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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142 **NOTICE OF FILING REBUTTAL TESTIMONY**

UNS Electric, Inc., through undersigned counsel, submits the Rebuttal Testimony of David G. Hutchens, Kentton C. Grant, Ann E. Bulkley, David J. Lewis, Jason J. Rademacher, Michael E. Sheehan, Carmine Tilghman, Dallas J. Dukes, Craig A. Jones, H. Edwin Overcast and Denise A. Smith.

RESPECTFULLY SUBMITTED this 19th day of January 2016.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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

UNS ELECTRIC, INC.

REBUTTAL
TESTIMONY AND EXHIBITS

VOLUME 1 of 2

JANUARY 19, 2016

Rebuttal Testimony of
David G. Hutchens

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
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IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-15-0142

Rebuttal Testimony of

David G. Hutchens

on Behalf of

UNS Electric, Inc.

January 19, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is David G. Hutchens and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. How is your Rebuttal Testimony organized?

A. My testimony is organized as follows:

Section II. The Company's current position on three-part rates.
Section III. Response to Staff's Testimony.
Section IV. Limited response to RUCO's testimony.
Section V. Net metering proposal.
Section VI. The Company's current position on revenue requirement.
Section VII. Economic Development Rate.

II. THE COMPANY SUPPORTS THREE-PART RATES FOR ALL RESIDENTIAL AND SMALL GENERAL SERVICE CUSTOMERS.

Q. Briefly summarize the Company's current position on three-part rates.

A. In our Direct Testimony, the Company proposed (i) mandatory three-part rates for all residential and small commercial customers who installed distributed generation after June 1, 2015 (collectively, "New DG Customers") and (ii) optional three-part rates for non-DG residential and small general service customers.

As I describe later in my testimony, the Company now supports Staff's proposed migration of all residential and small general service ("SGS") customers to three-part rates.

Q. Why is the Company supporting three-part rates for all residential and SGS customers?

A. Simply stated, we need rates that reflect reality. Our current rates were designed for use in an earlier era with different technology, energy usage patterns, economic trends and public policy priorities. We need a sustainable rate structure that is well adapted to current conditions as well as the opportunities and challenges our industry will face going forward. We could try to achieve this objective through adjustments to our current two-part rates, such as higher basic service charges, minimum bills and declining block volumetric rates. But our proposed three-part rate represents a clear step forward to a more equitable, sustainable rate structure, and we support Staff's recommendation that we take that step now for all residential and SGS customers.

A Three-Part Rate Structure is a Sustainable Pricing Model.

Three-part rates (i) can be applied equitably to various types of customers with varying energy demands, (ii) encourage the adoption of emerging technologies such as energy storage and demand-based energy efficiency, and (iii) provide flexibility to meet future changes in the way customers use energy and access the grid. Over time, each component of the three-part rate can be modified to respond to changes in our customers' energy needs while sending more accurate cost-based price signals.

Three-part rates promote fairness and equity.

Three-part rates are fair in that they send accurate, cost-based price signals to all customers. Unlike two-part volumetric rates, three-part rates allow utilities to match the price they charge customers with the way the utility system must be built and maintained. Regardless of technology developments and changing usage patterns, a utility must have facilities in place to safely and reliably meet the maximum demand of every customer, 24 hours a day, 365 days a year. Even if a customer's maximum usage occurs only once or twice a year, we must have the resources in place to meet that demand. A demand charge, by definition, captures and appropriately allocates these infrastructure costs to customers more accurately than usage charges, thus mitigating inter- and intra-class subsidies.

Properly designed three-part rates will send accurate economic signals that promote more cost-effective energy options to all our customers, ultimately leading to more efficient use of the grid and energy resources.

Q. Please provide your general thoughts on the Intervenor rate design testimony filed in this proceeding as it relates to UNS Electric's proposals for three-part rates and net metering.

A. I am pleased that certain parties acknowledge the need to modernize UNS Electric's rate structure in light of our customers' evolving use of electricity and the grid. These parties include ACC Staff[1], RUCO[2], Arizona Investment Council ("AIC")[3] and Arizona Public Service ("APS").[4]

The testimonies filed by the Alliance for Solar Choice ("TASC"), Vote Solar and the Arizona Utility Ratepayer Alliance ("AURA") ignore the very real cost shift that is occurring between DG and non-DG customers. Their testimonies also failed to offer any alternatives to the Company's net metering proposal.

In this proceeding, the Company is attempting to modify its rates to (i) recover costs more equitably, (ii) provide flexibility to accommodate changing customer usage patterns, (iii) encourage the integration of new energy technologies into the electric system, (iv) promote the efficient use of the Company's electric system, and (v) ensure the continued provision of safe, reliable and affordable electric services for the benefit of all of our customers.

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[1] Direct Rate Design Testimony of Thomas M. Broderick ("Broderick"), Executive Summary.
[2] Direct Testimony of Lon Huber ("Huber"), page 10 lines 2-3.
[3] Direct Testimony of Daniel G. Hansen, page 20 lines 15-22, page 21 lines 1-5.
[4] Direct Testimony of AhmadFaruqui ("Faruqui") page 13 lines 21-27 page 14; Direct Testimony of Charles A. Miessner, page 4 lines 6-22.

III. RESPONSE TO STAFF'S TESTIMONY.

Q. Have you reviewed Staff's rate design testimony?

A. Yes, I have.

Q. Does the Company support Staff's rate design recommendation to migrate all of UNS Electric's residential and SGS customers to a new tariff that includes a demand charge?

A. Yes. If such rates are properly designed, the Company fully supports transitioning all of our residential and SGS customers to three-part rates.

Q. Did the Company consider a similar proposal in this proceeding?

A. Yes. The Company firmly believes that three-part rates provide fair and equitable price signals while offering the flexibility to meet our customers' evolving energy needs. We stopped short of proposing their mandatory use in part because, when we were preparing this rate filing in 2014 and 2015, the Company did not have the meters in place to implement three-part rates for all residential and SGS customers. With that in mind, we felt like our proposals in this case to (i) increase the basic service charge, (ii) eliminate the third tier in the Company's inclining block volumetric rate structure, (iii) implement three-part rates and a new net metering tariff for new DG customers, and (iv) make three-part rates optional for all customers, would represent progress toward the future introduction of three-part rates for all customers. Company witness Dallas Dukes alludes to this in his Direct Testimony.

> Although UNS Electric is proposing a three-part rate structure as an option, it is not proposing to require all residential and small commercial customers to migrate to a three-part rate structure... UNS Electric is

> requesting to begin moving toward a more balanced rate structure that would make such a move possible in the future.[5]

Q. What rationale does Staff provide for transitioning all residential and SGS customers to three-part rates?

A. Staff provides the following explanation for its recommendation regarding three-part rates.

> A three-part rate design better informs customers who are considering adopting new technologies, including DG, about the utility bill impact of their technology choices prior to purchase and installation. A three-part rate design makes significant progress toward addressing essentially all of the issues presented by the difficult transition underway to new DG technologies.
>
> A demand charge is a proven successful rate design component which better reflects cost causation than rate designs which rely upon energy charges only to recovery utility fixed costs. Metering and communications technology improvements, DG penetration, and recent regulatory issues have made its adoption for residential and small general service customers possible, appropriate, timely and even necessary.[6]

Q. Do you agree with Staff's rationale?

A. Yes, I do. The public interest is not well served by clinging to an outdated rate design that does not properly address changes in the industry and that results in inaccurate price signals and increasingly inequitable cost allocations. Properly designed three-part rates provide many benefits, ranging from charging customers more equitably for electric service to encouraging the integration of new technologies, as described by APS witness Ahmad Faruqui.

> Now is the time to take advantage of this opportunity to make cost-reflective three-part rates a standard offering for all residential customers. These rates will recover costs from customers in an equitable manner by more accurately charging customers for their use of the power grid. A more cost-reflective rate will also encourage the adoption of emerging

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[5] Direct Testimony of Dallas J. Dukes, page 18, lines 8-13.
[6] Broderick, page 2, lines 5-9 and 20-25.

> energy technologies and changes in energy consumption behavior that will lead to more efficient use of power grid infrastructure and resources.[7]
>
> Three-part rates will incentivize customers to smooth their energy consumption profile even if they are not equipped with enabling technologies. More than 40 pilot studies and full-scale rate deployments involving over 200 rate offerings over roughly the past dozen years have found that customers respond to new price signals by changing their energy consumption pattern. Further, there is some evidence that customers respond not just to changes in the rate structure generally, but specifically to demand charges.[8]

Q. Does the Company currently have the ability to meter demand for all non-DG customers?

A. No, but we expect to have demand meters installed for all residential and SGS customers by the end of 2016.

Q. Earlier you mentioned that the Company supports a plan to move all residential and SGS customers to three-part rates if these rates are "properly designed." Please elaborate.

A. Each component of a three-part rate must be cost-based and accurately reflect the expenses and investments associated with providing electric service to a customer.

- The monthly basic service charge should recover a certain level of fixed costs, such as the meter, service lines, customer service and billing functions, and minimum distribution system costs.
- The demand charge must reflect the cost of meeting a customer's peak electricity load over a specified period of time. Ideally, the demand charge would allow the utility to recover the related generation, distribution and transmission costs and investments necessary to satisfy a customer's demand on the system.

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[7] Faruqui, page 13 lines 21-27.
[8] Faruqui, page 14, lines 13-22.

- Finally, the volumetric energy component should be a pass-through of the utility's actual fuel and purchased power costs. Staff's proposed volumetric energy charge also includes a certain level of non-fuel revenue recovery.

Q. Does the Company agree with Staff's proposed basic service charge, demand charge and energy charge?

A. Staff's proposal to increase the residential basic service charge to $15 per month is a step in the right direction. It is important to note that our proposed $20 basic service charge is still far below the average cost to provide service to a residential customer. However, the Company is willing to accept Staff's proposed basic service charge if the Commission adopts an acceptable three-part rate structure for all customers. The Company reserves the right to maintain its original recommendation of $20 in the event the Commission approves the continuation of two-part rates.

We are generally in agreement with Staff's proposed demand and energy charges, with a few modifications that are described in the Rebuttal Testimonies of Dallas Dukes and Craig Jones.

Q. Is the Company recommending any safeguards to protect customers from unusually high bills once they are transitioned to demand-based rates?

A. Yes. During the transition period, the Company will put safeguards in place to promote a smooth transition and minimize any unintended consequences. Four important safeguards include (i) a proposed transition period that will provide the Company with ample time to analyze billing data and adjust rates as necessary to protect vulnerable customers (as discussed by Staff), (ii) a temporary relief valve mechanism to limit demand charge changes for low load factor customers to allow time to adapt to demand-based rates (as discussed in the Rebuttal Testimony of Company witness Dallas Dukes),

(iii) the measurement of customer demand over a one-hour period and (iv) making those measurements during the Company's peak usage periods. As our customers become accustomed to demand-based rates, we expect to phase out these safeguards as part of UNS Electric's next rate case. The Rebuttal Testimonies of Dallas Dukes and Craig Jones address this in more detail.

Q. Please describe the Company's plans to help customers understand three-part rates.

A. We take very seriously our duty and obligation to make sure our customers receive open and honest communication about their electric rates. The Company is developing a comprehensive customer outreach and education plan that will include many of the elements proposed by Staff, including:

- **Usage data.** We will provide customers with demand data for at least three months prior to implementing three-part rates. Such data will also be made available on an ongoing basis.[9]
- **Phase-in.** The Company believes the transition to new rates could begin as soon as the first quarter of 2017. While Staff suggests that the transition could be completed in phases[10], the Company is proposing to migrate all customers at the same time. In addition, we are recommending that the transition occur in February or March 2017.
- **Unintended consequences.** We support Staff's recommendation that the rate design portion of the case remain open for at least 18 months to monitor the transition and address problems as they occur.[11]

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[9] Direct Rate Design Testimony of Howard Solganick ("Solganick Rate"), page 13 lines 17-20, page 30 lines 17-26.

[10] Solganick Rate, page 13 lines 22-26, page 14 lines 103.

[11] Solganick Rate, page 14 lines 5-10.

- **Vulnerable customers.** We support Staff's position on vulnerable customers. Potentially vulnerable customers should self-identify; however, existing DG customers do not comprise a vulnerable group.[12]

Despite TASC's claim that the Company would not educate customers about three-part rates[13], we already are preparing a comprehensive plan to educate customers about all important rate and rate design changes that are approved by the Commission at the conclusion of this proceeding. We would also work closely with Commission Staff and other stakeholders in developing and implementing this plan. In my Direct Testimony in TEP's rate case, I stated the following:

> Equally important as getting the rate design right is promoting customer awareness. If mandatory three-part rates are applied to all residential customers, we, along with Commission Staff and other stakeholder groups, would need to conduct outreach to educate our customers about three-part rates. Any customer awareness efforts should include a phase-in or transitional period in order to provide for a smoother implementation of demand-based rates. A phase-in period should also include the ability to make revenue-neutral rate design changes to avoid unintended consequences.[14]

Needless to say, we hold an identical view for UNS Electric. Moreover, I strongly disagree with the intervenors who suggest that our customers will be unable to understand three part rates. Company witness Dallas Dukes discusses the guidelines of our transition plan in his Rebuttal Testimony.

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[12] Broderick, page 9, lines 14-23, page 10 lines 1-8.
[13] Direct Rate Design and Cost of Service Testimony of Mark Fulmer ("Fulmer"), Page 23, lines 1-7.
[14] Direct Testimony of David G. Hutchens in Docket No. E-01933A-15-0322 (filed November 5, 2015), page 19, lines 18-24).

Q. Does the Company support Staff's position that existing DG customers be transitioned to three-part rates?

A. Yes. Although the Company originally sought to exempt most existing DG customers from mandatory use of three-part rates, we recognize that doing so would preserve inaccurate price signals and lock in a cost-shift that increases rates for other customers. Approved changes in base rates and rate design are typically applied to all customers, including those with DG systems.

IV. RESPONSE TO RUCO'S TESTIMONY.

Q. Have you reviewed RUCO's rate design testimony?

A. Yes.

Q. Do you have any general comments on RUCO's testimony?

A. Yes. The Company opposes RUCO's recommendations to (i) keep the third tier in the Company's existing two-part residential rates and (ii) increase the residential basic service charge to just $12.26[15], which is far below the Company's and Staff's proposals. If the Commission decides to continue offering two-part volumetric rates to customers, it is critical that we address the Company's ability to recover its non-fuel revenues. As I stated in my Direct Testimony:

> …the "new normal" of flat or declining sales - resulting primarily from DG and EE - limits the Company's opportunity to recover its cost through rates that feature an inclining block structure. This problem is exacerbated by DG customers whose energy usage rarely reaches the upper tiers, thus shift fixed costs to other customers who use more energy. UNS Electric is proposing to eliminate certain upper tiers to reduce this cost shift and enhance the Company's ability to recover its fixed costs.[16]

[15] Huber, Exhibit 2 page 1.
[16] Hutchens, page 13 lines 1-7.

The Company's billing data provides perspective regarding the ongoing decline in residential use per customer. During 2014 (the test year used in this case), the Company issued more than 23,000 bills that reflected zero electric use.[17,18] This represents a 144% increase over zero-consumption bills issued during the previous test year (12 months ended June 30, 2012). Also during 2014, the Company issued over 14,000 bills to net metering customers, of which 57% reflect zero electric use.

We also oppose RUCO's recommendations regarding net metering and three-part rates. Please refer to the testimonies of Dallas Dukes, Carmine Tilghman and Craig Jones for more information.

V. <u>THE COMPANY'S NET METERING TARIFF SHOULD BE APPROVED IN THIS RATE CASE.</u>

Q. Briefly summarize the Company's proposed net metering tariff

A. Under UNS Electric's proposed Net Metering Tariff, new users of DG systems (i) would not be allowed to "bank" or carry-forward excess kilowatt-hours ("kWh") to offset future electricity consumption and (ii) would be compensated for excess energy at the Renewable Credit Rate.[19]

Q. Is the Company willing to consider other net metering proposals or alternative methodologies of valuing excess generation produced by DG customers?

A. Certainly. However, with the exception of RUCO, none of the other parties in this proceeding provided any new net metering proposals or alternatives in their testimony.

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[17] Schedule H-5, page 1 (filed May 4, 2015 with the Company's rate application).
[18] Of the 23,000 bills, over 8,000, or 35%, were issued to net metering customers.
[19] Equivalent to the most recent utility-scale renewable purchased power agreement connected to the distribution system of Tucson Electric Power.

Q. Is the current rate case proceeding the proper venue to approve a new net metering tariff?

A. Yes, without question. I would like to point out that UNS Electric and its sister company, TEP, filed applications in March 2015 to update their net metering tariffs.[20] Although both UNS Electric and TEP believe that the Commission can approve a net metering tariff outside of a rate case, several parties who are intervenors in this rate case, including TASC,[21] Vote Solar,[22] the Arizona Solar Deployment Alliance[23] and the Arizona Solar Energy Industry Association,[24] argued that a net metering tariff must be approved in a rate case.[25] Yet these parties have yet to offer any new net metering proposals in this docket.

While we understand Staff's desire to wait for the outcome of the Commission's investigation of the value and cost of DG (Docket No. E-00000J-14-0023),[26] this proceeding is the proper venue for approval of a new net metering tariff for UNS Electric. It is unclear when the value and cost of DG proceeding will conclude and what result it will ultimately produce. On the other hand, this rate proceeding will provide sufficient Company specific data and evidence to support the Commission's approval, modification or rejection of UNS Electric's proposed net metering tariff.

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[20] March 25, 2015, Docket No. E-04204A-15-0099 (UNS Electric) and Docket No. E-01933A-15-0100 (TEP).

[21] TASC brief (May 15, 2015, Docket No. E-01933A-15-0100), page 1 lines 23-24, page 4 lines 5-6.

[22] Vote Solar brief (May 15, 2015, Docket No. E-01933A-15-0100), page 1 lines 23-24, page 2 line 1, and lines 11-24.

[23] Arizona Solar Deployment Alliance brief (May 15, 2015, Docket No. E-01933A-15-0100) page 1 line 16.

[24] Arizona Solar Energy Industry Association brief (May 18, 2015, Docket No. E-01933A-15-0100) page 2 line 9.

[25] In light of the procedural posture in that docket, in June 2015, TEP withdrew its net metering application and accelerated the filing of its rate case (Notice of Withdrawal of Application filed June 19, 2015, Docket No. E-01933A-15-0100).

[26] Broderick, Executive Summary; Solganick Rate, page 45 lines 16-25.

Q. How would you respond to accusations that UNS Electric's proposed net metering tariff will "kill" solar in the Company's service territory?

A. Despite the doom and gloom predictions by TASC,[27] Vote Solar[28] and AURA,[29] DG installations have continued to increase in UNS Electric's service territory since the Company announced it would request changes to its net metering tariff. As described in the Direct Testimony of Dallas Dukes, new DG customers would still realize significant savings under the Company's proposed three-part rate structure and net metering tariff.

Q. Would you like to make any further comments on the third-part solar DG market?

A. Yes. In December 2015, Congress extended the solar investment tax credit to the end of 2021 thus preserving significant subsidies for the third-party solar DG market. The following are excerpts from a Wall Street Journal article from December 16, 2015.[30]

> U.S. home solar adoption has soared in recent years, thanks to heavy government underwriting and falling prices for solar equipment. So far this year nearly 1,500 megawatts of solar panels have been installed on 214,000 homes across the country, according to the Solar Energy Industries Association and GTM Research.
>
> Extending the tax credits would likely boost the amount of solar panels installed over the next five years by more than half, to 72,000 megawatts, GTM analysts predicted. That is enough power to serve nearly 12 million homes, according to SEIA.
>
> The nonpartisan Joint Committee on Taxation estimates that extending tax credits for wind power will cost taxpayers $14.5 billion, while continued solar tax credits will cost $9.3 billion.

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[27] Fulmer, page 17 lines 10-11.
[28] Direct Testimony of Briana Kobor ("Kobor"), page 5 lines 21-22.
[29] Rate Design Testimony of Thomas Alston ("Alston"), page 5 lines 2-3.
[30] http://www.wsj.com/articles/wind-solar-companies-get-boost-from-tax-credit-extension-1450311501

VI. THE COMPANY IS STIPULATING TO CERTAIN ELEMENTS OF STAFF'S PROPOSED NON-FUEL REVENUE INCREASE.

Q. Is the Company willing to stipulate to Staff's proposed non-fuel revenue increase?

A. Yes. The Company will stipulate to an $18.5 million increase to adjusted test-year non-fuel revenues, which reflects Staff's recommendation of an $18.1 million[31] base rate increase with some minor adjustments that are described in the Rebuttal Testimony of David Lewis. The primary difference between the Company's proposed non-fuel revenue increase of $22.6 million and Staff's recommended $18.1 million increase relates to return on equity and the return on the fair value increment. The Rebuttal Testimonies of Ann Bulkley and Kentton Grant provide further explanation regarding these differences.

VII. ECONOMIC DEVELOPMENT RATE.

Q. Briefly describe the Company's proposed Economic Development Rate ("EDR").

A. As a way to help promote economic development in the Company's service territories, UNS Electric proposed to offer discounted rates to new or existing large business customers that meet certain requirements, including a minimum load factor.

Q. Would you like to make any clarifying remarks about the Company's proposed EDR?

A. Yes. The testimonies of Staff,[32] RUCO,[33] NUCOR,[34] Walmart[35] and AIC[36] generally recognize the merits of UNS Electric's EDR; however, some of these parties express

[31] Staff's revenue requirement testimony, Direct Testimony of Donna Mullinax, page 8 line 12.
[32] Solganick Rate, page 52 lines 5-7.
[33] Huber, page 8, lines 20-23, page 9 lines 1-6.
[34] Direct Testimony of Dr. Jay Zarnikau page 30, lines 15-18.
[35] Testimony of Gregory W. Tillman, page 9 lines 8-19.

concerns about costs being shifted from EDR customers to other customer classes. I would like to emphasize that the any lost non-fuel revenues resulting from discounts provided to customers through the EDR will be borne by the Company. UNS Electric will not seek recovery of any lost non-fuel revenues associated with the EDR in future rate case proceedings. The long-term benefits of attracting or retaining large, high load factor customers greatly outweigh the short-term costs. The Rebuttal Testimony of Dallas Dukes provides further information regarding the Company's EDR proposal.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

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[36] Direct Testimony of GaryYaquinto, pages 8-9, lines 1-22.

Rebuttal Testimony of

Kentton C. Grant

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

January 19, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Kentton C. Grant and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses the testimony of four witnesses. With respect to the testimony of Dr. J. Randall Woolridge filed on behalf of The Alliance for Solar Choice ("TASC"), I take issue with his use of a hypothetical capital structure for UNS Electric. With respect to the testimony of Robert B. Mease filed on behalf of the Residential Utility Consumer Office ("RUCO"), I discuss the shortcomings of the methodology he used to calculate the rate of return on fair value rate base, which is commonly referred to as the fair value rate of return ("FVROR"). Lastly, I address the cost of equity and FVROR recommendations of Commission Staff ("Staff") witnesses Elijah Abinah and Donna M. Mullinax.

II. REBUTTAL OF TASC WITNESS DR. J. RANDALL WOOLRIDGE.

Q. What capital structure does Dr. Woolridge use in his cost of capital analysis?

A. Dr. Woolridge uses a hypothetical capital structure consisting of 50% common equity and 50% long-term debt. His only explanation for using this capital structure, instead of the Company's actual capital structure consisting of 52.83% common equity and 47.17% long-term debt, is that UNS Electric "has a higher common equity ratio" than the two proxy groups of electric utilities listed in Exhibit JRW-4 attached to his direct testimony. (See page 13 of Woolridge Direct Testimony, lines 15-17.)

Q. Is there any reasonable basis for using a hypothetical capital structure for UNS Electric?

A. No. The Company's capital structure is nearly identical to that adopted by the Commission in UNS Electric's last rate case (52.6% common equity), and it is also comparable to that approved by the Commission in Arizona Public Service Company's last rate case (53.9% common equity). Additionally, the percentage of common equity in UNS Electric's capital structure is only slightly higher than the median value of common equity in the two proxy groups cited by Dr. Woolridge (47.8% and 49.3%, respectively), and it falls well within the range of values for both groups. By substituting his hypothetical capital structure for the Company's actual capital structure, Dr. Woolridge is effectively assigning a 4.66% cost of debt to a portion of the common equity invested by UNS Electric in plant and equipment used to serve customers.

Q. Is there a logical explanation as to why UNS Electric would have more common equity in its capital structure relative to the median value for each of the proxy groups cited by Dr. Woolridge?

A. Yes. As discussed in the Rebuttal Testimony of UNS Electric witness Ann Bulkley, the common equity ratios cited by Dr. Woolridge are based on consolidated holding company financials, and not on utility stand-alone financials. Second, and more importantly, UNS Electric is much smaller than all of the publicly traded companies included in each of the proxy groups, and the Company's credit rating is also higher than most of the companies in the two proxy groups. As may be seen in Exhibit JRW-4 attached to his testimony, the median credit rating assigned by Moody's Investors Service to the electric utilities in each of the proxy groups is "Baa1". By contrast, UNS Electric has a Moody's credit rating of "A3", which is one notch higher than Baa1. By deploying less debt in its capital structure, UNS Electric enjoys a slightly higher credit rating, resulting in more favorable debt pricing and improved access to credit, benefits which ultimately accrue to the Company's customers.

Q. Is the capital structure of UNS Electric referenced in the 2014 Commission order approving the merger of UNS Energy Corporation and Fortis Inc.?

A. Yes. In the Settlement Agreement approved by the Commission in Decision No. 74689 (August 12, 2014), Condition No. 16 restricts the ability of UNS Electric to pay dividends for a period of five years or until its common equity ratio reaches 50%. Although it is not determinative for rate making purposes, that decision implies that a common equity ratio of 50% is the minimum amount of equity deemed by the Commission to be reasonable for UNS Electric.

Q. Should the Commission reject the use a hypothetical capital structure for UNS Electric?

A. Yes, for the reasons described above.

III. <u>REBUTTAL OF RUCO WITNESS ROBERT B. MEASE.</u>

Q. What methodology does Mr. Mease use to calculate a FVROR for UNS Electric?

A. As described in his Executive Summary, lines 30-36, he subtracts an inflation adjustment of 1.35% from his recommended cost of capital of 6.61% to arrive at a FVROR of 5.26%. In support of this approach, he cites two Commission rate orders involving UNS Electric and its sister company, UNS Gas, Inc. On page 32 of his testimony, he also discusses the need to eliminate a "double-counting" of inflation that would otherwise supposedly occur.

Q. Do you agree with the methodology used by Mr. Mease to determine the FVROR?

A. No, I do not. Although it has been adopted by the Commission on two occasions in the past, it is a methodology that is not practically or theoretically sound. It also conflicts with the methodology approved by the Commission in more recent rate cases - as well as the methodology proposed by UNS Electric and by Commission Staff in this docket.

Q. Please comment on the theoretical shortcomings of this methodology.

A. As noted by Mr. Mease, the difference between the Company's original cost rate base ("OCRB") and the fair value rate base ("FVRB") is caused by inflation. That is because UNS Electric relied on a traditional 50/50 weighting of the OCRB and the reconstructed cost new less depreciation ("RCND") rate base in calculating the FVRB. However, since the Company's FVRB is 50% weighted by the OCRB, which includes no inflation over original cost, Mr. Mease over-compensates for inflation by deducting a full rate of inflation from the weighted average cost of capital ("WACC"). Had he deducted only 50% of the rate of inflation from the WACC, his methodology would have been more theoretically sound.

Q. Are there other theoretical shortcomings associated with this methodology?

A. Yes. While the RCND rate base and 50% of the FVRB have been impacted by historical inflation, the Company's WACC is forward-looking, and is therefore impacted by future expectations for inflation. To complicate matters even further, the Company's embedded cost of debt reflects expectations for inflation as of each historical debt issuance date, whereas the cost of equity is a forward-looking estimate that reflects current expectations for inflation. Consequently, there will always be a mismatch between the historical cost of inflation embedded in the RCND rate base and the forward-looking rates of inflation embedded in the cost of capital. There is simply no perfect way to eliminate the "double counting" of inflation that is embedded in both the RCND rate base and the WACC.

Q. What are some of the practical shortcomings of the FVROR methodology employed by Mr. Mease?

A. One practical shortcoming is the choice of an appropriate forward-looking inflation rate. Mr. Mease decided to average the forward-looking inflation rates observed over a seven-year period ending in 2015. His decision to use a seven-year average, as opposed to a more recent (and much lower) rate, is not discussed anywhere in his testimony. A second practical issue, and one that the Commission should be more concerned about, is that this methodology produces inherently unstable results as inflation expectations rise and fall over time.

Q. Please explain.

A. As an example, the inflation expectations calculated by Mr. Mease over the period 2009-2015 ranged from a low of 0.48% in 2015 to a high of 2.23% in 2011. (See Schedule RBM-4 attached to his testimony.) Even though this range of expected inflation is modest by historical standards, the resulting FVROR would be very different if either of those values had been selected in lieu of the 1.35% average rate used by Mr. Mease. The following table illustrates the impact of using these different rates on the FVROR and revenue requirement for UNS Electric, based on the Company's proposed WACC and FVRB:

	Low Rate from RBM-4	Avg. Rate from RBM-4	High Rate from RBM-4
WACC	7.67%	7.67%	7.67%
Inflation Adjustment	-0.48%	-1.35%	-2.23%
FVROR	**7.19%**	**6.32%**	**5.44%**
x FVRB ($000s)	$355,720	$355,720	$355,720
Return ($000s)	**$25,562**	**$22,482**	**$19,337**
x Gross-Up Factor	1.6084	1.6084	1.6084
Return & Taxes ($000s)	**$41,114**	**$36,159**	**$31,101**

As illustrated above, the impact of even minor changes in expected inflation can produce very different results in terms of the FVROR and overall revenue requirement. During periods of low inflation or deflation, the methodology used by Mr. Mease would produce a large return premium for most utilities. Conversely, during periods of high inflation, his proposed methodology would impose severe return penalties on most utilities, even if the FVRB exceeded the OCRB by a wide margin. Since having a FVRB in excess of the OCRB is a plus in terms of lowering perceived investor risk and the cost of capital to a utility, the potential for a significant FVROR penalty is something the Commission should be aware of in assessing the methodology proposed by Mr. Mease.

Q. Does the inflation adjustment proposed by Mr. Mease result in a FVROR penalty to UNS Electric?

A. No, it does not. As illustrated in the table above, subtracting an inflation adjustment of 1.35% from the Company's 7.67% WACC would result in a FVROR of 6.32%. This value is higher than the FVROR of 6.22% proposed by UNS Electric. However, for the reasons described above, the Company does not support the methodology used by Mr. Mease in calculating the FVROR.

Q. What FVROR does Mr. Mease recommend for UNS Electric?

A. As mentioned earlier, he recommends a FVROR of 5.26%. The reason it is lower than the 6.32% value referenced above is that his WACC is based on a cost of equity of only 8.35% (200 basis points lower than the value proposed by UNS Electric). Company witness Ann Bulkley addresses the cost of equity analysis of Mr. Mease in her Rebuttal Testimony.

IV. <u>REBUTTAL OF STAFF WITNESSES ELIJAH ABINAH AND DONNA H. MULLINAX.</u>

Q. What did Staff recommend regarding the FVROR for UNS Electric?

A. Staff witness Elijah Abinah recommends applying a rate of return ("ROR") of 0.5% to the fair value increment of rate base, which represents the difference between the Company's FVRB and OCRB. Staff witness Mullinax then used this rate, along with Staff's recommended values for FVRB, OCRB, and the WACC to arrive at a FVROR of 5.60%. This calculation is shown in Attachment DHM-2, lines 22-26 of Schedule D, attached to the testimony of Ms. Mullinax.

Q. Did Ms. Mullinax use the same methodology proposed by UNS Electric in calculating the FVROR?

A. Yes. Although some of the input values are different from those proposed by the Company, namely the values for OCRB, FVRB, the cost of equity, and the ROR on the fair value increment of rate base, the method she used to calculate the FVROR is the same as proposed by the Company.

Q. Did you find any mathematical errors in Staff's calculation of the FVROR?

A. Yes. The relative weightings for long-term debt, common equity and the fair value increment of rate base shown in column C, lines 23-25, of Attachment DHM-2 (Schedule D) were incorrect. Had Ms. Mullinax used the correct weightings, Staff's FVROR would have been slightly higher at 5.63%, as shown below:

	Balance	% Total	Cost	Wtd. Cost
OCRB L-T Debt	$127,451	36.01%	4.66%	1.68%
OCRB Equity	$142,738	40.33%	9.50%	3.83%
Fair Value Increment	$83,707	23.65%	0.50%	0.12%
	$353,896	100.00%		**5.63%**

Q. What is the Company's position with respect to the 9.5% cost of equity and 0.5% return on the fair value increment of rate base recommended by Staff?

A. Both of these values are significantly lower than what the Company proposed, and what can be reasonably justified based on the analysis of UNS Electric witness Ann Bulkley. However, they are consistent with the values UNS Electric stipulated to as part of a comprehensive settlement agreement in the Company's last rate case. As long as the overall revenue increase and rate design approved for UNS Electric provides the Company with a reasonable opportunity to actually earn a 9.5% return on equity, the Company would not be opposed to the adoption of Staff's recommended values.

Q. Does this conclude your Testimony?

A. Yes, it does.

Rebuttal Testimony of

Ann E. Bulkley

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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.	DOCKET NO. E-04204A-15-0142

Rebuttal Testimony of

Ann E. Bulkley

on Behalf of

UNS Electric, Inc.

January 19, 2016

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- AEB-R-1 Constant DCF
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- AEB-R-9 FVROR
- AEB-R-10 Internal Growth Rate JRW
- AEB-R-11 EPS Growth Rates JRW
- AEB-R-12 RP Excl. Settled

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. On whose behalf are you submitting this testimony?

A. I am submitting this testimony on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Did you previously submit testimony in this proceeding?

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

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to the cost of capital issues within the Direct Testimonies of Mr. Elijah Abinah on behalf of the Utilities Division Staff (the "Staff") of the Arizona Corporation Commission (the "Commission"), Mr. Robert B. Mease on behalf of the Residential Utility Consumer Office ("RUCO"), Dr. J. Randall Woolridge on behalf of The Alliance for Solar Choice ("TASC"), and Mr. Steve W. Chriss on behalf of Wal-Mart Stores, Inc. (collectively, the "Opposing ROE Witnesses").

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

A. Yes. My updated analysis and recommendations are supported by the data presented in Exhibits AEB-R-1 through AEB-R-12, which have been prepared by me or under my direction.

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

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

- In Section II, I provide a summary and overview of my Rebuttal Testimony.
- In Section III, I provide a summary of capital market conditions and their effect on the Cost of Equity for UNS Electric.
- In Section IV, I respond to Mr. Abinah's recommendations.
- In Section V, I respond to Mr. Mease's analyses and recommendations.
- In Section VI, I respond to Dr. Woolridge's analyses and recommendations.
- In Section VII, I respond to Mr. Chriss' recommendations.
- In Section VIII, I provide updated analyses regarding the Company's ROE and capital structure.
- Finally, in Section IX, I summarize my conclusions and recommendations.

II. SUMMARY AND OVERVIEW

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

A. The Opposing ROE witnesses have recommended ROE levels ranging from 8.35 percent in the case of Mr. Mease to 9.50 percent in the case of Mr. Abinah (see Table 1, below). The FVROR recommendations of the Opposing ROE witnesses range from 5.24 percent to 5.64 percent.

