRIC
TEST PERIOD ENDING JUNE 30, 2012
PURCHASE POWER & FUEL CHARGES

Exhibit CAJ-3

Test Year Fuel Cost ($000)	**$90,058**
Test Year Adjusted Sales (kWh)	**1,740,589,963**
System Average Rate ($/kWh)	**$0.051740**

	Proposed Fuel Rates	Dollar Change from System Average	Multiplier to System Average
Standard Fuel	$0.058443	$0.006703	1.129552
School Fuel Summer On-Peak	$0.121740	$0.070000	2.352918
Standard Fuel Summer On-Peak	$0.101350	$0.049610	1.958833
Standard Fuel Summer Off-Peak	$0.046609	-$0.005131	0.900831
Standard Fuel Winter On-Peak	$0.082740	$0.031000	1.599150
Standard Fuel Winter Off-Peak	$0.020610	-$0.031130	0.398338
Large General Service Standard	$0.051740	$0.000000	1.000000
Interruptible Standard	$0.035540	-$0.016200	0.686896
Industrial Standard	$0.035740	-$0.016000	0.690762
Industrial Fuel Summer On-Peak	$0.060460	$0.008720	1.168535
Industrial Fuel Summer Off-Peak	$0.022440	-$0.029300	0.433707
Industrial Fuel Winter On-Peak	$0.060460	$0.008720	1.168535
Industrial Fuel Winter Off-Peak	$0.020470	-$0.031270	0.395632

Notes:

(1) Standard Fuel Rates Include: Residential Including CARES, Small General Service and Lighting.

(2) School Fuel Summer On-Peak includes Small and Large General Service.

(3) Standard TOU Rates include Residential, Small and Large General Service and Schools except for On-peak - see note 2.

(4) Industrial Standard includes Large Power Service and Mining

EXHIBIT

CAJ-4

UNS ELECTRIC, INC.
LOST FIXED COST RECOVERY MECHANISM ("LFCR")
PLAN OF ADMINISTRATION

Table of Contents

1. General Description 1
2. Definitions 1
3. LFCR Annual Incremental Cap 3
4. Filing and Procedural Deadlines 3
5. Compliance Reports 3

1. General Description

This document describes the plan of administration for the LFCR mechanism approved for UNS Electric, Inc. ("UNSE" or "Company") by the Arizona Corporation Commission ("ACC") on xxx xx, xxxx in Decision No. xxxxx. The LFCR mechanism provides for the recovery of lost fixed costs, as measured by a reduction in non-fuel revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the fixed cost portion exclusive of the Customer Charge, 50% of the demand rates in effect and purchased power and fuel for each of the applicable rate classes.

2. Definitions

Applicable Company Revenues - The amount of revenue generated by sales to retail customers, for all applicable rate schedules, less the amount attributable to sales to those residential customers who chose the Fixed Cost Option.

Current Period - The most recent adjustment year.

Demand Stability Factor – Fifty percent of Demand-based revenue (excluding any purchased power and fuel costs) produced by base rates.

Delivery Revenue - The amount of revenue determined at the conclusion of a rate case by multiplying each participating rate classes' adjusted test year billing determinants (kWh) by their approved fixed cost-related delivery charges as reduced by the customer charge, purchased power and fuel costs and 50% of any demand-based charges.

Distributed Generation ("DG") Savings – The amount of kWh sales reduced by DG. UNSE will use meter data for determining the kWh lost through the implementation of DG systems. Where the meter data is not available, the lost sales will be quantified using statistical verification, output profile or other Commission authorized methods as appropriate. Each year, UNSE will use actual data through December to calculate the savings. The calculation of DG savings will consist of the following by class:

1. Current Period: The annual energy production (kWh) produced by the cumulative total of DG installations since the end of the test year used in UNSE's most recent general rate case.

2. The only DG Savings that will be excluded from the calculated Lost Fixed Cost Revenue calculation are those kWh that were lost as the result of actions by customers in excluded rate classes or that chose the Fixed Cost Option.

Fixed Cost Option – The rate schedule choice for residential customers who prefer contributing to the recovery of Lost Fixed Cost Revenue in the form of an optional fixed rate added as an incremental charge to the Customer Charge in the applicable residential tariff rate. The total dollars paid as an incremental amount added to the otherwise effective Customer Charge will be accumulated over the Current Period and used to reduce the total Lost Fixed Cost Revenue recovered as part of the LFCR adjustment. The variable LFCR adjustment shall not be applied to residential customers who choose the Fixed Cost option. This rate will be reflected as an incremental addition to the customer charge on the otherwise effective tariff and made available to customers at the time of the first LFCR adjustment.

EE Programs - Any program approved in UNSE's Energy Efficiency/Demand Side Management ("EE/DSM") implementation plan or Energy Efficiency Resource Plan.

EE Savings - The amount of sales, expressed in kWh, reduced by Energy Efficiency activities as demonstrated by the Measurement, Evaluation, and Report ("MER") conducted for UNSE's EE Programs. Since this process will be a thorough review of the Company's EE activities and will determine the total kWh lost as a result of those activities, no further review by Staff will be necessary. However, as part of this filing the Commission Staff will have the option of reviewing any portion of the filing they deem necessary to verify the filings accuracy. EE Savings shall be quantified based on the accumulated lost kWh occurring since the end of the test year used in the rate case approving the initial implementation of the LFCR and shall be reset based on EE related losses as of the end of the test year in each subsequent rate case. The calculation of EE Savings will consist of the following by class:

1. Cumulative Verified: The cumulative total kWh reduction as determined by the MER using the end of the test year in UNSE's most recent general rate case as a starting point.
2. Current Period: The annual EE related sales reductions (kWh). Each year, UNSE will use actual MER data through December to calculate savings.
3. Excluded kWh reduction: The reduction of recoverable EE Savings calculated as follows: (1) for residential Fixed Option customers by, dividing the number of Fixed Option residential customers by the total number of residential customers and multiplying that result by Current Period Savings, and (2) for all other applicable rate schedules, by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules if included in the total reported in the annual EE/DSM filing.

Effective Period – The twelve month period beginning with July 1 of each year.

Excluded Rate Schedule - The LFCR mechanism shall not apply to the lighting rate class.

LFCR Adjustment - An amount calculated by dividing Lost Fixed Cost Revenue (As reduced by the total incremental fixed cost option dollars paid by the residential customers who have chosen the Fixed Cost Option and will be based on the incremental increase in the customer charge they have paid over the twelve-months during the Current Period.) by the total forecasted sales (less

the estimated sales to the residential customers who chose the Fixed Cost Option) during the Effective Period for the participating rate classes. This adjustment rate per kWh will be applied to all customer bills, excluding those on Excluded Rate Schedules.

Lost Fixed Cost Rate - A rate determined at the conclusion of a rate case by taking the sum of allowed Delivery Revenue (which excludes purchased power and fuel) for each rate class and dividing each by their respective class adjusted test year kWh billing determinants.

Lost Fixed Cost Revenue - The amount of fixed costs not recovered by the utility because of EE Savings and DG Savings during the measurement period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable kWh Savings, by rate class.

Prior Period - The twelve-months in the calendar year preceding the Current Period.

Recoverable kWh Savings - The sum of EE Savings and DG Savings by applicable rate class.

Total Fixed Revenue – The total Delivery Revenue (which excludes purchased power and fuel costs) by Rate Class.

True-up – All LFCR compliance filings submitted subsequent to the first one will contain a calculation of all the Lost Fixed Cost Revenue recovered based on the total kWh actually sold during the Effective Period and the LFCR rate in effect for that period. In the second filing the rate may have only been in effect for a partial year. If so, UNSE will only true-up the portion of the year that the rate was in effect through December 31 of that year. This calculation will quantify an over or under collection. This over or under collection will be included as an increase or decrease to the Lost Fixed Cost Revenue calculated for recovery during the subsequent Effective Period. In Effective Periods subsequent to the second year there will be two rates in effect during any calendar year and the actual recovery will be based on the kWh sold during the months each individual rate was in effect. This True-Up will be done to protect both the Company and the Customer from over or under collections of the Lost Fixed Cost Revenues.