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

Witness	Recommended ROE Range	Original Cost ROE Recommendation	FVROR Recommendation
Mr. Abinah	N/A	9.50%	5.64%
Mr. Mease	6.00%-8.95%	8.35%	5.26%
Dr. Woolridge	8.10%-9.00%	8.75%	5.24%
Mr. Chriss	N/A	Max of 9.50%	NA

Q. **Please provide a brief overview of your response to Staff witness Abinah with respect to the ROE for UNS Electric.**

A Staff recommends an ROE of 9.50 percent and a 0.50 percent Fair Value Increment for UNS Electric.[1] Staff's recommendations are based on the analysis that was prepared in two prior UNS Electric cases: Docket No. E-04204A-09-0206, and Docket No. E-04204-12-0504.[2] I understand that, as explained in the Rebuttal Testimony of Company witness Kentton Grant, UNS Electric would not oppose Staff's recommendation as long as the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn that ROE. I also understand that the Company is not opposing Staff's recommendations for this specific case, while reserving the right to challenge such an approach in future rate cases for UNS Electric and its affiliates.

Mr. Abinah correctly recognizes that the Cost of Equity is prospective-looking even as he relies on the Staff witness analysis from two prior UNS Electric rate cases. Mr. Abinah's ROE recommendation is based on his view that a cost of capital analysis in

[1] *See* Direct Testimony of Elijah Abinah, at 2.
[2] *Ibid.*, at 3-4.

this docket would produce a similar, if not identical, range as was recommended by Staff in those cases of 8.5 percent to 10.5 percent. However, current capital market conditions fully support an ROE well in excess of 9.5 percent, and that 9.5 percent is, at best, the bottom of the range at this time. I disagree that the range identified by Staff in the two prior rate cases is appropriate, particularly the 8.5 percent bottom bracket. UNS Electric's willingness to accept the 9.5 percent ROE should not be interpreted to support the range previously recommended by Staff. My Rebuttal Testimony with respect to Staff's recommendation is intended to refute any assertions that the lower end of an appropriate ROE range is less than 9.5 percent, let alone 8.5 percent. Indeed, none of the ROE models in my Direct Testimony would support 8.5 percent as the low end of a reasonable range for ROE and would support an ROE above 9.5 percent.

As discussed in my Direct Testimony, capital market conditions today are different than the conditions that were present in Docket No. E-04204-12-0504.[3] In particular, credit spreads are wider today, suggesting higher risk aversion among investors. Government and corporate bond yields are projected to increase during the period in which rates are likely to be in effect for UNS Electric. Furthermore, market conditions are very different from when the Staff witness, Mr. Parcell, filed his analysis in Docket No. E-04204A-09-0206 in November 2009. At that time, the capital markets were just beginning to stabilize after the financial and credit crisis and the subsequent Great Recession. It is not reasonable to draw comparisons to that time period because financial markets were far from "normal", as evidenced by the unprecedented level of credit spreads and the extreme volatility in equity prices.

I have reviewed the analyses that were presented by Mr. Parcell in Docket Nos. E-04204-12-0504 and E-04204A-09-206, and I find that many aspects of those analyses are no

[3] Direct Testimony of Ann E. Bulkley, at 16-17.

longer relevant. For example, several of the proxy companies that were relied on in Mr. Parcell's analysis no longer exist as publicly traded companies due to merger activities, and many of the assumptions used in the ROE estimation models have changed significantly due to market conditions. Against the current economic and financial market backdrop, but for the Company's willingness to not oppose Staff's recommendation in this docket, it would certainly be reasonable to set the authorized ROE for UNS Electric above the current level of 9.50 percent.

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

A The methodology that Staff relies on to develop the FVROR is consistent with the methodology that was used in my Direct Testimony, assigning a return to the Fair Value Increment of one half the rate of inflation. As discussed above, the Company is prepared not to oppose Staff's recommendation. Absent this position by the Company, I believe that Staff's proposed cost rate for the Fair Value Increment is lower than what is reflective of current market conditions. Moreover, although this rate was approved by the Commission in Decision No. 74235, it was approved as one component of a settlement agreement that included many compromises between the parties in the case. In Decision No. 74235, the Commission found that the Settlement Agreement provided benefits to ratepayers, shareholders and the community "[b]ased on the totality of circumstances".[4] Therefore, the Commission did not specifically determine the methodology or cost rate to use in setting the FVROR in that case. Simply updating the inflation rate used in Staff's FVROR to the rate used in my analysis results in an increase in the FVROR of 24 basis points to 5.87 percent. Considering current economic and financial market conditions and the analysis presented in my direct

[4] Docket No. E-04204A-12-0504, Decision No. 74235, at 25.

testimony, but for the Company's willingness to not oppose Staff's recommendation in this docket, it would certainly be reasonable to set the FVROR above the current level of 0.50 percent.

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

A. As shown in Table 1 above, the range of ROE results presented by Mr. Mease is between 6.00 percent and 8.95 percent. Mr. Mease establishes this range using the low end of the range of his CAPM results and the mean result from his Constant Growth DCF model. In setting his range, Mr. Mease ignores the 9.63 percent ROE estimate that sets the high end of the range of his DCF analysis. Mr. Mease's recommended ROE of 8.35 percent is 115 basis points below the return that was authorized for UNS Electric in Docket No. E-04204-12-0504 and 95 to 205 basis points below the range of returns that has been authorized for integrated electric utilities in 2014 and 2015. Mr. Mease's recommended ROE is not a reasonable estimate of the Cost of Equity for UNS Electric. The specific areas of disagreement with Mr. Mease's ROE analyses on which he bases this recommendation are summarized below:

- Mr. Mease's recommendation to lower UNS Electric's currently authorized ROE by 115 basis points is inconsistent with the historical relationship between ROEs and interest rates. As discussed in my Direct Testimony, investors expect an increase in interest rates. As shown by the Bond Yield Risk Premium analysis, there is a positive relationship between interest rates and ROEs; therefore, suggesting a decrease in UNS Electric's authorized ROE in an increasing interest rate environment ignores that historical relationship.
- While Mr. Mease outlines the assumptions regarding dividend growth that are the foundation of the Constant Growth DCF model (i.e., dividends will grow at a

constant rate into perpetuity, and the dividend payout ratio will remain at a constant rate), he does not consider whether these assumptions are reasonable given recent and current market conditions. Mr. Mease's sole reliance on the Constant Growth DCF model does not take into consideration the effect of current market conditions. Other regulatory commissions have acknowledged that the results of the traditional ROE estimation models can be affected by market conditions. In particular, the FERC recently recognized that the DCF model results have been affected by "anomalous market conditions" and has relied on other ROE estimation models (such as the CAPM) for guidance on where within the range of results the ROE should fall.

- Mr. Mease's reliance on a historical market risk premium, calculated as an arithmetic or geometric mean, is inconsistent with the theory of a forward-looking ROE. Furthermore, the historical risk premium over the period from 2007-2009 decreased during the Great Recession, which is counterintuitive because risk aversion was higher among investors during this period (as shown by elevated market volatility and exaggerated credit spreads), suggesting that the market risk premium should also have been higher.

- Mr. Mease's sole reliance on the historical yields on U.S Treasury bonds in his CAPM analysis does not take into consideration the market's expectation that interest rates will be increasing over the period when the rates established in this proceeding are in effect.

- The results of Mr. Mease's CAPM analysis range from 6.00 percent to 7.19 percent. Mr. Mease states that these returns exceed a 4.60 percent yield by 107 to 228 basis points, suggesting that this range is an appropriate equity risk premium in current market conditions.[5] However, Mr. Mease's range is also 153 to 272

[5] *See* Direct Testimony of Robert B. Mease, at 14. The actual spread between Mr. Mease's results and a 4.60 percent yield is 140 to 259 basis points.

basis points below any authorized ROE for electric utilities in more than 30 years.[6] Therefore, it is not reasonable to afford any weight to the results of Mr. Mease's CAPM analysis.

- Applying reasonable adjustments to Mr. Mease's CAPM analysis results in a range of returns of 8.46 percent to 10.74 percent, with a mean of 9.93 percent. This represents an increase in the range of results of approximately 250 to 350 basis points.
- Mr. Mease's recommended FVROR is calculated by removing inflation from the Original Cost Rate of Return. Mr. Mease's calculation overstates the inflation in the FVRB by adjusting the FVROR by the full inflation rate. The FVRB is estimated using equal weightings of OCRB, which does not include inflation, and the estimated RCND, which is affected by inflation. Therefore, since only 50 percent of the FVRB is affected by inflation, it is not appropriate to adjust the entire FVROR by inflation. Rather, in order to properly remove inflation using Mr. Mease's approach, the inflation factor that is applied to the equity and debt cost rates should have been reduced by 50 percent, increasing Mr. Mease's FVROR by 67 basis points to 5.93 percent. Furthermore, adjusting the original cost ROE recommendation used in Mr. Mease's FVROR calculation to 9.36 percent increases the FVROR by 121 basis points to 6.47 percent.

Q. Please summarize your response to TASC witness Dr. Woolridge's ROE and equity ratio recommendations for UNS Electric.

A. Dr. Woolridge's analyses and ROE recommendation do not provide a reasonable estimate of UNS Electric's cost of capital. In particular, I disagree with Dr. Woolridge's recommendation for several reasons:

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6 Source: SNL Energy, Inc. RRA rate case data from 1979 through 2015.

- Dr. Woolridge's 8.75 percent ROE recommendation is well below any recent ROE awards for vertically-integrated electric utilities and would not allow UNS Electric to compete for capital with other investments of comparable risk;
- Dr. Woolridge's Constant Growth DCF results of 8.70 percent to 9.00 percent are not reasonable because of the growth rate assumptions he relies on to specify the model. Dr. Woolridge's analysis includes historical growth rates for earnings, dividends and book value, projected internal or sustainable growth rates, and negative forecasted earnings growth rates. My Rebuttal Testimony discusses each of these assumptions and why it is more appropriate to rely on projected earnings growth rates in a DCF model.
- Dr. Woolridge's CAPM results of 8.10 percent to 8.30 percent are substantially lower than any authorized ROE for a vertically integrated electric utility in the U.S. in the last 25 years. Dr. Woolridge's analysis produces unreasonably low results because of the assumption he uses for the market risk premium. Dr. Woolridge has relied on a market risk premium of 5.50 percent, which does not reflect the inverse relationship between the equity risk premium and interest rates.
- Dr. Woolridge's proxy group of 29 electric utilities is not risk comparable to UNS Electric because he uses a revenue screen rather than an operating income screen; the proxy group includes companies that derive a significant percentage of their revenues from gas distribution operations, and companies that should be excluded for company-specific reasons.
- Dr. Woolridge has relied primarily on the results of his Constant Growth DCF analysis to support his ROE recommendation. He has given little or no weight to other, well-established models that I have used to estimate the Cost of Equity, such as the Multi-Stage DCF, a forward-looking CAPM, and the Bond Yield Plus Risk Premium analysis.

- Dr. Woolridge's 8.75 percent ROE recommendation fails to adequately consider capital market conditions, including the fact that credit spreads have been widening throughout 2015, and that interest rates on government and corporate bonds are expected to increase substantially over the next few years.
- Dr. Woolridge's proposal to impute a hypothetical capital structure consisting of 50 percent common equity and 50 percent long-term debt should be rejected. He has provided no reasonable basis for deviating from UNS Electric's actual test year capital structure which contains 52.83 percent common equity. The Company's proposed equity ratio is somewhat lower than the proxy group average common equity ratio of 53.72 percent.
- Dr. Woolridge does not propose a methodology to estimate the FVROR, agreeing to adopt the methodology relied on by Staff, substituting his recommendations for the OCRB ROE and capital structure. Applying those assumptions to the Staff methodology results in the lowest recommended FVROR of the Opposing ROE witnesses of 5.24 percent. As discussed previously, I disagree with Dr. Woolridge's capital structure and original cost rate base ROE estimates. Furthermore, as discussed in my response to the Staff, the use of a cost rate from 2009 and 2012 for the Fair Value Increment does not relate to the current market conditions and is not reasonable.

Q. Please summarize your response to Wal-Mart witness Mr. Chriss with respect to the ROE for UNS Electric.

A. Mr. Chriss does not recommend a specific ROE for UNS Electric. Rather, he suggests that the Commission should examine the Company's proposed 10.35 percent request in light of the customer impact of the resulting revenue requirement increases and recent returns on equity for electric utilities approved by commissions nationwide.[7] Mr. Chriss testifies that the average authorized ROE for vertically-integrated electric utilities from 2012-2015 has been 9.98 percent, and that the trend in recent years has been toward declining allowed returns on equity. Mr. Chriss ultimately recommends that the Commission not allow an ROE higher than the current authorized level of 9.50 percent unless there is a showing that economic or capital market conditions are significantly different than at the time the current ROE was established.[8]

As discussed in my Direct and Rebuttal Testimony, economic and capital market conditions today are, in fact, different than in late 2013 when the Commission approved the settlement agreement, which included the current 9.50 percent ROE. As discussed in my response to Mr. Abinah, credit spreads are substantially wider today, suggesting higher risk aversion among investors, and both government and corporate bond yields are projected to increase during the period in which rates are likely to be in effect for UNS Electric, both of which suggest a Cost of Equity for UNS Electric above the current authorized level of 9.50 percent.

Q. **Do you agree with Mr. Mease, Dr. Woolridge and Mr. Chriss that the Commission should consider ROE awards in other jurisdictions as a practical benchmark for assessing ROE recommendations?**

A. Yes. I agree that ROE awards in other jurisdictions provide a useful benchmark to assist the Commission in assessing overall reasonableness and send an important signal to investors regarding whether there is regulatory support for financial integrity, dividends, and financial growth, and fair compensation for business and financial risk. The cost of capital represents an opportunity cost to investors. If higher returns are available for other investments of comparable risk, investors have the incentive to direct

7 *See* Direct Testimony of Steve W. Chriss, at 4.
8 *Ibid.*, at 17.

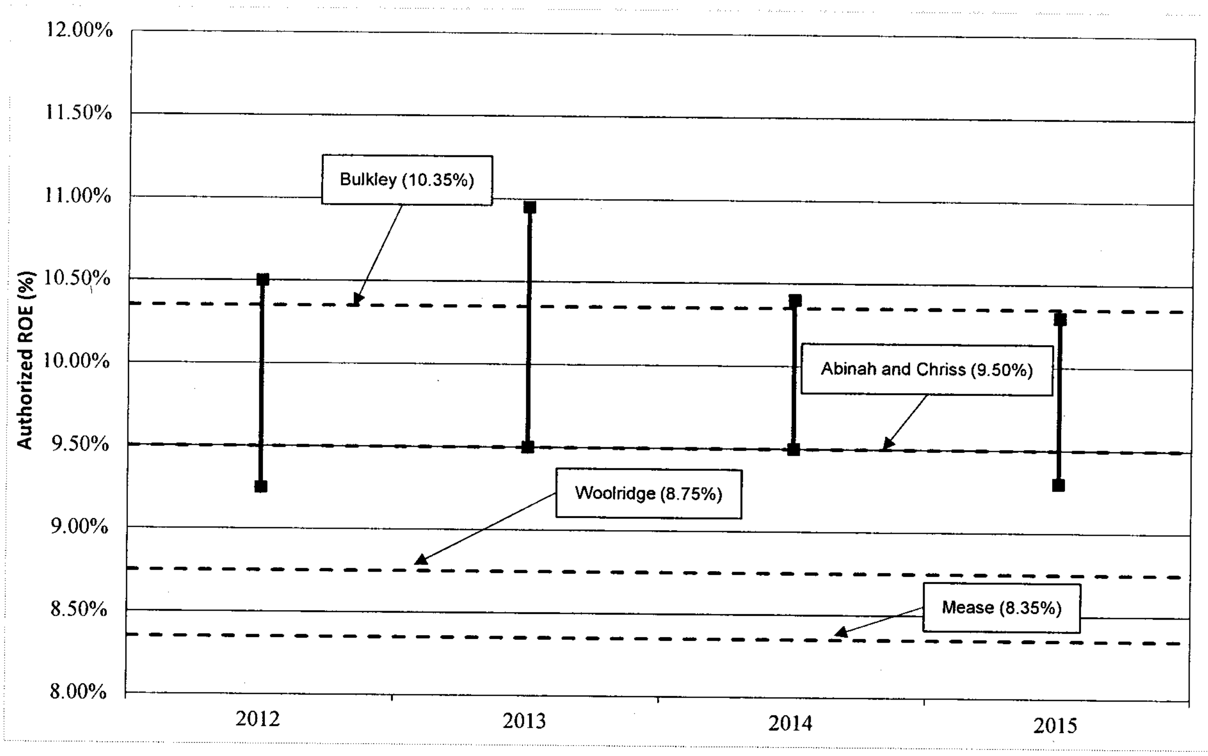
their capital to those investments. Thus, an ROE significantly below authorized ROEs in other jurisdictions can inhibit the Company's ability to attract capital for investment in Arizona.

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

A. Chart 1 provides the range of recently authorized ROEs. As shown on Chart 1, the ROE recommendations of Mr. Mease (8.35 percent) and Dr. Woolridge (8.75 percent) are well below the lowest authorized ROE for an integrated electric utility between January 1, 2012 and November 30, 2015. Both Messrs. Abinah and Chriss recommend an ROE not to exceed 9.50 percent, which is at the low end of the range of authorized returns for integrated electric utilities over this period, and well below the average ROE for integrated electric utilities of 9.98 percent that Mr. Chriss cites.

Chart 1: Authorized ROEs for Integrated Electric Utilities

January 1, 2012 – November 30, 2015[9]



Q. Have you updated your ROE analyses?

A. Yes. I have updated the analyses for the proxy group companies contained in my Direct Testimony to reflect data through November 30, 2015. My updated analysis excludes Southern Company and Duke Energy Corporation, which are both now parties to merger agreements and no longer meet my screening criteria on that basis. The results of my updated analyses are summarized in Table 2.

9 Source: SNL Energy, Inc.

Table 2: Updated Analytical Results

	Mean Low	Mean	Mean High
Constant Growth DCF			
30-Day Average	8.41%	9.35%	10.32%
90-Day Average	8.50%	9.44%	10.42%
180-Day Average	8.52%	9.46%	10.43%
Multi-Stage DCF			
30-Day Average	9.29%	9.52%	9.78%
90-Day Average	9.39%	9.63%	9.89%
180-Day Average	9.40%	9.64%	9.91%
CAPM			
	Current Risk Free Rate (2.98%)	**2015-2017 Projected Risk Free Rate (3.37%)**	**2017-2021 Projected Risk Free Rate (4.80%)**
Bloomberg	9.67%	9.81%	10.34%
Value Line	11.21%	11.30%	11.61%
Bond Yield Plus Risk Premium			
	Low	**Mean**	**High**
Risk Premium	9.87%	10.04%	10.67%

Q. **What is your conclusion regarding the appropriate Cost of Equity for the Company?**

A. The ROE results presented in my Direct Testimony indicated a range of 10.00 percent to 10.60 percent from a combination of models and alternative input assumptions. As shown in Exhibits AEB-R-1 through AEB-R-6, I have updated my analyses through November 30, 2015, using the same models to estimate the Cost of Equity for UNS Electric. These updated results continue to support my initial ROE recommendation of 10.35 percent. ROEs at the levels proposed by Mr. Mease and Dr. Woolridge are not reasonable and would not meet the standards established in *Hope* and *Bluefield* for a fair return. Notwithstanding the Company's willingness to not oppose Staff's recommended 9.50 percent ROE, I believe that economic and financial market conditions have changed since 2013 and that current conditions support an ROE higher than 9.50 percent. In particular, credit spreads are wider, market volatility has increased in 2015, and interest rates on government and corporate bonds are projected to rise over the next few years. For these reasons, capital costs are now higher than in 2013 and support my ROE recommendation of 10.35 percent for UNS Electric.

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

Q. Have the Opposing ROE witnesses considered the effect of economic and capital market conditions in establishing their respective ROE recommendations?

A. Messrs. Mease and Chriss, and Dr. Woolridge cite the current low interest rate environment as an important consideration in the Cost of Equity and as support for their low ROE recommendations. Staff does not discuss current economic and capital market conditions.. Dr. Woolridge and Mr. Chriss also cite the recent trend of declining average ROE awards for regulated electric utilities. The Opposing ROE witnesses' recommendations, however, are based on capital market conditions over the past few years, and do not adequately consider the changes that have occurred in recent months or the prospects for financial markets on a going-forward basis. In particular, Mr. Mease devotes a considerable portion of his testimony to discussing financial market conditions and utility stock performance in 2014, but does not consider market conditions in the last year or the expectations for changes in market conditions during the period when the rates that are decided in this case will be in effect. In my view, it is not reasonable to dismiss current and projected market conditions or to base the authorized ROE for UNS Electric in this proceeding on economic and financial market conditions from 2013 or 2014.

Rather, the ROE that is authorized in this proceeding is intended to provide a reasonable return to investors over the forward-looking period during which these rates will be in effect. For that reason, it is important to consider the prospects for financial markets during that period. As discussed in my Direct Testimony, extraordinary and persistent federal intervention in capital markets has artificially lowered government bond yields since the Great Recession of 2008-09, as the Federal Reserve has used monetary policy (both reductions in short-term interest rates and purchases of Treasury bonds and mortgage backed securities) to stimulate the U.S. economy.[10] This highly accommodative monetary policy has resulted in government bond yields that have been artificially suppressed by the Federal Reserve. However, as shown in Charts 2 and 3, market data suggest that investors perceive greater risk in the current market environment and expect rising interest rates. Therefore, it is important to consider the current and prospective market conditions and investor expectations for higher interest rates, all of which put upward pressure on utility capital costs going forward.

Q. Please discuss the recent change in monetary policy by the Federal Reserve.

A. At its December 2015 meeting, the FOMC voted to increase short-term interest rates by 25 basis points, and indicated its intention to gradually raise interest rates in coming months as economic conditions returned to normal after the financial and economic shocks that took place during the credit crisis and the ensuing Great Recession. The December 2015 FOMC decision provides confirmation that central bankers believe that economic conditions have improved sufficiently so as to justify a gradual increase in short-term rates. More importantly, yields on longer-term corporate and utility bonds, which are directly controlled by market forces rather than monetary policy, have been increasing throughout 2015. These market-based interest rates offer clear evidence that

[10] Direct Testimony of Ann E. Bulkley, at 11-12.

investors are requiring higher rates of return to assume the risks associated with corporate debt. In short, capital costs are increasing and are expected to continue increasing as the FOMC gradually raises short-term interest rates.

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

A. As previously discussed, in mid-December 2015 the Federal Reserve announced the first increase in short-term interest rates since the financial market collapse in 2008. In its statement, the Federal Reserve indicated that further increases in short-term interest rates would be gradual as the economy strengthens further and inflation rises from undesirably low levels. The January 2016 issue of the Blue Chip Financial Forecasts ("Blue Chip") surveyed leading economists and market participants concerning their views about the likelihood of future increases in short-term interest rates by the Federal Reserve. Blue Chip reports that 73 percent of market participants surveyed expect the Federal Reserve to raise short-term interest rates again at the FOMC meeting in March with the expectation that there could be up to three short-term interest rate increases in 2016.[11]

According to Blue Chip, yields on 30-year Treasury bonds are forecasted to increase to 4.80 percent between 2017 and 2021.[12] Dr. Woolridge acknowledges the probability of tighter monetary policy, and uses a risk free rate of 4.00 percent in his CAPM analysis. However, Dr. Woolridge fails to recognize that current dividend yields of approximately 3.90 percent for utility shares will not be competitive with higher yields on government and corporate bonds. Consequently, the results of Dr. Woolridge's Constant Growth DCF analysis are understated because the current dividend yield

[11] Blue Chip Financial Forecasts, Volume 35, No. 1, January 1, 2016, at 14.

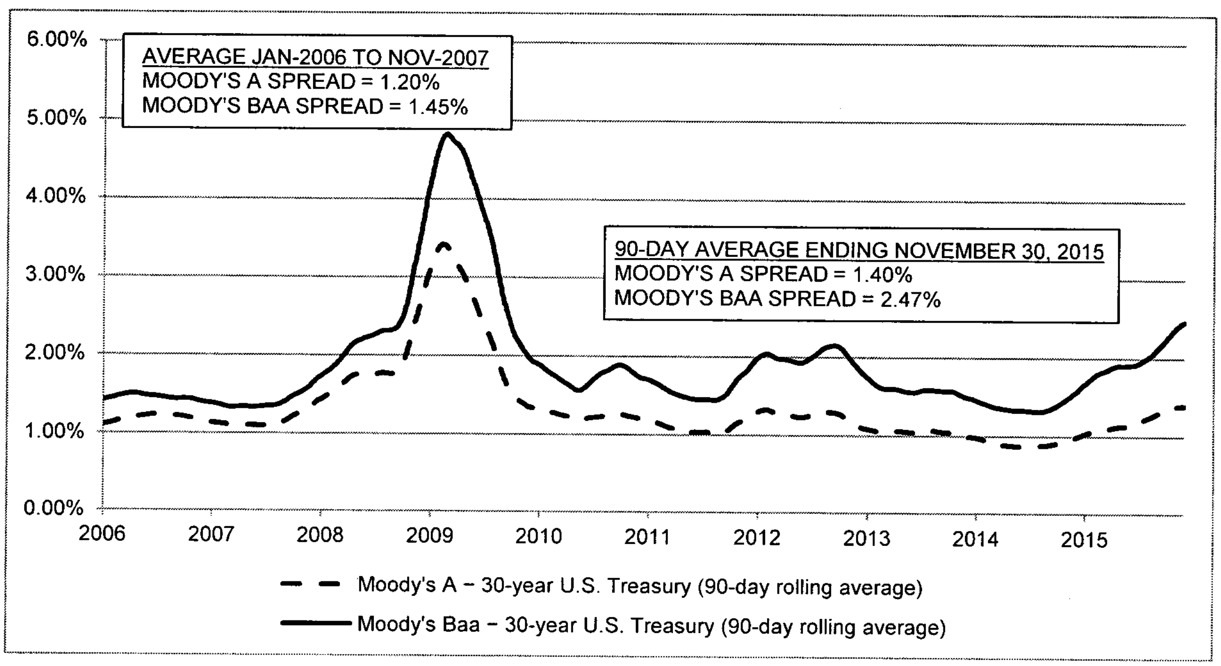
[12] Blue Chip Financial Forecasts, Volume 34, No. 6, June 1, 2015, at 14.

component does not adequately reflect the higher interest rate environment that he expects in his CAPM analysis.

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

A. The evidence of investors' increased risk sentiment is strong. Even as Treasury bond yields have remained relatively low in 2015, yields on corporate and utility bonds have increased steadily throughout the year. Consequently, as shown on Chart 2, credit spreads between government and utility bonds have increased to the highest level since the credit and financial crisis. In particular, the spread between Baa-rated utility debt and Treasury bonds is now more than 240 basis points, which is greater than the spread that occurred just prior to the Great Recession.

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



Q. What do higher credit spreads indicate about the market?

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

> The U.S. corporate-bond market is starting to flash caution signals about the broader economy. The difference in yield, called the "spread," between bonds from America's strongest companies and ultrasafe U.S. Treasury securities has been steadily increasing, a trend that in the past has foreshadowed economic problems. Wider spreads mean that investors want more yield relative to Treasurys to own bonds from U.S. companies. It can signal that investors are less confident about companies' business prospects and financial health, though other factors likely also are at play.
>
> Spreads in investment-grade corporate bonds – debt from companies rated triple-B minus or higher – are on track to increase for the second year in a row, according to Barclays data. That would be the first time since the financial crisis in 2007 and 2008 that spreads widened in two consecutive years.
>
> ***
>
> Investors and analysts say they are closely watching the action to determine whether trouble is brewing once again. Concerns are growing about companies' ability to pay back the massive debt load taken on in recent years, as ultralow interest rates spurred corporate finance chiefs to sell record amounts of bonds.[13]

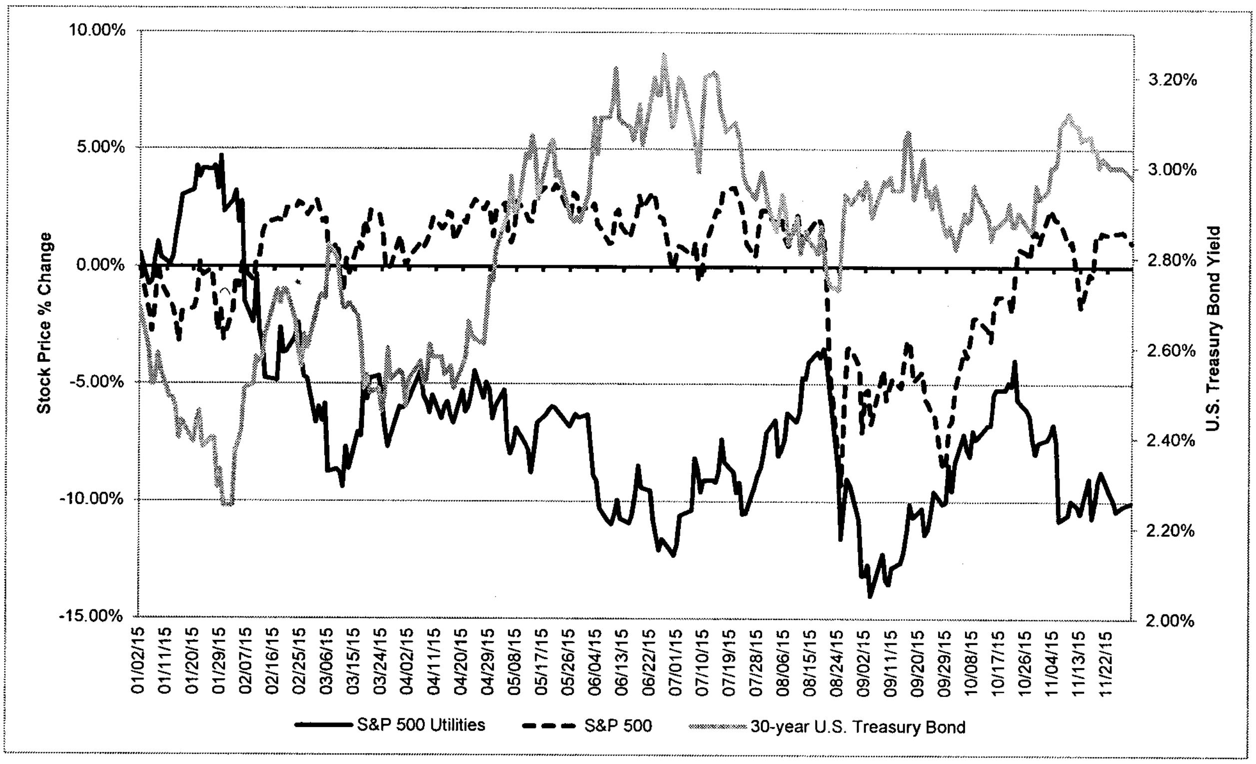
Q. How have equity markets reacted to widening credit spreads and the prospect for higher interest rates?

A. Equity markets have been declining in recent weeks and widening credit spreads signal possible economic distress ahead. As shown in Chart 3, utility stocks have underperformed the broader market since February 2015, as investors reacted to the gradual rise in Treasury bond yields. The broader market, as measured by the S&P 500, has been particularly volatile since mid-August, as equity investors contemplated the

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

prospect for higher interest rates and as global economic growth has slowed, especially in China.

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



Q. What is your conclusion regarding the effect of capital market conditions on the authorized ROE for UNS Electric?

A. Wider credit spreads between government and utility bond yields and increased market volatility are indications that investors are becoming more risk averse. Moreover, investors expect interest rates to increase as the Federal Reserve withdraws the extraordinary level of monetary stimulus that has been provided to the U.S. economy since the Great Recession. As interest rates rise, dividend yields on utility shares become less competitive with higher yields on government and corporate bonds. As a result of higher credit spreads, increased market volatility and rising interest rates, it is reasonable to expect that the cost of capital for electric utilities such as UNS Electric is increasing, not decreasing.

IV. RESPONSE TO STAFF WITNESS ABINAH

Q. Please summarize Staff's ROE recommendation.

A. Staff recommends an ROE for UNS Electric of 9.50 percent, based on the Commission's December 31, 2013 decision approving the Settlement Agreement filed by the parties in Docket No. E-04204-A-12-0504. Staff cites the 2009 and 2012 rate cases filed by UNS Electric, in which Staff retained Mr. David Parcell to conduct cost of capital studies. Staff states that by approving the Settlement Agreement, the Commission found that the resulting rates were just, fair and reasonable.[14]

Q. What is your response to Staff's testimony and recommendation concerning the cost of capital?

A. I do not agree that it is "relevant, reasonable and consistent" to rely on the 2013 Settlement Agreement to set the authorized ROE for UNS Electric in this proceeding. One of the fundamental principles of the *Hope* and *Bluefield* decisions is that the cost of capital should be commensurate with returns available to other companies with comparable risk. Another fundamental principle of those decisions is that the cost of capital should be consistent with current economic and capital market conditions. As I have stated, the current economic and financial market conditions are not similar to those in 2013. Further, the 9.50 percent ROE recommendation is not consistent with recently authorized ROEs for vertically-integrated electric utilities in other jurisdictions.

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[14] Direct Testimony of Elijah Abinah, at 5.

As shown in Chart 1, that recommendation is lower than almost all recently authorized ROEs.

Q. Do you agree with Staff that it is reasonable to conclude that the Cost of Equity for electric utilities today is in the range of 8.50 percent to 10.50 percent?

A. No, I do not. The basis for Staff's conclusion is that the Commission should rely on the Cost of Equity range presented in the testimony of Staff's witness, David C. Parcell, in the 2009 and 2012 UNS Electric rate cases. However, a reasonable cost of capital is highly dependent on the time period in which it is being established. Numerous changes have occurred since those 2009 and 2012 rate cases that make comparisons difficult, if not impossible. For example, many of the companies in the proxy groups used by Mr. Parcell have been involved in mergers and could not be used to estimate the Cost of Equity for UNS Electric today. Furthermore, economic and capital market conditions are very different in November 2015 than in June 2013 (when Mr. Parcell filed testimony in the 2012 rate case) or in November 2009 (when Mr. Parcell filed testimony in the 2009 rate case). In particular, monetary policy has evolved as the Federal Reserve introduced and ultimately discontinued its Quantitative Easing programs. Similarly, the interest rate outlook is very different because economic conditions have improved and unemployment has declined substantially, allowing the Federal Reserve to start the new cycle of monetary tightening. Likewise, credit spreads have increased significantly in 2015, as yields on utility bonds have risen more than 60 basis points since January, while yields on government bonds have been held down by highly accommodative monetary policy.[15] In addition, equity valuations have increased substantially since 2009, as investors have been willing to pay higher multiples for the earnings stream because the relative returns from bonds have been so depressed due to

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[15] The Moody's A-rated utility bond index credit spread is 65 basis points. The spread for the Moody's Baa-rated utility bond index is greater than 100 basis points.

the low interest rate environment since the Great Recession. These higher equity valuations have been driven by monetary policy, which was intended to push investors out of lower-risk asset classes such as savings accounts and certificates of deposit, into higher-risk asset classes such as common equity. For all of these reasons, I do not agree that it is reasonable to rely on equity cost rates that were established under very different economic and capital market conditions, and using very different proxy groups of electric utility companies.

Q. Have you compared projected economic conditions today with those at the time when Mr. Parcell filed testimony in the 2009 and 2012 UNS Electric rate cases?

A. Yes, I have compared the current outlook for the U.S. economy to projected conditions in November 2009 and June 2013 when Mr. Parcell filed testimony in the two previous UNS Electric rate cases. As shown in Table 3, projected unemployment rates have declined substantially from 9.9 percent in November 2009 to 4.8 percent in November 2015. Similarly, projected growth in disposable personal income has increased from 1.4 percent in November 2009 to 2.7 percent in November 2015, as U.S. consumers are feeling more confident about prospects for employment, wage gains and economic growth. Forecasted real GDP growth has remained steady since 2009 as the economic recovery has been weaker than after most recessions, while the projected inflation rate is slightly lower than in November 2009, which allowed the Federal Reserve to maintain its "highly accommodative" monetary stance for longer than expected.

Table 3: Projected Key Economic Indicators[16]

	Nov. 2015 (for 2016)	June 2013 (data used in 2014 Settlement Agreement)	Nov. 2009 (data used in 2010)
Unemployment Rate	4.8%	7.1%	9.9%
Real GDP (annualized)	2.6%	2.6%	2.7%
Inflation (CPI)	1.8%	1.9%	2.0%
Disposable Personal Income	2.7%	2.6%	1.4%

Based on stronger conditions in employment markets, the Federal Reserve announced at the conclusion of the December 2015 FOMC meeting that it would increase short-term interest rates by 25 basis points, which marks the first increase in the Fed Funds rate in nine years.

Q. **How do interest rates and credit spreads in December 2015 today compare with those at the time when Mr. Parcell filed testimony in the 2009 and 2012 UNS Electric rate cases?**

A. As discussed in Section III, credit spreads have increased steadily throughout 2015 as yields on corporate and utility bonds have risen much more than yields on government bonds, which are still held artificially low by monetary policy. As shown in Table 4, 90-day rolling average credit spreads between 30-year Treasury bonds and Moody's Baa and A-rated utility bonds are higher now than in June 2013. It is not reasonable to compare the current market conditions to those in November 2009 because financial and credit markets in 2009 were still impacted by the financial crisis, and credit spreads were exaggerated.

16 Sources: Blue Chip Economic Indicators, Volume 40, No. 11, November 10, 2015, at 4, Blue Chip Economic Indicators, Volume 38, No. 6, June 10, 2013, at 4, and Blue Chip Economic Indicators, Volume 34, No. 11, November 10, 2009, at 4.

Table 4: Interest Rates and Credit Spreads[17]

	11/30/2015	6/28/2013	11/6/2009
90-day average yield U.S. Treasury bonds	2.93%	3.14%	4.29%
90-day average yield Moody's Baa-rated bond	5.40%	4.73%	6.37%
Spread between 30-year U.S. Treasury and Moody's Baa-rated utility bond index	2.47%	1.58%	2.08%
Spread between 30-year U.S. Treasury and Moody's A-rated utility bond index	1.40%	1.07%	1.40%
Spread between Moody's Baa and A-rated bond index	1.07%	0.51%	0.68%

Rising credit spreads are an indication of increased investor risk aversion. Equity markets have been more volatile in 2015, and stock prices have declined in 2015 for dividend paying stocks such as electric utilities which are more sensitive to higher interest rates. As such, rising credit spreads are another indication that capital costs are higher today than at the time Mr. Parcell filed his testimony in the 2012 UNS Electric rate case.

Q. Which proxy group companies that were used by Mr. Parcell in his DCF, CAPM, and Comparable Earnings analyses in the 2009 and 2012 rate cases could not be used today to estimate the Cost of Equity for UNS Electric?

A. Consistent with most analysts, Mr. Parcell relies on a merger screening criteria, excluding companies from his analysis that are involved in transformative transactions. Several companies that were included in Mr. Parcell's 2009 and 2012 analyses of the Cost of Equity could not be used currently because they have either been acquired or are involved in mergers/acquisitions. Based on his November 2009 testimony, three of

17 Source: Bloomberg Professional.

seven companies would be excluded from his proxy group on this basis: Hawaiian Electric; Pepco Holdings; and TECO Energy. Based on Mr. Parcell's June 2013 testimony, four of the eight companies would be excluded from his proxy group: Cleco Corp; Hawaiian Electric; Pepco Holdings; and UIL Holdings. In both cases, that would leave only four companies in the Parcell proxy group, which is generally not considered a sufficient sample size for an ROE analysis.

Q. Is Staff's ROE recommendation of 9.50 percent consistent with returns for integrated electric utilities in other jurisdictions across the U.S.?

A. As shown in Chart 1, Staff's ROE recommendation of 9.50 percent is on the lower end of recent ROE awards for integrated electric utilities. Forward-looking economic and capital market conditions as well as UNS Electric's additional business risks support an authorized ROE *above* the proxy group average and higher than 9.50 percent. As discussed in my Direct Testimony, UNS Electric is smaller than the proxy group companies, has an elevated level of capital expenditures compared to the companies in the proxy group, and has above average regulatory risk in Arizona.[18]

Q. What is your conclusion regarding Staff's ROE recommendation of 9.50 percent?

A. While UNS Electric would not oppose Staff's ROE recommendation as long as the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn that ROE, the results of the ROE estimation models and the risk factors discussed in my Direct and Rebuttal Testimony demonstrate that the appropriate ROE today is significantly higher than the 9.50 percent that was approved in the Settlement Agreement in the Company's last rate case. As I have demonstrated, conditions in capital markets suggest that investors are more risk averse now than in

[18] Direct Testimony of Ann E. Bulkley, at 41-49.

2013, as shown by higher yields on corporate and utility bonds, wider credit spreads between government and corporate debt, declining valuations for utility shares, and more volatility in the broader equity markets. Furthermore, ROE awards for integrated electric utilities have generally been above the 9.50 percent level in 2014 and 2015. Taking into consideration UNS Electric's above average business risk, I believe that an authorized ROE above recent returns for other integrated electric utilities is justified.

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

A. Staff summarizes the FVROR that was adopted by the Commission in the UNS Electric cases since 2009, noting that the Commission applied a cost rate of 2.10 percent to the Fair Value Increment in Decision No. 71914 and 0.50 percent in Decision No. 74235. Based on this review, Staff recommends that the Commission approve a cost rate of 0.50 percent for the Fair Value Increment in this proceeding.[19]

Q. Do you agree with Staff's recommendation?

A. The methodology that was used in Decision Nos. 71914 and 74235 and are relied on currently by Mr. Abinah is consistent with the methodology used in my Direct Testimony, assigning a return to the Fair Value Increment. However, I believe that current economic and market conditions would support a cost rate that is higher than Staff proposes to apply to the Fair Value Increment. Similar to the ROE recommendation, Staff's proposed cost rate on the Fair Value Increment is based on the recommendation of Mr. Parcell in Docket No. E-04204-A-12-0504, which relied on data from 2012.

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[19] Direct Testimony of Elijah Abinah, at 11.

While the Commission approved a 0.50 percent cost rate for the Fair Value Increment in Decision No. 74235, that rate was approved as part of a Settlement Agreement. In the conclusions in that decision, the Commission specifically noted that the Settlement Agreement provided benefits to ratepayers, shareholders and the community and represented a fair and balanced resolution of all issues "[b]ased on the totality of circumstances". Therefore, the Commission did not specifically determine that this cost rate was the appropriate rate to be used for the Fair Value Increment.

Even if the Commission had specifically approved a 0.50 percent rate in Decision No. 74235, that cost rate was based on market conditions at the time of that proceeding, which relied on data from 2012. As discussed in my response to Staff's ROE recommendation, market conditions have changed significantly since December 2013. Therefore, even though UNS Electric would not oppose Staff's 0.50 percent rate recommendation as long as the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn its authorized ROE, the data presented in my Direct Testimony demonstrates that the inflation rate that could be applied to the fair value increment rate is higher than the 0.50 percent in the Settlement Agreement approved in the Company's last rate case.

V. RESPONSE TO RUCO WITNESS MEASE

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

A. Based on his analyses, Mr. Mease develops a range of ROE results from 6.00 percent to 8.95 percent, and recommends an ROE for UNS Electric of 8.35 percent.[20] The mean result of Mr. Mease's Constant Growth DCF analysis forms the upper boundary of his range of results, while the lower boundary is based on the lowest result from his CAPM

[20] Direct Testimony of Robert B. Mease, at 14.

analysis using a geometric mean market risk premium. Mr. Mease ignores the high end of the range of results of 9.63 percent established using his DCF analysis. Mr. Mease indicates that his point estimate of 8.35 percent is slightly above the midpoint of his arithmetic mean CAPM result of 7.19 percent and his Constant Growth DCF result of 8.95 percent. Mr. Mease testifies that his ROE recommendation is consistent with the current low interest rate environment[21], and that electric utility shares enjoyed strong returns in 2014 as compared to the broader market.[22] Mr. Mease supports the Company's proposed capital structure of 52.83 percent common equity and 47.17 percent long-term debt. Mr. Mease calculates the weighted average cost of capital of 6.86 percent, then deducts 0.25 percent as an inflation adjustment. Further, Mr. Mease recommends a FVROR for UNS Electric of 5.26 percent, which he derives by subtracting an inflation rate of 1.35 percent from his inflation adjusted weighted average cost of capital of 6.61 percent.

Q. Is Mr. Mease's ROE recommendation of 8.35 percent fair and reasonable for UNS Electric?

A. No, Mr. Mease's ROE recommendation of 8.35 percent is 115 basis points below UNS Electric's currently authorized ROE and is substantially lower than returns available from other comparable-risk investments. Mr. Mease provides no analysis that demonstrates that the Cost of Equity has declined since UNS Electric's last rate proceeding to justify such a significant reduction in the Company's Cost of Equity. Mr. Mease's discussion of economic and capital conditions is largely outdated and does not reflect the reality of higher credit spreads, or prospects for higher interest rates, or the volatility that has characterized the broader equity market in recent months. As a result, Mr. Mease's recommendation does not reflect the current and prospective market

21 *Ibid.*, at 26.
22 *Ibid.*, at 21.

conditions that UNS Electric will experience when the return that is decided in this case will be in effect. Finally, Mr. Mease has failed to take into consideration additional business and regulatory risks which differentiate UNS Electric from the proxy group companies, such as UNS Electric's significant capital expenditure requirements, the Company's small size, and the uncertain regulatory environment in Arizona.

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

A. I disagree with the following aspects of Mr. Mease's analyses: (1) his sole reliance on a Constant Growth DCF model and his failure to consider a Multi-Stage DCF analysis; (2) his use of projected dividend growth rates in the Constant Growth DCF model; (3) his failure to consider the full range of results in the DCF analysis; (4) his application of the CAPM and the reasonableness of his CAPM results; (5) his failure to take into consideration the higher business and regulatory risks to which UNS Electric is exposed relative to the proxy group companies; and (6) his FVROR recommendation and the method used to derive that recommendation.

A. Application of the Constant Growth DCF Model

Q. What are your concerns with Mr. Mease's sole reliance on the Constant Growth form of the DCF model?

A. Mr. Mease's analysis does not consider the possibility that growth rates may change over time, something that is important to consider, especially as macroeconomic conditions are recovering very slowly from a significant market shock. Mr. Mease identifies specifically that the DCF model he relies on assumes that: 1) dividends will grow at a constant rate into perpetuity, and 2) the dividend payout ratio will remain at a constant rate.[23] Mr. Mease notes that both assumptions are based on the underlying assumption that earnings, dividends, book value and share growth all increase at the same rate into infinity. Based on recent market conditions, it is reasonable to expect that growth rates will change over time and to reflect that in the analysis using a Multi-Stage model.

Q. Do you agree with the proxy group that Mr. Mease relies on for his DCF analysis?

A. While the proxy group companies are generally similar to the group that I relied on in my Direct Testimony, since that testimony was filed, Southern Company has entered into a merger agreement. Therefore, Southern Company would no longer meet my screening criteria and would be excluded from the proxy group during the analytical period that Mr. Mease relied on. As shown on Exhibit AEB-R-7, removing Southern Company from Mr. Mease's analysis would increase the mean results of his DCF analysis to 9.00 percent and the high end of the range to 9.71 percent.

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

A. Mr. Mease states that dividend growth can be measured using the product of a company's retention ratio and its return on book equity.[24] This is the sustainable growth rate commonly expressed as the "b" x "r" growth rate. However, in Exhibit RBM-5, Mr. Mease's analysis relies on both projected dividend growth rates, as reported by Value Line, and analysts' projected earnings growth rates as, reported by Yahoo! Finance, not on sustainable growth, as his testimony implies.

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23 Direct Testimony of Robert B. Mease, at 8.

24 Ibid, at 9.

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

A. Not entirely. Mr. Mease relies on an average of projected dividend per share growth and earnings per share growth rates to estimate the growth rate in the DCF model. Estimates of earnings growth are more indicative of long-term investor expectations than are dividend or book value growth estimates because earnings growth is least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Furthermore, earnings are the fundamental driver of a company's ability to pay dividends. As noted by Brigham and Houston:

> Growth in dividends occurs primarily as a result of growth in earnings per share (EPS). Earnings growth, in turn, results from a number of factors, including (1) inflation, (2) the amount of earnings the company retains and invests, and (3) the rate of return the company earns on its equity (ROE).[25]

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

Q. How would the results of Mr. Mease's DCF analysis change if he relied only on projected earnings per share growth rates?

A. As shown on Exhibit AEB-R-7, the results of Mr. Mease's DCF analysis excluding Southern Company would increase by 35 basis points to 9.35 percent.

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

Q. Are there other assumptions in Mr. Mease's DCF analysis that you disagree with?

A. Yes. Mr. Mease's growth rates and the pricing data are not based on the same time periods. Mr. Mease relies on pricing data for the period from July 1, 2015 through September 30, 2015 from Yahoo! Finance, but uses earnings growth rates as of October 29, 2015. The more common approach to specifying the DCF model is to use growth rates and pricing data for the same valuation period.

Q. What is the appropriate correction to make for this error?

A. It is necessary to align the growth rates and the prices to the same analytical period. As shown in Exhibit AEB-R-7, adjusting Mr. Mease's analytical period to September 30, 2015, to be consistent with the pricing data that he has relied on increases his DCF result using EPS growth rates and excluding Southern Company to 9.36 percent.

Q. Please summarize the effects of the changes that you made to Mr. Mease's DCF results.

A. As shown in Table 5 below, by making corrections and appropriate changes to Mr. Mease's DCF analysis, the mean ROE range of results increases by 28 to 56 basis points and overlaps my recommended range of 10.00 to 10.60 percent.

Table 5: Summary of Adjustments to Mease DCF

	ROE Range
Filed	8.26%-9.63%
Excl. SO	8.28%-9.71%
Excl. SO, & Using EPS	8.44%-10.27%
Excl. SO, Using EPS & Using Sept. Data	8.54%-10.19%

Q. Do you agree with the range of results Mr. Mease relies on from his DCF analysis?

A. No, I do not. Mr. Mease's DCF analysis estimates the ROE that results from using a low, mean, and high growth rate. As shown in Exhibit RBM-5, the range of results from that analysis is 8.26 percent to 9.63 percent, with a mean result of 8.95 percent. Mr. Mease's recommended ROE for UNS Electric of 8.35 percent is 60 basis points below the mean result of his DCF analysis and only nine basis points higher than his low DCF result. Mr. Mease provides no evidence to demonstrate why he believes that the business risk that UNS Electric faces is lower than the average risk of the proxy companies that he relies on. Furthermore, Mr. Mease disregards the high end of the range of his DCF results without providing any rationale for excluding these results.

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

A. Yes, I have. While the commission in that case did rely on the DCF model, there are other important factors to be noted from this decision. First, the commission indicated that while it has a preference for the DCF model, it does not preclude parties from filing other approaches and most importantly, the commission considered the entire record, "which may include actions taken by other commissions and recent changes in the law."[26] Furthermore, the commission set the upper bound of the ROE at the high end of the range of the Constant Growth DCF results, calculated based on the high earnings per share growth rates; similar to the calculation that Mr. Mease performed that resulted in an ROE of 9.63 percent which was ignored in establishing his range. Finally, it is important to note that the ROE that was established by that commission in 2014 for Potomac Electric Power (a lower-risk transmission and distribution only utility) was 9.50 percent, or 115 basis points higher than the ROE recommended by Mr. Mease.

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

B. **Application of Capital Asset Pricing Model**

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

A. Mr. Mease's CAPM analysis relies on a historical market risk premium ("MRP"), calculated using both the geometric and arithmetic averages, and the three month historical average yield on 30-year Treasury bonds of 3.01 percent as the risk free rate. That analysis produces an ROE estimate for UNS Electric of 6.00 percent using a geometric mean MRP and 7.19 percent using an arithmetic mean MRP.[27] Mr. Mease relies on average Value Line Beta coefficients for the proxy group of 0.75, and a MRP of either 4.0 percent (geometric mean) or 5.60 percent (arithmetic mean).[28] Despite the fact that Mr. Mease's CAPM analysis produces an ROE estimate as much as 350 basis points below the currently authorized ROE for UNS Electric, Mr. Mease does not question the reasonableness of his CAPM results, establishing the low end of his range for a cost of common equity for UNS Electric at 6.00 percent, which is the low end of the results of his CAPM analysis.[29]

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

A. Mr. Mease's CAPM results of 6.00 percent and 7.19 percent are entirely inconsistent with the returns required by equity investors for companies with commensurate risk. As noted previously, these results are 231 to 350 basis points below UNS Electric's currently authorized ROE and suggest an equity risk premium of only 134 to 253 basis points above the Company's embedded debt cost of 4.66 percent. The high end of this range is approximately half of the equity risk premium implied by Staff's

27 Direct Testimony of Robert B. Mease, at 14.
28 Exhibit RBM-6.
29 Direct Testimony of Robert B. Mease, at 14.

recommendation, and a 6.00 percent ROE suggests an equity risk premium that is slightly more than 25 percent of the equity risk premium proposed by Staff's recommended ROE. Furthermore, neither of Mr. Mease's average CAPM results has ever been observed as an authorized ROE for any electric utility in at least the past 25 years. Mr. Mease's CAPM results are as low as 5.21 percent (geometric mean) and 6.09 percent (arithmetic mean) for an individual company (Southern Company).

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

A. No, I do not. As Mr. Mease notes, the Commission has stated that "the consideration of both historical and projected data is appropriate in evaluating the Cost of Equity".[30] Therefore, the use of only the three month historical average yield of 3.01 percent as the risk free rate in the CAPM analysis is not reasonable, especially when considering investors' expectation for rising interest rates during the period when this return will be in effect. Furthermore, Mr. Mease fails to take into consideration the inverse relationship between interest rates and the MRP. That is, if current interest rates are approximately 300 basis points below historical levels, it is not appropriate to use the three month average historical yield on 30-year Treasury securities as the risk free rate in conjunction with the historical MRP from Morningstar. Furthermore, Mr. Mease submitted the only independent CAPM analysis that does not consider the effect of rising interest rates on the Cost of Equity. Projected yields on 30-year Treasury securities indicate that investors are expecting substantially higher interest rates and higher inflation over the next five years.

30 Direct Testimony of Robert B. Mease at 16. See also Decision No. 75268.

Q. Do you agree with the method Mr. Mease has used to derive his MRPs of 4.00 percent and 5.60 percent?

A. No. I disagree with Mr. Mease's MRPs for three reasons. First, Mr. Mease has subtracted the total return on government bonds rather than the income only return on those bonds from the total return on large company stocks. Second, Mr. Mease relies on both the geometric and arithmetic mean MRP. Third, as noted above, Mr. Mease has failed to consider the inverse relationship between interest rates and the MRP, which suggests that it is not appropriate to use a current risk free rate in conjunction with a historical MRP when the current risk free rate is substantially lower than the government bond yield that was used to derive the historical MRP. For all of these reasons, Mr. Mease's MRP is under-stated and does not reflect investors' expectations for future equity returns.

Q. How would you correct the MRP used in Mr. Mease's analysis?

A. It is important to take into consideration the relationship between interest rates and the MRP. Therefore, if Mr. Mease is relying on the three month average historical yield on Treasuries of 3.01 percent as the estimate of the risk-free rate, that same yield should also be used in the estimation of the MRP. As shown in Schedule RBM-6, Mr. Mease's calculation of the MRP is based on a risk-free rate of 6.40 percent and relies on a three-month historical risk-free rate of 3.01 percent in the CAPM. The estimation of the MRP should reflect the current MRP and therefore should rely on the estimate of the current risk-free rate. Correcting the MRP to rely on the current risk-free rate of 3.01 percent increases the MRP to 8.99 percent from 5.60 percent.

Q. Why is it not appropriate to use the total return on government bonds to derive the MRP?

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

> Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. The total return is comprised of three return components: the income return, the capital appreciation return, and the reinvestment return…The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return.[31]

By subtracting the total return on government bonds from the total return on large company stocks, Mr. Mease has understated the historical MRP by approximately 140 basis points (using the arithmetic mean).[32] Based on Mr. Mease's average Beta coefficient of 0.75, the effect on his mean CAPM estimate is approximately 35 basis points. Even that correction, however, renders results that are far too low to be reasonable estimates of UNS Electric's Cost of Equity.

Q. What is the difference between the geometric and arithmetic mean for calculating the MRP?

A. Although I do not endorse the use of a historical MRP, the arithmetic risk premium best approximates the uncertainty associated with returns from year to year. The arithmetic mean is the simple average of single period rates of return, while the geometric mean is the compound rate that equates a beginning value to its ending value. The important distinction between the two methods is that the arithmetic mean assumes that each

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

32 *Ibid.*, at 23.

periodic return is an independent observation and, therefore, incorporates uncertainty into the calculation of the long-term average. By contrast, the geometric mean does not incorporate the same degree of uncertainty because it assumes that returns remain constant from year to year. In his review of literature on the topic, Cooper noted the following rationale for using the arithmetic mean:

> Note that the arithmetic mean, not the geometric mean is the relevant value for this purpose. The quantity desired is the rate of return that investors expect over the next year for the random annual rate of return on the market. The arithmetic mean, or simple average, is the unbiased measure of the expected value of repeated observations of a random variable, not the geometric mean....[The] geometric mean underestimates the expected annual rate of return.[33]

Q. How can the projected MRP be estimated?

A. As discussed in my Direct Testimony, a reasonable method to estimate the forward-looking MRP is to subtract the projected 30-year Treasury bond yield from the expected return on the S&P 500 Index.[34] Based on an estimated weighted-index dividend yield of 2.13 percent and a weighted-index long-term growth rate of 11.26 percent, the required S&P 500 market return is approximately 13.51 percent. The implied MRP over the projected 30-year Treasury yield is 8.71 percent, or 311 to 471 basis points higher than Mr. Mease's estimates of 4.00 percent and 5.60 percent.

Q. Have you estimated the change in the CAPM range of returns resulting from these proposed adjustments?

A. Yes. Exhibit AEB-R-8 adjusts Mr. Mease's CAPM analysis for the following changes: 1) updated the historical arithmetic mean market return; 2) adjusted the risk free rate used in the calculation of the MRP to be consistent with the current risk free rate; and 3)

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

34 Direct Testimony of Ann E. Bulkley, at 36-37.

adjusted proxy group to exclude Southern Company. As shown in that Exhibit, the range of returns increases to 8.46 percent to 10.74 percent, with a mean ROE estimate of 9.93 percent.

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

A. Mr. Mease's inputs to the CAPM analysis are based on historical data rather than forward-looking investor expectations. Under the current interest rate environment, the CAPM does not produce reliable results without making adjustments to certain inputs and assumptions. Consequently, Mr. Mease's CAPM analysis provides no meaningful insight into the Cost of Equity for UNS Electric and should not be used to establish the reasonable range of ROE estimates in this proceeding.

C. Fair Value Rate of Return

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

A. Mr. Mease recommends a FVROR of 5.26 percent for UNS Electric, which is derived by subtracting an inflation rate of 1.35 percent from his overall cost of capital of 6.61 percent.[35] Mr. Mease's inflation rate is based on a seven-year historical average difference between the yield on Treasury Inflation Protected Securities ("TIPS") and comparable Treasury securities with similar liquidity and duration.

[35] Direct Testimony of Robert B. Mease, at 5. Also, see Schedule RBM- 1, page 1.

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

A. No, I do not. First, I disagree with the application of the entire inflation factor to the OCROR; in addition, I disagree with the specific estimate of inflation that was used in Mr. Mease's analysis.

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

A. Based on the methodology that has been used to estimate the FVRB, it is not reasonable to reduce the entire OCROR by the inflation factor. The FVRB is estimated by equally weighing the Original Cost Rate Base ("OCRB") and the Replacement Cost New Depreciated ("RCND") estimate of the value of the rate base. Only the RCND has an inflation component. Therefore, the application of the inflation rate to the entire FVRB incorrectly reduces the original cost portion of the rate base when that cost component does not include inflation. Therefore, if the inflation factor is to be applied to the OCROR, it should be reduced by 50 percent to reflect the fact that 50 percent of the FVRB has no inflation component.

Q. Does Mr. Mease recognize that the FVRB is based on OCRB and RCND?

A. Yes, Mr. Mease recognizes that it is the RCND that includes inflation and suggests that the difference in the value of the OCRB and the FVRB is "due entirely to inflation."[36]

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

A. The calculation proposed in my Direct Testimony is consistent with the methodology proposed by Staff. This approach assigns a separate return on the Fair Value Increment,

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[36] RUCO response to UNS 3.1.

which is the difference between the OCRB and the FVRB. As shown in Exhibit AEB-R-11, I calculate the FVROR by applying the equity cost rate of 10.35 percent to the equity component of the OCRB, and the debt cost rate to the debt component of the OCRB without adjustment. The Fair Value Increment is then assigned a cost rate equal to one half of the inflation rate.

Q. Why do you disagree with the inflation rate relied on by Mr. Mease?

A. The inflation expectations over the historical period Mr. Mease relied on range from 0.48 percent in 2015 to 2.23 percent in 2011.[37] Since 2011, the inflation rate that is projected using Mr. Mease's methodology has been declining. Therefore, relying on a long-term historical average over this period significantly overstates the expected inflation using his methodology. Furthermore, as discussed in the Rebuttal Testimony of Mr. Grant, very minor changes in expected inflation produce significant changes in the FVROR and overall revenue requirement. Significant variability in the revenue requirement resulting from this methodology exposes UNS Electric to much greater risk than the proxy companies.

Q. Does the inflation adjustment proposed by Mr. Mease result in a FVROR penalty to UNS Electric?

A. As discussed in the testimony of Company witness Grant, the application of Mr. Mease's 1.35 percent inflation factor to the Company's proposed WACC would result in a FVROR of 6.32 percent, which is slightly higher than the result of the methodology developed in my Direct Testimony.

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37 Schedule RBM-4.

Q. Do you agree then with Mr. Mease's recommended FVROR?

A. No, I do not. Mr. Mease applies the inflation factor of 1.35 percent to his recommended OCROR, which includes an equity rate of 8.35 percent. For the reasons discussed in my response to Mr. Mease's estimated ROE, I disagree with that proposed equity rate. Mr. Mease's recommended FVROR of 5.26 percent, which is developed from his equity cost rate and FVROR methodology, is significantly below the returns for other companies of similar risk and does not reflect the cost of capital for UNS Electric.

Q. What changes would you propose to Mr. Mease's recommended FVROR?

A. As discussed above, it is appropriate to adjust the inflation factor by 50 percent to reflect the fact that the FVRB is derived only 50 percent from the RCND. In addition, it would be appropriate to adjust the equity cost rate to a more reasonable estimate of the cost of equity.

Q. What is the resulting FVROR with your proposed changes to Mr. Mease's analysis?

A. Exhibit AEB-R-9 provides the result of those proposed changes. Relying on the adjusted DCF value shown in Table 5, and applying 50 percent of Mr. Mease's inflation factor results in a FVROR of 6.47 percent.[38]

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

A. I continue to support the methodology used in my Direct Testimony to establish the FVROR. That approach suggests a return on the Fair Value Increment between the

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[38] The use of a 9.35 percent ROE in this calculation does not suggest that this is the appropriate cost of equity for UNS Electric. Rather, this analysis demonstrates that using a return that is more consistent with Staff's proposal and a reasonable inflation factor would result in a FVROR that is similar to the FVROR proposed by the Company.

projected risk free rate and the ROE. The methodology that I have employed is consistent with the approach proposed by Staff, though the inflation factors differ. Specifically, I conclude that the minimum ROR that should be applied to the Fair Value "Increment" of rate base is the real risk free rate, which I estimate to be 3.01 percent.[39] The Company continues to advocate the use of 50.00 percent of the risk free rate in the estimate of the FVROR calculation to moderate the effect of the rate increase on customers. Applying 50 percent of the risk free rate to the Fair Value Increment results in a FVROR of 6.22 percent, which I believe is conservative.

VI. RESPONSE TO TASC WITNESS DR. WOOLRIDGE

Q. Please provide a summary of Dr. Woolridge's testimony and recommendations.

A. Dr. Woolridge develops a range of results from 8.10 percent to 9.00 percent, and recommends an ROE for UNS Electric of 8.75 percent. Dr. Woolridge arrives at his recommendation by relying primarily on the results of his Constant Growth DCF analysis. He presents results for his proxy group of electric utilities, as well as my original proxy group excluding Southern Company. Dr. Woolridge's DCF results of 8.70 percent to 9.00 percent are based on his use of historical earnings growth rates, projected dividend and book value growth rates, and retention growth rates, as well as projected earnings growth rates from Value Line, First Call, Zack's and Reuters. In addition, Dr. Woolridge presents a CAPM analysis, which produces a Cost of Equity estimate between 8.10 percent and 8.30 percent depending on the proxy group. Dr. Woolridge also recommends a hypothetical capital structure comprised of 50 percent common equity and 50 percent long-term debt, rather than UNS Electric's actual test year capital structure of 52.83 percent equity and 47.17 percent long-term debt.

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[39] *See* Direct Testimony Exhibit AEB-R-11.

Q. Is Dr. Woolridge's 8.75 percent ROE recommendation fair and reasonable for UNS Electric?

A. No. Dr. Woolridge's 8.75 percent ROE recommendation is not fair and reasonable because it is not comparable to returns available from other investments of comparable risk and could have a detrimental effect on the financial integrity of the Company and its ability to access capital on reasonable terms. Furthermore, the rates set in this case, including the ROE and capital structure, will directly affect UNS Electric's cash flows in the period during which rates are in effect. The Company's cash flows, in turn, have a direct bearing on its credit quality and investors' perception of the riskiness of the enterprise. Given this, Dr. Woolridge's recommended ROE of 8.75 percent could exert pressure on the credit metrics that are of the greatest concern to both debt and equity investors. For these reasons, Dr. Woolridge's ROE recommendation is not consistent with the comparability and capital attraction standards established in *Hope* and *Bluefield,* which were discussed in my Direct Testimony.[40]

Q. What are the principal areas of disagreement between you and Dr. Woolridge?

A. As discussed in more detail below, there are several areas in which Dr. Woolridge and I disagree, including: 1) the composition of our respective proxy groups; 2) the growth rates to be applied in the Constant Growth DCF model; 3) the long-term growth rate to be applied in the Multi-Stage DCF model; 4) the market risk premium and the risk free rate inputs to the CAPM; 5) the applicability of the Bond Yield Plus Risk Premium approach; 6) the relevance of market-to-book ratios; 7) the effect of business risks on the Company's ROE; and 8) the appropriate capital structure for UNS Electric.

A. Proxy Group Selection

Q. Please explain your disagreement with Dr. Woolridge regarding the appropriate proxy group for UNS Electric.

A. Dr. Woolridge and I have each developed a proxy group to estimate the Cost of Equity for UNS Electric. However, we have used somewhat different screening criteria in developing our respective proxy groups. Consequently, Dr. Woolridge's proxy group consists of 29 electric utility companies, whereas my initial proxy group was comprised of 13 electric utilities (now reduced to 11 companies due to the exclusion of Southern Company and Duke Energy Corporation).

Q. What is the purpose of a proxy group?

A. An appropriate proxy group consists of companies that are comparable in business and financial risk to UNS Electric. The importance of selecting a proxy group that is similar in overall financial and business risk to the subject company was endorsed by the United States Court of Appeals for the District of Columbia (the "Circuit Court") in the *Petal Gas Storage* decision. The Circuit Court acknowledged that the goal of a proxy group is to rely on companies that possess similar risk to the subject company for the determination of the Cost of Equity:

> That proxy group arrangements must be risk-appropriate is the common theme in each argument. The principle is well-established. See Hope Natural Gas Co., 320 U.S. at 603 ("[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."); CAPP I, 254 F.3d at 293 ("[A] utility must offer a risk-adjusted expected rate of return sufficient to attract investors."). The principle captures what proxy groups do, namely, provide market-determined stock and dividend figures from public companies comparable to a target company for which those figures are unavailable. CAPP I, 254 F.3d at 293–94. Market determined stock figures reflect a company's risk level and, when combined with dividend values, permit calculation of the "risk-adjusted expected rate of return sufficient to attract investors."

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> What matters is that the overall proxy group arrangement makes sense in terms of relative risk and, even more importantly, in terms of the statutory command to set "just and reasonable" rates, 15 U.S.C. § 717c, that are "commensurate with returns on investments in other enterprises having corresponding risks" and "sufficient to assure confidence in the financial integrity of the enterprise . . . [and] maintain its credit and . . . attract capital," Hope Natural Gas Co., 320 U.S. at 603.[41]

Consistent with the Circuit Court's decision, I have selected a proxy group of companies with comparable investment risk as UNS Electric. In contrast, Dr. Woolridge has applied less stringent screening criteria, which result in a larger, less comparable proxy group. Consequently, there are companies in Dr. Woolridge's proxy group that do not meet the standards established in the *Petal Gas Storage* decision.

Q. Please explain the areas in which you disagree with either Dr. Woolridge's screening criteria or with specific companies in his proxy group.

A. While many of Dr. Woolridge's screening criteria are similar to mine, there are several important differences that affect the composition of our respective proxy groups. First, Dr. Woolridge screens based on the percentage of regulated revenue derived from electric operations rather than the percentage of regulated electric operating income. Since equity investors are primarily concerned with earnings, a net operating income screen is better aligned with the factor that matters most to investors. In addition, the percentage of total revenue can fluctuate considerably from period to period, based on the cost of purchased power or purchased fuel, even though the percentage of operating income is not likely to change as commodity prices fluctuate. Reliance on an operating income screen removes this distortion by excluding large pass-through costs such as the cost of purchased fuel and purchased power that have some, but considerably less, risk than other expense items.

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[41] *Petal Gas Storage v. FERC*, 496 F.3d 695, 699 (D.C. Cir. 2007).

Second, Dr. Woolridge has included several companies in his proxy group that derive more than 30 percent of their operating revenues from natural gas distribution operations, which have a different risk profile than vertically-integrated electric utilities such as UNS Electric. This includes the following companies: Avista Corporation, Black Hills Corporation (which is also involved in a merger with SourceGas), CMS Energy Corporation, and MGE Energy Corporation.

Third, I have concerns with several specific companies that Dr. Woolridge has included in his proxy group. In particular, Dr. Woolridge has included Edison International, First Energy Corp., and PG&E Corp., all of which I excluded from my proxy group due to significant company-specific risk factors that are not reflective of the risks faced by UNS Electric. As discussed in my Direct Testimony, I excluded Edison International from the proxy group due to the ongoing financial implications of the bankruptcy of its subsidiary, Edison Mission Energy.[42] With regard to First Energy Corp., in January 2014, First Energy announced a 35 percent reduction in its dividend. In testimony in other jurisdictions, Dr. Woolridge has previously excluded companies that had reduced or omitted their dividends during the prior three years.[43] However, in this proceeding, Dr. Woolridge has relaxed that screen to six months, which allows him to include First Energy in his proxy group. Finally, I have excluded PG&E Corporation from the proxy group because of the ongoing uncertainty regarding fines and penalties related to the San Bruno incident. Until investors have more certainty with respect to PG&E's liability, it is not appropriate to include PG&E in the proxy group.