3. *LFCR Annual Incremental Cap*

The LFCR Adjustment will be subject to an annual 2% year over year cap based on Applicable Company Revenues. If the annual incremental LFCR Adjustment results in a surcharge in excess of 2% of Applicable Company Revenues, any amount in excess of the 2% cap will be deferred for collection until the next year its inclusion does not result in the 2% year-over-year cap being exceeded. Any deferred amounts will be collected in a subsequent year or rolled into the next rate case, whichever occurs first. Where the 2% cap limits the recovery of deferrals in any program year, and thus moves their recovery to the following year, a first-in, first-out ("FIFO") approach will be applied. In connection therewith, the new surcharge billed in the following year will first recover any such carried-over deferrals, and then recover new deferrals arising in that following year. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

Since the initial LFCR filing will reconcile unrecovered lost revenues from the end of the test year through the end of 2013, it encompasses more than one year of lost revenues. Therefore, the initial LFCR will not be capped by the 2% limit, but all subsequent LFCR adjustments will be subject to the cap.

4. *Filing and Procedural Deadlines*

UNSE will file the calculated Annual LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by May 15th. Staff will use its best efforts to process the matter based on the results of the Company's annual EE/DSM and Renewable Energy Standard Tariff ("REST") filings such that a new LFCR adjustment may go into effect by July 1st of each year. However, the new LFCR Adjustment will not go into effect until approved by the Commission.

5. *Compliance Reports*

UNSE will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office by May 15th of each year. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1 : LFCR Annual Adjustment Rate in kWh
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: Delivery Revenue Calculation

EXHIBIT

CAJ-5

Estimated Lost Revenues Resulting from EE and DG Programs

Line No.		A Total LFCR $	B Incremental Lost Revenues	C % of Total Rev Assume $169.7 mil	D Total Accum lost revenues	E Incremental Recovery rate	F Accum Recovery rate per kWh
1	2011	$ 697,610					
2		$ 697,610					
3	2012	$ 1,672,829					
4		$ 975,220	$975,220	0.57%			
5	2013	$ 2,691,740					
6		$ 1,018,910	$1,018,910	0.60%	$2,481,740	$0.000585	$0.001426
7	2014	$ 3,925,156					
8		$ 1,089,986	$1,089,986	0.64%	$5,565,856	$0.000626	$0.003198
9	2015	$ 5,055,818					
10		$ 1,130,662	$1,130,662	0.67%	$9,780,634	$0.000650	$0.005619
11	2016	$ 6,244,474					
12		$ 1,188,656	$1,188,656	0.70%	$15,184,067	$0.000683	$0.008724

Note:

2013 recovery amounts do not include 2011 lost revenues or 1/2 of 2012 lost revenues, but the accumulated totals for future years do include revenues lost from equipment and activity experience in those periods.

EXHIBIT

CAJ-6

UNS Electric, Inc.
Transmission Cost Adjustor
Plan of Administration

Table of Contents

1. General Description 1
2. Calculations 1
3. Filing and Procedural Deadlines 2

1. GENERAL DESCRIPTION

The purpose of the Transmission Cost Adjustor ("TCA") is to provide a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission ("FERC") at the same time as new transmission rates become effective for UNS Electric, Inc. ("UNS Electric" or "Company") transmission customers. UNS Electric shall file a notice with Docket Control (the "Informational Filing") that includes its revised TCA based on the Company's updated transmission service rates, which are revised annually in accordance with the Company's Open Access Transmission Tariff ("OATT") (available on the FERC eTariff website at: http://etariff.ferc.gov/TariffBrowser.aspx?tid=1697). This notice shall be filed with the Commission on the date that the rate is adjusted in accordance with the provisions of the Company's OATT.

The TCA applies to all UNS Electric Retail Electric Rate Schedules. For Standard Offer customers that are not demand billed, the TCA is applied to the bill as a monthly kWh charge. For Standard Offer customers that are demand billed, the TCA is applied as a kW charge. The charge and modifications to it will take effect in first billing cycle after the date of the Informational Filing without proration.

UNS Electric's transmission service rates (the "Transmission Rates") are calculated annually in accordance with UNS Electric's formula rate. The formula rate calculation is specified within UNS Electric's OATT, as may be amended from time to time, as filed with and approved by FERC.

2. CALCULATIONS

The calculated Transmission Rates will be set forth in UNS Electric's Informational Filing. Transmission Rates are determined for the following classes:

Residential Service Customers
General Service Customers

In addition to the Transmission Rate, UNS Electric may charge retail customers for other transmission-related services ("ancillary services") in accordance with its OATT ("Ancillary Services Rates"). These additional ancillary services could include:

Scheduling System Control and Dispatch Service
Regulation and Frequency Response Service
Energy Imbalance Service
Operating Reserve – Spinning Reserve Service
Operating Reserve – Supplemental Reserve Service

The total UNS Electric OATT rate is the sum of providing Transmission Rates and Ancillary Service Rates. The revenue requirement resulting from the UNS Electric OATT rate are collected by UNS Electric from its retail customers, partly in base rates and the remaining through the TCA rate. The table below is an example of the TCA calculation using the UNS Electric OATT rate in effect as of December 31, 2012.

Line	Service Type		
		$/kWh	$/kW
		(A)	(B)
1.	Transmission Rate	$0.0059	$2.3022
2.	Scheduling	N/A	N/A
3.	Regulation and Frequency	N/A	N/A
4.	Energy Imbalance	N/A	N/A
5.	Spinning Reserve	N/A	N/A
6.	Supplemental Reserve	N/A	N/A
7.	Total	$0.0059	$2.3022
8.	Included in Retail Base Rates per OATT	$0.0059	$2.3022
9.	TCA (Line 7) – (Line 8)	$0.0000	$0.0000

UNS Electric's Transmission Rate shown on line 1 will change annually, whereas the Ancillary Rates shown on lines 2 through 6 will change only through a separate filing with FERC by UNS Electric.

3. *FILING AND PROCEDURAL DEADLINES*

UNS Electric will file the Informational Filing regarding the calculated TCA rates, including all supporting data, with the Commission on the date that the rate is adjusted in accordance with the provisions of the Company's OATT.

The new TCA rates proposed by UNS Electric shall be effective in first billing cycle after the date of the Informational Filing unless otherwise ordered by the Commission. The TCA rates are not prorated.

EXHIBIT

CAJ-7

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 801

Superseding:

UNS ELECTRIC STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Trip Charge: Service Establishment and Reestablishment During Regular Business Hours – service reads only Special Meter Reading fee Meter Change-Out fee Meter Re-Read	$26.00	PENDING	PENDING
Service Establishment and Reestablishment under usual operating procedures During Regulator Business Hours	$41.00	PENDING	PENDING
Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Single Phase Service	$137.00	PENDING	PENDING
Service Reestablishment under other than usual operating procedures	$150.00	PENDING	PENDING
Meter Test	$74.00	PENDING	PENDING
Returned Payment Fee	$10.00	PENDING	PENDING
Late Payment Finance Charge	1.5%	PENDING	PENDING

UniSource Energy SERVICES

UNS Electric, Inc.

Original Sheet No.: 801-1

Superseding:

UNS ELECTRIC, INC. STATEMENT OF CHARGES
(continued)

Description	Rate	Effective Date	Decision No.
Rider R-1 – Purchased Power and Fuel Adjustment Clause (PPFAC)[1]			
Non-Time-of-Use (TOU) Rates:			
Standard PPFAC	$0.XXXXX per kWh		
Large General Service Standard PPFAC	$0.XXXXX per kWh		
Interruptible Standard PPFAC	$0.XXXXX per kWh		
Industrial Standard PPFAC	$0.XXXXX per kWh		
Time-of-Use Rates:			
Summer		PENDING	PENDING
School On-Peak PPFAC	$0.XXXXX per kWh		
Standard On-Peak PPFAC	$0.XXXXX per kWh		
Standard Off-Peak PPFAC	$0.XXXXX per kWh		
Industrial On-Peak PPFAC	$0.XXXXX per kWh		
Industrial Off-Peak PPFAC	$0.XXXXX per kWh		
Winter			
Standard On-Peak PPFAC	$0.XXXXX per kWh		
Standard Off-Peak PPFAC	$0.XXXXX per kWh		
Industrial On-Peak PPFAC	$0.XXXXX per kWh		
Industrial Off-Peak PPFAC	$0.XXXXX per kWh		
[1]Notes:			
1) Standard Fuel Rates Include: Residential including CARES, Small General Service and Lighting.			
2) School Fuel Summer On-Peak Includes: Small and Large General Service.			
3) Standard TOU Rates Includes: Residential, Small and Large General Service and Schools except for On-Peak – See Note 2.			
4) Industrial Standard Include: Large Power Service and Mining.			