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42 Direct Testimony of Ann E. Bulkley, at 20.

43 *See*, for example, Green Mountain Power, Docket No. 8190, submitted March 21, 2014, at 12.

Q. What is your conclusion with respect to the proxy group for UNS Electric?

A. My conclusion is that the proxy group developed in my Direct Testimony (now excluding Southern Company and Duke Energy Corporation) is more risk comparable to UNS Electric than the Woolridge Proxy Group.

B. Constant Growth DCF Analysis

Q. Please summarize the results of Dr. Woolridge's Constant Growth DCF analysis.

A. Dr. Woolridge's Constant Growth DCF analysis produces ROE estimates of 8.70 percent to 9.00 percent, depending on the proxy group.

Q. Have other regulators recognized the value of considering different models to estimate the Cost of Equity as market conditions change?

A. Yes. I recognize that the Commission has traditionally relied primarily on the results of the DCF model. However, as discussed in my Direct Testimony, there are concerns that the DCF models are producing anomalous results under current market conditions.[44] For that reason, I believe it is appropriate to also consider the results of other models as a check on the reasonableness of the DCF results. In addition to the example provided in my Direct Testimony, in Opinion No. 531 the Federal Energy Regulatory Commission ("FERC") recently recognized that the inputs to the DCF model have been affected by anomalous market conditions and therefore for the first time, is considering the use of other ROE estimation models.

> [W]e also understand that any DCF analysis may be affected by potentially unrepresentative financial inputs to the DCF formula, including those produced by historically anomalous capital market conditions. *Therefore, while the DCF model remains the*

[44] Direct Testimony of Ann E. Bulkley, at 18.

Commission's preferred approach to determining allowed rate of return, the Commission may consider the extent to which economic anomalies may have affected the reliability of DCF analyses in determining where to set a public utility's ROE within the range of reasonable returns established by the two-step constant growth DCF methodology.[45]

The FERC indicated that it will look at other ROE estimation methodologies to inform their judgment as to where, within the zone of reasonableness, the ROE should be set. In particular, the FERC found risk premium based approaches, such as the CAPM, informative.

Q. Are the results of Dr. Woolridge's Constant Growth DCF analysis consistent with ROEs awarded recently to electric utility companies?

A. No, as shown in Chart 1, Dr. Woolridge's Constant Growth DCF results are not consistent with the range of authorized ROEs for electric utility companies. Furthermore, Dr. Woodridge's results are not consistent with the results of other ROE estimation models, such as the Multi-Stage DCF, the forward-looking CAPM analysis, or the Bond Yield Plus Risk Premium analysis.

Q. What growth rates does Dr. Woolridge use in his Constant Growth DCF analysis?

A. Dr. Woolridge arrives at growth rate estimates of 4.75 percent for his proxy group and 5.0 percent for the Bulkley Proxy Group.[46] Dr. Woolridge's growth rates are based on consideration of both historical and projected growth in EPS, as well as historical and projected dividends per share ("DPS") and book value per share ("BVPS"), and the internal growth rate. Dr. Woolridge obtains projected EPS growth rates from Value

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[45] 147 FERC ¶ 61,234, para. 41. (Emphasis added.)

[46] Direct Testimony of Dr. J. Randall Woolridge, at 21.

Line, Yahoo! Finance, Zacks, and Reuters, and all other historical and projected DPS, BVPS, and internal growth rates from Value Line.

Q. How does Dr. Woolridge select the growth rate estimates he has used in his Constant Growth DCF model?

A. Dr. Woolridge's growth rate estimates appear to be subjectively set within the range for each proxy group. Dr. Woolridge states that he has given "primary weight to the projected EPS growth rate of Wall Street analysis,"[47] but the weight he has ascribed to projected EPS growth rates is unclear and is inconsistent between proxy groups. For his proxy group, Dr. Woolridge finds that the range of "projected growth rate indicators (ignoring historical growth)" is from 4.20 percent (equal to Value Line's projected mean BVPS growth rates) to 4.80 percent (equal to Value Line's projected mean DPS growth rates and Zack's projected EPS growth rate).[48] For the Bulkley proxy group, Dr. Woolridge finds that the range of growth rates is from 3.50 percent (equal to Value Line's 10-year historical mean BVPS growth rate and Value Line's projected sustainable growth rate) to 5.20 percent (which corresponds to the mean consensus projected EPS growth rates from Zack's, Reuters, and Yahoo! Finance).[49]

Q. Do you agree with Dr. Woolridge that "there are several issues with using the EPS growth rate forecasts of Wall Street analysts as DCF growth rates"?[50]

A. No, I strongly disagree with Dr. Woolridge on this point. As discussed in my Direct Testimony, earnings are the fundamental determinant of a company's ability to pay dividends.[51] Further, both dividends and book value per share may be directly affected

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47 *Ibid.*
48 *See* Exhibit JRW-10.
49 *Ibid.*
50 Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-15.
51 Direct Testimony of Ann E. Bulkley, at 25.

by short run management decisions. As a result, dividend growth rates and book value growth rates may not accurately reflect a company's long-term growth. In contrast, earnings growth is not affected by short run cash management decisions.

In addition, EPS growth rates are the only forward-looking growth rates available on a consensus basis. With the exception of his EPS growth rates, the source for all of Dr. Woolridge's growth rates is Value Line. Dr. Woolridge's reliance on Value Line's historical and forecasted DPS and BVPS growth rates, as well as Value Line's estimates of ROE and retention rates for his internal growth rate, unnecessarily introduces "sole source" bias into his calculations. By contrast, my Constant Growth DCF analysis is based on forecasted EPS growth rates from multiple sources, including Zack's and Thomson First Call, both of which provide consensus estimates from multiple analysts.

Q. Do you share Dr. Woolridge's concern that "long-term EPS growth rate forecasts of Wall Street securities analysts are overly optimistic and upwardly biased"?[52]

A. No, I do not. Dr. Woolridge has provided no evidence that the growth rates for the companies in my DCF analysis are the result of consistent and pervasive analyst bias. Moreover, the 2003 Global Analysts Research Settlement (the "Global Settlement") served to significantly reduce the bias referred to by Dr. Woolridge. In fact, the Global Settlement required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research. In addition, analysts covering the common stock of the proxy companies certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation. Thus, it is unclear why investors would assume that the proxy companies are susceptible to a continuing upward bias in earnings projections.

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52 Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-16.

A 2010 article in Financial Analysts Journal found that analyst forecast bias declined significantly or disappeared entirely since the Global Settlement:

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[53]

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

A. No, I do not. The Constant Growth and Multi-Stage DCF models are both forward-looking models that evaluate investors' required returns based on future cash flows. As such, the appropriate measure of growth to incorporate for DCF analyses is investors' expectations, not historical results. Dr. Woolridge himself observes that historical growth rates must be treated with caution because "in some cases, past growth may not reflect future growth potential."[54] In addition, securities' analysts forecasted growth rates incorporate historical performance to the extent the analysts believe it is likely to continue. Additional consideration of historical growth rates, therefore, provides no meaningful incremental information regarding the proxy companies' future growth potential.

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

54 Direct Testimony of J. Randall Woolridge, Appendix D, at D-13.

Q. Do you agree with Dr. Woolridge's use of retention growth rates as measured by the product of earnings retention ratios and earned returns on common equity?

A. No, I do not. Dr. Woolridge's calculation of retention growth rates (also known as "internal growth rates" or "sustainable growth rates") considers only the product of earnings retention rates and earned returns on common equity, or what are commonly known as internally-generated funds. In the sustainable growth formula, this is commonly referred to as the product of "b X r", where "b" is the retention ratio or the portion of net income not paid in dividends, and "r" is the expected ROE on the portion of net income that is retained within the Company as a means for future growth.

Dr. Woolridge fails to consider that earnings growth also occurs as a result of new equity issuances, or what are commonly known as externally-generated funds. In the sustainable growth formula, this is shown as the product of "s X v", where "s" represents the growth in shares outstanding and "v" is that portion of the M/B ratio that exceeds unity. This methodology is recognized as a common approach to calculating the sustainable growth rate.[55] By only considering the funds from internally-generated sources, Dr. Woolridge's sustainable growth rate calculation understates the prospective growth rates for his proxy group companies. As shown on Exhibit AEB-R-10, had Dr. Woolridge included the "s X v" component in his computation, his median sustainable growth rate would increase by approximately 20 basis points from 4.20 percent to 4.40 percent.

[55] *See* Roger Morin, New Regulatory Finance, at 306.

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

A. Yes. In Opinion No. 531, the FERC changed its approach on the DCF methodology to be applied in public utility rate cases.[56] In summary, the FERC adopted the same two-step DCF methodology it has employed in gas and oil pipeline rate proceedings since the mid-1990s, in place of the one-step methodology previously used. The FERC's two-stage DCF approach does not rely on a sustainable growth calculation.

Q. Do you have other concerns with the reasonableness of Dr. Woolridge's sustainable growth rate calculation?

A. Yes, I do. Since the "r" in the "b x r" approach refers to the ROE, Dr. Woolridge has effectively pre-supposed Value Line's ROE and payout ratio projections for his proxy group companies. By using this growth measure, Dr. Woolridge has assumed the reasonableness of Value Line's ROE projections, yet, as shown on Dr. Woolridge's Exhibit JRW-10, page 4, the mean and median ROE projections for the electric utility companies in his proxy group are 10.2 percent and 9.5 percent, respectively, which is significantly higher than his recommended ROE for UNS Electric of 8.75 percent.

Q. What would be the average growth rate for Dr. Woolridge's proxy group companies if he had used only analysts' forecasted, positive EPS growth rates?

A. As shown in Exhibit AEB-R-11, if Dr. Woolridge had used only analysts' forecasted EPS growth rates for his proxy group companies, and if he had excluded negative EPS growth rate projections for proxy companies that are not involved in mergers or

[56] Opinion No. 531 147 FERC ¶ 61,234 (June 19, 2014).

transformative transactions, his median growth rate would be 5.50 percent rather than 4.80 percent.

C. Multi-Stage DCF Model

Q. Has Dr. Woolridge performed a Multi-Stage DCF analysis to estimate the Cost of Equity for UNS Electric?

A. No, he has not. While Dr. Woolridge recognizes that the Dividend Discount Model or three-stage model is commonly used to estimate the Cost of Equity, he does not develop recommendations based on either of these forms of the DCF model.[57]

Q. Please summarize Dr. Woolridge's criticisms of the assumptions relied on in your Multi-Stage DCF model.

A. Dr. Woolridge does not take issue with the near-term growth rates (*i.e.*, analysts' forecasts of EPS growth) used in my Multi-Stage DCF model. However, he asserts that the long-term growth rate I have used is "clearly inflated."[58] In support of this assertion, Dr. Woolridge points to recent trends in GDP growth that he states suggest that "nominal GDP growth in recent decades has slowed."[59]

Q. Please summarize Dr. Woolridge's criticism of your long-term growth rate.

A. Dr. Woolridge disagrees with the use of a long-term historical estimate of GDP growth, stating that there is no empirical or theoretical support for the use of that time period. Dr. Woolridge presents, in Table 4 of his testimony, five shorter term averaging periods for GDP growth, demonstrating a range from 6.8 percent to 3.9 percent. Dr. Woolridge

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57 Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-9.
58 Direct Testimony of Dr. J. Randall Woolridge, at 34.
59 *Ibid.*

concludes that economic growth in more recent historical periods has been lower than the long-term historical average.

Q. How do you respond to this criticism?

A. Investors understand that the U.S. economy goes through cycles of growth and contraction. It is not appropriate to exclude certain periods simply because economic growth was unusually weak or strong. Rather, as Morningstar explains, it is appropriate to use the longest time period possible to measure historical real growth in GDP:

> Growth in real GDP (with only a few exceptions) has been reasonably stable over time; therefore, its historical performance is a good estimate of expected long-term future performance. By combining the inflation estimate with the real growth rate estimate, a long-term estimate of nominal growth is formed…[60]

In response to Dr. Woolridge's desire to use a more recent period to measure GDP growth, I agree with Morningstar's view on this issue as well. They write:

> The 87-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.[61]

Q. Dr. Woolridge states that economists and various government agencies are forecasting lower GDP growth rates.[62] What is your response?

A. Nominal GDP growth rates of 4.20 percent to 4.70 percent, as published in the reports cited by Dr. Woolridge, are well below the average nominal GDP growth rate in the

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60 Ibbotson and Associates, Stocks, Bonds, Bills and Inflation, 1926-2012, 2013 Valuation Yearbook, at 52.
61 *Ibid.*, at 59.
62 Direct Testimony of Dr. J. Randall Woolridge, at 35.

U.S. since 1929. By comparison, my historical GDP growth rate of 5.40 percent is based on a projected inflation rate of 2.09 percent (based on three sources), and actual historical growth in real GDP of 3.25 percent from 1929-2014.

Moreover, as discussed in my Direct Testimony, there has been a tendency to under-estimate GDP growth in the decade after severe economic events.[63] The financial crisis and recession that began in 2007 were qualitatively different from most other U.S. economic downturns, which were followed by a rapid return to pre-recession overall output growth levels. The current U.S. economic growth situation is similar to that following the two most severe economic events in U.S. history (*i.e.*, the 1929 stock market crash and the 1973 oil shock).

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

A. In my view, current estimates of real GDP growth are understated relative to the long-term average because forecasters are placing too much weight on recent economic weakness. For that reason, I believe that it is reasonable to use historical long-term GDP growth as the terminal growth rate in the Multi-Stage DCF model, as I have done. However, the Multi-Stage DCF model does not directly reflect the substantial increase in interest rates that is projected over the next five years, as borrowing costs increase from the artificially low levels of the recent past. For that reason, it is also appropriate to consider the results of a forward-looking CAPM analysis, because that model is more sensitive to expected changes in interest rates.

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63 Direct Testimony of Ann E. Bulkley, at 28-29.

D. CAPM Analysis

Q. Please summarize Dr. Woolridge's CAPM results and explain how he uses that analysis.

A. As shown in Table 2 of Dr. Woolridge's Direct Testimony, his CAPM results are 8.10 for the Woolridge Proxy Group and 8.30 percent for the Bulkley Proxy Group. These results are based on a risk free rate of 4.00 percent, a Beta coefficient between 0.75 and 0.78, and a MRP of 5.50 percent. The results of Dr. Woolridge's CAPM analysis form the lower boundary of his range of results for UNS Electric. Dr. Woolridge testifies that he ultimately relies primarily on the results of his Constant Growth DCF model.[64] The results of Dr. Woolridge's CAPM analysis are well below the authorized ROE for any U.S. electric utility company in the past 25 years.[65]

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

A. I have two areas of concern with the inputs and assumptions that Dr. Woolridge has relied on to derive his CAPM results. First, I do not believe that Dr. Woolridge's risk free rate of 4.00 percent adequately considers projected increases in Treasury bond yields. Second, I take issue with Dr. Woolridge's use of an MRP of 5.50 percent because it is based on the results of investor surveys and academic research rather than forward-looking market data, and does not reflect the inverse relationship between interest rates and the equity risk premium.

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64 Direct Testimony of Dr. J. Randall Woolridge, at 26.

65 Source: Regulatory Research Associates.

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

A. The inputs and assumptions used in the ROE analysis should reflect the forward-looking Cost of Equity. As discussed in Section III of my Rebuttal Testimony, leading economists surveyed by Blue Chip are expecting a substantial increase in long-term interest rates over the next five years. This is a very important consideration for equity investors as they assess their return requirements. Dr. Woolridge attempts to take into consideration the prospect for higher interest rates by choosing a risk free rate of 4.00 percent, which is approximately half-way between the current yield on 30-year Treasury bonds and their projected yield of 4.80 percent for the period from 2017-2021.[66] However, I do not believe that Dr. Woolridge's risk free rate of 4.00 percent adequately takes into consideration the effect of the market's expectation for higher interest rates on the Cost of Equity for UNS Electric. For that reason, I believe that Dr. Woolridge's CAPM results are understated.

Q. What MRP does Dr. Woolridge use in his CAPM analysis?

A. Dr. Woolridge estimates the MRP as being in the range of 4.00 percent to 6.00 percent. From within that range, he chooses an MRP of 5.50 percent.[67]

Q. What is the basis for Dr. Woolridge's MRP of 5.50 percent?

A. Dr. Woolridge, measures the equity risk premium as the difference between historical average stock and bond returns based on information reported by Ibbotson and Associates.[68] Dr. Woolridge notes that most historical assessments of the equity risk premium were in the range of 5.0 percent to 7.0 percent above the rate on long-term

66 Blue Chip Financial Forecasts, Vol. 34, Issue No. 6, June 1, 2015, at 14.
67 Direct Testimony of Dr. J Randall Woolridge, at 25.
68 *Ibid.*, Appendix D, at D-21.

U.S. Treasury bonds. However, Dr. Woolridge states that the use of historical MRPs can be problematic because MRPs can change over time, and market conditions can change such that historical returns are poor estimates of future returns.[69]

The other way to measure the MRP, according to Dr. Woolridge, is to rely on investor surveys and the results of academic research.[70] Dr. Woolridge presents the results of several surveys that have been published since January 2010. The median MRP reported in those surveys is 4.82 percent.[71] In particular, Dr. Woolridge highlights a 2015 survey of expected market returns of academics, financial analysts and companies which included over 4,000 responses. The median equity risk premium for U.S. companies derived from the Fernandez survey was 5.50 percent.[72]

Q. What is your concern with Dr. Woolridge's MRP estimate of 5.50 percent?

A. Given the current low yields on Treasury bonds, and the inverse relationship between interest rates and the MRP, my concern is that Dr. Woolridge's MRP estimate of 5.50 percent is understated. The average historical income only return on long-term government bonds that is used to calculate the historical MRP is 5.18 percent, while the current 30-day average risk free rate on long-term government bonds is approximately 2.98 percent.[73] The historical MRP as reported by Ibbotson and Associates is 7.0 percent through 2014. Because interest rates on long-term government bonds are well below the historical average of 5.18 percent, the inverse relationship between interest rates and the MRP implies that the forward-looking MRP should be higher than 7.0 percent.

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69 *Ibid.*

70 *Ibid.*, at D-22.

71 Exhibit JRW-11, page 6 of 6.

72 Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-25.

73 Using the regression equation in AEB-R-6, I calculated the ROE at the current 30-day average risk free rate and the average historical risk free rate. Using the current 30-day average risk free rate of 2.98% as compared to the historical average risk free rate of 5.18% results in an understatement of the ROE of approximately 96 basis points. (9.87% vs. 10.83%).

Q. Do you have any concerns regarding the investor surveys that Dr. Woolridge has relied upon to derive his range of 4.00 percent to 6.00 percent for the MRP?

A. Yes. Neither the Philadelphia Federal Reserve survey nor the Duke University/CFO magazine survey asks participants to provide their expected MRP. Instead, both surveys ask participants for expected returns on stocks and bonds without defining what is meant by "returns." To the extent that "return" does not include both income (dividend yield) and growth (capital appreciation), the survey results may understate the expected total return of survey respondents.

According to Dr. Woolridge, the February 2015 survey by the Philadelphia Fed reports that the median long-term expected stock return is 5.79 percent. That return is generally consistent with the GDP and EPS growth rates shown in Table 5 of Dr. Woolridge's Direct Testimony. The returns in Table 5 represent growth in the S&P 500 stock prices and the growth rate of nominal GDP and S&P 500 earnings per share. The Philadelphia Fed's survey does not specify whether the expected returns for the S&P 500 represent total returns or only capital appreciation. To the extent the Philadelphia Fed survey includes only capital gains and not dividends, the survey understates the actual return that investors expect, which, in turn, suggests the MRP that Dr. Woolridge calculates using this data is understated because the long-term growth rate for the S&P 500 is understated. Further, as shown in Exhibit JRW-11, the Philadelphia Fed survey considered the responses of 20 financial forecasters with regards to the expected returns for the S&P 500; however, about 40 financial forecasters participated in the 2015 first quarter survey, meaning that approximately half (i.e., 19) of the survey participants did not respond to the specific question on market returns.[74]

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[74] Survey of Professional Forecasters, Philadelphia Federal Reserve, February 13, 2015, at 17.

Similarly, the Global Business Outlook Survey conducted quarterly by Duke University and CFO magazine asks participants to predict the average annual return for the S&P 500 over the next ten years given the current annual yield on ten-year Treasury bonds. CFO magazine uses this information to estimate the MRP by subtracting the current yield on ten-year Treasury bonds from the expected return on the S&P 500. As with the Philadelphia Fed survey, the Duke survey asks respondents for expectations regarding the "average annual S&P 500 return," but does not define return.[75] Moreover, while the Duke survey addresses return expectations (however defined), it does not ask whether the respondents would be willing to invest (*i.e.*, meets their required return expectations) in equity at those return levels. To the extent that expected and required returns differ, the usefulness of survey responses for the purpose of establishing UNS Electric's required ROE becomes increasingly tenuous.

Q. Have others also expressed concerns with the use of investor surveys to estimate the equity risk premium?

A. Yes. For example, Finance Professor Aswath Damodoran, who has published extensively on the question of how to estimate the equity risk premium, discussed his concerns with using investor surveys to estimate the equity risk premium:[76]

While survey premiums have become more accessible, very few practitioners seem to be inclined to use the numbers from these surveys in computations and there are several reasons for this reluctance:

> 1. Survey risk premiums are responsive to recent stock price movements, with survey numbers generally increasing after bullish periods and decreasing after market declines…;
>
> 2. Surveys premiums are sensitive not only to whom the question is directed at but how the question is asked. For example, asking the question, "What do you think stocks will do next year?" generates

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[75] *See* CFO Magazine Survey, Q2-15, Section 9.

[76] Aswath Damodoran, *Equity Risk Premiums (ERP): Determinants, Estimation, and Implications – The 2013 Edition*, Updated March 2013, at 19-20.

> different numbers than asking, "What should the risk premium be for investing in stocks?";
>
> 3. In keeping with other surveys that show differences across sub-groups, the premium seems to vary depending on who gets surveyed…; and
>
> 4. Studies that have looked at the efficacy of survey premiums indicate that if they have any predictive power, it is in the wrong direction...

Dr. Damodoran ultimately concludes that "it is also likely that these survey premiums will be more reflections of the recent past than good forecasts of the future."[77]

Q. What is Dr. Woolridge's concern with the MRPs you have used in your CAPM analysis?

A. Dr. Woolridge is concerned that my forward-looking MRP is over-stated because it was developed using the expected return for the S&P 500 based on analysts' forecasted EPS growth rates. In particular, Dr. Woolridge testifies: "The bottom line is that Ms. Bulkley's estimated expected stock market return of 13.19% is not realistic."[78] Dr. Woolridge also incorrectly states that I have only used a projected MRP of 10.67 percent in my CAPM analysis.[79]

Q. Does Dr. Woolridge agree that the MRP can be estimated based on expected returns for the S&P 500?

A. Yes. According to Dr. Woolridge: "The MRP is the difference in the expected total return between investing in equities and investing in "safe" fixed income assets, such as long-term government bonds."[80] Dr. Woolridge states that the expected total return for

77 *Ibid.*, at 20.
78 Direct Testimony of Dr. J. Randall Woolridge, at 37.
79 *Ibid.*, at 5.
80 *Ibid.*, at D-20.

the market is often measured by reference to the S&P 500.[81] This is consistent with the approach I have used to estimate the forward-looking MRP in my CAPM analysis.

Q. What is your response to Dr. Woolridge's concern about your forward-looking MRP?

A. Dr. Woolridge expresses concern that the forward-looking MRP in my CAPM analysis is based on five-year EPS growth rates from Wall Street analysts, which he claims are "overly optimistic and upwardly biased."[82] He supports this assertion by arguing that the EPS growth rate for the S&P 500 of 11.06 percent is significantly higher than long-term nominal GDP growth and long-term EPS growth for the S&P 500.[83] However, the analysts' forecasted growth rates are market-based growth rates upon which current stock prices for the companies in the S&P 500 are based. In other words, 13.19 percent is not my estimate of the expected market return; it is based on market data such as forecasted earnings growth rates and dividend yield for the companies in the S&P 500. Dr. Woolridge supports the use of the Constant Growth DCF model to estimate the Cost of Equity for UNS Electric. Yet, he dismisses the expected five-year EPS growth rates as overly-optimistic even though the model upon which he relies assumes that investors set stock prices based on expectations for future growth in dividends and share price. As discussed previously in my Rebuttal Testimony, recent academic research has found that analyst bias has been reduced or eliminated, if it ever existed, after the financial market reforms of the early 2000s.

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81 *Ibid.*

82 Direct Testimony of Dr. J. Randall Woolridge, at 51.

83 *Ibid.*, at 38.

Q. What is your conclusion regarding the appropriate MRP in the context of current market data?

A. My conclusion is that Dr. Woolridge's estimated MRP of 5.50 percent is substantially lower than (1) the historical MRP using large company stocks (7.0 percent); and (2) the forward-looking MRP in my updated CAPM analysis, which was derived using forecasted total returns for the S&P 500 less the risk free rate (between 8.71 percent and 10.53 percent). Dr. Woolridge's MRP of 5.50 percent, when added to the 30-day average yield on the 30-year Treasury as of November 30, 2015 of 2.98 percent, suggests that market participants are expecting a total return for equities of around 8.48 percent. By contrast, the long-term average total return for large company stocks since 1926, as reported by Morningstar, has been 12.1 percent, or approximately 360 basis points higher than Dr. Woolridge's MRP estimate assumes. For these reasons, I continue to support the method I used to estimate the MRP.

E. Bond Yield Plus Risk Premium Method

Q. Please summarize Dr. Woolridge's concerns with your Risk Premium analysis.

A. Dr. Woolridge has expressed several concerns with my Bond Yield Plus Risk Premium analysis, including: (1) that I have used historical authorized ROEs and Treasury yields and applied the resulting risk premium to projected Treasury yields; (2) that the analysis is a gauge of regulatory commission behavior, not investor behavior; and (3) that my analysis includes returns from settled as well as litigated rate cases.[84]

[84] *Ibid.*, at 77-78.

Q. Does your Risk Premium analysis only apply a historical risk premium to a projected Treasury yield?

A. No, it does not. As shown in Exhibit AEB-R-6, my Risk Premium analysis determines the appropriate risk premium based on the relationship between historic authorized ROEs and bonds yields. I derive three separate estimates of the ROE based on this analysis, which forms the range of my results. I also disagree with Dr. Woolridge that it is incorrect to apply the historical risk premium from this analysis to current and projected Treasury yields in order to estimate the ROE at specified interest rates.

Q. What is your response to Dr. Woolridge's concern that your Risk Premium analysis is a gauge of regulatory commission behavior rather than investor behavior?

A. While my Risk Premium analysis is based on authorized ROEs and the corresponding Treasury yields at the time the regulatory decisions were issued, I believe that investors are informed by allowed ROEs from hundreds of rate case decisions to frame their return expectations. One of the fundamental principles in setting a just and reasonable return is that the return must be comparable to returns available to investors in companies with commensurate risk. In that regard, the returns that have been authorized to other electric utility companies are a relevant consideration for investors. My Risk Premium analysis simply shows what those returns are in relation to the risk free rate, so that it is possible to use historical returns to estimate future returns given investor expectations as shown by current and projected Treasury yields.

Q. Do you share Dr. Woolridge's concern that your Risk Premium analysis includes settled rate case decisions?

A. No, I do not. In order to test Dr. Woolridge's premise that settled rate decisions are different than litigated rate decisions, I performed my Risk Premium analysis for electric utility companies for the period from 1992 through February 28, 2015 using only litigated cases. Based on that analysis, as shown on Exhibit AEB-R-12, the resulting ROE estimate ranges from 9.69 percent to 10.76 percent, with an average of 10.15 percent. As such, there is no basis for Dr. Woolridge's concern that the inclusion of settled rate case decisions impacted my Risk Premium analysis.

Q. What is your conclusion regarding the Risk Premium analysis?

A. I continue to support the use of the Risk Premium analysis to corroborate the reasonableness of my DCF and CAPM results.

F. Relevance of Market-to-Book Ratios

Q. Please summarize Dr. Woolridge's position regarding the relationship between the Market-to-Book ("M/B") ratio and authorized equity returns.

A. Dr. Woolridge states that a M/B ratio above 1.0 indicates that the company is earning a return "above its Cost of Equity."[85] Dr. Woolridge further asserts that there is a strong positive relationship between the estimated ROE and M/B ratios for public utilities, based on a regression analysis he performed using Value Line data.[86]

Q. What is the M/B ratio?

A. The M/B ratio equals the market value (or stock price) per share divided by the total common equity (or the "book equity") per share. Book value per share is an accounting construct which reflects historical costs. In contrast, market value per share (*i.e.*, the stock price) is forward-looking and is a function of many variables, including (but not

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[85] Direct Testimony of Dr. J. Randall Woolridge, Appendix D, at D-2 through D-3.
[86] *Ibid,* at D-4.

limited to) expected earnings and cash flow growth, expected payout ratios, measures of "earnings quality," the regulatory climate, the equity ratio, expected capital expenditures, and the expected return on book equity.[87] It follows, therefore, that the M/B ratio is also a function of numerous variables in addition to the historical or expected return on book equity.

Q. Do you agree with Dr. Woolridge that utility companies with M/B ratios above 1.0 are earning returns above their Cost of Equity?

A. No, I do not. I have several concerns with Dr. Woolridge's position. Chart 4 shows the M/B ratio for companies in Dr. Woolridge's proxy group for the period January 1, 2005 through December 31, 2014. Over that period, the proxy group average (represented by the dotted line) was 1.49. Even though the proxy group companies were subject to numerous ROE awards during that period, I am not aware of any state regulatory commission that has set the authorized ROE for a public utility based on a M/B ratio of 1.0. The only time during this period that the M/B ratio for the Woolridge proxy group approached 1.0 was during the Great Recession, clearly not an indicator of normal market conditions. Based on this evidence, it appears that state regulatory commissions do not share Dr. Woolridge's concern that such companies are earning returns in excess of their required returns, and that authorized returns should be set at levels that force the M/B ratio to unity.

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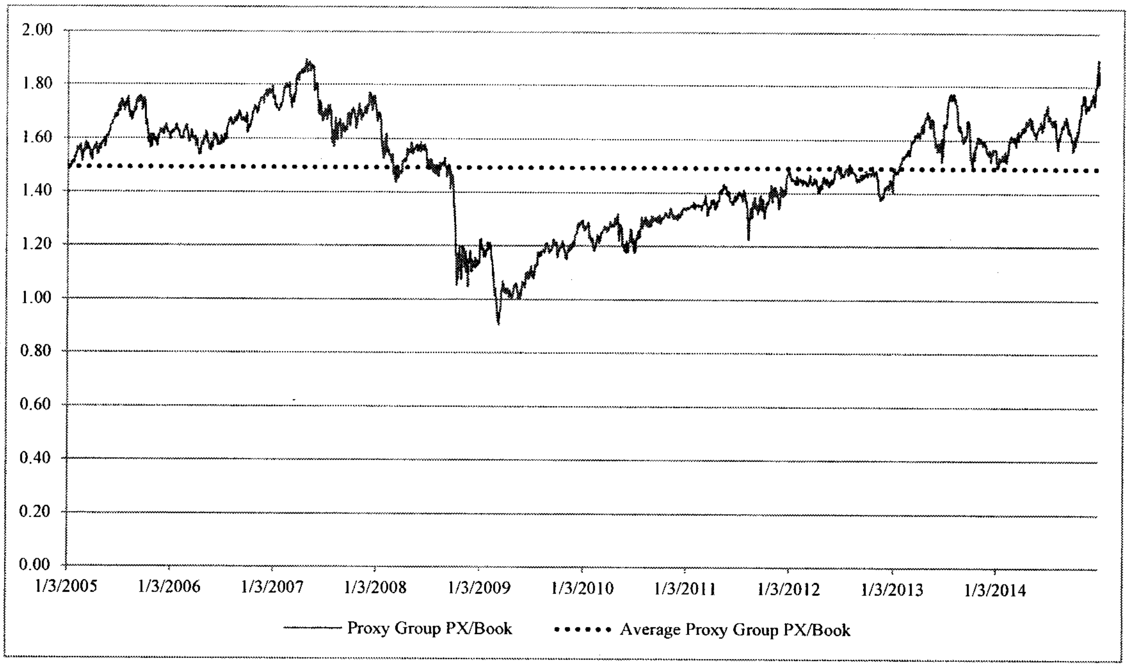
87 *See* Roger A. Morin, New Regulatory Finance, Public Utilities Reports, Inc., 2006 at 366.

Chart 4: Proxy Group Average Market-to-Book Ratio[88]



Further, the notion that book values should be set at unity by regulatory commissions has been refuted for many years. As noted by Stewart Meyers in 1972:

> In short, a straightforward application of the cost of capital to a book value rate base does not automatically imply that the market and book values will be equal. This is an obvious but important point. If straightforward approaches did imply equality of market and book values, then there would be no need to estimate the cost of capital. It would suffice to lower (raise) allowed earnings whenever markets were above (below) book.[89]

Q. What would be the practical effect of setting an allowed ROE for utility stocks that reduced the M/B ratio to 1.0?

A. As a practical matter, no rational investor would invest in utility stocks if they believed that utility commissions would set rates in an effort to move the M/B ratio to unity. If, for example, an investor purchased a utility stock at the long-term average M/B ratio of 1.49 (*i.e.*, the proxy group average), that investor would incur a loss of approximately

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88 Source: Bloomberg.

89 Stewart C. Meyers, *The Application of Finance Theory to Public Utility Rate Cases*, The Bell Journal of Economics and Management Science, Vol. 2, No. 1 (Spring, 1972) at 76.

33 percent once the ratio reached unity (1.00 / (1.49 – 1) = -32.98%). Such a result would impede a utility's ability to attract the capital required to support its operations, in direct contravention of the *Hope* and *Bluefield* standards.

Q. Are you aware of any contemporary text suggesting that M/B ratios for utilities should be expected to revert to 1.0?

A. No. To the contrary, Dr. Roger Morin provides an extensive review of the issue of M/B reversion to unity and makes the following summation:

> In short, economic principles do not support the notion that the market value of utility shares should necessarily equal book value. A basic economic principle holds that, in the long run, market value should equal asset replacement cost in a given industry. In the presence of inflation and absent significant technological advances, replacement cost exceeds the original cost book value of assets. Consequently it is quite reasonable for the market value of utility shares to exceed their book value and there is no reason to conclude that market value should equal book value when one recognizes that regulation is intended to emulate competition.[90]

Q. What is your conclusion regarding the relevance of M/B ratios in setting the allowed ROE for UNS Electric in this proceeding?

A. My conclusion is that investors do not expect allowed returns for utilities to be set at levels that would cause the M/B ratio to approximate unity. Such returns would provide unreasonably low equity risk premia and are inconsistent with prevailing levels of authorized ROEs for comparable risk electric utilities. Dr. Woolridge's own regression analysis demonstrates that the market is expecting higher returns on equity than what he is recommending for UNS Electric in this proceeding. For all of these reasons, the Commission should not be concerned with setting the allowed ROE for UNS Electric in this proceeding at a level that would cause the M/B ratio to move toward unity.