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 801-2

Superseding:

Rider R-2 – Demand Side Management Surcharge (DSMS) Effective Date of Order – December 2014 January 2015 – December 2015 January 2016 – December 2016	 $0. XXXXX per kWh $0. XXXXX per kWh $0. XXXXX per kWh	PENDING	PENDING
Rider R-3 – Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS	$0.029003 per kWh	June 1, 2012	73159
Rider R-5 – Electric Service Solar Rider (Bright Arizona Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate SGS-10 Solar Block Energy Rate for Large General Service, Rate LGS	 $0.087445 per kWh $0.085495 per kWh $0.077991 per kWh	January 1, 2011	72034
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Monthly Cap For Residential customers: For Commercial customers: For Industrial customers: For Lighting (PSHL):	$0.008887 per kWh Monthly Cap $4.50 per month $150.00 per month $5,500.00 per month $135.00 per month	January 18, 2012	72738
Rider R-8 – Lost Fixed Cost Recovery (LFCR) Mechanism	$0.XXXXX per kWh	PENDING	PENDING
Rider R-9 – Transmission Cost Adjustor (TCA)	$0.XXXXX per kWh	PENDING	PENDING

EXHIBIT

CAJ-8

Residential Service (RES 01)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase and three-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:

Standard

Customer Charge and minimum bill	$10.50 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge with usage less than 2,000 kWh	$13.00 per month
Customer Charge with usage more than 2,000 kWh	$17.00 per month

Energy Charges (per kWh):

Description	Delivery Rate
First 400 kWh	$0.0214
All remaining kWh	$0.0387

The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC.

LOST FIXED COST RECOVERY (LFCR) – RIDER-8

For those Customers who choose not to participate in the volumetric recovery of lost revenues associated with the promotion of energy efficiency, a higher monthly Customer Charge will apply and the volumetric LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the volumetric LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period.

CUSTOMER ASSISTANCE RESIDENTIAL ENERGY SUPPORT (CARES) DISCOUNT

No CARES discount will be applied that will reduce the Customer's monthly bill to less than zero. All CARES Customers will receive a monthly discount of up to $13.00 if the Customer meets the qualification requirements.

TERMS AND CONDITIONS

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others. Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

METER OPT-OUT

If a Customer chooses to not benefit from the less expensive option of automated meter reading equipment the Customer may choose an analog meter as long as the obsolete technology is economically available as an option. This is the only rate class this option is available to (*i.e.* no Time-of-Use or CARES Rates). This option will result in a one-time meter change-out fee and a monthly special read fee as specified in UNS Electric Statement of Charges. The monthly fee will apply even if the Customer chooses to self-read.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	
Meter Services	$00.98 per month
Meter Reading	$02.49 per month
Billing & Collection	$05.13 per month
Customer Delivery	$01.90 per month
Total	**$10.50 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	
Meter Services	$00.98 per month
Meter Reading	$02.49 per month
Billing & Collection	$05.13 per month
Customer Delivery	$01.90 per month
LFCR	$02.50 per month
Total	**$13.00 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage more than 2,000 kWh	
Description	
Meter Services	$00.98 per month
Meter Reading	$02.49 per month
Billing & Collection	$05.13 per month
Customer Delivery	$01.90 per month
LFCR	$06.50 per month
Total	**$17.00 per month**

Energy Charge Components of Delivery Services (Unbundled) ($/kWh):

Component	Rate
Delivery Services- Energy 1st 400 kWhs	
Generation	$0.0077
Transmission	$0.0065
Local Delivery	$0.0072
Delivery Services - Energy All Additional kWhs	
Generation	$0.0010
Transmission	$0.0065
Local Delivery	$0.0312

Power Supply Charges (Unbundled) ($/kWh):

Component	Rate
PPFAC (see Rider-1 for current Rate)	Varies

Residential Service Time-of-Use (RES-01 TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:

Standard

Customer Charge and minimum bill	$12.50 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge with usage less than 2,000 kWh	$15.00 per month
Customer Charge with usage more than 2,000 kWh	$19.00 per month

Energy Charges (per kWh):

Description	Delivery Rate
First 400 kWh	$0.0214
All remaining kWh	$0.0387

The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC. The PPFAC Rate will reflect a different Rate for the on-peak and off-peak period.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 12:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER-8

For those Customers who choose not to participate in the volumetric recovery of lost revenues associated with the promotion of energy efficiency, a higher monthly Customer Charge will apply and the volumetric LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the volumetric LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period.

TERMS AND CONDITIONS

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others. Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	
Meter Services	$02.98 per month
Meter Reading	$02.49 per month
Billing & Collection	$05.13 per month
Customer Delivery	$01.90 per month
Total	**$12.50 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	
Meter Services	$02.98 per month
Meter Reading	$02.49 per month
Billing & Collection	$05.13 per month
Customer Delivery	$01.90 per month
LFCR	$02.50 per month
Total	**$15.00 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage more than 2,000 kWh	
Description	
Meter Services	$02.98 per month
Meter Reading	$02.49 per month
Billing & Collection	$05.13 per month
Customer Delivery	$01.90 per month
LFCR	$06.50 per month
Total	**$19.00 per month**

Energy Charge Components of Delivery Services (Unbundled) ($/kWh):

Component	Rate
Delivery Services- Energy 1st 400 kWhs	
Generation	$0.0077
Transmission	$0.0065
Local Delivery Energy	$0.0072
Delivery Services - Energy All Additional kWhs	
Generation	$0.0010
Transmission	$0.0065
Local Delivery Energy	$0.0312

Power Supply Charges (Unbundled) ($/kWh):

Component	Rate
PPFAC (see Rider-1 for current Rate)	Varies

Small General Service (SGS-10)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific Rates, when all energy is supplied at one point of delivery and through one metered service.

The supply of electric service under a residential Rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service Rate will be applied.

Only available to Customers with imputed demand less than 500 KW. However, service is available for customer-owned, operated, and maintained area, street, or stadium lighting, and for firm irrigation service with a maximum monthly demand less than 25 kW.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge: $14.50 per month

Energy Charges (per kWh):

Description	Delivery Rate
First 400 kWh	$0.0351
Between 401 kWh and 7,500 kWh	$0.0482
All remaining kWh	$0.0743

The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC.

TERMS AND CONDITIONS

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others. Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

PARTIAL REQUIREMENTS SERVICE (PRS)

A customer that would otherwise qualify for service under this tariff for their full requirements but desires to take partial requirements service may do so only under the conditions of the tariff herein plus the following conditions:

1. Must have a demand meter installed and operating before any partial requirements service will be allowed. This service also requires a dedicated telephone line that is to be installed and maintained by the Customer and at the Customer's expense. Any equipment necessary to provide partial requirement service that would not otherwise be necessary for full requirements service will meet all Company standards and will be installed at the customer's expense.
2. In additional to any other charges that may be included in this tariff, the customer will be charged a monthly demand charge of $15.29 per kW and kWh delivery charges effective for customers taking service to meet their full requirements.
3. The above demand charge will be applied to the Billing Demand in any month which will be the greater of (i) the maximum fifteen (15) minute demand in that month or (ii) the maximum fifteen (15) minute demand in the preceding 23 billing months, or (iii) the Minimum Contract Demand as set forth by mutual agreement. The Minimum Contract Demand shall be based on the measured kW output of each generating unit at the time of the start-up test.
4. For QF's or net metered customers only- Any buyback provision will be priced at the Market Cost of Comparable Conventional Generation (MCCCG) Calculation as applicable to Rider-4 in effect at the time the buyback occurred.
5. The Company may require a written contract and a minimum term of contract, at its discretion.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	
Meter Services	$01.47 per month
Meter Reading	$02.89 per month
Billing & Collection	$07.39 per month
Customer Delivery	$02.75 per month
Total	**$14.50 per month**

Energy Charge Components of Delivery Services (Unbundled) ($/kWh):

Component	Rate
Delivery Services- Energy 1st 400 kWh	
Generation	$0.0096
Transmission	$0.0062
Local Delivery	$0.0193
Delivery Services- Energy Between 401 kWh and 7,500 kWh	
Generation	$0.0010
Transmission	$0.0062
Local Delivery	$0.0410
Delivery Services - Energy All Additional kWh	
Generation	$0.0010
Transmission	$0.0062
Local Delivery Energy	$0.0671

Power Supply Charges (Unbundled) ($/kWh):

Component	Rate
PPFAC (see Rider-1 for current Rate)	Varies

Small General Service Time-of-Use (SGS-10 TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific Rates, when all energy is supplied at one point of delivery and through one metered service.