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90 *See*, New Regulatory Finance, Roger A. Morin Ph.D., Public Utility Reports, 2006, at 376 - 378.

G. Adjustment for Business Risk

Q. Has Dr. Woolridge adjusted his recommended ROE for UNS's business risk?

A. No, Dr. Woolridge has not adjusted his DCF and CAPM results to account for UNS Electric's above-average risk relative to the proxy group. As discussed in my Direct Testimony, UNS Electric's projected capital expenditures will remain elevated over time which increases its overall risk.[91] This is especially important due to the fact that UNS Electric is much smaller than the average proxy group company, which means that investors' return requirements are higher. While I did not adjust my ROE recommendation for any of these risks individually, I did take them into consideration in aggregate when selecting the appropriate ROE for UNS Electric. Specifically, based on UNS Electric's higher risk on these factors, my recommendation falls above the midpoint of my range of results, but well within the range.

Q. Do you agree with Dr. Woolridge that the small size of UNS Electric does not support an authorized ROE above the proxy group average?

A. No, I do not. Dr. Woolridge contends that there is no need for a size adjustment or premium because: 1) a company's credit rating reflects the risk associated with the size of the company; 2) the size premium is based on historical returns which are upwardly biased measures of expected risk premiums; and 3) empirical studies show that size premiums are not required for utilities.[92]

Dr. Woolridge, however, fails to take into consideration that the authorized ROE for UNS Electric should be set on a stand-alone basis. In other words, the stand-alone principle requires that the authorized return be set at a level that allows the company on a stand-

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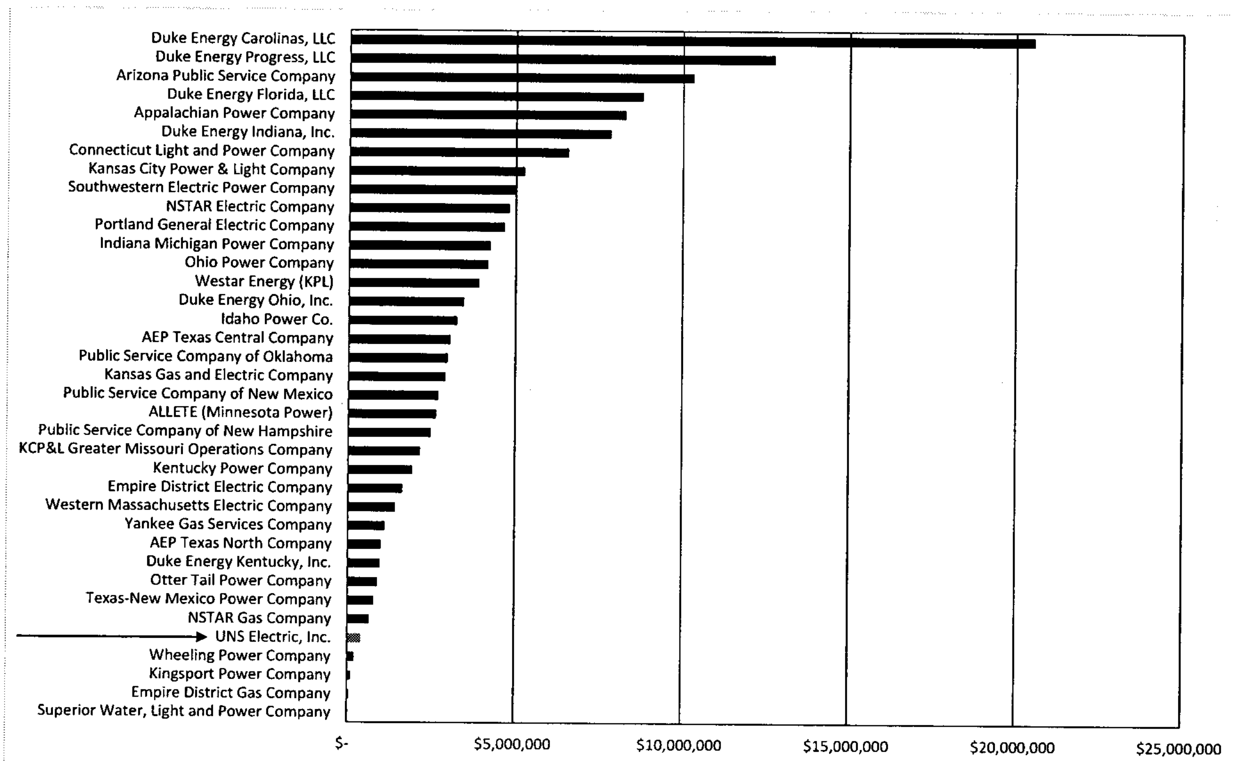
[91] Direct Testimony of Ann E. Bulkley, at 43.

[92] Direct Testimony of Dr. J. Randall Woolridge, at 44.

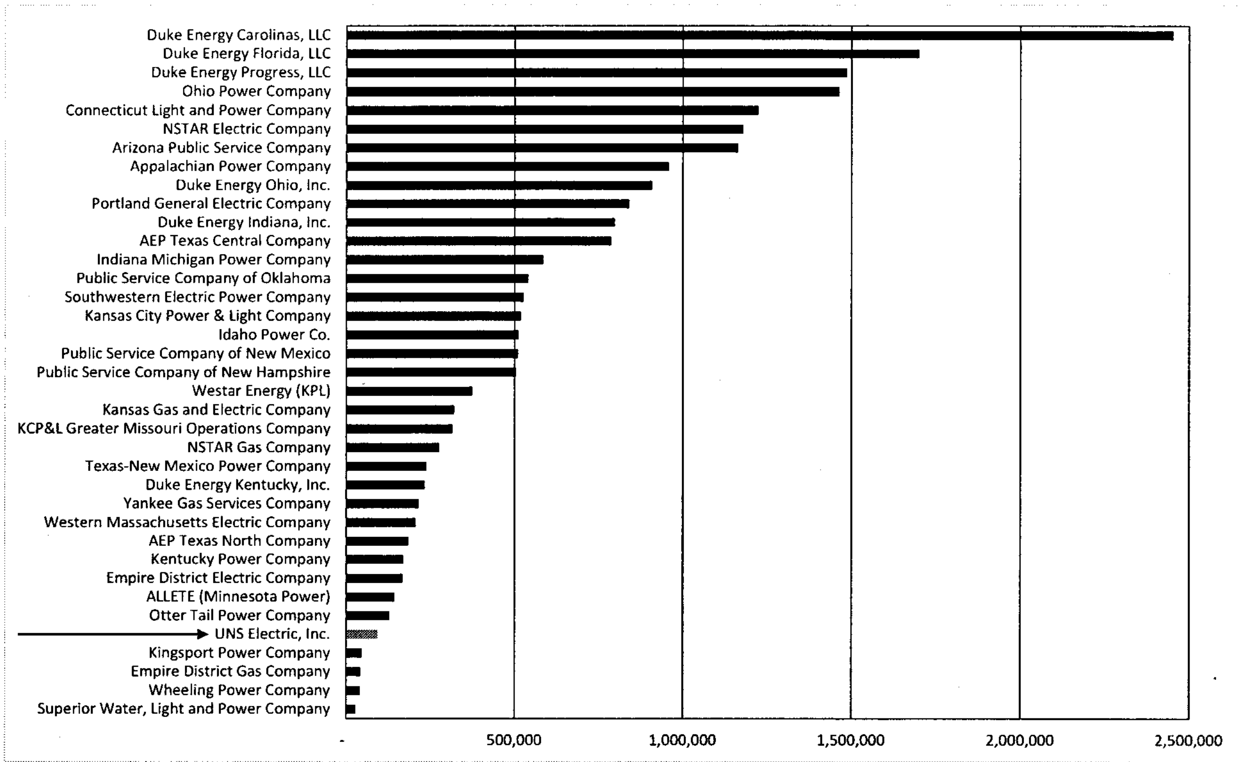
alone basis to attract capital. As discussed in my Direct Testimony, UNS Electric is substantially smaller than the proxy group companies. As shown in Charts 5 and 6 below, UNS Electric is also smaller in terms of both net utility plant and customers than all but four of the 36 operating companies that are held by the proxy group companies. Even on this basis, UNS Electric is much smaller than average, which supports an authorized ROE above the proxy group average.

Chart 5: Comparison of 2014 Net Plant ($000)[93]



93 Source: SNL Energy, Inc.

Chart 6: Comparison of 2014 Customer Count[94]



H. Proposal to Impute Capital Structure

Q. Please summarize Dr. Woolridge's proposed adjustment to UNS Electric's capital structure.

A. Dr. Woolridge proposes an imputed capital structure consisting of 50.0 percent common equity and 50.0 percent long-term debt, as compared to UNS Electric's actual test year capital structure of 52.83 percent common equity and 47.17 percent long-term debt.[95] Dr. Woolridge states that the Company's requested capital structure does not reflect the capital structures of companies in the Woolridge or Bulkley proxy groups or the parent company of UNS Electric, Fortis, Inc.[96] In particular, Dr. Woolridge testifies that the median common equity ratio for the companies in the Woolridge and Bulkley proxy

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94 Source: SNL Energy, Inc.

95 Direct Testimony of Dr. J. Randall Woolridge, at 5.

96 *Ibid.*, at 26-27.

groups is 47.7 percent and 49.3 percent, respectively.[97] On that basis, he concludes that a hypothetical capital structure is more appropriate.

Q. Have any of the other ROE witnesses in this proceeding recommended an adjustment to UNS Electric's proposed capital structure?

A. No, they have not. In fact, Mr. Mease explicitly testifies that he supports the Company's proposed capital structure as reasonable because it is consistent with the capital structures of his proxy group companies.[98]

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

A. Yes. The AUS report that Dr. Woolridge relies on for his analysis of the proxy company capital structures reports the holding company capital structures.

Q. Do you agree with Dr. Woolridge's analysis of the capital structure?

A. No, I do not. The relevant capital structure for comparison purposes is at the operating company level not the holding company, as used by Dr. Woolridge. The Commission in this case will be setting the capital structure for UNS Electric, the operating company, which will be used to finance investments in rate base that provides electric utility service to customers. As shown in Exhibit JRW-4, Dr. Woolridge's comparison of UNS Electric's common equity ratio to the median for the proxy group companies is performed using data from AUS Utilities, which are reported at the holding company level rather than the operating company level. As such, Dr. Woolridge's analysis

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97 *Ibid.*, Appendix C, at C-1.
98 Direct Testimony of Robert B. Mease, at 30.

includes corporate-level debt that is not part of the regulated or financial capital structure of the operating utilities.

As discussed in my Direct Testimony, UNS Electric's proposed common equity ratio of 52.83 percent is below the mean common equity ratio of the operating companies in my proxy group of 53.72 percent.[99] The Company's proposed capital structure is consistent with the actual percentage of equity and debt that UNS Electric has used to finance its rate base, consistent with the range of equity ratios at the operating company level for the electric utility companies in my proxy group, and consistent with the requirements to maintain the Company's current credit rating. For those reasons, I continue to support UNS Electric's proposed capital structure as reasonable.

VII. RESPONSE TO WAL-MART WITNESS CHRISS

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

A. Mr. Chriss does not recommend a specific ROE. Rather, he observes that the Company's proposed 10.35 percent recommendation exceeds recently authorized ROEs across the country which, according to Mr. Chriss, have averaged 9.85 percent for all electric utilities from 2012 through 2015, and 9.98 percent for vertically-integrated electric utilities.[100] Mr. Chriss also testifies that the industry trend has been toward declining ROEs for electric utilities over this time period.[101] Mr. Chriss concludes that the Commission should approve an ROE no higher than the currently allowed ROE of 9.50 percent unless the Commission "determines that UNSE has sufficiently and substantially demonstrated a significant change in the economic environment faced by the Company"[102] since the Commission's decision in the 2012 rate case.

99 Direct Testimony of Ann E. Bulkley, at 50.
100 *See* Direct Testimony of Steve W. Chriss, at 8.
101 *Ibid.*, at 9.
102 *Ibid.*

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

A. With respect to Mr. Chriss' observation that the recommended ROE of 10.35 percent is higher than returns authorized for electric utilities by other regulatory commissions, my response is that those returns were set during a period when interest rates were generally declining. Furthermore, UNS Electric's business and regulatory risk is above average, which supports an authorized ROE above the proxy group average. Mr. Chriss recommends an allowed ROE of no more than 9.50 percent for UNS Electric, which is almost 50 basis points below the average ROE of 9.98 percent for vertically integrated electric utilities in recent years. Further, if the Commission finds recently authorized ROEs to be a useful benchmark in this proceeding, my recommended ROE and range of 10.00 percent to 10.60 percent is within the range of ROEs authorized for electric utilities from 2012-2015 on a nationwide basis, while Mr. Mease's and Dr. Woolridge's recommended ROEs of 8.35 percent and 8.75 percent, respectively, are well below the lowest of all such authorizations, as shown in Chart 1

Lastly, both my Direct and Rebuttal Testimony explain how current economic and forward-looking capital market conditions are different than those at the time of the Commission's decision in the 2012 rate case for UNS Electric. In particular, in Section III of my Rebuttal Testimony, I discuss how wider credit spreads and investor expectations for higher interest rates provide support for the conclusion that the Cost of Equity is higher now than in December 2013 and will continue increasing from current levels.

VIII. UPDATED ANALYSES AND RECOMMENDATION

Q. Have you updated your ROE analyses?

A. Yes. I have updated the Constant Growth and Multi-Stage DCF analyses, the CAPM analysis, and the Bond Yield Plus Risk Premium analysis based on market data through November 30, 2015. The results of my updated analyses are shown in Table 6.

Table 6: Summary of Analytical Results

	Mean Low	Mean	Mean High
Constant Growth DCF			
30-Day Average	8.41%	9.35%	10.32%
90-Day Average	8.50%	9.44%	10.42%
180-Day Average	8.52%	9.46%	10.43%
Multi-Stage DCF			
30-Day Average	9.29%	9.52%	9.78%
90-Day Average	9.39%	9.63%	9.89%
180-Day Average	9.40%	9.64%	9.91%
CAPM			
	Current Risk Free Rate (2.98%)	**2015-2017 Projected Risk Free Rate (3.37%)**	**2017-2021 Projected Risk Free Rate (4.80%)**
Bloomberg	9.67%	9.81%	10.34%
Value Line	11.21%	11.30%	11.61%
Bond Yield Plus Risk Premium			
	Low	**Mean**	**High**
Risk Premium	9.87%	10.04%	10.67%

Q. Please summarize your analytical results and conclusions.

A. Based on the results of my updated analyses, I continue to recommend an ROE range between 10.00 percent and 10.60 percent, with a point estimate of 10.35 percent. My ROE recommendation is supported by mean high results of my Constant Growth DCF analysis,, and by the mean results of my CAPM analyses. In my view, 10.35 percent is a reasonable ROE estimate for UNS Electric, particularly in light of the Company's higher than average business and regulatory risks.

Q. What is your recommendation for the FVROR for UNS Electric?

A. I continue to recommend a FVROR of 6.22 percent, based on the analysis presented in my Direct Testimony. The methodology used in my Direct Testimony is consistent with the approach that Staff has recommended, updated for current inflation rates. However, I understand that UNS Electric would not oppose Staff's recommendations related to the ROE and fair value increment rate underlying the FVROR as long as the overall revenue increase and rate design approved provides UNS Electric a reasonable opportunity to earn its authorized ROE.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit AEB-R-1

30-DAY CONSTANT GROWTH DCF

Company	Ticker	[1] Annualized Dividend	[2] Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Value Line Earnings Growth	[6] Yahoo! Finance Earnings Growth	[7] Zacks Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
ALLETE, Inc.	ALE	$2.02	$50.97	3.96%	4.08%	6.50%	5.50%	5.00%	5.67%	9.06%	9.74%	10.59%
American Electric Power Company, Inc.	AEP	$2.24	$56.45	3.97%	4.06%	5.00%	4.68%	4.80%	4.83%	8.74%	8.89%	9.07%
Empire District Electric Company	EDE	$1.04	$22.76	4.57%	4.67%	3.00%	5.00%	5.00%	4.33%	7.64%	9.00%	9.68%
Eversource Energy	ES	$1.67	$51.00	3.27%	3.39%	8.50%	6.57%	6.80%	7.29%	9.95%	10.68%	11.91%
Great Plains Energy Inc.	GXP	$1.05	$27.21	3.86%	3.96%	5.00%	5.23%	6.00%	5.41%	8.95%	9.37%	9.97%
IDACORP, Inc.	IDA	$2.04	$67.21	3.04%	3.08%	1.00%	4.00%	4.00%	3.00%	4.05%	6.08%	7.10%
Otter Tail Corporation	OTTR	$1.23	$26.97	4.56%	4.73%	9.00%	6.00%	NA	7.50%	10.70%	12.23%	13.77%
Pinnacle West Capital Corporation	PNW	$2.50	$63.72	3.92%	4.02%	4.00%	5.15%	5.00%	4.72%	8.00%	8.73%	9.17%
PNM Resources, Inc.	PNM	$0.80	$28.29	2.83%	2.96%	9.00%	10.30%	8.10%	9.13%	11.04%	12.09%	13.27%
Portland General Electric Company	POR	$1.20	$36.90	3.25%	3.33%	6.00%	3.92%	4.10%	4.67%	7.24%	8.00%	9.35%
Westar Energy, Inc.	WR	$1.44	$40.87	3.52%	3.60%	6.00%	3.50%	3.60%	4.37%	7.09%	7.97%	9.63%
MEAN				**3.71%**	**3.81%**	**5.73%**	**5.44%**	**5.24%**	**5.54%**	**8.41%**	**9.35%**	**10.32%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 30-day average as of November 30, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

90-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.02	$49.89	4.05%	4.16%	6.50%	5.50%	5.00%	5.67%	9.15%	9.83%	10.68%
American Electric Power Company, Inc.	AEP	$2.24	$56.09	3.99%	4.09%	5.00%	4.68%	4.80%	4.83%	8.77%	8.92%	9.09%
Empire District Electric Company	EDE	$1.04	$22.43	4.64%	4.74%	3.00%	5.00%	5.00%	4.33%	7.71%	9.07%	9.75%
Eversource Energy	ES	$1.67	$49.67	3.36%	3.48%	8.50%	6.57%	6.80%	7.29%	10.04%	10.77%	12.01%
Great Plains Energy Inc.	GXP	$1.05	$26.43	3.97%	4.08%	5.00%	5.23%	6.00%	5.41%	9.07%	9.49%	10.09%
IDACORP, Inc.	IDA	$2.04	$63.77	3.20%	3.25%	1.00%	4.00%	4.00%	3.00%	4.21%	6.25%	7.26%
Otter Tail Corporation	OTTR	$1.23	$26.61	4.62%	4.80%	9.00%	6.00%	NA	7.50%	10.76%	12.30%	13.83%
Pinnacle West Capital Corporation	PNW	$2.50	$62.62	3.99%	4.09%	4.00%	5.15%	5.00%	4.72%	8.07%	8.80%	9.25%
PNM Resources, Inc.	PNM	$0.80	$27.17	2.94%	3.08%	9.00%	10.30%	8.10%	9.13%	11.16%	12.21%	13.40%
Portland General Electric Company	POR	$1.20	$36.26	3.31%	3.39%	6.00%	3.92%	4.10%	4.67%	7.29%	8.06%	9.41%
Westar Energy, Inc.	WR	$1.44	$38.70	3.72%	3.80%	6.00%	3.50%	3.60%	4.37%	7.29%	8.17%	9.83%
MEAN				**3.80%**	**3.90%**	**5.73%**	**5.44%**	**5.24%**	**5.54%**	**8.50%**	**9.44%**	**10.42%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 90-day average as of November 30, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

180-DAY CONSTANT GROWTH DCF

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average Earnings Growth	Low ROE	Mean ROE	High ROE
ALLETE, Inc.	ALE	$2.02	$49.81	4.06%	4.17%	6.50%	5.50%	5.00%	5.67%	9.16%	9.84%	10.69%
American Electric Power Company, Inc.	AEP	$2.24	$55.79	4.01%	4.11%	5.00%	4.68%	4.80%	4.83%	8.79%	8.94%	9.12%
Empire District Electric Company	EDE	$1.04	$22.95	4.53%	4.63%	3.00%	5.00%	5.00%	4.33%	7.60%	8.96%	9.65%
Eversource Energy	ES	$1.67	$49.08	3.40%	3.53%	8.50%	6.57%	6.80%	7.29%	10.08%	10.82%	12.05%
Great Plains Energy Inc.	GXP	$1.05	$26.12	4.02%	4.13%	5.00%	5.23%	6.00%	5.41%	9.12%	9.54%	10.14%
IDACORP, Inc.	IDA	$2.04	$61.69	3.31%	3.36%	1.00%	4.00%	4.00%	3.00%	4.32%	6.36%	7.37%
Otter Tail Corporation	OTTR	$1.23	$27.71	4.44%	4.60%	9.00%	6.00%	NA	7.50%	10.57%	12.10%	13.64%
Pinnacle West Capital Corporation	PNW	$2.50	$61.63	4.06%	4.15%	4.00%	5.15%	5.00%	4.72%	8.14%	8.87%	9.31%
PNM Resources, Inc.	PNM	$0.80	$26.97	2.97%	3.10%	9.00%	10.30%	8.10%	9.13%	11.19%	12.24%	13.42%
Portland General Electric Company	POR	$1.20	$35.68	3.36%	3.44%	6.00%	3.92%	4.10%	4.67%	7.35%	8.11%	9.46%
Westar Energy, Inc.	WR	$1.44	$37.69	3.82%	3.90%	6.00%	3.50%	3.60%	4.37%	7.39%	8.27%	9.94%
MEAN				**3.82%**	**3.92%**	**5.73%**	**5.44%**	**5.24%**	**5.54%**	**8.52%**	**9.46%**	**10.43%**

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, equals 180-day average as of November 30, 2015
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.50 x [8])
[5] Source: Value Line
[6] Source: Yahoo! Finance
[7] Source: Zacks
[8] Equals Average ([5], [6], [7])
[9] Equals [3] x (1 + 0.50 x Minimum ([5], [6], [7]) + Minimum ([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.50 x Maximum ([5], [6], [7]) + Maximum ([5], [6], [7])

Exhibit AEB-R-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	$50.97	$2.02	5.67%	5.62%	5.58%	5.53%	5.49%	5.45%	5.40%	9.84%
American Electric Power Company, Inc.	AEP	$56.45	$2.24	4.83%	4.92%	5.02%	5.11%	5.21%	5.31%	5.40%	9.62%
Empire District Electric Company	EDE	$22.76	$1.04	4.33%	4.51%	4.69%	4.87%	5.05%	5.22%	5.40%	10.13%
Eversource Energy	ES	$51.00	$1.67	7.29%	6.98%	6.66%	6.35%	6.03%	5.72%	5.40%	9.46%
Great Plains Energy Inc.	GXP	$27.21	$1.05	5.41%	5.41%	5.41%	5.41%	5.40%	5.40%	5.40%	9.65%
IDACORP, Inc.	IDA	$67.21	$2.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	8.23%
Otter Tail Corporation	OTTR	$26.97	$1.23	7.50%	7.15%	6.80%	6.45%	6.10%	5.75%	5.40%	11.14%
Pinnacle West Capital Corporation	PNW	$63.72	$2.50	4.72%	4.83%	4.94%	5.06%	5.17%	5.29%	5.40%	9.54%
PNM Resources, Inc.	PNM	$28.29	$0.80	9.13%	8.51%	7.89%	7.27%	6.65%	6.02%	5.40%	9.33%
Portland General Electric Company	POR	$36.90	$1.20	4.67%	4.79%	4.92%	5.04%	5.16%	5.28%	5.40%	8.80%
Westar Energy, Inc.	WR	$40.87	$1.44	4.37%	4.54%	4.71%	4.88%	5.06%	5.23%	5.40%	9.02%
MEAN											**9.52%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 30, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.89	$2.02	5.67%	5.62%	5.58%	5.53%	5.49%	5.45%	5.40%	9.94%
American Electric Power Company, Inc.	AEP	$56.09	$2.24	4.83%	4.92%	5.02%	5.11%	5.21%	5.31%	5.40%	9.65%
Empire District Electric Company	EDE	$22.43	$1.04	4.33%	4.51%	4.69%	4.87%	5.05%	5.22%	5.40%	10.20%
Eversource Energy	ES	$49.67	$1.67	7.29%	6.98%	6.66%	6.35%	6.03%	5.72%	5.40%	9.57%
Great Plains Energy Inc.	GXP	$26.43	$1.05	5.41%	5.41%	5.41%	5.41%	5.40%	5.40%	5.40%	9.78%
IDACORP, Inc.	IDA	$63.77	$2.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	8.39%
Otter Tail Corporation	OTTR	$26.61	$1.23	7.50%	7.15%	6.80%	6.45%	6.10%	5.75%	5.40%	11.22%
Pinnacle West Capital Corporation	PNW	$62.62	$2.50	4.72%	4.83%	4.94%	5.06%	5.17%	5.29%	5.40%	9.61%
PNM Resources, Inc.	PNM	$27.17	$0.80	9.13%	8.51%	7.89%	7.27%	6.65%	6.02%	5.40%	9.49%
Portland General Electric Company	POR	$36.26	$1.20	4.67%	4.79%	4.92%	5.04%	5.16%	5.28%	5.40%	8.86%
Westar Energy, Inc.	WR	$38.70	$1.44	4.37%	4.54%	4.71%	4.88%	5.06%	5.23%	5.40%	9.23%
MEAN											**9.63%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 30, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- AVERAGE FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.81	$2.02	5.67%	5.62%	5.58%	5.53%	5.49%	5.45%	5.40%	9.95%
American Electric Power Company, Inc.	AEP	$55.79	$2.24	4.83%	4.92%	5.02%	5.11%	5.21%	5.31%	5.40%	9.67%
Empire District Electric Company	EDE	$22.95	$1.04	4.33%	4.51%	4.69%	4.87%	5.05%	5.22%	5.40%	10.09%
Eversource Energy	ES	$49.08	$1.67	7.29%	6.98%	6.66%	6.35%	6.03%	5.72%	5.40%	9.62%
Great Plains Energy Inc.	GXP	$26.12	$1.05	5.41%	5.41%	5.41%	5.41%	5.40%	5.40%	5.40%	9.84%
IDACORP, Inc.	IDA	$61.69	$2.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	8.49%
Otter Tail Corporation	OTTR	$27.71	$1.23	7.50%	7.15%	6.80%	6.45%	6.10%	5.75%	5.40%	10.98%
Pinnacle West Capital Corporation	PNW	$61.63	$2.50	4.72%	4.83%	4.94%	5.06%	5.17%	5.29%	5.40%	9.68%
PNM Resources, Inc.	PNM	$26.97	$0.80	9.13%	8.51%	7.89%	7.27%	6.65%	6.02%	5.40%	9.52%
Portland General Electric Company	POR	$35.68	$1.20	4.67%	4.79%	4.92%	5.04%	5.16%	5.28%	5.40%	8.92%
Westar Energy, Inc.	WR	$37.69	$1.44	4.37%	4.54%	4.71%	4.88%	5.06%	5.23%	5.40%	9.34%
MEAN											**9.64%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 30, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$50.97	$2.02	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.66%
American Electric Power Company, Inc.	AEP	$56.45	$2.24	4.68%	4.80%	4.92%	5.04%	5.16%	5.28%	5.40%	9.58%
Empire District Electric Company	EDE	$22.76	$1.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.74%
Eversource Energy	ES	$51.00	$1.67	6.57%	6.38%	6.18%	5.99%	5.79%	5.60%	5.40%	9.28%
Great Plains Energy Inc.	GXP	$27.21	$1.05	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.54%
IDACORP, Inc.	IDA	$67.21	$2.04	1.00%	1.73%	2.47%	3.20%	3.93%	4.67%	5.40%	7.85%
Otter Tail Corporation	OTTR	$26.97	$1.23	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.64%
Pinnacle West Capital Corporation	PNW	$63.72	$2.50	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	9.35%
PNM Resources, Inc.	PNM	$28.29	$0.80	8.10%	7.65%	7.20%	6.75%	6.30%	5.85%	5.40%	9.08%
Portland General Electric Company	POR	$36.90	$1.20	3.92%	4.17%	4.41%	4.66%	4.91%	5.15%	5.40%	8.63%
Westar Energy, Inc.	WR	$40.87	$1.44	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	8.82%
MEAN											**9.29%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 30, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.89	$2.02	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.75%
American Electric Power Company, Inc.	AEP	$56.09	$2.24	4.68%	4.80%	4.92%	5.04%	5.16%	5.28%	5.40%	9.61%
Empire District Electric Company	EDE	$22.43	$1.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.80%
Eversource Energy	ES	$49.67	$1.67	6.57%	6.38%	6.18%	5.99%	5.79%	5.60%	5.40%	9.38%
Great Plains Energy Inc.	GXP	$26.43	$1.05	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.67%
IDACORP, Inc.	IDA	$63.77	$2.04	1.00%	1.73%	2.47%	3.20%	3.93%	4.67%	5.40%	7.99%
Otter Tail Corporation	OTTR	$26.61	$1.23	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.71%
Pinnacle West Capital Corporation	PNW	$62.62	$2.50	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	9.42%
PNM Resources, Inc.	PNM	$27.17	$0.80	8.10%	7.65%	7.20%	6.75%	6.30%	5.85%	5.40%	9.23%
Portland General Electric Company	POR	$36.26	$1.20	3.92%	4.17%	4.41%	4.66%	4.91%	5.15%	5.40%	8.69%
Westar Energy, Inc.	WR	$38.70	$1.44	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	9.02%
MEAN											**9.39%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 30, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MINIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.81	$2.02	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.76%
American Electric Power Company, Inc.	AEP	$55.79	$2.24	4.68%	4.80%	4.92%	5.04%	5.16%	5.28%	5.40%	9.63%
Empire District Electric Company	EDE	$22.95	$1.04	3.00%	3.40%	3.80%	4.20%	4.60%	5.00%	5.40%	9.70%
Eversource Energy	ES	$49.08	$1.67	6.57%	6.38%	6.18%	5.99%	5.79%	5.60%	5.40%	9.43%
Great Plains Energy Inc.	GXP	$26.12	$1.05	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.72%
IDACORP, Inc.	IDA	$61.69	$2.04	1.00%	1.73%	2.47%	3.20%	3.93%	4.67%	5.40%	8.09%
Otter Tail Corporation	OTTR	$27.71	$1.23	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.49%
Pinnacle West Capital Corporation	PNW	$61.63	$2.50	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	9.49%
PNM Resources, Inc.	PNM	$26.97	$0.80	8.10%	7.65%	7.20%	6.75%	6.30%	5.85%	5.40%	9.26%
Portland General Electric Company	POR	$35.68	$1.20	3.92%	4.17%	4.41%	4.66%	4.91%	5.15%	5.40%	8.75%
Westar Energy, Inc.	WR	$37.69	$1.44	3.50%	3.82%	4.13%	4.45%	4.77%	5.08%	5.40%	9.12%
MEAN											**9.40%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 30, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

30-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$50.97	$2.02	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.08%
American Electric Power Company, Inc.	AEP	$56.45	$2.24	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.67%
Empire District Electric Company	EDE	$22.76	$1.04	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.33%
Eversource Energy	ES	$51.00	$1.67	8.50%	7.98%	7.47%	6.95%	6.43%	5.92%	5.40%	9.77%
Great Plains Energy Inc.	GXP	$27.21	$1.05	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.82%
IDACORP, Inc.	IDA	$67.21	$2.04	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.43%
Otter Tail Corporation	OTTR	$26.97	$1.23	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	11.67%
Pinnacle West Capital Corporation	PNW	$63.72	$2.50	5.15%	5.19%	5.23%	5.28%	5.32%	5.36%	5.40%	9.66%
PNM Resources, Inc.	PNM	$28.29	$0.80	10.30%	9.48%	8.67%	7.85%	7.03%	6.22%	5.40%	9.62%
Portland General Electric Company	POR	$36.90	$1.20	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.11%
Westar Energy, Inc.	WR	$40.87	$1.44	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.43%
MEAN											**9.78%**

Notes:
[1] Source: Bloomberg Professional, equals 30-trading day average as of November 30, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

90-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.89	$2.02	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.19%
American Electric Power Company, Inc.	AEP	$56.09	$2.24	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.69%
Empire District Electric Company	EDE	$22.43	$1.04	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.40%
Eversource Energy	ES	$49.67	$1.67	8.50%	7.98%	7.47%	6.95%	6.43%	5.92%	5.40%	9.89%
Great Plains Energy Inc.	GXP	$26.43	$1.05	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.95%
IDACORP, Inc.	IDA	$63.77	$2.04	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.60%
Otter Tail Corporation	OTTR	$26.61	$1.23	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	11.75%
Pinnacle West Capital Corporation	PNW	$62.62	$2.50	5.15%	5.19%	5.23%	5.28%	5.32%	5.36%	5.40%	9.73%
PNM Resources, Inc.	PNM	$27.17	$0.80	10.30%	9.48%	8.67%	7.85%	7.03%	6.22%	5.40%	9.79%
Portland General Electric Company	POR	$36.26	$1.20	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.18%
Westar Energy, Inc.	WR	$38.70	$1.44	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.66%
MEAN											**9.89%**

Notes:
[1] Source: Bloomberg Professional, equals 90-trading day average as of November 30, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] – [3]) / 6
[5] Equals [4] + ([9] – [3]) / 6
[6] Equals [5] + ([9] – [3]) / 6
[7] Equals [6] + ([9] – [3]) / 6
[8] Equals [7] + ([9] – [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

180-DAY MULTI-STAGE DCF -- MAXIMUM FIRST STAGE GROWTH RATE

Inputs		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
					Second Stage Growth						
Company	Ticker	Stock Price	Annualized Dividend	First Stage Growth	Year 6	Year 7	Year 8	Year 9	Year 10	Third Stage Growth	ROE
ALLETE, Inc.	ALE	$49.81	$2.02	6.50%	6.32%	6.13%	5.95%	5.77%	5.58%	5.40%	10.19%
American Electric Power Company, Inc.	AEP	$55.79	$2.24	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	9.72%
Empire District Electric Company	EDE	$22.95	$1.04	5.00%	5.07%	5.13%	5.20%	5.27%	5.33%	5.40%	10.29%
Eversource Energy	ES	$49.08	$1.67	8.50%	7.98%	7.47%	6.95%	6.43%	5.92%	5.40%	9.94%
Great Plains Energy Inc.	GXP	$26.12	$1.05	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	10.00%
IDACORP, Inc.	IDA	$61.69	$2.04	4.00%	4.23%	4.47%	4.70%	4.93%	5.17%	5.40%	8.71%
Otter Tail Corporation	OTTR	$27.71	$1.23	9.00%	8.40%	7.80%	7.20%	6.60%	6.00%	5.40%	11.50%
Pinnacle West Capital Corporation	PNW	$61.63	$2.50	5.15%	5.19%	5.23%	5.28%	5.32%	5.36%	5.40%	9.80%
PNM Resources, Inc.	PNM	$26.97	$0.80	10.30%	9.48%	8.67%	7.85%	7.03%	6.22%	5.40%	9.82%
Portland General Electric Company	POR	$35.68	$1.20	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.24%
Westar Energy, Inc.	WR	$37.69	$1.44	6.00%	5.90%	5.80%	5.70%	5.60%	5.50%	5.40%	9.77%
MEAN											**9.91%**

Notes:
[1] Source: Bloomberg Professional, equals 180-trading day average as of November 30, 2015.
[2] Source: Bloomberg Professional
[3] Source: Exhibit AEB-1
[4] Equals [3] + ([9] − [3]) / 6
[5] Equals [4] + ([9] − [3]) / 6
[6] Equals [5] + ([9] − [3]) / 6
[7] Equals [6] + ([9] − [3]) / 6
[8] Equals [7] + ([9] − [3]) / 6
[9] Source: Exhibit AEB-3
[10] Equals internal rate of return of cash flows for Year 0 through Year 200

Exhibit AEB-R-3

CALCULATION OF LONG-TERM GDP GROWTH RATE

Step 1	
Real GDP ($ Billions) [1]	
1929	$ 1,056.6
2014	$ 15,961.7
Compound Annual Growth Rate	**3.25%**
Step 2	
Consumer Price Index (YoY % Change) [2]	
2022-2026	2.30%
Average	2.30%
Consumer Price Index (All-Urban) [3]	
2025	2.89
2040	3.95
Compound Annual Growth Rate	2.11%
GDP Chain-type Price Index (2009=1.000) [3]	
2025	1.31
2040	1.73
Compound Annual Growth Rate	1.85%
Average Inflation Forecast	**2.09%**
Long-Term GDP Growth Rate	**5.40%**

Notes:
[1] Bureau of Economic Analysis, November 24, 2015
[2] Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14
[3] Energy Information Administration, Annual Energy Outlook 2015, Table 20

Exhibit AEB-R-4

BETA
AS OF NOVEMBER 30, 2015

		[1]	[2]
		Bloomberg	Value Line
ALLETE, Inc.	ALE	0.602	0.800
American Electric Power Company, Inc.	AEP	0.569	0.700
Empire District Electric Company	EDE	0.566	0.700
Eversource Energy	ES	0.559	0.750
Great Plains Energy Inc.	GXP	0.622	0.850
IDACORP, Inc.	IDA	0.710	0.800
Otter Tail Corporation	OTTR	0.759	0.850
Pinnacle West Capital Corporation	PNW	0.626	0.750
PNM Resources, Inc.	PNM	0.662	0.850
Portland General Electric Company	POR	0.683	0.800
Westar Energy, Inc.	WR	0.636	0.750
Mean		0.636	0.782

Notes:
[1] Source: Bloomberg Professional
[2] Source: Value Line; dated Sep. 18, 2015, Oct. 30, 2015, and Nov. 20, 2015.