The supply of electric service under a residential Rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service Rate will be applied.

Only available to Customers with imputed demand less than 500 kW. However, service is available for customer-owned, operated, and maintained area, street, or stadium lighting, and for firm irrigation service with a maximum monthly demand less than 25 kW.

Service under this Rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge: $16.50 per month

Energy Charges (per kWh):

Description	Delivery Rate
First 400 kWh	$0.0351
Between 401 kWh and 7,500 kWh	$0.0482
All remaining kWh	$0.0743

The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC. The PPFAC Rate will reflect a different Rate for the on-peak and off-peak period.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 12:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TERMS AND CONDITIONS

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others. Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 202-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	
Meter Services	$03.47 per month
Meter Reading	$02.89 per month
Billing & Collection	$07.39 per month
Customer Delivery	$02.75 per month
Total	**$16.50 per month**

Energy Charge Components of Delivery Services (Unbundled) ($/kWh):

Component	**Rate**
Delivery Services- Energy 1st 400 kWh	
Generation	$0.0096
Transmission	$0.0062
Local Delivery Energy	$0.0193
Delivery Services- Energy Between 401 kWh and 7,500 kWh	
Generation	$0.0010
Transmission	$0.0062
Local Delivery Energy	$0.0410
Delivery Services - Energy All Additional kWh	
Generation	$0.0010
Transmission	$0.0062
Local Delivery Energy	$0.0671

Power Supply Charges (Unbundled) ($/kWh):

Component	**Rate**
PPFAC (see Rider-1 for current Rate)	Varies

Large General Service (LGS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$50.00 per month
Demand Charge:	$14.52 per kW
Energy Charge:	$0.0040 per kWh

The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC.

BILLING DEMAND
The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the billing period;
ii. the highest demand metered during the preceding eleven (11) months; or
iii. the contract capacity or 20 kW, whichever is higher.

TERMS AND CONDITIONS

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others. Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings. The rates contained in this Tariff are designed to reflect secondary service but primary service is available

PARTIAL REQUIREMENTS SERVICE (PRS)

A customer that would otherwise qualify for service under this tariff for their full requirements but desires to take partial requirements service may do so only under the conditions of the tariff herein plus the following conditions:

1. Must have a demand meter installed and operating before any partial requirements service will be allowed. This service also requires a dedicated telephone line that is to be installed and maintained by the Customer and at the Customer's expense. Any equipment necessary to provide partial requirement service that would not otherwise be necessary for full requirements service will meet all Company standards and will be installed at the customer's expense.
2. In additional to any other charges that may be included in this tariff, the customer will be charged a monthly demand charge of $14.52 per kW and a delivery charge of $0.0040 per kWh.
3. The above demand charge will be applied to the Billing Demand in any month which will be the greater of (i) the maximum fifteen (15) minute demand in that month or (ii) the maximum fifteen (15) minute demand in the preceding 23 billing months, or (iii) the Minimum Contract Demand as set forth by mutual agreement. The Minimum Contract Demand shall be based on the measured kW output of each generating unit at the time of the start-up test.
4. For QF's or net metered customers only- Any buyback provision will be priced at the Market Cost of Comparable Conventional Generation (MCCCG) Calculation as applicable to Rider-4 in effect at the time the buyback occurred.
5. The Company may require a written contract and a minimum term of contract, at its discretion.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	
Meter Services	$04.03 per month
Meter Reading	$18.39 per month
Billing & Collection	$20.11 per month
Customer Delivery	$07.47 per month
Total	**$50.00 per month**

Demand Charge ($/kW):

Component	Rate
Delivery Services- All kW	
Generation	$04.34
Transmission	$01.86
Local Delivery Energy	$08.32

Energy Charge Components of Delivery Services (Unbundled) ($/kWh):

Component	Rate
Delivery Services- All kWh	
Generation	$0.0010
Transmission	$0.0008
Local Delivery Energy	$0.0022

Power Supply Charges (Unbundled) ($/kWh):

Component	Rate
PPFAC (see Rider-1 for current Rate)	Varies

Large General Service Time-of-Use (LGS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

Service under this Rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$52.00 per month
Demand Charge:	$14.52 per kW
Energy Charge:	$0.0040 per kWh

The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC. The PPFAC Rate will reflect a different Rate for the on-peak and off-peak period.

BILLING DEMAND
The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period;
ii. one-half the highest measured fifteen minute integrated reading of the demand meter during the off-peak hours;
iii. the highest demand metered during the preceding eleven (11) months; or
iv. the contract capacity or 20 kW, whichever is higher.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 12:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TERMS AND CONDITIONS

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others. Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings. The rates contained in this Tariff are designed to reflect secondary service but primary service is available

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 205-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	
Meter Services	$06.03 per month
Meter Reading	$18.39 per month
Billing & Collection	$20.11 per month
Customer Delivery	$07.47 per month
Total	**$52.00 per month**

Demand Charge ($/kW)

Delivery Services- All kW	
Generation	$04.34
Transmission	$01.86
Local Delivery Energy	$08.32

Energy Charge Components of Delivery Services (Unbundled) ($/kWh):

Component	Rate
Delivery Services- All kWh	
Generation	$0.0010
Transmission	$0.0008
Local Delivery Energy	$0.0022

Power Supply Charges (Unbundled) ($/kWh):

Component	Rate
PPFAC (see Rider-1 for current Rate)	Varies

Large Power Service (LPS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$1,500.00 per month
Demand Charges:	
Demand Charge (<69 kV Service)	$24.37 per kW per month
Demand Charge (≥69 kV Service)	$18.37 per kW per month
Energy Charge:	$0.0004 per kWh

The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC.

A credit of three percent (3%) will be applied to the demand charge if the Customer receives Distribution Service at primary voltage.

In the event a Customer achieves permanent, verifiable demand reduction through involvement in UNS Electric's Demand-Side Management (DSM) programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

BILLING DEMAND
The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period;
ii. the highest demand metered during the preceding eleven (11) months; or
iii. the contract capacity or 500 kW, whichever is higher.

POWER FACTOR ADJUSTMENT

(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR

1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.
2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

TERMS AND CONDITIONS

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others. Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings. The rates contained in this Tariff are designed to reflect secondary service but primary service is available

PARTIAL REQUIREMENTS SERVICE (PRS) – LPS

A customer that would otherwise qualify for service under this tariff for their full requirements but desires to take partial requirements service may do so only under the conditions of the tariff herein plus the following conditions:

1. Must have a demand meter installed and operating before any partial requirements service will be allowed. This service also requires a dedicated telephone line that is to be installed and maintained by the Customer and at the Customer's expense. Any equipment necessary to provide partial requirement service that would not otherwise be necessary for full requirements service will meet all Company standards and will be installed at the customer's expense.
2. In additional to any other charges that may be included in this tariff, the customer will be charged a monthly demand charge of $24.37 per kW and a delivery charge of $0.0004 per kWh.
3. The above demand charge will be applied to the Billing Demand in any month which will be the greater of (i) the maximum fifteen (15) minute demand in that month or (ii) the maximum fifteen (15) minute demand in the preceding 23 billing months, or (iii) the Minimum Contract Demand as set forth by mutual agreement. The Minimum Contract Demand shall be based on the measured kW output of each generating unit at the time of the start-up test.
4. For QF's or net metered customers only- Any buyback provision will be priced at the Market Cost of Comparable Conventional Generation (MCCCG) Calculation as applicable to Rider-4 in effect at the time the buyback occurred.
5. The Company may require a written contract and a minimum term of contract, at its discretion.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 301-4
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	
Meter Services	$159.46 per month
Meter Reading	$436.96 per month
Billing & Collection	$659.66 per month
Customer Delivery	$243.92 per month
Total	**$1,500.00 per month**

Demand Charge <69kW ($/kW)

Delivery Services- All kW	
Generation	$02.68
Transmission	$02.22
Local Delivery Energy	$19.46

Demand Charge ≥69kW ($/kW)

Delivery Services- All kW	
Generation	$02.68
Transmission	$02.22
Local Delivery Energy	$13.46

Energy Charge Components of Delivery Services (Unbundled) ($/kWh):

Component	Rate
Delivery Services- All kWh	
Generation	$.0001
Transmission	$.0002
Local Delivery Energy	$.0001

Power Supply Charges (Unbundled) ($/kWh):

Component	Rate
PPFAC (see Rider-1 for current Rate)	Varies

Large Power Service Time-of-Use (LPS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service.

CHARACTER OF SERVICE
The service shall be three-phase, 60 Hertz, and at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$1,500.00 per month
Demand Charges:	
Demand Charge (<69 kV Service)	$24.37 per kW per month
Demand Charge (≥69 kV Service)	$18.37 per kW per month
Energy Charge:	$0.0004 per kWh

The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC. The PPFAC Rate will reflect a different Rate for the on-peak and off-peak period.

A credit of three percent (3%) will be applied to the demand charge if the Customer receives Distribution Service at primary voltage.

In the event a Customer achieves permanent, verifiable demand reduction through involvement in UNS Electric's Demand-Side Management (DSM) programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period;
ii. one-half the highest measured fifteen minute integrated reading of the demand meter during the off-peak hours;
iii. the highest demand metered during the preceding eleven (11) months; or
iv. the contract capacity or 500 kW, whichever is higher.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 12:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

POWER FACTOR ADJUSTMENT

(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR

1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.
2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

TERMS AND CONDITIONS

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others. Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings. The rates contained in this Tariff are designed to reflect secondary service but primary service is available

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the Customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the Customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Customer Charge Components (Unbundled):

Description	
Meter Services	$159.46 per month
Meter Reading	$436.96 per month
Billing & Collection	$659.66 per month
Customer Delivery	$243.92 per month
Total	**$1,500.00 per month**

Demand Charge <69kW ($/kW)

Delivery Services- All kW	
Generation	$02.68
Transmission	$02.22
Local Delivery Energy	$19.46

Demand Charge >69kW ($/kW)

Delivery Services- All kW	
Generation	$02.68
Transmission	$02.22
Local Delivery Energy	$13.46

Energy Charge Components of Delivery Services (Unbundled) ($/kWh):

Component	Rate
Delivery Services- All kWh	
Generation	$.0001
Transmission	$.0002
Local Delivery Energy	$.0001

Power Supply Charges (Unbundled) ($/kWh):

Component	Rate
PPFAC (see Rider-1 for current Rate)	Varies

Lighting Service (LTG)

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
Applicable to any Customer for private and public street lighting or outdoor area lighting where this service can be supplied from existing facilities of the Company. The Company will install, own, operate, and maintain the complete lighting installation including lamp and globe replacements. Not applicable to resale service.

To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE
Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages. Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE– SUMMARY OF CUSTOMER AND ENERGY CHARGES:

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.00	$ 2.28
New 30' Wood Pole (Class 6)	$4.55	$ 7.02
New 30' Metal or Fiberglass	$9.10	$11.45

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.0588 per watt

Energy Charges:
The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC.

CONTRACT PERIOD
All lighting installations for public agencies will require an agreement for service.

All lighting installations for other than public agencies will require a contract for service as follows:

Three (3) years initial term for installations on existing facilities.

TERMS AND CONDITIONS

1. Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.
2. The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.
3. Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the Customer.
4. The Customer is expected to notify the Company when lamp outages occur.
5. The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.
6. The Company will require a non-refundable advance for the installation of new construction for facilities of $150.00.
7. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 501-3
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

New 30' Wood Pole (Class 6) - Overhead	
Billing and Collections	$1.61 per unit
Customer Delivery	$2.94 per unit
New 30' Metal or Fiberglass - Overhead	
Billing and Collections	$1.61 per unit
Customer Delivery	$7.49 per unit
Existing Wood Pole – Underground	
Billing and Collections	$1.61 per unit
Customer Delivery	$0.67 per unit
New 30' Wood Pole Class 6 – Underground	
Billing and Collections	$1.61 per unit
Customer Delivery	$5.41 per unit
New 30' Metal or Fiberglass – Underground	
Billing and Collections	$1.61 per unit
Customer Delivery	$9.84 per unit
Lighting Charge	
Production (not included in Power Supply)	$0.000280 per watt
Delivery	$0.058520 per watt

Interruptible Power Service (IPS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

Any new Customers taking service under this Rate must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

TRANSITION PERIOD
Customers taking service under this Rate prior to XXXXXX XX, 201X will be given twenty-four (24) months from XXXXX XX, 2013 (the date of the Rate Order) to furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station. After XXXXX XX, 2013, if the Customer has not installed this equipment, they will be placed on the otherwise applicable firm Rate.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the UNS Electric Engineering Department.

To any Customer with a minimum demand of 50 kW and is interruptible within ten (10) minutes of notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE
Service shall be three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES:

Customer Charge:	$18.00 per month
Demand Charge:	$7.37 per kW
Energy Charge:	$0.0199 per kWh

The Purchased Power and Fuel Adjustment Clause (PPFAC) is the sum of all purchased power and fuel cost on a per kWh charge. The per kWh charge will be updated annually in accordance with Rider-1-PPFAC.

PENALTY FOR FAILURE TO INTERRUPT:
In the event that the Customer fails to interrupt its load when requested to do so by the Company, the Customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $25.00
Unbundled $/kWh Charge is entirely a Delivery Charge

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm Rate for a period of at least twelve (12) months.

DETERMINATION OF BILLING DEMAND
The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

TERMS AND CONDITIONS
A late payment charge as stated in the Company's Rules and Regulations will be applied to account balances carried forward from prior billings.

The Company reserves the right to interrupt service to the Customer at any time.
Customers who qualify for service under this Rate must remain on the Rate for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Service hereunder shall require the Customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the Customer with as much advance notice as possible of the required interruptions. However, the Customer shall interrupt service within ten (10) minutes.

The Company reserves the right to have automatic equipment installed for immediate interruption of the Customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption of service under this Rate.

Standby, supplemental or breakdown service shall not be rendered under this Rate.

Service under this Rate is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Commission shall apply where not inconsistent with this Rate.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Description	
Meter Services	$01.18 per month
Meter Reading	$05.18 per month
Billing & Collection	$08.48 per month
Customer Delivery	$03.16 per month
Total	**$18.00 per month**

Demand Charge ($/kW) $7.37 per kW per month

Energy Charge Components of Delivery Services (Unbundled) ($/kWh):

Component	**Rate**
Delivery Services- All kWh	
Generation	$0.0010
Transmission	$0.0055
Local Delivery Energy	$0.0134

Power Supply Charges (Unbundled) ($/kWh):

Component	**Rate**
PPFAC (see Rider-1 for current Rate)	Varies

Rider R-1
Purchased Power Fuel Adjustor Clause (PPFAC)

APPLICABILITY
The Purchased Power and Fuel Adjustment Clause (PPFAC) will be applied to all customers taking Standard Offer service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No 70360 dated May 27, 2008 and as updated and defined in the Company's PPFAC Plan of Administration approved in ACC Decision No. XXXXX.

RATE
The Customer monthly bill shall consist of the applicable Rate charges and adjustments in addition to the PPFAC. The PPFAC adjustor rate, as shown in the UNS Electric Statement of Charges, is an amount expressed as a rate per kWh charge to reflect the cost to the Company for energy either generated or purchased.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider.