Exhibit AEB-R-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	2.98%	0.636	10.53%	9.67%
[2] Near-term projected 30-year U.S. Treasury bond yield (Q4 2015 - Q1 2017)	3.37%	0.636	10.14%	9.81%
[3] Projected 30-year U.S. Treasury bond yield (2017 - 2021)	4.80%	0.636	8.71%	10.34%
			Mean:	9.94%
Proxy Group Average Value Line Beta				
[1] Current 30-day average of 30-year U.S. Treasury bond yield	2.98%	0.782	10.53%	11.21%
[2] Near-term projected 30-year U.S. Treasury bond yield (Q4 2015 - Q1 2017)	3.37%	0.782	10.14%	11.30%
[3] Projected 30-year U.S. Treasury bond yield (2017 - 2021)	4.80%	0.782	8.71%	11.61%
			Mean:	11.37%

[1] Source: Bloomberg Professional
[2] Source: Blue Chip Financial Forecasts, Vol. 34, No. 11, November 1, 2015, at 2
[3] Source: Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14
[4] See Notes [1], [2], and [3]
[5] Source: Exhibit AEB-4
[6] Source: Exhibit AEB-5, at 2
[7] Equals [4] + ([5] x [6])

MARKET RISK PREMIUM DERIVED FROM ANALYSTS LONG-TERM GROWTH ESTIMATES

[8] Estimated Weighted Average Dividend Yield		2.13%	
[9] Estimated Weighted Average Long-Term Growth Rate		11.26%	
[10] S&P 500 Estimated Required Market Return		13.51%	
[11] Risk-Free Rate	2.98%	3.37%	4.80%
[12] Implied Market Risk Premium	10.53%	10.14%	8.71%

STANDARD AND POOR'S 500 INDEX

		[13]	[14]	[15]	[16]	[17]
Name	Ticker	Weight in Index	Estimated Dividend Yield	Cap-Weighted Dividend Yield	Long-Term Growth Est.	Cap-Weighted Long-Term Growth Est.
Alcoa Inc	AA	0.06%	1.28%	0.00%	9.77%	0.01%
LyondellBasell Industries NV	LYB	0.23%	3.26%	0.01%	5.86%	0.01%
American Express Co	AXP	0.37%	1.62%	0.01%	10.00%	0.04%
Verizon Communications Inc	VZ	0.98%	4.97%	0.05%	7.55%	0.07%
Avago Technologies Ltd	AVGO	0.19%	1.29%	0.00%	20.11%	0.04%
Boeing Co/The	BA	0.52%	2.50%	0.01%	12.42%	0.06%
Caterpillar Inc	CAT	0.22%	4.24%	0.01%	9.00%	0.02%
JPMorgan Chase & Co	JPM	1.30%	2.64%	0.03%	7.82%	0.10%
Chevron Corp	CVX	0.91%	4.69%	0.04%	-3.57%	-0.03%
Coca-Cola Co/The	KO	0.98%	3.10%	0.03%	5.79%	0.06%
AbbVie Inc	ABBV	0.50%	3.92%	0.02%	8.64%	0.04%
Walt Disney Co/The	DIS	0.99%	1.16%	0.01%	11.58%	0.11%
EI du Pont de Nemours & Co	DD	0.31%	2.26%	0.01%	5.20%	0.02%
Exxon Mobil Corp	XOM	1.80%	3.58%	0.06%	-0.35%	-0.01%
Phillips 66	PSX	0.26%	2.45%	0.01%	5.39%	0.01%
General Electric Co	GE	1.50%	3.07%	0.05%	7.86%	0.12%
HP Inc	HPQ	0.12%	3.96%	0.00%	4.53%	0.01%
Home Depot Inc/The	HD	0.90%	1.76%	0.02%	14.06%	0.13%
International Business Machines Corp	IBM	0.72%	3.73%	0.03%	6.48%	0.05%
Johnson & Johnson	JNJ	1.48%	2.96%	0.04%	5.91%	0.09%
McDonald's Corp	MCD	0.55%	3.12%	0.02%	8.62%	0.05%
Merck & Co Inc	MRK	0.78%	3.47%	0.03%	6.70%	0.05%
3M Co	MMM	0.51%	2.62%	0.01%	9.05%	0.05%
Bank of America Corp	BAC	0.96%	1.15%	0.01%	24.88%	0.24%
CSRA Inc	CSRA	0.02%	n/a	n/a	n/a	n/a
Pfizer Inc	PFE	1.07%	3.42%	0.04%	4.66%	0.05%
Procter & Gamble Co/The	PG	1.08%	3.54%	0.04%	7.11%	0.08%
AT&T Inc	T	1.10%	5.58%	0.06%	4.42%	0.05%
Travelers Cos Inc/The	TRV	0.18%	2.13%	0.00%	7.81%	0.01%
United Technologies Corp	UTX	0.45%	2.67%	0.01%	8.30%	0.04%
Analog Devices Inc	ADI	0.10%	2.60%	0.00%	10.45%	0.01%
Wal-Mart Stores Inc	WMT	1.00%	3.33%	0.03%	0.59%	0.01%
Cisco Systems Inc	CSCO	0.73%	3.08%	0.02%	7.86%	0.06%
Intel Corp	INTC	0.87%	2.76%	0.02%	8.60%	0.07%
General Motors Co	GM	0.30%	3.98%	0.01%	11.69%	0.03%
Microsoft Corp	MSFT	2.30%	2.65%	0.06%	9.93%	0.23%
Dollar General Corp	DG	0.10%	1.35%	0.00%	12.29%	0.01%
Kinder Morgan Inc/DE	KMI	0.28%	8.66%	0.02%	6.13%	0.02%
Citigroup Inc	C	0.85%	0.37%	0.00%	25.41%	0.22%
American International Group Inc	AIG	0.42%	1.76%	0.01%	9.04%	0.04%
Honeywell International Inc	HON	0.42%	2.29%	0.01%	9.69%	0.04%
Altria Group Inc	MO	0.60%	3.92%	0.02%	7.78%	0.05%
HCA Holdings Inc	HCA	0.15%	n/a	n/a	10.63%	0.02%
Under Armour Inc	UA	0.08%	n/a	n/a	23.43%	0.02%
International Paper Co	IP	0.09%	4.21%	0.00%	8.56%	0.01%
Hewlett Packard Enterprise Co	HPE	0.14%	1.48%	0.00%	4.09%	0.01%
Abbott Laboratories	ABT	0.35%	2.14%	0.01%	11.95%	0.04%
Aflac Inc	AFL	0.15%	2.51%	0.00%	8.53%	0.01%
Air Products & Chemicals Inc	APD	0.16%	2.37%	0.00%	5.00%	0.01%
Airgas Inc	ARG	0.05%	1.74%	0.00%	7.47%	0.00%
Royal Caribbean Cruises Ltd	RCL	0.11%	1.62%	0.00%	19.70%	0.02%
American Electric Power Co Inc	AEP	0.15%	4.00%	0.01%	5.27%	0.01%
Hess Corp	HES	0.09%	1.69%	0.00%	-26.25%	-0.02%
Anadarko Petroleum Corp	APC	0.16%	1.80%	0.00%	8.33%	0.01%
Aon PLC	AON	0.14%	1.27%	0.00%	11.68%	0.02%
Apache Corp	APA	0.10%	2.03%	0.00%	-1.92%	0.00%
Archer-Daniels-Midland Co	ADM	0.12%	3.07%	0.00%	2.70%	0.00%
AGL Resources Inc	GAS	0.04%	3.26%	0.00%	6.00%	0.00%
Automatic Data Processing Inc	ADP	0.21%	2.46%	0.01%	10.33%	0.02%
Verisk Analytics Inc	VRSK	0.07%	n/a	n/a	12.00%	0.01%
AutoZone Inc	AZO	0.13%	n/a	n/a	12.40%	0.02%
Avery Dennison Corp	AVY	0.03%	2.24%	0.00%	9.05%	0.00%
Baker Hughes Inc	BHI	0.12%	1.26%	0.00%	8.00%	0.01%
Ball Corp	BLL	0.05%	0.75%	0.00%	6.05%	0.00%
Bank of New York Mellon Corp/The	BK	0.25%	1.55%	0.00%	12.57%	0.03%
CR Bard Inc	BCR	0.07%	0.51%	0.00%	13.78%	0.01%
Baxter International Inc	BAX	0.11%	1.22%	0.00%	8.75%	0.01%
Becton Dickinson and Co	BDX	0.17%	1.76%	0.00%	11.42%	0.02%
Berkshire Hathaway Inc	BRK/B	0.89%	n/a	n/a	5.00%	0.04%
Best Buy Co Inc	BBY	0.06%	2.89%	0.00%	10.00%	0.01%
H&R Block Inc	HRB	0.05%	2.18%	0.00%	11.00%	0.01%
Boston Scientific Corp	BSX	0.13%	n/a	n/a	9.12%	0.01%
Bristol-Myers Squibb Co	BMY	0.59%	2.21%	0.01%	13.53%	0.08%
Brown-Forman Corp	BF/B	0.07%	1.33%	0.00%	8.36%	0.01%
Cabot Oil & Gas Corp	COG	0.04%	0.42%	0.00%	48.42%	0.02%
Campbell Soup Co	CPB	0.09%	2.39%	0.00%	5.42%	0.00%
Kansas City Southern	KSU	0.05%	1.45%	0.00%	9.60%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Carnival Corp	CCL	0.16%	2.37%	0.00%	19.17%	0.03%
Qorvo Inc	QRVO	0.04%	n/a	n/a	16.21%	0.01%
CenturyLink Inc	CTL	0.08%	8.02%	0.01%	0.19%	0.00%
Chubb Corp/The	CB	0.16%	1.75%	0.00%	9.20%	0.01%
Cigna Corp	CI	0.18%	0.03%	0.00%	11.40%	0.02%
Frontier Communications Corp	FTR	0.03%	8.42%	0.00%	3.00%	0.00%
Clorox Co/The	CLX	0.08%	2.48%	0.00%	6.87%	0.01%
CMS Energy Corp	CMS	0.05%	3.31%	0.00%	6.25%	0.00%
Coca-Cola Enterprises Inc	CCE	0.06%	2.23%	0.00%	6.04%	0.00%
Colgate-Palmolive Co	CL	0.31%	2.31%	0.01%	7.88%	0.02%
Comerica Inc	CMA	0.04%	1.81%	0.00%	9.28%	0.00%
CA Inc	CA	0.07%	3.56%	0.00%	5.50%	0.00%
Computer Sciences Corp	CSC	0.02%	1.79%	0.00%	3.60%	0.00%
ConAgra Foods Inc	CAG	0.09%	2.44%	0.00%	8.50%	0.01%
Consolidated Edison Inc	ED	0.10%	4.18%	0.00%	2.74%	0.00%
SL Green Realty Corp	SLG	0.06%	2.03%	0.00%	4.98%	0.00%
Corning Inc	GLW	0.12%	2.56%	0.00%	5.55%	0.01%
CSX Corp	CSX	0.15%	2.53%	0.00%	8.59%	0.01%
Cummins Inc	CMI	0.09%	3.89%	0.00%	6.90%	0.01%
Danaher Corp	DHR	0.35%	0.56%	0.00%	12.90%	0.05%
Target Corp	TGT	0.24%	3.09%	0.01%	9.82%	0.02%
Deere & Co	DE	0.14%	3.02%	0.00%	5.15%	0.01%
Dominion Resources Inc/VA	D	0.21%	3.84%	0.01%	6.00%	0.01%
Dover Corp	DOV	0.05%	2.55%	0.00%	12.00%	0.01%
Dow Chemical Co/The	DOW	0.32%	3.53%	0.01%	6.53%	0.02%
Duke Energy Corp	DUK	0.25%	4.87%	0.01%	4.10%	0.01%
Eaton Corp PLC	ETN	0.14%	3.78%	0.01%	8.09%	0.01%
Ecolab Inc	ECL	0.19%	1.11%	0.00%	13.22%	0.02%
PerkinElmer Inc	PKI	0.03%	0.53%	0.00%	6.14%	0.00%
EMC Corp/MA	EMC	0.26%	1.82%	0.00%	8.53%	0.02%
Emerson Electric Co	EMR	0.17%	3.80%	0.01%	7.82%	0.01%
EOG Resources Inc	EOG	0.24%	0.80%	0.00%	2.05%	0.00%
Entergy Corp	ETR	0.06%	5.10%	0.00%	1.64%	0.00%
Equifax Inc	EFX	0.07%	1.04%	0.00%	10.00%	0.01%
EQT Corp	EQT	0.05%	0.21%	0.00%	30.00%	0.01%
XL Group PLC	XL	0.06%	2.10%	0.00%	9.50%	0.01%
FedEx Corp	FDX	0.24%	0.63%	0.00%	13.78%	0.03%
Macy's Inc	M	0.07%	3.68%	0.00%	7.88%	0.01%
FMC Corp	FMC	0.03%	1.54%	0.00%	9.00%	0.00%
Ford Motor Co	F	0.30%	4.19%	0.01%	13.79%	0.04%
NextEra Energy Inc	NEE	0.24%	3.08%	0.01%	7.00%	0.02%
Franklin Resources Inc	BEN	0.13%	1.43%	0.00%	7.69%	0.01%
Freeport-McMoRan Inc	FCX	0.05%	2.45%	0.00%	-55.40%	-0.03%
TEGNA Inc	TGNA	0.03%	1.98%	0.00%	4.43%	0.00%
Gap Inc/The	GPS	0.06%	3.44%	0.00%	8.79%	0.01%
General Dynamics Corp	GD	0.25%	1.88%	0.00%	9.02%	0.02%
General Mills Inc	GIS	0.18%	3.05%	0.01%	7.50%	0.01%
Genuine Parts Co	GPC	0.07%	2.71%	0.00%	8.62%	0.01%
WW Grainger Inc	GWW	0.07%	2.33%	0.00%	10.08%	0.01%
Halliburton Co	HAL	0.18%	1.81%	0.00%	6.02%	0.01%
Harley-Davidson Inc	HOG	0.05%	2.53%	0.00%	10.13%	0.01%
Harman International Industries Inc	HAR	0.04%	1.36%	0.00%	16.00%	0.01%
Harris Corp	HRS	0.05%	2.41%	0.00%	n/a	n/a
HCP Inc	HCP	0.09%	6.36%	0.01%	2.78%	0.00%
Helmerich & Payne Inc	HP	0.03%	4.72%	0.00%	1.10%	0.00%
Hershey Co/The	HSY	0.07%	2.70%	0.00%	8.93%	0.01%
Synchrony Financial	SYF	0.14%	n/a	n/a	5.34%	0.01%
Hormel Foods Corp	HRL	0.10%	1.55%	0.00%	8.00%	0.01%
Starwood Hotels & Resorts Worldwide Inc	HOT	0.06%	2.09%	0.00%	8.35%	0.01%
Mondelez International Inc	MDLZ	0.37%	1.56%	0.01%	10.76%	0.04%
CenterPoint Energy Inc	CNP	0.04%	5.84%	0.00%	4.50%	0.00%
Humana Inc	HUM	0.13%	0.69%	0.00%	12.33%	0.02%
Illinois Tool Works Inc	ITW	0.18%	2.34%	0.00%	8.20%	0.01%
Ingersoll-Rand PLC	IR	0.08%	1.98%	0.00%	10.11%	0.01%
Interpublic Group of Cos Inc/The	IPG	0.05%	2.09%	0.00%	6.50%	0.00%
International Flavors & Fragrances Inc	IFF	0.05%	1.87%	0.00%	11.00%	0.01%
Jacobs Engineering Group Inc	JEC	0.03%	n/a	n/a	7.22%	0.00%
Johnson Controls Inc	JCI	0.16%	2.52%	0.00%	10.33%	0.02%
Hanesbrands Inc	HBI	0.06%	1.30%	0.00%	16.30%	0.01%
Kellogg Co	K	0.13%	2.91%	0.00%	4.06%	0.01%
Perrigo Co PLC	PRGO	0.12%	0.33%	0.00%	12.73%	0.01%
Kimberly-Clark Corp	KMB	0.23%	2.95%	0.01%	8.10%	0.02%
Kimco Realty Corp	KIM	0.06%	3.91%	0.00%	4.49%	0.00%
Kohl's Corp	KSS	0.05%	3.82%	0.00%	7.52%	0.00%
Oracle Corp	ORCL	0.88%	1.54%	0.01%	7.72%	0.07%
Kroger Co/The	KR	0.19%	1.12%	0.00%	10.19%	0.02%
Legg Mason Inc	LM	0.03%	1.80%	0.00%	15.95%	0.00%
Leggett & Platt Inc	LEG	0.03%	2.75%	0.00%	n/a	n/a
Lennar Corp	LEN	0.05%	0.31%	0.00%	n/a	n/a
Leucadia National Corp	LUK	0.03%	1.41%	0.00%	n/a	n/a
Eli Lilly & Co	LLY	0.48%	2.44%	0.01%	10.63%	0.05%
L Brands Inc	LB	0.15%	2.10%	0.00%	10.91%	0.02%
Lincoln National Corp	LNC	0.07%	1.82%	0.00%	10.18%	0.01%
Loews Corp	L	0.07%	0.66%	0.00%	n/a	n/a
Lowe's Cos Inc	LOW	0.38%	1.46%	0.01%	16.83%	0.06%
Host Hotels & Resorts Inc	HST	0.07%	4.82%	0.00%	5.00%	0.00%
Marsh & McLennan Cos Inc	MMC	0.15%	2.24%	0.00%	11.99%	0.02%
Masco Corp	MAS	0.05%	1.27%	0.00%	14.79%	0.01%
Mattel Inc	MAT	0.04%	6.11%	0.00%	9.43%	0.00%
McGraw Hill Financial Inc	MHFI	0.14%	1.37%	0.00%	11.17%	0.02%
Medtronic PLC	MDT	0.56%	2.02%	0.01%	8.18%	0.05%

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.
CVS Health Corp	CVS	0.55%	1.49%	0.01%	14.50%	0.08%
Micron Technology Inc	MU	0.09%	n/a	n/a	2.22%	0.00%
Motorola Solutions Inc	MSI	0.07%	2.28%	0.00%	3.00%	0.00%
Murphy Oil Corp	MUR	0.03%	4.90%	0.00%	13.00%	0.00%
Mylan NV	MYL	0.13%	n/a	n/a	9.75%	0.01%
Laboratory Corp of America Holdings	LH	0.07%	n/a	n/a	10.26%	0.01%
Tenet Healthcare Corp	THC	0.02%	n/a	n/a	13.17%	0.00%
Newell Rubbermaid Inc	NWL	0.06%	1.70%	0.00%	9.42%	0.01%
Newmont Mining Corp	NEM	0.05%	0.54%	0.00%	1.43%	0.00%
Twenty-First Century Fox Inc	FOXA	0.18%	1.02%	0.00%	14.92%	0.03%
NIKE Inc	NKE	0.47%	0.97%	0.00%	13.37%	0.06%
NiSource Inc	NI	0.03%	3.23%	0.00%	n/a	n/a
Noble Energy Inc	NBL	0.08%	1.96%	0.00%	1.23%	0.00%
Norfolk Southern Corp	NSC	0.15%	2.48%	0.00%	8.14%	0.01%
Eversource Energy	ES	0.09%	3.28%	0.00%	6.58%	0.01%
Northrop Grumman Corp	NOC	0.18%	1.72%	0.00%	6.57%	0.01%
Wells Fargo & Co	WFC	1.49%	2.72%	0.04%	11.28%	0.17%
Nucor Corp	NUE	0.07%	3.59%	0.00%	10.10%	0.01%
PVH Corp	PVH	0.04%	0.16%	0.00%	9.76%	0.00%
Occidental Petroleum Corp	OXY	0.31%	3.97%	0.01%	8.00%	0.02%
Omnicom Group Inc	OMC	0.09%	2.71%	0.00%	5.33%	0.01%
ONEOK Inc	OKE	0.03%	8.34%	0.00%	8.60%	0.00%
Owens-Illinois Inc	OI	0.02%	n/a	n/a	2.90%	0.00%
PG&E Corp	PCG	0.14%	3.45%	0.00%	3.83%	0.01%
Parker-Hannifin Corp	PH	0.08%	2.41%	0.00%	8.69%	0.01%
PPL Corp	PPL	0.12%	4.44%	0.01%	1.94%	0.00%
PepsiCo Inc	PEP	0.77%	2.81%	0.02%	6.04%	0.05%
Exelon Corp	EXC	0.13%	4.54%	0.01%	5.18%	0.01%
ConocoPhillips	COP	0.35%	5.48%	0.02%	-0.45%	0.00%
PulteGroup Inc	PHM	0.04%	1.64%	0.00%	17.19%	0.01%
Pinnacle West Capital Corp	PNW	0.04%	3.95%	0.00%	5.20%	0.00%
Pitney Bowes Inc	PBI	0.02%	3.47%	0.00%	14.00%	0.00%
Plum Creek Timber Co Inc	PCL	0.05%	3.46%	0.00%	22.82%	0.01%
PNC Financial Services Group Inc/The	PNC	0.26%	2.14%	0.01%	6.99%	0.02%
PPG Industries Inc	PPG	0.15%	1.36%	0.00%	7.03%	0.01%
Praxair Inc	PX	0.17%	2.54%	0.00%	6.85%	0.01%
Precision Castparts Corp	PCP	0.17%	0.05%	0.00%	11.67%	0.02%
Progressive Corp/The	PGR	0.10%	2.23%	0.00%	7.93%	0.01%
Public Service Enterprise Group Inc	PEG	0.10%	3.99%	0.00%	3.94%	0.00%
Raytheon Co	RTN	0.20%	2.16%	0.00%	7.41%	0.01%
Robert Half International Inc	RHI	0.04%	1.56%	0.00%	15.62%	0.01%
Ryder System Inc	R	0.02%	2.49%	0.00%	10.70%	0.00%
SCANA Corp	SCG	0.04%	3.69%	0.00%	6.00%	0.00%
Edison International	EIX	0.10%	2.81%	0.00%	3.42%	0.00%
Schlumberger Ltd	SLB	0.52%	2.59%	0.01%	14.33%	0.07%
Charles Schwab Corp/The	SCHW	0.23%	0.71%	0.00%	20.35%	0.05%
Sherwin-Williams Co/The	SHW	0.14%	0.97%	0.00%	18.05%	0.02%
JM Smucker Co/The	SJM	0.08%	2.21%	0.00%	9.38%	0.01%
Snap-on Inc	SNA	0.05%	1.42%	0.00%	3.30%	0.00%
AMETEK Inc	AME	0.07%	0.64%	0.00%	10.41%	0.01%
Southern Co/The	SO	0.21%	4.87%	0.01%	3.83%	0.01%
BB&T Corp	BBT	0.16%	2.80%	0.00%	11.30%	0.02%
Southwest Airlines Co	LUV	0.16%	0.65%	0.00%	18.09%	0.03%
Southwestern Energy Co	SWN	0.02%	n/a	n/a	9.33%	0.00%
Stanley Black & Decker Inc	SWK	0.09%	2.02%	0.00%	10.67%	0.01%
Public Storage	PSA	0.22%	2.83%	0.01%	4.80%	0.01%
SunTrust Banks Inc	STI	0.12%	2.21%	0.00%	5.86%	0.01%
Sysco Corp	SYY	0.12%	3.02%	0.00%	9.02%	0.01%
TECO Energy Inc	TE	0.03%	3.42%	0.00%	6.00%	0.00%
Tesoro Corp	TSO	0.07%	1.74%	0.00%	16.14%	0.01%
Texas Instruments Inc	TXN	0.31%	2.62%	0.01%	9.48%	0.03%
Textron Inc	TXT	0.06%	0.19%	0.00%	9.26%	0.01%
Thermo Fisher Scientific Inc	TMO	0.29%	0.43%	0.00%	11.60%	0.03%
Tiffany & Co	TIF	0.05%	2.01%	0.00%	10.53%	0.01%
TJX Cos Inc/The	TJX	0.25%	1.19%	0.00%	10.96%	0.03%
Torchmark Corp	TMK	0.04%	0.89%	0.00%	7.19%	0.00%
Total System Services Inc	TSS	0.05%	0.71%	0.00%	11.00%	0.01%
Tyco International Plc	TYC	0.08%	2.32%	0.00%	10.60%	0.01%
Union Pacific Corp	UNP	0.38%	2.62%	0.01%	8.66%	0.03%
UnitedHealth Group Inc	UNH	0.57%	1.77%	0.01%	11.83%	0.07%
Unum Group	UNM	0.05%	2.02%	0.00%	9.00%	0.00%
Marathon Oil Corp	MRO	0.06%	1.14%	0.00%	-3.70%	0.00%
Varian Medical Systems Inc	VAR	0.04%	n/a	n/a	11.37%	0.00%
Ventas Inc	VTR	0.09%	5.47%	0.01%	2.63%	0.00%
VF Corp	VFC	0.15%	2.29%	0.00%	11.53%	0.02%
Vornado Realty Trust	VNO	0.10%	2.60%	0.00%	4.90%	0.00%
ADT Corp/The	ADT	0.03%	2.37%	0.00%	6.47%	0.00%
Vulcan Materials Co	VMC	0.07%	0.39%	0.00%	44.44%	0.03%
Weyerhaeuser Co	WY	0.09%	3.85%	0.00%	3.60%	0.00%
Whirlpool Corp	WHR	0.07%	2.22%	0.00%	16.65%	0.01%
Williams Cos Inc/The	WMB	0.15%	7.00%	0.01%	n/a	n/a
WEC Energy Group Inc	WEC	0.08%	3.71%	0.00%	4.35%	0.00%
Xerox Corp	XRX	0.06%	2.65%	0.00%	8.55%	0.00%
Adobe Systems Inc	ADBE	0.24%	n/a	n/a	18.87%	0.05%
AES Corp/VA	AES	0.04%	4.00%	0.00%	3.71%	0.00%
Amgen Inc	AMGN	0.65%	1.96%	0.01%	8.38%	0.05%
Apple Inc	AAPL	3.49%	1.76%	0.06%	13.50%	0.47%
Autodesk Inc	ADSK	0.08%	n/a	n/a	-1.51%	0.00%
Cintas Corp	CTAS	0.05%	1.15%	0.00%	11.60%	0.01%
Comcast Corp	CMCSA	0.67%	1.64%	0.01%	13.39%	0.09%
Molson Coors Brewing Co	TAP	0.08%	1.78%	0.00%	12.10%	0.01%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
KLA-Tencor Corp	KLAC	0.05%	3.13%	0.00%	13.47%	0.01%
Marriott International Inc/MD	MAR	0.10%	1.41%	0.00%	12.67%	0.01%
McCormick & Co Inc/MD	MKC	0.05%	2.00%	0.00%	6.50%	0.00%
Nordstrom Inc	JWN	0.06%	2.63%	0.00%	8.22%	0.00%
PACCAR Inc	PCAR	0.10%	1.85%	0.00%	9.14%	0.01%
Costco Wholesale Corp	COST	0.37%	0.99%	0.00%	9.80%	0.04%
St Jude Medical Inc	STJ	0.09%	1.84%	0.00%	11.25%	0.01%
Stryker Corp	SYK	0.19%	1.43%	0.00%	11.00%	0.02%
Tyson Foods Inc	TSN	0.08%	1.20%	0.00%	8.60%	0.01%
Altera Corp	ALTR	0.08%	1.36%	0.00%	10.45%	0.01%
Applied Materials Inc	AMAT	0.12%	2.13%	0.00%	12.08%	0.01%
Time Warner Inc	TWX	0.30%	2.00%	0.01%	12.37%	0.04%
Bed Bath & Beyond Inc	BBBY	0.05%	n/a	n/a	7.35%	0.00%
American Airlines Group Inc	AAL	0.14%	0.97%	0.00%	18.37%	0.03%
Cardinal Health Inc	CAH	0.15%	1.78%	0.00%	12.36%	0.02%
Celgene Corp	CELG	0.46%	n/a	n/a	24.08%	0.11%
Cerner Corp	CERN	0.11%	n/a	n/a	17.28%	0.02%
Cincinnati Financial Corp	CINF	0.05%	3.01%	0.00%	n/a	n/a
Cablevision Systems Corp	CVC	0.04%	1.97%	0.00%	2.30%	0.00%
DR Horton Inc	DHI	0.06%	0.99%	0.00%	19.20%	0.01%
Flowserve Corp	FLS	0.03%	1.56%	0.00%	7.14%	0.00%
Electronic Arts Inc	EA	0.11%	n/a	n/a	14.33%	0.02%
Express Scripts Holding Co	ESRX	0.31%	n/a	n/a	16.70%	0.05%
Expeditors International of Washington Inc	EXPD	0.05%	1.48%	0.00%	10.06%	0.00%
Fastenal Co	FAST	0.06%	2.76%	0.00%	12.65%	0.01%
M&T Bank Corp	MTB	0.12%	2.23%	0.00%	6.98%	0.01%
Fiserv Inc	FISV	0.12%	n/a	n/a	12.80%	0.01%
Fifth Third Bancorp	FITB	0.09%	2.52%	0.00%	4.58%	0.00%
Gilead Sciences Inc	GILD	0.81%	1.62%	0.01%	11.70%	0.09%
Hasbro Inc	HAS	0.05%	2.52%	0.00%	9.55%	0.00%
Huntington Bancshares Inc/OH	HBAN	0.05%	2.40%	0.00%	8.28%	0.00%
Welltower Inc	HCN	0.12%	5.22%	0.01%	4.49%	0.01%
Biogen Inc	BIIB	0.34%	n/a	n/a	12.00%	0.04%
Linear Technology Corp	LLTC	0.06%	2.62%	0.00%	6.76%	0.00%
Range Resources Corp	RRC	0.03%	0.56%	0.00%	13.48%	0.00%
Northern Trust Corp	NTRS	0.09%	1.92%	0.00%	13.71%	0.01%
Paychex Inc	PAYX	0.10%	3.10%	0.00%	9.39%	0.01%
People's United Financial Inc	PBCT	0.03%	4.00%	0.00%	n/a	n/a
Patterson Cos Inc	PDCO	0.02%	1.93%	0.00%	9.50%	0.00%
QUALCOMM Inc	QCOM	0.39%	3.94%	0.02%	11.27%	0.04%
Roper Technologies Inc	ROP	0.10%	0.52%	0.00%	11.77%	0.01%
Ross Stores Inc	ROST	0.11%	0.90%	0.00%	10.79%	0.01%
AutoNation Inc	AN	0.04%	n/a	n/a	13.29%	0.00%
Starbucks Corp	SBUX	0.48%	1.30%	0.01%	18.16%	0.09%
KeyCorp	KEY	0.06%	2.29%	0.00%	7.34%	0.00%
Staples Inc	SPLS	0.04%	3.98%	0.00%	0.71%	0.00%
State Street Corp	STT	0.16%	1.87%	0.00%	8.62%	0.01%
US Bancorp	USB	0.41%	2.32%	0.01%	5.75%	0.02%
Symantec Corp	SYMC	0.07%	3.06%	0.00%	6.72%	0.00%
T Rowe Price Group Inc	TROW	0.10%	2.73%	0.00%	10.83%	0.01%
Waste Management Inc	WM	0.13%	2.86%	0.00%	7.98%	0.01%
CBS Corp	CBS	0.12%	1.19%	0.00%	14.02%	0.02%
Allergan plc	AGN	0.65%	n/a	n/a	11.91%	0.08%
Whole Foods Market Inc	WFM	0.05%	1.85%	0.00%	10.96%	0.01%
Constellation Brands Inc	STZ	0.13%	0.88%	0.00%	13.62%	0.02%
Xilinx Inc	XLNX	0.07%	2.50%	0.00%	8.12%	0.01%
DENTSPLY International Inc	XRAY	0.04%	0.48%	0.00%	9.07%	0.00%
Zions Bancorporation	ZION	0.03%	0.80%	0.00%	7.15%	0.00%
Invesco Ltd	IVZ	0.08%	3.21%	0.00%	10.48%	0.01%
Intuit Inc	INTU	0.14%	1.20%	0.00%	17.57%	0.02%
Morgan Stanley	MS	0.35%	1.75%	0.01%	17.07%	0.06%
Microchip Technology Inc	MCHP	0.05%	2.97%	0.00%	7.51%	0.00%
ACE Ltd	ACE	0.20%	2.33%	0.00%	11.20%	0.02%
Chesapeake Energy Corp	CHK	0.02%	n/a	n/a	0.28%	0.00%
O'Reilly Automotive Inc	ORLY	0.14%	n/a	n/a	17.70%	0.02%
Allstate Corp/The	ALL	0.13%	1.91%	0.00%	9.00%	0.01%
FLIR Systems Inc	FLIR	0.02%	1.44%	0.00%	15.00%	0.00%
Equity Residential	EQR	0.15%	2.77%	0.00%	5.99%	0.01%
BorgWarner Inc	BWA	0.05%	1.22%	0.00%	10.59%	0.01%
Newfield Exploration Co	NFX	0.03%	n/a	n/a	6.86%	0.00%
Urban Outfitters Inc	URBN	0.01%	n/a	n/a	13.26%	0.00%
Simon Property Group Inc	SPG	0.31%	3.44%	0.01%	6.75%	0.02%
Eastman Chemical Co	EMN	0.06%	2.20%	0.00%	7.03%	0.00%
AvalonBay Communities Inc	AVB	0.13%	2.75%	0.00%	6.13%	0.01%
Prudential Financial Inc	PRU	0.21%	3.24%	0.01%	11.00%	0.02%
United Parcel Service Inc	UPS	0.38%	2.83%	0.01%	11.44%	0.04%
Apartment Investment & Management Co	AIV	0.03%	3.15%	0.00%	8.34%	0.00%
Walgreens Boots Alliance Inc	WBA	0.48%	1.71%	0.01%	15.90%	0.08%
McKesson Corp	MCK	0.23%	0.59%	0.00%	14.73%	0.03%
Lockheed Martin Corp	LMT	0.36%	3.01%	0.01%	7.80%	0.03%
AmerisourceBergen Corp	ABC	0.11%	1.38%	0.00%	12.50%	0.01%
Cameron International Corp	CAM	0.07%	n/a	n/a	-5.90%	0.00%
Capital One Financial Corp	COF	0.22%	2.04%	0.00%	6.62%	0.01%
Waters Corp	WAT	0.06%	n/a	n/a	9.59%	0.01%
Dollar Tree Inc	DLTR	0.09%	n/a	n/a	19.67%	0.02%
Darden Restaurants Inc	DRI	0.04%	3.92%	0.00%	12.50%	0.00%
SanDisk Corp	SNDK	0.08%	n/a	n/a	11.00%	0.01%
Diamond Offshore Drilling Inc	DO	0.02%	2.21%	0.00%	13.40%	0.00%
NetApp Inc	NTAP	0.05%	2.35%	0.00%	9.98%	0.00%
Citrix Systems Inc	CTXS	0.06%	n/a	n/a	14.38%	0.01%
Goodyear Tire & Rubber Co/The	GT	0.05%	0.80%	0.00%	7.00%	0.00%