Rider R-2
Demand Side Management Surcharge (DSMS)

APPLICABILITY
The Demand Side Management Surcharge (DSMS) applies to all Customersin the entire territory served by the Company as mandated by the Arizona Corporation Commission (ACC), unless otherwise specified.

RATE
The DSMS shall be applied to all monthly bills. The rates for 2014, 2015 and 2016 are shown in the UNS Electric Statement of Charges.

REQUIREMENTS
The 2014 UNS Electric DSMS is effective XXXX, XX, 2014, and will remain in effect until December 31, 2014. The 2015 DSMS is effective January 1, 2015, and will remain in effect until December 31, 2015. The 2016 DSMS is effective January 1, 2016, and remain in effect until further order of the ACC.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company, and/or the price of, or revenue from, gas sales or service sold and/or the volume of gas sales generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file from time to time with the ACC shall apply where not inconsistent with this Rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 703
Superseding:

Rider-3
Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS

AVAILABILITY

The Market Cost of Comparable Conventional Generation (MCCCG) calculation, Rider-3, is restricted solely to Rider-4, Net Metering for Certain Partial Requirements Service (NM-PRS). If for a billing month a Rider-4 NM-PRS Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation as described in Rider-4 NM-PRS. The excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the positive balance of excess kWhs (if any) after netting against billing period usage. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of Rider-4 NM-PRS shall be the simple average of the hourly MCCCG as described below for the applicable year.

The Arizona Corporation Commission (ACC) provided guidance on defining MCCCG in the context of its REST Rules and identified the MCCCG as "the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal and long term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs." R14-2-1801.11.

CALCULATION/METHODOLOGY

For purposes of calculating credits to the Customer for Excess Generation, the unit price paid (Credit for Excess Generation) shall be the simple average of the MCCCG over the 8,760 hours (8,784 in a leap year) hours in the forecasted year. The MCCCG in each hour is based on whether native load requirements will be met by internally owned or contracted generation resources or if market purchases will be required to meet native load requirements. The following table provides a description of the MCCCG methodology. The hourly MCCCG cost determination criteria is based on the Market Condition and Dispatch Type. This method of cost determination is very data intensive and will be calculated annually by running UNS Electric's "Planning and Risk" modeling software, and the rate will be filed with the Commission by April 1 of each year and its applicability will coincide with the next Purchased Power and Fuel Adjustment Clause (PPFAC) rate effective period.

RATE

The Customer monthly bill shall consist of the applicable Rate charges and adjustments in addition to the Credit for Excess Generation based on the MCCCG. The MCCCG rate is an amount expressed as a rate per kWh charge that is approved by the ACC on or before June 1 of each year and effective with the first billing cycle in June, as shown in the UNS Electric Statement of Charges.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

MCCCG Cost Determination Matrix

Market Condition and Dispatch Type	Selling to Market from In House Real and Contracted Generation Sources	MCCCG Cost Based on Incremental Production/Purchase Cost of Base Load Generation for that hour
	No Market Transactions from/to In House and Contracted Generation Sources	
	Purchasing from Day Ahead Market, but not Spot Market, to meet Native Load Requirements	MCCCG Cost Based on Average Day Ahead Market Price of Purchased Power for that hour
	Purchasing from Spot Market to meet Native Load Requirements	MCCCG Cost Based on Average Spot Market Price of Purchased Power for that hour

Incremental Production / Purchase of Base Load - The cost of the next kWh (incremental) amount of load that has to be provided by UNS Electric generation sources and/or purchased power. This will be dependent on the season, month and time of day.

If Day Ahead Market or Spot Market purchases are being used to provide for reliability support capacity to meet native load requirements by freeing up in house or contracted generation resources for regulation or spinning reserve purposes for support of native load requirements, that would still represent a Market Purchase for purposes of determining which matrix box is applicable.

Rider-4
Net Metering for Certain
Partial Requirements Service (NM-PRS)

AVAILABILITY

Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources [1], a Fuel Cell [2] or Combined Heat and Power (CHP) [3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this Rate, the following notes and/or definitions apply:

[1] Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2] Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3] Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE

The service shall be single- or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE

Customer Charges shall be billed pursuant to the Customer's standard offer Rate otherwise applicable under full requirements of service.

Power sales and special services supplied by the Company to the Customer in order to meet the Customer's supplemental or interruptible electric requirements will be priced pursuant to the Customer's standard offer Rate otherwise applicable under full requirements service.

Non-Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is not a time-of-use rate, the Customer Supplied kWh shall be credited against the Company Supplied kWh. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is a time-of-use rate, the Customer Supplied kWh during on-peak hours shall be credited against the Company Supplied kWh during on-peak hours. All Customer Supplied kWh during off-peak hours shall be credited against the Company Supplied kWh during off-peak hours. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

EXCESS GENERATION

If for a billing month the Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation. That is, the excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Customers taking service under a time-of-use rate who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit in the next billing period for the on-peak, or off-peak periods in which the kWh were generated by the Customer. Time-of-Use Customer's taking service in the billing month of April shall receive a credit to summer on-peak and summer off-peak usage in the billing month of May for any winter on-peak and/or winter off-peak excess generation for April.

Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the balance of excess kWhs after netting. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of this Rate shall be the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) Rider-3 for the applicable year. The MCCCG, as it applies to this Rate, is specified in Rider-3 MCCCG - Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS (Net Metering for Certain Partial Requirements Service).

METERING

The Company will install a bi-directional meter at the point of delivery to the customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the customer to the metering to allow remote interegation of the meters at each site. If by mutal agreement between company and customer that a phone line is impractical or can not be provided - the customer will work with company to allow for the installation of equipment, on or with customer facilities or equipment to allow remote acces to each meter. Any additional cost of communication, such as but not limited too, cell phone service fees will be the responsibility of the customer.

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 705
Superseding:

Rider-5
Electric Service Solar Rider
(Bright Arizona Community Solar™)

APPLICABILITY

Rider-5 is for individually metered Customers who wish to participate in the Bright Arizona Community Solar Program. Under Rider-5, customers will be able to purchase blocks of electricity from solar generation sources. Participation in Rider-5 is limited in the Company's sole discretion to the amount of solar generation available and subscription will be made on a first come, first served basis. In order to maximize subscription under Rider-5, the Company may limit the amount of solar block energy purchased by individual Customers. Rider-5 is further restricted to Customers being served under one of the following Rates:

1. Residential Electric Service, Pricing Plan R-01(RES-TOU is not applicable)
2. Small General Service, Pricing Plan SGS-10 (SGS-TOU is not applicable)
3. Large General Service, Pricing Plan LGS (LGS-TOU is not applicable)

Customers being served under self-generation riders or plans may not purchase power under Rider-5 (including, but not limited to Net Metering for Certain Partial Requirements Service Rider-4 and Non-Firm Power Purchase from Renewable Energy Resources and Qualifying Cogeneration Facilities of 100 kilowatts (kW) or Less Capacity Rider-101).

RATE

Customers can contract for a portion or up to their average annual usage in solar blocks of 150 kilowatt hours (kWh) each. Transmission and distribution charges will be applied to all energy delivered, including energy delivered under Rider-5. The Customer is responsible for paying (each month) all charges incurred under their applicable rate schedule, and the total solar energy contracted for multiplied by the applicable solar block energy rate. Any demand based charges under the Customer's current Rate will not be affected by elections under Rider-5.

Period	Prior to October 1, 2013	Effective October 1, 2013
Rate Schedule	Solar Block Energy Rate	Solar Block Energy Rate
Residential Service R-01	$0.087445	XXXXX
General Service SGS-10	$0.085495	XXXXX
Large General Service-LGS	$0.077991	XXXXX

UNS ELECTRIC STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rate.

TAX CLAUSE

To the charges computed under the above Rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMS AND CONDITIONS

1. Customers may contract for a portion or up to their average annual usage in solar blocks of 150 kWh. If Customer's annual average usage is not available, UNS Electric will apply the appropriate class average. This limit can be reviewed annually at the request of the Customer.
2. Each solar block's energy rate will be maintained for twenty years from the date of purchase. For the purposes of the twenty year energy rate, solar blocks will be attributed to the Customer's original service address. Transfer of service under Rider-5 is prohibited. Should the Customer cancel service for any reason, his or her subscription under Rider-5 will expire.
3. Customers may add or delete solar blocks once within a twelve month period. Any addition of solar blocks will be at the then offered solar block energy rate.
4. Solar blocks will be applied to the actual energy usage each month. Electricity used in excess of the purchased solar blocks will be billed at the Customer's regular energy rate. If electricity usage is below the amount covered by the solar block(s), then the excess kWhs will be rolled forward and credited again the Customer's usage in the following month. The Customer will still be responsible for the full cost of the block(s) each month.
5. Customers will be credited for the balance of any excess kWhs annually, or on their final bill should the Customer terminate service under Rider-5. Each year, for the bills produced in October (September usage), UNS Electric will credit Customers their excess kWhs after netting and reset their balance to zero. Credit for excess kWhs will be at the energy rate of the oldest solar block.
6. All contracted solar block kWhs and associated charges in a billing month will be excluded from the calculation of PPFAC and REST charges and/or credits.

Rider-6
Renewable Energy Standard and Tariff (REST) Surcharge
REST-TS1 Renewable Energy Program Expense Recovery

APPLICABILITY
Mandatory, non-bypassable surcharge applied to all energy consumed by all Customers throughout Company's entire electric service area.

RATES
The REST shall be applied to all monthly bills. The REST rates are shown in the UNS Electric Statement of Charges.

Notes:

1. An industrial customer is one with monthly demand equal to or greater than 3,000 kW.
2. For non-metered services, the lesser of the load profile or otherwise estimated kWh required to provide the service in question, or the service's contract kWh shall be used in the calculation of the surcharge.

This charge will be a line item on customer bills reading "Renewable Energy Standard Tariff."

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rate.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Rider-7
Customer Self-Directed Renewable Energy Option
REST-TS2 Renewable Energy Standard Tariff

AVAILABILITY
Open to all Eligible Customers as defined at A.A.C. R14-02-1801.H.

APPLICABILITY
Any Eligible Customer that applies to the Company under this program and receives approval shall participate at its option.

PARTICIPATION PROCESS
An Eligible Customer seeking to participate shall submit to the Company a written application that describes the Distributed Renewable Energy (DRE) resources or facilities that it proposes to install and the estimated costs of the project. The Company shall have sixty (60) calendar days to evaluate and respond in writing to the Eligible Customer, either accepting or declining the project. If accepted, the Customer shall be reimbursed up to the actual dollar amounts of customer surcharge paid under the REST-TS1Tariff in any calendar year in which DRE facilities are installed as part of the accepted project. To qualify for such funds, the Customer shall provide at least half of the funding necessary to complete the project described in the accepted application, and shall provide the Company with sufficient and reasonable written documentation of the project's costs. Customer shall submit their application prior to May 1 of a given year to apply for funding in the following calendar year.

FACILITIES INSTALLED
The maintenance and repair of the facilities installed by a Customer under this program shall be the responsibility of the Customer following completion of the project. In order to be accepted by the Company for reimbursement purposes, the project shall, at a minimum, conform to the Company's System Qualification standards on file with the Commission. (REST Impolementation Plan, Renewable Energy Credit Purchase Program – RECPP, Distributed Generation Interconnection Requirements, Net Metering Tariff, Company's Interconnection Manual)

PAYMENTS AND CREDITS
All funds reimbursed by the Company to the Customer for installation of approved DRE facilities shall be paid on an annual basis no later than March 30th of each calendar year. All Renewable Energy Credits derived from a project, including generation and Extra Credit Multipliers, shall become the property of the Company and shall be applied towards the Company's Annual Renewable Energy Requirement as defined in A.A.C. R14-2-1801.B.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this Rate.

RELATED SCHEDULES

- REST-TS1 - Renewable Energy Program Expense Recovery

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 708
Superseding:

Rider R-8
Lost Fixed Cost Recovery (LFCR)

APPLICABILITY
The Lost Fixed Cost Recovery (LFCR) will be applied to all Customers taking service from the Company other than lighting and water pumping as defined in the Company's LFCR Plan of Administration (POA). As provided for in the POA, in the event a residential Customer chooses to contribute to this program by paying a fixed charge option, the monthly Customer Charge specified on the appropriate Standard Offer tariff will be charged in lieu of the per kWh rate shown in the UNS Electric. Statement of Charges.

CHANGE IN RATE
The LFCR recovers a portion of the authorized margin approved in the Company's most recent rate case that has been lost as the result of implementing Arizona CC-mandated Energy Efficiency and Distributed Generation programs. Each year, a per kWh charge will be placed in effect and charged to the participating Rate classes for the 12-month period the LFCR adjustment is applicable. The total year-on-year adjustment cannot exceed 2% of the Company's most recent total combined retail calendar year revenues for all participating Rate classes.

The LFCR adjustment shall be applied to all monthly bills as a per kWh charge and is anticipated to become effective on or around January 1, 2014.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rate.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 709
Superseding:

Rider R-9
Transmission Cost Adjustor (TCA)

APPLICABILITY
The Transmission Cost Adjustor (TCA) will be applied to all Customers taking service from the Company as defined in the Company's TCA Plan of Administration (POA).

CHANGE IN RATE
The TCA recovers the change in transmission costs resulting from the Federal Energy Regulatory Commission (FERC) approved formula rate that is updated annually in accordance with the provisions of the Company's Open Access Transmission Tariff (OATT), available through the FERC eTariff website at: http://etariff.ferc.gov/TariffBrowser.aspx?tid=1697. The adjustment captures the difference between the level of transmission costs approved in the Company's last rate case and the amount calculated based on the FERC-approved formula rate. The adjustment can be a charge or a credit and will be updated annually as of the date set forth in the OATT.

> The TCA shall apply to all monthly bills either as a per kWh charge or as a per kW rate, depending on the Customer's effective service tariff, and is anticipated to become effective on the date the TCA is updated.

UNS ELECTRIC STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the UNS Electric Statement of Charges which is available on UNS Electric's website at www.uesaz.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 802
Superseding:

Bill Estimation Methodologies

UNS Electric, Inc. (UNS Electric) regularly encounters situations in which UNS Electric cannot obtain a complete and valid meter read. No matter the cause of the need to estimate the read, the following methods are used depending on the circumstances.

PREVIOUS YEAR FORMULA

SAME CUSTOMER WITH AT LEAST ONE YEAR OF HISTORY

UNS Electric would generate a bill based on customer usage from the previous year using the "PREVIOUS YEAR" formula as follows:

LAST YEAR'S USAGE FOR SAME MONTH / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR "TIME OF USE" (TOU) THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

PREVIOUS MONTH FORMULA

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

UNS Electric would generate a bill based on customer usage from the previous month using the "PREVIOUS MONTH" formula as follows:

LAST MONTHS USAGE / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE x NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

TREND FORMULA

NEW CUSTOMER AT SAME PREMISE

UNS Electric would generate a bill using the "TREND" formula, based on customer's usage trend as described below:

UNS Electric's customer information system (CIS) would generate a bill based on trend. Customers are assigned to a Trend area which differentiate consumption based on different geographic areas. Secondly, the customer is assigned to a Trend class which is used to differentiate consumption trends based on the type of service and type of property. An example of this would be residential, commercial, and industrial usage. Thirdly, all consumption is identified using unit of measure code and a time of use code. Within UNS Electric's CIS, a trend record is created from each billed service. This record becomes part of a trend table. During estimation, consumption from three prior bill cycles is compared to the consumption from the same cycle in the previous month to determine a trend. This trend, plus a tolerance, is used to create a usage amount for bill estimation.

CUSTOMER'S USAGE IN PREVIOUS PERIOD/ AVERAGE CUSTOMER'S USAGE IN PREVIOUS PERIOD X AVERAGE CUSTOMER'S USAGE IN CURRENT PERIOD = ESTIMATED CONSUMPTION FOR REGISTER READ

NO HISTORY

UNS Electric would not generate a bill until a good meter read was acquired then use known consumption to estimate previous bills.

Demand Estimate

For accounts that have a demand billing component UNS Electric collects interval data. This interval data is used to manually estimate demands using the following methodologies:

SAME CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY
UNS Electric would generate a bill based on customer usage from the previous year using the following formula:

LAST YEAR'S DEMAND FOR SAME MONTH = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY
UNS Electric would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY
UNS Electric would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY
UNS Electric would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NO HISTORY
UNS Electric would not generate a bill until a good demand read was acquired then use known demand to estimate previous bills.