STANDARD AND POOR'S 500 INDEX

Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
DaVita HealthCare Partners Inc	DVA	0.08%	n/a	n/a	9.29%	0.01%
Hartford Financial Services Group Inc/The	HIG	0.10%	1.84%	0.00%	9.25%	0.01%
Iron Mountain Inc	IRM	0.03%	6.98%	0.00%	7.30%	0.00%
Estee Lauder Cos Inc/The	EL	0.10%	1.43%	0.00%	12.36%	0.01%
Yahoo! Inc	YHOO	0.17%	n/a	n/a	10.25%	0.02%
Principal Financial Group Inc	PFG	0.08%	2.95%	0.00%	11.50%	0.01%
Stericycle Inc	SRCL	0.05%	n/a	n/a	15.40%	0.01%
Universal Health Services Inc	UHS	0.06%	0.33%	0.00%	10.35%	0.01%
E*TRADE Financial Corp	ETFC	0.05%	n/a	n/a	16.36%	0.01%
Skyworks Solutions Inc	SWKS	0.08%	1.25%	0.00%	18.90%	0.02%
National Oilwell Varco Inc	NOV	0.07%	4.93%	0.00%	-5.45%	0.00%
Quest Diagnostics Inc	DGX	0.05%	2.22%	0.00%	10.46%	0.01%
Activision Blizzard Inc	ATVI	0.15%	0.61%	0.00%	11.33%	0.02%
Rockwell Automation Inc	ROK	0.07%	2.72%	0.00%	8.98%	0.01%
Kraft Heinz Co/The	KHC	0.47%	3.12%	0.01%	15.87%	0.08%
American Tower Corp	AMT	0.22%	1.85%	0.00%	14.88%	0.03%
Regeneron Pharmaceuticals Inc	REGN	0.29%	n/a	n/a	21.69%	0.06%
Amazon.com Inc	AMZN	1.65%	n/a	n/a	62.40%	1.03%
Ralph Lauren Corp	RL	0.04%	1.61%	0.00%	12.85%	0.00%
Boston Properties Inc	BXP	0.10%	2.08%	0.00%	6.06%	0.01%
Amphenol Corp	APH	0.09%	1.02%	0.00%	8.70%	0.01%
Pioneer Natural Resources Co	PXD	0.11%	0.06%	0.00%	5.60%	0.01%
Valero Energy Corp	VLO	0.18%	2.78%	0.01%	2.79%	0.01%
L-3 Communications Holdings Inc	LLL	0.05%	2.12%	0.00%	6.69%	0.00%
Western Union Co/The	WU	0.05%	3.29%	0.00%	6.73%	0.00%
CH Robinson Worldwide Inc	CHRW	0.05%	2.25%	0.00%	10.63%	0.01%
Accenture PLC	ACN	0.35%	2.05%	0.01%	10.37%	0.04%
Yum! Brands Inc	YUM	0.17%	2.54%	0.00%	11.45%	0.02%
Prologis Inc	PLD	0.12%	3.74%	0.00%	4.77%	0.01%
FirstEnergy Corp	FE	0.07%	4.59%	0.00%	-0.30%	0.00%
VeriSign Inc	VRSN	0.05%	n/a	n/a	8.40%	0.00%
Quanta Services Inc	PWR	0.02%	n/a	n/a	8.00%	0.00%
Henry Schein Inc	HSIC	0.07%	n/a	n/a	10.78%	0.01%
Ameren Corp	AEE	0.06%	3.88%	0.00%	7.10%	0.00%
Broadcom Corp	BRCM	0.16%	1.03%	0.00%	12.36%	0.02%
NVIDIA Corp	NVDA	0.09%	1.45%	0.00%	8.53%	0.01%
Sealed Air Corp	SEE	0.05%	1.15%	0.00%	9.50%	0.00%
Cognizant Technology Solutions Corp	CTSH	0.21%	n/a	n/a	16.28%	0.03%
Intuitive Surgical Inc	ISRG	0.10%	n/a	n/a	14.53%	0.01%
CONSOL Energy Inc	CNX	0.01%	0.51%	0.00%	14.40%	0.00%
Affiliated Managers Group Inc	AMG	0.05%	n/a	n/a	13.01%	0.01%
Aetna Inc	AET	0.19%	0.97%	0.00%	11.95%	0.02%
Republic Services Inc	RSG	0.08%	2.73%	0.00%	6.77%	0.01%
eBay Inc	EBAY	0.19%	n/a	n/a	7.25%	0.01%
Goldman Sachs Group Inc/The	GS	0.43%	1.37%	0.01%	8.31%	0.04%
Sempra Energy	SRE	0.13%	2.82%	0.00%	8.35%	0.01%
Moody's Corp	MCO	0.11%	1.32%	0.00%	13.00%	0.01%
Priceline Group Inc/The	PCLN	0.33%	n/a	n/a	18.71%	0.06%
F5 Networks Inc	FFIV	0.04%	n/a	n/a	15.90%	0.01%
Akamai Technologies Inc	AKAM	0.05%	n/a	n/a	15.40%	0.01%
Reynolds American Inc	RAI	0.35%	3.11%	0.01%	6.48%	0.02%
Devon Energy Corp	DVN	0.10%	2.09%	0.00%	6.99%	0.01%
Alphabet Inc	GOOGL	1.18%	n/a	n/a	18.08%	0.21%
Red Hat Inc	RHT	0.08%	n/a	n/a	18.58%	0.01%
Allegion PLC	ALLE	0.03%	0.60%	0.00%	14.89%	0.01%
Netflix Inc	NFLX	0.28%	n/a	n/a	27.33%	0.08%
Agilent Technologies Inc	A	0.07%	1.10%	0.00%	11.80%	0.01%
Anthem Inc	ANTM	0.18%	1.92%	0.00%	9.61%	0.02%
CME Group Inc/IL	CME	0.17%	2.05%	0.00%	12.61%	0.02%
Juniper Networks Inc	JNPR	0.06%	1.33%	0.00%	11.38%	0.01%
BlackRock Inc	BLK	0.32%	2.40%	0.01%	11.97%	0.04%
DTE Energy Co	DTE	0.08%	3.63%	0.00%	5.30%	0.00%
Nasdaq Inc	NDAQ	0.05%	1.71%	0.00%	6.88%	0.00%
Philip Morris International Inc	PM	0.72%	4.67%	0.03%	6.12%	0.04%
Time Warner Cable Inc	TWC	0.28%	1.62%	0.00%	5.50%	0.02%
salesforce.com inc	CRM	0.28%	n/a	n/a	27.72%	0.08%
MetLife Inc	MET	0.30%	2.94%	0.01%	7.38%	0.02%
Monsanto Co	MON	0.22%	2.27%	0.01%	9.82%	0.02%
Coach Inc	COH	0.05%	4.25%	0.00%	10.67%	0.00%
Fluor Corp	FLR	0.04%	1.73%	0.00%	5.73%	0.00%
Dun & Bradstreet Corp/The	DNB	0.02%	1.72%	0.00%	10.15%	0.00%
Edwards Lifesciences Corp	EW	0.09%	n/a	n/a	15.20%	0.01%
Ameriprise Financial Inc	AMP	0.10%	2.37%	0.00%	13.00%	0.01%
Xcel Energy Inc	XEL	0.10%	3.59%	0.00%	4.75%	0.00%
Rockwell Collins Inc	COL	0.06%	1.42%	0.00%	7.97%	0.01%
FMC Technologies Inc	FTI	0.04%	n/a	n/a	-11.80%	0.00%
Zimmer Biomet Holdings Inc	ZBH	0.11%	0.87%	0.00%	10.48%	0.01%
CBRE Group Inc	CBG	0.07%	n/a	n/a	10.50%	0.01%
MasterCard Inc	MA	0.57%	0.65%	0.00%	16.50%	0.09%
Signet Jewelers Ltd	SIG	0.06%	0.67%	0.00%	12.50%	0.01%
GameStop Corp	GME	0.02%	4.11%	0.00%	12.74%	0.00%
CarMax Inc	KMX	0.06%	n/a	n/a	15.27%	0.01%
Intercontinental Exchange Inc	ICE	0.15%	1.15%	0.00%	15.83%	0.02%
Fidelity National Information Services Inc	FIS	0.10%	1.63%	0.00%	12.78%	0.01%
Chipotle Mexican Grill Inc	CMG	0.10%	n/a	n/a	19.93%	0.02%
Pepco Holdings Inc	POM	0.03%	4.21%	0.00%	5.53%	0.00%
Wynn Resorts Ltd	WYNN	0.03%	3.19%	0.00%	8.93%	0.00%
Assurant Inc	AIZ	0.03%	2.34%	0.00%	8.62%	0.00%
NRG Energy Inc	NRG	0.02%	4.69%	0.00%	26.60%	0.01%
Regions Financial Corp	RF	0.07%	2.37%	0.00%	2.08%	0.00%
Monster Beverage Corp	MNST	0.17%	n/a	n/a	16.63%	0.03%

STANDARD AND POOR'S 500 INDEX

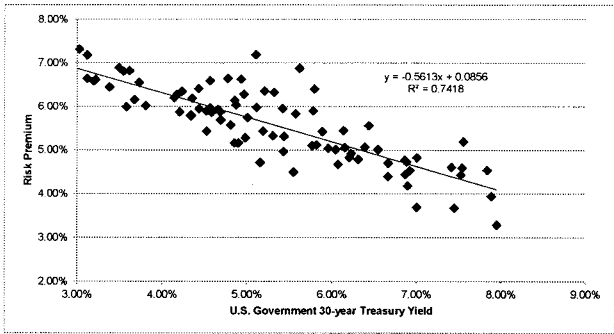
Name	Ticker	[13] Weight in Index	[14] Estimated Dividend Yield	[15] Cap-Weighted Dividend Yield	[16] Long-Term Growth Est.	[17] Cap-Weighted Long-Term Growth Est.
Teradata Corp	TDC	0.02%	n/a	n/a	8.22%	0.00%
Mosaic Co/The	MOS	0.06%	3.48%	0.00%	15.37%	0.01%
Expedia Inc	EXPE	0.08%	0.78%	0.00%	21.25%	0.02%
Discovery Communications Inc	DISCA	0.02%	n/a	n/a	15.50%	0.00%
CF Industries Holdings Inc	CF	0.06%	2.60%	0.00%	20.00%	0.01%
Viacom Inc	VIAB	0.09%	3.21%	0.00%	9.10%	0.01%
Wyndham Worldwide Corp	WYN	0.05%	2.21%	0.00%	9.00%	0.00%
Alphabet Inc	GOOG	1.36%	n/a	n/a	18.08%	0.25%
Spectra Energy Corp	SE	0.09%	5.65%	0.01%	4.63%	0.00%
First Solar Inc	FSLR	0.03%	n/a	n/a	1.03%	0.00%
Mead Johnson Nutrition Co	MJN	0.08%	2.05%	0.00%	8.80%	0.01%
Ensco PLC	ESV	0.02%	3.50%	0.00%	-4.00%	0.00%
TE Connectivity Ltd	TEL	0.14%	1.97%	0.00%	10.00%	0.01%
Discover Financial Services	DFS	0.13%	1.97%	0.00%	8.59%	0.01%
TripAdvisor Inc	TRIP	0.06%	n/a	n/a	15.73%	0.01%
Dr Pepper Snapple Group Inc	DPS	0.09%	2.14%	0.00%	7.70%	0.01%
Scripps Networks Interactive Inc	SNI	0.03%	1.62%	0.00%	11.46%	0.00%
Visa Inc	V	0.81%	0.71%	0.01%	17.37%	0.14%
Xylem Inc/NY	XYL	0.04%	1.51%	0.00%	11.30%	0.00%
Marathon Petroleum Corp	MPC	0.16%	2.19%	0.00%	2.62%	0.00%
Level 3 Communications Inc	LVLT	0.10%	n/a	n/a	8.00%	0.01%
Tractor Supply Co	TSCO	0.06%	0.90%	0.00%	15.69%	0.01%
Transocean Ltd	RIG	0.03%	n/a	n/a	26.29%	0.01%
Essex Property Trust Inc	ESS	0.08%	2.50%	0.00%	6.25%	0.01%
General Growth Properties Inc	GGP	0.12%	2.98%	0.00%	7.05%	0.01%
Realty Income Corp	O	0.07%	4.61%	0.00%	4.30%	0.00%
Seagate Technology PLC	STX	0.06%	7.01%	0.00%	7.06%	0.00%
WestRock Co	WRK	0.07%	2.96%	0.00%	n/a	n/a
Western Digital Corp	WDC	0.08%	3.20%	0.00%	5.00%	0.00%
Twenty-First Century Fox Inc	FOX	0.13%	1.00%	0.00%	14.92%	0.02%
Comcast Corp	CMCSK	0.11%	1.64%	0.00%	13.39%	0.02%
Fossil Group Inc	FOSL	0.01%	n/a	n/a	0.00%	0.00%
JB Hunt Transport Services Inc	JBHT	0.05%	1.07%	0.00%	14.13%	0.01%
Lam Research Corp	LRCX	0.07%	1.53%	0.00%	5.48%	0.00%
Mohawk Industries Inc	MHK	0.07%	n/a	n/a	12.00%	0.01%
Pentair PLC	PNR	0.05%	2.26%	0.00%	7.23%	0.00%
Vertex Pharmaceuticals Inc	VRTX	0.17%	n/a	n/a	30.00%	0.05%
Facebook Inc	FB	1.25%	n/a	n/a	28.98%	0.36%
United Rentals Inc	URI	0.04%	n/a	n/a	12.64%	0.00%
United Continental Holdings Inc	UAL	0.11%	n/a	n/a	19.72%	0.02%
Baxalta Inc	BXLT	0.12%	0.81%	0.00%	2.30%	0.00%
Delta Air Lines Inc	DAL	0.19%	1.16%	0.00%	21.88%	0.04%
Navient Corp	NAVI	0.02%	5.37%	0.00%	n/a	n/a
Mallinckrodt PLC	MNK	0.04%	n/a	n/a	13.19%	0.01%
News Corp	NWS	0.02%	1.38%	0.00%	13.95%	0.00%
Keurig Green Mountain Inc	GMCR	0.04%	2.48%	0.00%	12.08%	0.00%
Macerich Co/The	MAC	0.07%	3.48%	0.00%	5.70%	0.00%
Martin Marietta Materials Inc	MLM	0.06%	1.02%	0.00%	18.99%	0.01%
PayPal Holdings Inc	PYPL	0.23%	n/a	n/a	16.33%	0.04%
Alexion Pharmaceuticals Inc	ALXN	0.21%	n/a	n/a	21.71%	0.05%
Columbia Pipeline Group Inc	CPGX	0.03%	2.61%	0.00%	36.00%	0.01%
Endo International PLC	ENDP	0.07%	n/a	n/a	12.13%	0.01%
News Corp	NWSA	0.03%	1.39%	0.00%	13.95%	0.00%
Crown Castle International Corp	CCI	0.15%	4.12%	0.01%	22.80%	0.03%
Delphi Automotive PLC	DLPH	0.13%	1.14%	0.00%	10.61%	0.01%
Advance Auto Parts Inc	AAP	0.06%	0.15%	0.00%	11.95%	0.01%
Michael Kors Holdings Ltd	KORS	0.04%	n/a	n/a	7.45%	0.00%
Illumina Inc	ILMN	0.14%	n/a	n/a	20.48%	0.03%
Alliance Data Systems Corp	ADS	0.09%	n/a	n/a	14.50%	0.01%
Nielsen Holdings PLC	NLSN	0.09%	2.40%	0.00%	12.33%	0.01%
Garmin Ltd	GRMN	0.04%	5.39%	0.00%	8.45%	0.00%
Cimarex Energy Co	XEC	0.06%	0.54%	0.00%	-2.79%	0.00%
Zoetis Inc	ZTS	0.12%	0.71%	0.00%	9.85%	0.01%
Equinix Inc	EQIX	0.10%	2.28%	0.00%	17.00%	0.02%
Discovery Communications Inc	DISCK	0.04%	n/a	n/a	15.50%	0.01%

Notes:
[8] Equals sum of Col. [15]
[9] Equals sum of Col. [17]
[10] Equals ([8] x (1 + (0.5 x [9]))) + [9]
[11] Source: Exhibit AEB-5, at 1
[12] Equals [10] – [11]
[13] Equals weight in S&P 500 based on market capitalization
[14] Source: Bloomberg Professional
[15] Equals [13] x [14]
[16] Source: Bloomberg Professional
[17] Equals [13] x [16]

Exhibit AEB-R-6

BOND YIELD PLUS RISK PREMIUM

	[1]	[2]	[3]
	Average Authorized Electric ROE	30-year U.S. Treasury Bond	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	10.39%	4.70%	5.69%
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	10.43%	4.53%	5.90%
2008.1	10.15%	4.34%	5.81%
2008.2	10.54%	4.57%	5.97%
2008.3	10.38%	4.44%	5.95%
2008.4	10.39%	3.49%	6.89%
2009.1	10.45%	3.62%	6.83%
2009.2	10.58%	4.23%	6.35%
2009.3	10.46%	4.18%	6.28%
2009.4	10.54%	4.35%	6.19%
2010.1	10.45%	4.59%	5.86%
2010.2	10.08%	4.20%	5.87%
2010.3	10.29%	3.73%	6.56%
2010.4	10.34%	4.14%	6.20%
2011.1	9.96%	4.53%	5.44%
2011.2	10.12%	4.33%	5.79%
2011.3	10.36%	3.54%	6.82%
2011.4	10.34%	3.03%	7.32%
2012.1	10.30%	3.12%	7.18%
2012.2	9.92%	2.84%	7.08%
2012.3	9.78%	2.68%	7.10%
2012.4	10.07%	2.87%	7.20%
2013.1	9.77%	3.12%	6.65%
2013.2	9.84%	3.22%	6.62%
2013.3	9.83%	3.67%	6.16%
2013.4	9.82%	3.81%	6.02%
2014.1	9.57%	3.58%	5.99%
2014.2	9.83%	3.38%	6.45%
2014.3	9.79%	3.20%	6.59%
2014.4	9.78%	2.90%	6.88%
2015.1	9.66%	2.45%	7.21%
2015.2	9.50%	2.92%	6.58%
2015.3	9.40%	2.91%	6.49%
2015.4	9.77%	2.95%	6.82%
AVERAGE	10.80%	5.11%	5.69%
MEDIAN	10.73%	4.97%	5.82%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.861251
R Square	0.741754
Adjusted R Square	0.739007
Standard Error	0.004667
Observations	96

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005879	0.005879	269.993823	0.000000
Residual	94	0.002047	0.000022		
Total	95	0.007926			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0856	0.001809	47.33	0.000000	0.082012	0.089193	0.082012	0.089193
30-year U.S. Treasury Bond	(0.5613)	0.034160	(16.43)	0.000000	(0.629122)	(0.493472)	(0.629122)	(0.493472)

	[7]	[8]	[9]
	U.S. Govt. 30-year Treasury	Risk Premium	ROE
Current 30-Day Average [4]	2.98%	6.89%	9.87%
Blue Chip Consensus Forecast (Q1 2015-Q2 2016) [5]	3.37%	6.67%	10.04%
Blue Chip Consensus Forecast (2016-2020) [6]	4.80%	5.87%	10.67%
MEAN			10.19%

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. 34, No. 11, November 1, 2015, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 34, No. 6, June 1, 2015, at 14
[7] See notes [4], [5] & [6]
[8] Equals 0.085602 + (-0.561297 x Column [7])
[9] Equals Column [7] + Column [8]

Exhibit AEB-R-7

ADJUSTMENTS TO MEASE DCF - DCF 90 DAY CONSTANT GROWTH - ES & PNM YAHOO! EPS GROWTH RATES & EXCLUDES SO

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND PER SHARE	/	(B) AVERAGE STOCK PRICE (PER SHARE)		(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) FIVE YEAR GROWTH YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02		$ 48.28	=	4.18%	4.28%	4.00%	5.50%	4.75%	8.27%	9.03%	9.80%
2	AEP	American Electric Power Company, Inc.	$ 2.12		$ 55.29	=	3.83%	3.93%	5.00%	4.63%	4.82%	8.55%	8.74%	8.93%
3	DUK	Duke Energy Corporation	$ 3.30		$ 72.04	=	4.58%	4.67%	3.50%	4.04%	3.77%	8.16%	8.44%	8.71%
4	EE	El Paso Electric Company	$ 1.18		$ 35.62	=	3.31%	3.41%	5.00%	7.00%	6.00%	8.40%	9.41%	10.43%
5	EDE	Empire District Electric Company	$ 1.04		$ 22.11	=	4.70%	4.79%	3.00%	4.00%	3.50%	7.77%	8.29%	8.80%
6	ES	Eversource Energy	$ 1.67		$ 47.84	=	3.49%	3.60%	6.50%	5.85%	6.18%	9.45%	9.78%	10.11%
7	GXP	Great Plains Energy Inc.	$ 0.98		$ 25.42	=	3.86%	3.97%	6.00%	6.37%	6.19%	9.97%	10.16%	10.35%
8	IDA	IDACORP, Inc.	$ 1.88		$ 60.13	=	3.13%	3.20%	6.00%	4.00%	5.00%	7.19%	8.20%	9.22%
9	OTTR	Otter Tail Corporation	$ 1.23		$ 26.28	=	4.69%	4.78%	1.50%	6.00%	3.75%	6.22%	8.53%	10.83%
10	PNW	Pinnacle West Capital Corporation	$ 2.38		$ 60.93	=	3.91%	3.99%	3.50%	5.37%	4.44%	7.47%	8.43%	9.38%
11	PNM	PNM Resources, Inc.	$ 0.80		$ 25.85	=	3.09%	3.24%	10.00%	8.56%	9.28%	11.79%	12.52%	13.25%
12	POR	Portland General Electric Company	$ 1.20		$ 34.97	=	3.43%	3.51%	5.50%	3.92%	4.71%	7.42%	8.22%	9.03%
13	WR	Westar Energy, Inc.	$ 1.44		$ 36.66	=	3.93%	3.99%	3.00%	3.40%	3.20%	6.99%	7.19%	7.39%
		Average					3.86%	3.95%	4.81%	5.28%	5.04%	8.28%	9.00%	9.71%

AVERAGE OF LOW, MEAN AND HIGH 9.00%

REFERENCES:
COLUMN (A): ANNUALIZED DIVIDENDS PER VALUE LINE
COLUMN (B): AVERAGE STOCK PRICES, SEE ROBERT MEASE TESTIMONY ATTACHMENT (C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1 + .50 COLUMN (G))
COLUMN (G): AVERAGE OF COLUMN (E) AND (F)

ADJUSTMENTS TO MEASE DCF - DCF 90 DAY CONSTANT GROWTH - ES & PNM YAHOO! EPS GROWTH RATES, EXCLUDES SO & USES VALUE LINE EPS GROWTH RATES

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND PER SHARE	/	(B) AVERAGE STOCK PRICE (PER SHARE)		(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) FIVE YEAR GROWTH YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02		$ 48.28	=	4.18%	4.31%	6.50%	5.50%	6.00%	9.80%	10.31%	10.82%
2	AEP	American Electric Power Company, Inc.	$ 2.12		$ 55.29	=	3.83%	3.93%	5.00%	4.63%	4.82%	8.55%	8.74%	8.93%
3	DUK	Duke Energy Corporation	$ 3.30		$ 72.04	=	4.58%	4.68%	5.00%	4.04%	4.52%	8.71%	9.20%	9.70%
4	EE	El Paso Electric Company	$ 1.18		$ 35.62	=	3.31%	3.40%	3.50%	7.00%	5.25%	6.87%	8.65%	10.43%
5	EDE	Empire District Electric Company	$ 1.04		$ 22.11	=	4.70%	4.79%	3.00%	4.00%	3.50%	7.77%	8.29%	8.80%
6	ES	Eversource Energy	$ 1.67		$ 47.84	=	3.49%	3.62%	8.50%	5.85%	7.18%	9.45%	10.80%	12.14%
7	GXP	Great Plains Energy Inc.	$ 0.98		$ 25.42	=	3.86%	3.96%	5.00%	6.37%	5.69%	8.95%	9.65%	10.35%
8	IDA	IDACORP, Inc.	$ 1.88		$ 60.13	=	3.13%	3.17%	1.00%	4.00%	2.50%	4.14%	5.67%	7.19%
9	OTTR	Otter Tail Corporation	$ 1.23		$ 26.28	=	4.69%	4.86%	9.00%	6.00%	7.50%	10.83%	12.36%	13.90%
10	PNW	Pinnacle West Capital Corporation	$ 2.38		$ 60.93	=	3.91%	4.00%	4.00%	5.37%	4.69%	7.98%	8.68%	9.38%
11	PNM	PNM Resources, Inc.	$ 0.80		$ 25.85	=	3.09%	3.23%	9.00%	8.56%	8.78%	11.79%	12.01%	12.23%
12	POR	Portland General Electric Company	$ 1.20		$ 34.97	=	3.43%	3.52%	6.00%	3.92%	4.96%	7.42%	8.48%	9.53%
13	WR	Westar Energy, Inc.	$ 1.44		$ 36.66	=	3.93%	4.02%	6.00%	3.40%	4.70%	7.39%	8.72%	10.05%
		Average					3.86%	3.96%	5.50%	5.28%	5.39%	8.44%	9.35%	10.27%
									AVERAGE OF LOW, MEAN AND HIGH					9.35%

REFERENCES:
COLUMN (A): ANNUALIZED DIVIDENDS PER VALUE LINE
COLUMN (B): AVERAGE STOCK PRICES, SEE ROBERT MEASE TESTIMONY ATTACHMENT (C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1 + .50 COLUMN (G))
COLUMN (G): AVERAGE OF COLUMN (E) AND (F)

ADJUSTMENTS TO MEASE DCF - DCF 90 DAY CONSTANT GROWTH - EXCLUDES SO & USES SEPTEMBER VALUE LINE & YAHOO! EPS GROWTH RATES

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) ESTIMATED DIVIDEND PER SHARE	/	(B) AVERAGE STOCK PRICE (PER SHARE)		(C) DIVIDEND YIELD	(D) PROJECTED DIVIDEND YIELD	(E) FIVE YEAR GROWTH VALUE LINE	(F) YAHOO FINANCE	(G) AVERAGE EARNINGS GROWTH	(H) ROE LOW	(I) ROE MEAN	(J) ROE HIGH
1	ALE	ALLETE, Inc.	$ 2.02		$ 48.28	=	4.18%	4.31%	6.50%	6.00%	6.25%	10.31%	10.56%	10.82%
2	AEP	American Electric Power Company, Inc.	$ 2.12		$ 55.29	=	3.83%	3.93%	5.00%	4.63%	4.82%	8.55%	8.74%	8.93%
3	DUK	Duke Energy Corporation	$ 3.30		$ 72.04	=	4.58%	4.69%	5.00%	4.33%	4.67%	9.01%	9.35%	9.70%
4	EE	El Paso Electric Company	$ 1.18		$ 35.62	=	3.31%	3.40%	3.50%	7.00%	5.25%	6.87%	8.65%	10.43%
5	EDE	Empire District Electric Company	$ 1.04		$ 22.11	=	4.70%	4.77%	3.00%	3.00%	3.00%	7.77%	7.77%	7.77%
6	ES	Eversource Energy	$ 1.67		$ 47.84	=	3.49%	3.62%	8.50%	6.21%	7.36%	9.81%	10.98%	12.14%
7	GXP	Great Plains Energy Inc.	$ 0.98		$ 25.42	=	3.86%	3.96%	5.00%	6.37%	5.69%	8.95%	9.65%	10.35%
8	IDA	IDACORP, Inc.	$ 1.88		$ 60.13	=	3.13%	3.17%	1.00%	4.00%	2.50%	4.14%	5.67%	7.19%
9	OTTR	Otter Tail Corporation	$ 1.23		$ 26.28	=	4.69%	4.86%	9.00%	6.00%	7.50%	10.83%	12.36%	13.90%
10	PNW	Pinnacle West Capital Corporation	$ 2.38		$ 60.93	=	3.91%	4.00%	4.00%	5.37%	4.69%	7.98%	8.68%	9.38%
11	PNM	PNM Resources, Inc.	$ 0.80		$ 25.85	=	3.09%	3.23%	9.00%	8.56%	8.78%	11.79%	12.01%	12.23%
12	POR	Portland General Electric Company	$ 1.20		$ 34.97	=	3.43%	3.52%	6.00%	4.07%	5.04%	7.57%	8.55%	9.53%
13	WR	Westar Energy, Inc.	$ 1.44		$ 36.66	=	3.93%	4.02%	6.00%	3.40%	4.70%	7.39%	8.72%	10.05%
		Average					3.86%	3.96%	5.50%	5.30%	5.40%	8.54%	9.36%	10.19%

AVERAGE OF LOW, MEAN AND HIGH 9.36%

REFERENCES:
COLUMN (A): ANNUALIZED DIVIDENDS PER VALUE LINE
COLUMN (B): AVERAGE STOCK PRICES, SEE ROBERT MEASE TESTIMONY ATTACHMENT (C)
COLUMN (C): COLUMN (A) / COLUMN (B)
COLUMN (D): COLUMN (C) X (1 + .50 COLUMN (G))
COLUMN (G): AVERAGE OF COLUMN (E) AND (F)

Exhibit AEB-R-8

ADJUSTMENTS TO MEASE CAPM - BASED ON AN ARITHMETIC MEAN - USING CURRENT INTEREST RATE, EXCLUDING SOUTHERN COMPANY & USING UPDATED MARKET RETURN

LINE NO.	STOCK SYMBOL	COMPANY NAME	k	=	r_f	+	[	(A) β	x	(	r_m	-	r_f	)	]	=	(B) EXPECTED RETURN
1	ALE	ALLETE, Inc.	k	=	3.01%	+	[	0.80	x	(	12.10%	-	3.01%	)	]	=	10.28%
2	AEP	American Electric Power Company, Inc.	k	=	3.01%	+	[	0.70	x	(	12.10%	-	3.01%	)	]	=	9.37%
3	DUK	Duke Energy Corporation	k	=	3.01%	+	[	0.60	x	(	12.10%	-	3.01%	)	]	=	8.46%
4	EE	El Paso Electric Company	k	=	3.01%	+	[	0.75	x	(	12.10%	-	3.01%	)	]	=	9.83%
5	EDE	Empire District Electric Company	k	=	3.01%	+	[	0.70	x	(	12.10%	-	3.01%	)	]	=	9.37%
6	ES	Eversource Energy	k	=	3.01%	+	[	0.75	x	(	12.10%	-	3.01%	)	]	=	9.83%
7	GXP	Great Plains Energy Inc.	k	=	3.01%	+	[	0.85	x	(	12.10%	-	3.01%	)	]	=	10.74%
8	IDA	IDACORP, Inc.	k	=	3.01%	+	[	0.80	x	(	12.10%	-	3.01%	)	]	=	10.28%
9	OTTR	Otter Tail Corporation	k	=	3.01%	+	[	0.85	x	(	12.10%	-	3.01%	)	]	=	10.74%
10	PNW	Pinnacle West Capital Corporation	k	=	3.01%	+	[	0.70	x	(	12.10%	-	3.01%	)	]	=	9.37%
11	PNM	PNM Resources, Inc.	k	=	3.01%	+	[	0.85	x	(	12.10%	-	3.01%	)	]	=	10.74%
12	POR	Portland General Electric Company	k	=	3.01%	+	[	0.80	x	(	12.10%	-	3.01%	)	]	=	10.28%
13	WR	Westar Energy, Inc.	k	=	3.01%	+	[	0.75	x	(	12.10%	-	3.01%	)	]	=	9.83%
14	**AVERAGE**							0.76									9.93%

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

$k = r_f + [\ \beta\ (r_m - r_f)\ ]$

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

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

Exhibit AEB-R-9

UNS ELECTRIC
FAIR VALUE RATE OF RETURN
RUCO PROPOSED METHODOLOGY

	Amount ($M)	Weighting	Weighted Amount ($M)	
Original Cost Rate Base (OCRB)	$ 272.0	50.00%	$ 136.0	
Replacement Cost New, Depreciated Rate Base (RCN	$ 439.4	50.00%	219.7	
Fair Value Rate Base (FVRB)			355.7	[1]
Appreciation Above OCRB			$ 83.7	[2]
FVRB / OCRB Multiple			1.31	

FVROR Adjusted for 50% Inflation Factor

Capital	Amount ($M)		Percent		Cost Rate		Weighted Cost Rate
Proposed Equity Ratio			47.17%	[3]			
Proposed Debt Ratio			52.83%	[4]			
Inflation Rate			1.35%	[5]	0.68%		
Debt Cost Rate					4.66%		
Equity Cost Rate					8.35%		
Long-Term Debt	$ 167.8	[6]	47.17%		3.99%	[8]	1.88%
Common Equity	187.9	[7]	52.83%		7.68%	[9]	4.05%
Capital Financing FVRB	$ 355.7		100.00%				5.93%

[1] Direct Testimony of Dallas J. Dukes, Schedule B-1
[2] Direct Testimony of Dallas J. Dukes, Schedule B-1
[3] JMM-2
[4] JMM-2
[5] JMM-1
[6] =[1]*[3]
[7] = [1]*[4]
[8] = [5]*.5*debt cost rate
[9] = Equity cost rate -([3]*.5)

FVROR Adjusted for 50% Inflation Factor and Adjusted ROE

Capital	Amount ($M)		Percent		Cost Rate		Weighted Cost Rate
Proposed Equity Ratio			47.17%	[3]			
Proposed Debt Ratio			52.83%	[4]			
Inflation Rate			1.35%	[5]	0.68%		
Debt Cost Rate					4.66%		
Equity Cost Rate					9.36%		
Long-Term Debt	$ 167.8	[6]	47.17%		3.99%	[8]	1.88%
Common Equity	187.9	[7]	52.83%		8.69%	[9]	4.59%
Capital Financing FVRB	$ 355.7		100.00%				6.47%