UniSourceEnergy SERVICES

UNS Electric, Inc.

Original Sheet No.: 803

Superseding:

GUIDELINES FOR ELECTRIC LOAD CURTAILMENT

INTRODUCTION

While UNS Electric, Inc. (UNS Electric) strives to provide an uninterrupted supply of electricity, conditions could exist on the UNS Electric electric power system where:

- The power supply would be insufficient to meet the electric load demands during peak period. This condition will be classified as a "Bulk Power Supply Emergency".
- The transmission delivery would be insufficient to meet electric load demands. This will be considered a "Transmission Emergency".

Should a "Bulk Power Supply Emergency" or a "Transmission Emergency" seem imminent the following steps will be implemented as appropriate.

1. Evaluate alternative power supplies or Company owned generation.
2. Call on Interruptible Customers to interrupt load.
3. Reschedule any scheduled maintenance of the transmission system.
4. Reduce all non-essential Company uses such as office lighting, electric cooling and heating, etc.
5. Contact Western Area Power Administration for possible assistance.
6. Contact Nevada Energy and Aha Macav Power Service for possible emergency assistance.
7. Reduce distribution feeder voltage up to 5%, where possible.

Should additional remedial action be warranted, UNS Electric will make a public appeal via local radio stations and television for the voluntary curtailment of electric consumption by its customers.

Should voluntary curtailment result in insufficient load reduction to mitigate the emergency, the Arizona Corporation Commission (ACC) has directed UNS Electric to institute mandatory involuntary curtailment, pursuant to ACC Decision No. 42097 and Arizona Administrative Code R14-2-208, Provision of Service, Paragraph E.

CUSTOMER LOAD DEFINITIONS

Essential Loads: Loads that are necessary to the health, safety and welfare of the public or some portion or member thereof, such as police, fire service, national defense, sewage facilities, domestic water facilities, hospitals, essential medical devices (such as iron lungs, oxygen pumps or similar uses) and where uninterrupted electric service is essential to the providing of such essential uses or services. These loads will not be interrupted unless an area needs to be dropped to maintain the stability of the electric system, or adequate on-site generation is available to cover the Essential load.

Critical Loads: That portion of the electric load of those non-residential customers which in the event of interruption of service would cause excessive damage to the equipment or material in process or perishable items or where such interruption would create grave hazards to the employee's or the public. These areas will not be interrupted unless an area needs to be dropped to maintain the stability of the electric system, or adequate on–site generation is available to cover the Critical load level.

Others: All customers not meeting the above definitions will be interrupted, with or without, notice if voluntary curtailment measures are not sufficient to alleviate the problem.

LOAD CURTAILMENT NOTIFICATION

UNS Electric's load is served primarily by Tucson Electric Power Company (TEP) under a Power Services Agreement. Energy from TEP resources is delivered to UNS Electric's load areas in Mohave and Santa Cruz Counties through the bulk power transmission system of the Western Area Power Administration (WAPA). UNS Electric's load is in the control area of TEP for Power Supply purposes and in WAPA's control area for Transmission purposes. Either control area could initiate a call for load curtailment due to a system or regional power supply or transmission emergency. Local Transmission Emergencies could occur, affecting portions of UNS Electric's service area only.

Should either voluntary or involuntary load curtailment become necessary:

1. UNS Electric's Mohave Dispatch Center will be notified of a regional curtailment emergency by either TEP's Energy Control Center or the WAPA's Transmission Dispatch Desk.

2. UNS Electric's Mohave Dispatch Center will notify Mohave Management of the nature and type of curtailment emergency.

3. Mohave Management will notify Company Management, District Operations Management and the ACC of the nature of the curtailment.

4. District Customer Service Personnel will, if time permits:

   - Notify Interruptible Customer to drop load;
   - Notify key customers of the nature of the curtailment and request voluntary load; reductions or activation of on-site generation (if any);
   - Call local radio stations to request public announcements;
   - Notify County Emergency Management, and;
   - Notify City and County Police and Fire Departments.

5. District Operations Personnel will notify supervisory and assigned staff to report to their respective duty stations.

VOLUNTARY LOAD CURTAILMENT

If conditions allow for advanced notification, UNS Electric shall evaluate activating its own generation and will ask the public for a voluntary curtailment. In addition, all Interruptible Customers and Large Load Customers will be called by pre-assigned individuals to request load interruption as provided for under the Tariff or voluntary load reduction where no tariff exists.

INVOLUNTARY LOAD CURTAILMENT

Should the voluntary curtailment result in an insufficient reduction in load, Division Operations Management will determine the amount of additional load to curtail. Blackout periods are to be approximately 30 to 60 minutes in duration.

After proper notification Division Operations Management will utilize the capabilities of the System Control and Data Acquisition System ("SCADA") and manual operation to shed load throughout the District operations areas (Kingman, Lake Havasu City and Santa Cruz) based on circuit classification, unless the emergency is of a local nature. Individual Distribution Circuits will be classified for curtailment, according to the type of customers served on that feeder, as defined in the Guide to Circuit Loading for each District.

DISTRIBUTION CIRCUIT CLASSIFICATIONS

Essential: Circuits that serve essential customers will be so identified and will not be interrupted, unless an area must be dropped to maintain electric system stability.

Critical: Circuits that serve critical customers will be so identified and will not be interrupted, unless an area must be dropped to maintain electric system stability. Critical Customers will be notified and required to curtail the non-critical portions of their load. If a customer with a critical load refuses or fails to curtail their electric consumption down to the critical load, the customer shall not be considered to have a critical load and can be curtailed 100%.

Large Load Customers:

1. Circuits that serve Large Load Customers will be so identified and will not be interrupted until proper notice is given, unless an area must be dropped to maintain electric system stability.

2. Customers who can take 100 percent curtailment, if given sufficient notice, will be rotated on the same schedule as the "Others" circuits until the emergency is terminated by UNS Electric.

3. Customers served by circuits that cannot be rotated* will be notified. They will be required to reduce their load to their pre-determined level, in a rotating order and with a frequency or repetition necessary to meet the emergency situation.

Others:

Circuits that serve all remaining customers will be so identified and rotated without notice. Rotation of these circuits will be for a duration and frequency necessary to meet the emergency situation.

Customers on a non-rotating circuit* who normally could be rotated, will be required to curtail load. If these customers do not curtail to the extent needed, UNS Electric may discontinue or disconnect service and refuse to re-establish service until after the emergency condition is terminated.

***Non-Rotating Circuits are so classified based on the specific nature of the electric distribution system or due to having critical or essential customers served by that feeder.**

EMERGENCY INVOLUNTARY CURTAILMENT

In the event a major electrical disturbance threatens the interconnected Southwest system with blackout conditions or/and unexpected shortages of power that do not allow for the implementation of the Electric Curtailment Plan, emergency devices such as under-frequency/under-voltage load shedding relays will automatically shed load to maintain system stability, and the Company will resort to emergency operating procedures. These circuits will remain out of service until the Company can move from the emergency procedure to the Electric Load Curtailment Plan or the emergency is resolved.

INVOLUNTARY CURTAILMENT BY TRANSMISSION PROVIDER

UNS Electric purchases transmission service from the WAPA to deliver its power supply requirements. WAPA's Transmission Dispatch Desk would notify the UNS Electric Arizona Dispatch Center of situations on the bulk transmission system requiring load curtailment in the Company's service area.

ELECTRIC LOAD AND CURTAILMENT PLAN

A detailed electric load and curtailment plan will be kept on file with the ACC. This plan will contain specific procedures for implementation of the above, along with the name(s) and telephone number(s) of the appropriate Company personnel to contact in the event implementation of the plan becomes necessary. Updates to the plan will be filed annually or when they occur. Its amendments will become effective upon submission to the ACC.

The Company will contact the Director of the Utilities Division, or their designee, as soon as practical for any curtailment pursuant to this Tariff.

Application

E-04204A-12-0504

Part 1 of 2

To review remaining parts please see the following:

Part 2 of 2 BARCODE # 0000141159