[1] Direct Testimony of Dallas J. Dukes, Schedule B-1
[2] Direct Testimony of Dallas J. Dukes, Schedule B-1
[3] JMM-2
[4] JMM-2
[5] JMM-1
[6] =[1]*[3]
[7] = [1]*[4]
[8] = [5]*.5*debt cost rate
[9] = Equity cost rate -([3]*.5)

Exhibit AEB-R-10

ADJUSTMENTS TO WOOLRIDGE DCF EQUITY COST GROWTH RATE MEASURES
VALUE LINE PROJECTED GROWTH RATES

	Company	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
		Value Line Projected Growth Est'd. '12-'14 to '18-'20				*Value Line* Sustainable Growth					
		Earnings	Dividends	Book Value	Return on Equity	Retention Rate	Internal Growth	Shares Out	Value Change	S x V	BR + SV
1	ALLETE, Inc. (NYSE-ALE)	6.50%	4.00%	4.50%	9.00%	39.00%	3.5%	2.1%	19.0%	0.4%	3.9%
2	Alliant Energy Corporation (NYSE-LNT)	6.00%	4.50%	4.00%	11.50%	37.00%	4.3%	1.4%	46.7%	0.6%	4.9%
3	Ameren Corporation (NYSE-AEE)	7.00%	3.50%	3.50%	10.50%	44.00%	4.6%	0.8%	20.0%	0.2%	4.8%
4	American Electric Power Co. (NYSE-AEP)	5.00%	5.00%	4.00%	10.00%	34.00%	3.4%	0.6%	30.0%	0.2%	3.6%
5	Avista Corporation (NYSE-AVA)	5.00%	4.00%	3.50%	8.50%	35.00%	3.0%	0.7%	22.1%	0.2%	3.1%
6	Black Hills Corporation (NYSE-BKH)	4.50%	4.00%	3.50%	8.50%	40.00%	3.4%	0.8%	30.5%	0.3%	3.7%
7	CMS Energy Corporation (NYSE-CMS)	5.50%	6.50%	5.50%	13.50%	38.00%	5.1%	1.4%	49.3%	0.7%	5.8%
8	Consolidated Edison, Inc. (NYSE-ED)	3.00%	2.50%	3.50%	9.00%	36.00%	3.2%	0.0%	18.8%	0.0%	3.2%
9	Dominion Resources, Inc. (NYSE-D)	8.00%	7.50%	6.50%	17.50%	28.00%	4.9%	4.4%	66.1%	2.9%	7.8%
10	Duke Energy Corporation (NYSE-DUK)	5.00%	3.50%	1.50%	8.50%	30.00%	2.6%	-0.5%	22.1%	-0.1%	2.4%
11	Edison International (NYSE-EIX)	3.00%	10.00%	6.50%	11.50%	48.00%	5.5%	0.0%	36.1%	0.0%	5.5%
12	El Paso Electric Company (NYSE-EE)	3.50%	5.00%	4.50%	9.50%	50.00%	4.8%	0.5%	26.3%	0.1%	4.9%
13	Empire District Electric Co. (NYSE-EDE)	3.00%	3.00%	2.50%	9.00%	33.00%	3.0%	2.2%	19.0%	0.4%	3.4%
14	Entergy Corporation (NYSE-ETR)	0.00%	2.50%	3.00%	8.50%	31.00%	2.6%	0.0%	25.0%	0.0%	2.6%
15	Eversource Energy (NYSE-ES)	8.50%	6.50%	4.00%	10.00%	44.00%	4.4%	0.4%	27.1%	0.1%	4.5%
16	FirstEnergy Corporation (ASE-FE)	7.00%	-1.50%	3.00%	8.50%	48.00%	4.1%	0.7%	5.3%	0.0%	4.1%
17	Great Plains Energy Incorporated (NYSE-GXP)	5.00%	6.00%	3.00%	7.50%	39.00%	2.9%	0.2%	2.7%	0.0%	2.9%
18	IDACORP, Inc. (NYSE-IDA)	1.00%	6.00%	4.00%	8.50%	42.00%	3.6%	0.0%	24.7%	0.0%	3.6%
19	MGE Energy, Inc. (NYSE-MGEE)	7.00%	4.00%	6.00%	13.00%	58.00%	7.5%	1.4%	47.4%	0.7%	8.2%
20	NorthWestern Corporation (NYSE-NWE)	6.50%	6.50%	5.50%	10.00%	42.00%	4.2%	0.6%	27.6%	0.2%	4.4%
21	OGE Energy Corp. (NYSE-OGE)	3.00%	10.00%	5.00%	11.50%	32.00%	3.7%	0.4%	42.1%	0.2%	3.9%
22	Otter Tail Corporation (NDQ-OTTR)	9.00%	1.50%	3.50%	12.50%	41.00%	5.1%	5.4%	54.8%	3.0%	8.1%
23	PG&E Corporation (NYSE-PCG)	10.50%	3.00%	5.00%	10.00%	49.00%	4.9%	2.1%	15.0%	0.3%	5.2%
24	Pinnacle West Capital Corp. (NYSE-PNW)	4.00%	3.50%	3.50%	9.50%	36.00%	3.4%	1.7%	24.8%	0.4%	3.9%
25	PNM Resources, Inc. (NYSE-PNM)	9.00%	10.00%	3.50%	9.50%	51.00%	4.8%	0.1%	32.0%	0.0%	4.9%
26	Portland General Electric Company (NYSE-POR)	6.00%	5.50%	4.50%	9.50%	47.00%	4.5%	3.1%	12.9%	0.4%	4.9%
27	SCANA Corporation (NYSE-SCG)	4.50%	3.50%	5.50%	9.50%	44.00%	4.2%	1.1%	20.9%	0.2%	4.4%
28	Westar Energy, Inc. (NYSE-WR)	6.00%	3.00%	5.00%	9.50%	45.00%	4.3%	1.9%	35.0%	0.7%	4.9%
29	Xcel Energy Inc. (NYSE-XEL)	4.50%	6.00%	4.50%	10.50%	38.00%	4.0%	0.6%	29.3%	0.2%	4.2%
	Mean	5.4%	4.8%	4.2%	10.16%	40.66%	4.1%	1.2%	28.7%	0.4%	4.5%
	Median	5.0%	4.0%	4.0%	9.50%	40.00%	4.2%	0.7%	26.3%	0.2%	4.4%
	Average of Median Figures =		4.3%				4.2%				

Data Source: *Value Line Investment Survey*.

Exhibit AEB-R-11

ADJUSTMENTS TO WOOLRIDGE DCF EQUITY COST GROWTH RATE MEASURES
ANALYSTS PROJECTED EPS GROWTH RATE ESTIMATES

Step 1: Exhibit JRW-10, page 5 of 6, EPS Growth Rates | Step 2: Add VL EPS Growth Rates from Exhibit JRW-10, page 4 of 6 | Step 3: Removed six proxy companies for reasons stated

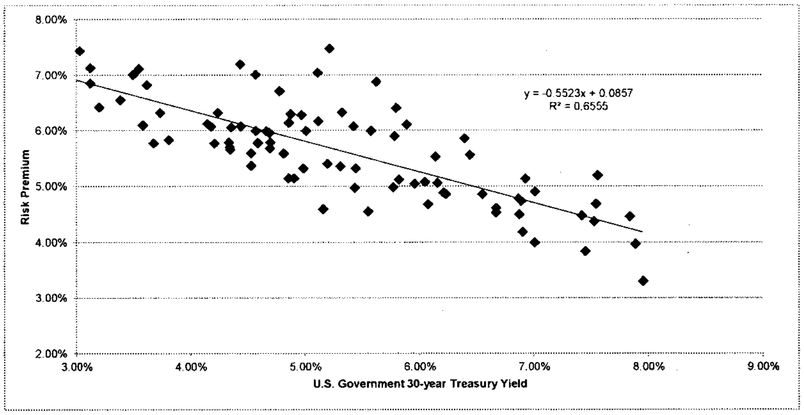
		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]	[15]
	Company	Yahoo	Zacks	Reuters	Mean	Yahoo	Zacks	Reuters	Value Line	Mean	Yahoo	Zacks	Reuters	Value Line	Mean	Reason Removed
1	ALLETE, Inc. (NYSE-ALE)	6.0%	NA	NA	6.0%	6.0%	NA	NA	6.5%	6.3%	6.0%	NA	NA	6.5%	6.3%	
2	Alliant Energy Corporation (NYSE-LNT)	5.8%	5.3%	5.8%	5.6%	5.8%	5.3%	5.8%	6.0%	5.7%	5.8%	5.3%	5.8%	6.0%	5.7%	
3	Ameren Corporation (NYSE-AEE)	4.6%	4.9%	4.6%	4.7%	4.6%	4.9%	4.6%	7.0%	5.3%	4.6%	4.9%	4.6%	7.0%	5.3%	
4	American Electric Power Co. (NYSE-AEP)	6.3%	6.8%	6.3%	6.5%	6.3%	6.8%	6.3%	5.0%	6.1%	6.3%	6.8%	6.3%	5.0%	6.1%	
5	Avista Corporation (NYSE-AVA)	5.0%	NA	NA	5.0%	5.0%	NA	NA	5.0%	5.0%	5.0%	NA	NA	5.0%	5.0%	
6	Black Hills Corporation (NYSE-BKH)	3.5%	NA	NA	3.5%	3.5%	NA	NA	4.5%	4.0%						M&A
7	CMS Energy Corporation (NYSE-CMS)	6.8%	6.2%	6.8%	6.6%	6.8%	6.2%	6.8%	5.5%	6.3%	6.8%	6.2%	6.8%	5.5%	6.3%	
8	Consolidated Edison, Inc. (NYSE-ED)	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	2.7%	3.0%	2.8%	2.7%	2.7%	2.7%	3.0%	2.8%	
9	Dominion Resources, Inc. (NYSE-D)	5.4%	6.3%	5.4%	5.7%	5.4%	6.3%	5.4%	8.0%	6.3%	5.4%	6.3%	5.4%	8.0%	6.3%	
10	Duke Energy Corporation (NYSE-DUK)	4.3%	4.7%	4.3%	4.4%	4.3%	4.7%	4.3%	5.0%	4.6%						M&A
11	Edison International (NYSE-EIX)	2.4%	4.7%	2.4%	3.2%	2.4%	4.7%	2.4%	3.0%	3.1%						Bankruptcy of EME
12	El Paso Electric Company (NYSE-EE)	7.0%	6.7%	NA	6.9%	7.0%	6.7%	NA	3.5%	5.7%	7.0%	6.7%	NA	3.5%	5.7%	
13	Empire District Electric Co. (NYSE-EDE)	3.0%	5.0%	NA	4.0%	3.0%	5.0%	NA	3.0%	3.7%	3.0%	5.0%	NA	3.0%	3.7%	
14	Entergy Corporation (NYSE-ETR)	-2.1%	-4.6%	-2.1%	-2.9%	-2.1%	-4.6%	-2.1%	0.0%	-2.2%						Negative Growth Rates
15	Eversource Energy (NYSE-ES)	6.3%	6.8%	6.2%	6.4%	6.3%	6.8%	6.2%	8.5%	7.0%	6.3%	6.8%	6.2%	8.5%	7.0%	
16	FirstEnergy Corporation (ASE-FE)	0.9%	NA	0.9%	0.9%	0.9%	NA	0.9%	7.0%	2.9%						Dividend Cut
17	Great Plains Energy Incorporated (NYSE-GXP)	6.4%	6.1%	6.4%	6.3%	6.4%	6.1%	6.4%	5.0%	6.0%	6.4%	6.1%	6.4%	5.0%	6.0%	
18	IDACORP, Inc. (NYSE-IDA)	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	4.0%	1.0%	3.3%	4.0%	4.0%	4.0%	1.0%	3.3%	
19	MGE Energy, Inc. (NYSE-MGEE)	4.0%	NA	NA	4.0%	4.0%	NA	NA	7.0%	5.5%	4.0%	NA	NA	7.0%	5.5%	
20	NorthWestern Corporation (NYSE-NWE)	5.3%	5.0%	5.3%	5.2%	5.3%	5.0%	5.3%	6.5%	5.5%	5.3%	5.0%	5.3%	6.5%	5.5%	
21	OGE Energy Corp. (NYSE-OGE)	3.3%	5.0%	3.3%	3.9%	3.3%	5.0%	3.3%	3.0%	3.7%	3.3%	5.0%	3.3%	3.0%	3.7%	
22	Otter Tail Corporation (NDQ-OTTR)	6.0%	NA	NA	6.0%	6.0%	NA	NA	9.0%	7.5%	6.0%	NA	NA	9.0%	7.5%	
23	PG&E Corporation (NYSE-PCG)	5.9%	4.9%	5.9%	5.6%	5.9%	4.9%	5.9%	10.5%	6.8%						Financial implications of San Bruno
24	Pinnacle West Capital Corp. (NYSE-PNW)	5.4%	5.2%	5.4%	5.3%	5.4%	5.2%	5.4%	4.0%	5.0%	5.4%	5.2%	5.4%	4.0%	5.0%	
25	PNM Resources, Inc. (NYSE-PNM)	8.6%	8.0%	8.6%	8.4%	8.6%	8.0%	8.6%	9.0%	8.6%	8.6%	8.0%	8.6%	9.0%	8.6%	
26	Portland General Electric Company (NYSE-POR)	4.1%	4.3%	4.1%	4.2%	4.1%	4.3%	4.1%	6.0%	4.6%	4.1%	4.3%	4.1%	6.0%	4.6%	
27	SCANA Corporation (NYSE-SCG)	4.3%	4.2%	4.3%	4.3%	4.3%	4.2%	4.3%	4.5%	4.3%	4.3%	4.2%	4.3%	4.5%	4.3%	
28	Westar Energy, Inc. (NYSE-WR)	3.4%	3.9%	3.4%	3.6%	3.4%	3.9%	3.4%	6.0%	4.2%	3.4%	3.9%	3.4%	6.0%	4.2%	
29	Xcel Energy Inc. (NYSE-XEL)	4.7%	5.0%	4.7%	4.8%	4.7%	5.0%	4.7%	4.5%	4.7%	4.7%	5.0%	4.7%	4.5%	4.7%	
	Mean	4.6%	4.8%	4.5%	4.6%					4.9%					5.3%	
	Median	4.7%	5.0%	4.7%	4.8%					5.0%					5.5%	

Data Sources; www.reuters.com,www.zacks.com, http://quote.yahoo.com, October, 2015.

Exhibit AEB-R-12

BOND YIELD PLUS RISK PREMIUM

	[1] Average Authorized Electric ROE	[2] 30-year U.S. Treasury Bond	[3] Risk Premium
1992.1	12.29%	7.84%	4.46%
1992.2	11.86%	7.88%	3.97%
1992.3	11.89%	7.42%	4.48%
1992.4	12.23%	7.54%	4.69%
1993.1	11.91%	7.01%	4.90%
1993.2	11.64%	6.86%	4.78%
1993.3	11.08%	6.23%	4.86%
1993.4	11.09%	6.21%	4.88%
1994.1	11.19%	6.66%	4.53%
1994.2	11.29%	7.45%	3.84%
1994.3	12.75%	7.55%	5.20%
1994.4	11.25%	7.95%	3.30%
1995.1	11.90%	7.52%	4.37%
1995.2	11.36%	6.87%	4.50%
1995.3	11.28%	6.66%	4.61%
1995.4	11.67%	6.14%	5.53%
1996.1	12.25%	6.39%	5.86%
1996.2	12.06%	6.92%	5.14%
1996.3	11.00%	7.00%	4.00%
1996.4	11.40%	6.54%	4.86%
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	11.12%	6.04%	5.08%
1998.1	12.00%	5.89%	6.11%
1998.2	12.20%	5.79%	6.41%
1998.3	11.65%	5.32%	6.33%
1998.4	12.15%	5.11%	7.05%
1999.1	10.40%	5.43%	4.97%
1999.2	10.94%	5.82%	5.12%
1999.3	10.75%	6.07%	4.68%
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	11.50%	5.42%	6.08%
2001.2	10.75%	5.77%	4.98%
2001.3	10.76%	5.44%	5.32%
2001.4	12.69%	5.21%	7.48%
2002.1	10.10%	5.55%	4.55%
2002.2	11.57%	5.57%	6.00%
2002.3	11.25%	4.96%	6.29%
2003.1	11.49%	4.78%	6.72%
2003.2	11.58%	4.57%	7.01%
2003.3	9.75%	5.15%	4.60%
2003.4	11.28%	5.11%	6.17%
2004.1	11.00%	4.86%	6.14%
2004.2	10.67%	5.31%	5.36%
2004.3	11.00%	5.01%	5.99%
2004.4	11.18%	4.87%	6.30%
2005.1	10.65%	4.69%	5.96%
2005.2	10.00%	4.34%	5.66%
2005.3	11.63%	4.43%	7.19%
2005.4	10.65%	4.66%	5.99%
2006.1	10.38%	4.69%	5.68%
2006.2	10.60%	5.19%	5.41%
2006.3	10.05%	4.90%	5.15%
2006.4	10.49%	4.70%	5.79%
2007.1	10.40%	4.81%	5.59%
2007.2	10.31%	4.98%	5.32%
2007.3	10.00%	4.85%	5.15%
2007.4	10.12%	4.53%	5.60%
2008.1	10.04%	4.34%	5.70%
2008.2	10.57%	4.57%	6.00%
2008.3	10.52%	4.44%	6.08%
2008.4	10.50%	3.49%	7.01%
2009.1	10.44%	3.62%	6.82%
2009.2	10.56%	4.23%	6.33%
2009.3	10.25%	4.18%	6.07%
2009.4	10.41%	4.35%	6.06%
2010.1	10.37%	4.59%	5.78%
2010.2	9.97%	4.20%	5.77%
2010.3	10.05%	3.73%	6.32%
2010.4	10.27%	4.14%	6.13%
2011.1	9.90%	4.53%	5.37%
2011.2	10.12%	4.33%	5.79%
2011.3	10.66%	3.54%	7.11%
2011.4	10.47%	3.03%	7.44%
2012.1	10.25%	3.12%	7.13%
2012.2	9.98%	2.84%	7.15%
2012.3	9.69%	2.68%	7.01%
2012.4	10.13%	2.87%	7.26%
2013.1	9.98%	3.12%	6.86%
2013.3	9.45%	3.67%	5.77%
2013.4	9.64%	3.81%	5.83%
2014.1	9.68%	3.58%	6.10%
2014.2	9.93%	3.38%	6.55%
2014.3	9.62%	3.20%	6.42%
2014.4	9.76%	2.90%	6.85%
2015.1	9.50%	2.41%	7.09%
AVERAGE	10.89%	5.19%	5.70%
MEDIAN	10.76%	5.06%	5.78%



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.809611
R Square	0.655469
Adjusted R Square	0.651554
Standard Error	0.005515
Observations	90

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.005091	0.005091	167.419934	0.000000
Residual	88	0.002676	0.000030		
Total	89	0.007767			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.0857	0.002290	37.41	0.000000	0.081130	0.090232	0.081130	0.090232
30-year U.S. Treasury Bond	(0.5523)	0.042688	(12.94)	0.000000	(0.637176)	(0.467509)	(0.637176)	(0.467509)

	[7] U.S. Govt. 30-year Treasury	[8] Risk Premium	[9] ROE
Current 30-Day Average [4]	2.51%	7.18%	9.69%
Blue Chip Consensus Forecast (Q1 2015-Q2 2016) [5]	3.20%	6.80%	10.00%
Blue Chip Consensus Forecast (2016-2020) [6]	4.90%	5.86%	10.76%
AVERAGE			10.15%

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. 34, No. 2, February 1, 2015, at 2
[6] Source: Blue Chip Financial Forecasts, Vol. 33, No. 12, December 1, 2014, at 14
[7] *See notes [4], [5] & [6]*
[8] Equals 0.085681 + (-0.552342 x Column [7])
[9] Equals Column [7] + Column [8]

Rebuttal Testimony of

David J. Lewis

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

Rebuttal Testimony of

David J. Lewis

on Behalf of

UNS Electric, Inc.

January 19, 2016

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Exhibits

Exhibit DJL-R-1 Comparison of Adjustments to Revenue Requirement

I. **INTRODUCTION.**

Q. Please state your name and business address.

A. My name is David Lewis and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc. ("UNS Electric" or "Company").

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. I address certain adjustments that Staff witness Donna Mullinax recommends in her Direct Testimony. I also address adjustments that Residential Utility Consumer Office ("RUCO") witness Jeffrey Michlik proposes in his Direct Testimony. While the Company will agree to most of Staff's adjustments for purposes of this rate case only, I am addressing only those adjustments where the Company is not in agreement. Any inadvertent omission of discussion of any adjustment should not be considered an acceptance of the position or recommendation.

II. <u>COMPUTATION CORRECTIONS TO STAFF'S AND RUCO'S DIRECT FILINGS.</u>

Q. Are there computation errors that you have identified within Staff's or RUCO's adjustments?

A. Yes, I have provided an attachment, **Exhibit DJL-R-1**, which summarizes and explains the computation corrections that I have identified and sets forth the appropriate computation.

Q. What computation errors did you identify?

A. As explained in **Exhibit DJL-R-1**, the following errors were identified.

1. Correction of Staff's adjustment E-3 Injuries and Damages. Staff inadvertently did not apply the ACC Jurisdictional factor in its calculation.
2. Correction of Staff's adjustment E-4 Payroll Expense & Taxes. This correction is needed to correct for the double exclusion of incentive compensation. Staff's adjustment was prepared based on information provided in data response STF 6.12. The question asked to "explain the Incentive Compensation shown on the Payroll Expense work papers." UNS Electric's response addressed the question by stating "the Incentive Comp as shown on the Payroll Expense work papers represents the amount of incentive compensation that is attributable to the labor dollars charged for each corresponding FERC account. This is also reflected in FERC Form on page 354." UNS Electric's response intended to identify how the incentive compensation was reconciled to FERC Form 1. It was not our intent to suggest that the Payroll Expense adjustment included incentive compensation dollars.
3. Correction of Staff's adjustment E-5 Incentive Compensation. Staff inadvertently did not apply the ACC Jurisdictional factor in the calculation.
4. Correction of Staff's Schedule D – Capital Structure. On Schedule D, the Fair Value Rate of Return ("FVROR") calculation was linking to UNS Electric's original filed

position and not to Staff's recommended position. Once corrected the FVROR should be 5.63%.

5. Correction of RUCO's Base cost of fuel Schedule JMM-13. RUCO adjusted the Company's updated base cost of fuel to revert the base cost of fuel back to the base cost of fuel authorized in the Company's last rate case. Using the updated base cost of fuel is standard practice in electric rate cases, and this approach was used in the Company's last rate case. Fuel costs are recovered on a dollar-for-dollar basis (no profit) through the purchased power and fuel adjustment mechanism. In a rate case, it is appropriate to update the base cost of fuel to provide a new base for the adjustment mechanism. If the revised revenue from base cost of fuel is not updated in this way, then the difference must be reflected in the revenue requirement through a corresponding adjustment to expenses. RUCO agrees that a correction is needed. In response to the Company's data request UNSE 2.14, RUCO states: "… RUCO agrees if Test Year Revenues are adjusted to reflect an updated Base Cost of Power, then expenses should reflect the adjusted level of power expense; as fuel revenues must equal fuel expense, RUCO will revise operating income adjustment no. 1, in its Surrebuttal testimony."

Q. Did you contact Staff or RUCO to address the computation corrections?

A. Yes. I contacted Staff witness Donna Mullinax. UNS Electric witness Craig Jones spoke to RUCO witness Jeffrey M. Michlik.

Q. Did Donna Mullinax agree with the Company's recommended corrections?

A. Yes, Donna Mullinax accepted our recommended corrections and it is the Company's understanding that she will be revising Staff's base rate increase to $18.5M in her surrebuttal testimony.

III. REBUTTAL TO OPERATING INCOME ADJUSTMENTS.

A. Short Term Incentive Compensation.

Q. Did Staff or RUCO reduce the pro forma Short-Term Incentive Compensation cost contained within the Company's requested revenue requirements?

A. Yes, Both Staff and RUCO witnesses recommended that the pro forma level of Short-Term Incentive Compensation expense be reduced. Although Staff and RUCO adjustments differ slightly in their calculations, they both support the conclusion that the Company's compensation program should be borne equally by the shareholders and ratepayers.

The Company strongly disagrees with the "who benefits" analysis as a tool for what percentage of recovery to be afforded to the Company. The decision to allow recovery should be based on whether the total compensation, including incentive pay, is fair and reasonable. If so, it is part of the cost of service and should be allowed. Neither Staff nor RUCO contend that the overall compensation, including incentive pay, is unreasonable or imprudent. Accordingly, it should be fully recoverable. To allow only partial recovery based on a "who benefits" approach is inappropriate. Almost any expense could be seen to "benefit" both ratepayers and shareholders. The Commission should allow the Company to recover its cost of service, which does not occur under Staff and RUCO's proposals to allow recovery of only a percentage of reasonable expenses.

Q. Are the arguments for full recovery of Short-term incentive compensation in your direct testimony similar to arguments in UNS Electric's previous rate case?

A. Yes, the arguments are essentially unchanged. The Company recognizes that recent Commission decisions rejected recovery of 100% of Short-Term incentive compensation.

However, the Commission recently allowed EPCOR Water Arizona, Inc. ("EPCOR") (Decision No. 75268) to recover in rates incentive compensation so long as the total compensation, including incentive pay was reasonable. The Company believes the costs associated with the short- term incentive program is reasonable, fair and prudent.

B. Rate Case Expense.

Q. Did Staff or RUCO dispute the Company's pro forma rate case expense?

A. Staff did not object to the Company's Rate Case Adjustment in their Direct Testimony. RUCO recommend the inclusion of $350,000 normalized over 3 years as opposed to $400,000 normalized over 3 years. See RUCO Schedule JMM-18.

Q. Do you agree with RUCO's recommendation of a normalized annual allowance of $116,667?

A. No. As of January 1, 2016 UNS Electric has already incurred costs well in excess of the $400,000 requested in its Application through the use of substantial TEP employee time (which is allocated to UNS Electric) and outside consulting services and is expected to increase. These costs are the incremental real cost associated with filing this case and should be fully recoverable. Moreover, there are additional factors present in this rate case that are outside of the control of the Company that has generated additional rate case expense. For example, there are 19 Intervenors in this rate case and the Company has responded to over 1,700 data requests, and there are approximately 40 witnesses that have pre-filed testimony which will result in a lengthy and costly hearing. Although the Company could easily update its rate case expense request to include these additional costs, it has elected to not do so.

Q. What is the reason for RUCO's recommendation to allow recovery of $350,000 of rate case expense?

A. RUCO seems to have predicated their recommendation based on the $300,000 authorized amounts from the prior three rate cases with an additional $50,000 due to the complexities in this case. This grossly understates the additional complexities and costs that I just discussed.

To base a recommendation purely on what was approved in UNS Electric's 2008 rate case and ignore the additional expenses that the Company has no choice but to incur, is simply unfair to the Company and is inherently unreasonable under the circumstances.

IV. <u>CONCLUSION.</u>

Q. What is the Company's recommendation for revenue requirement?

A. While UNS Electric strongly believes that the requested increase in non-fuel base rates of $22.6 million represents the true "Cost of Service" of providing dependable and reliable service to their customers, for purposes of this rate case, UNS Electric accepts Staffs revised non-fuel base rate increase of $18.5M.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit DJL-R-1

UNS Electric, Inc.
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
Test Year Ended December 31, 2014

	As Filed UNSE 12/31/14	STAFF Revised Pos.	RUCO Revised Pos.	UNSE Revised Pos.	STAFF Summary of Position	RUCO Summary of Position
Original Cost Rate Base - Unadjusted	$272,560,320	$ 272,560,320	$272,560,320	$ 272,560,320		
Rate Base Adjustments						
Acquisition Discount Adjustment	4,371,344	4,371,344	4,371,344	$ 4,371,344	No Adjustment	No Adjustment
Accumulated Deferred ITC	4,272,926	4,272,926	4,272,926	$ 4,272,926	No Adjustment	No Adjustment
Accumulated Deferred Income Taxes	(1,773,667)	(1,773,667)	(9,240,729)	$ (1,773,667)	No Adjustment	to reduce rate base for the NOL associated bonus depreciation.
Fortis Rate Base Adjustment	(10,249)	(10,249)	(10,249)	$ (10,249)	No Adjustment	No Adjustment
Gila River Adjustment	(11,389)	(2,011,389)	(11,389)	$ (2,011,389)	To Reduce RB by $2M related to depreciation expense as deferred by the accounting order for Gila River.	
ARO	(1,101,971)	(1,101,971)	(1,101,971)	$ (1,101,971)	No Adjustment	
Working Capital	(6,294,187)	(6,123,207)	(6,288,758)	$ (6,123,207)	CWC adjustment- Increase $187,758. D&O prepaid reduction by 50% ($16,778). Staff adjustment for D&O insurance is at Total Company not ACC jurisdiction. Staff also used 50% reduction based on total expense not average balance.	CWC and D&O prepaid
Total Adjustments to Rate Base	(547,193)	(2,376,213)	(8,008,826)	(2,376,213)		
Rate Base	$ 272,013,127	$ 270,183,980	$ 264,551,496	$ 270,183,980		
Requested Rate of Return	7.67%	7.22%	6.61%	7.22%	Capital Structure: 47.17 % debt @ 4.66% , 52.83% Equity @ 9.5%. FVI .50%. ROR on OCRB 7.22%	Capital Structure: 47.17 % debt @ 4.66% , 52.83% Equity @ 8.35%. FVI .82%. ROR on OCRB 6.61%
Required Operating Income OCRB	$20,852,600	$19,500,907	$17,486,854	$19,500,907		
Fair Value Increment of Rate Base	$83,704,602	$83,707,020	$80,579,090	$83,707,020		
Fair Value Rate Base (FVRB)	$355,717,730	$353,891,000	$345,130,586	$ 353,891,000	**Modified from original Position:** To correct formula error FVROR changed from 5.60% to 5.63%	Reflects OCRB proposed changes
Proposed FVROR	1.50%	0.50%	0.82%	0.50%		
Required Operating Income on FVRB	1,255,569	$418,548	$660,139	$418,548		
Original Operating Income - Unadjusted	$22,042,438	$22,042,438	$22,042,438	$22,042,438		
Operating Revenue Adjustments						
LFCR	(1,377,647)	(1,377,647)	(1,377,647)	(1,377,647)	No Adjustment	
Non-Retail Rev, Fuel & Purchase Power	-	7,781,533	3,090,705	7,781,533	Staff recommended a Base Cost of fuel of $0.053288 vs $0.048427 requested by UNSE. Staff's rate consists of actual costs from January through August 2015 and forecasted costs for September through December 2015.	RUCO adjusted base fuel revenue to reflect $0.056603 average rate. No corresponding expense adjustment.
Customer and Weather Adjustment	(6,021,912)	(6,021,912)	(6,021,912)	($6,021,912)	**No Adjustment for Weather.** Staff requests that the company monitor revenues and file quarterly. Concerns are surrounding the larger customers entering back into the market.	N/A
REST & DSM	(1,537,369)	(1,537,369)	(1,537,369)	($1,537,369)	No Adjustment	
Service Fees	95,034	95,034	95,034	$95,034	No Adjustment	
Other Revenues	(45,506)	(45,506)	(45,506)	($45,506)	No Adjustment	
Total Adjustments to Operating Revenues	(8,887,400)	($1,105,867)	($5,796,695)	($1,105,867)		

Rebuttal Testimony of
Jason J. Rademacher

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

Rebuttal Testimony of

Jason J. Rademacher

on Behalf of

UNS Electric, Inc.

January 19, 2016

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I. Introduction. 1

II. Net Operating Loss Carryforward ("NOLC"). 1

III. Property Tax. 7

Exhibits

Exhibit JJR-R-1 Private Letter Rulings

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Jason Rademacher and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses the Direct Testimony of Jeffrey M. Michlik on behalf on the Residential Utility Consumer Office ("RUCO").

II. NET OPERATING LOSS CARRYFORWARD ("NOLC").

Q. Has RUCO proposed an adjustment to remove UNS Electric's NOLC ADIT from rate base?

A. Yes. RUCO recommends increasing the ADIT balance by $7,467,062 from $35,161,108 to $42,628,170.

Q. Please explain what NOLC ADIT is.

A. An ADIT credit balance is typically included as a reduction to rate base in setting rates because it represents an interest-free loan from the government and a source of non-investor capital. The ADIT credit balance is generated primarily through the difference between accelerated tax depreciation and regulatory depreciation methods. NOLC ADIT is the recognition that the company did not receive an interest-free loan from the government for the full amount of the depreciation difference. The ADIT credit balance generated from accelerated depreciation is offset by a NOLC ADIT balance to reflect the actual interest-free loan obtained by the Company.

Q. Please summarize why UNS Electric included NOLC ADIT in rate base.

A. In order to retain and continue to claim valuable accelerated tax depreciation deductions which reduce rate base and customer rates, UNS Electric was required to include the NOLC ADIT under Internal Revenue Code ("IRC") §168, and the rules adopted thereunder.

Q. Please explain how IRC §168 places such a requirement on UNS Electric.

A. I discuss the IRS normalizations in detail on pages 8 and 9 of my Direct Testimony. The rules limit the accelerated depreciation ADIT rate base reduction to the amount of Federal income tax liability deferred from using accelerated depreciation methods. Simply put, only the ADIT that reduced taxable income to $0 can reduce rate base. If the normalization rules are not followed, a utility is not allowed to claim accelerated depreciation. The utility would be required to use straight line regulatory depreciation methods, which do not create any ADIT. Violating the normalization rules would harm customers by increasing rate base and increasing customer rates.

Q. How is UNS Electric certain that the normalization rules under §168 apply to NOLCs?

A. As a result of bonus depreciation allowed by Congress, many utilities are in the same position as UNS Electric and have large NOLCs. There have been several instances where a utility and their respective state commissions are uncertain as to whether the regulatory treatment of NOLCs is following the normalization rules. As a result, Private Letter Rulings ("PLR's) have been requested from the IRS. Each PLR is specific to the facts and circumstances of the utility and its commission's treatment of NOLC's. As I stated in my Direct Testimony on page 9, line 17, 3 PLR's had been issued for the NOLC issue. In each case the IRS ruled that a reduction of a taxpayer's rate base by the full amount of its ADIT balance (i.e. not reduced by the balance of its NOLC ADIT) would be a violation of the normalization rules. These three PLR's along with 3 others that I refer to later in my testimony have been attached as **Exhibit JJR-R-1**.

Q. Have there been additional PLRs issued since UNS Electric filed its rate case?

A. Yes. The IRS has issued PLRs 201519021 and 201534001. In both, the IRS again ruled that a reduction of a taxpayer's rate base by the full amount of its ADIT balance unreduced by the balance of its NOLC ADIT would be a violation of the normalization rules.

Q. Is UNS Electric's treatment of NOLC's in compliance with the five PLRs you refer to?

A. Yes. UNS Electric's treatment of the NOLC is consistent with the PLRs, is consistent with the normalization rules, and will allow the Company to retain and continue to claim accelerated depreciation deductions for the benefit of customers.

Q. Is RUCO's proposed removal of the NOLC ADIT from rate base consistent with the PLRs?

A. No. Based on the PLRs, RUCO's approach would violate the normalization rules, would eliminate the Company's ability to claim accelerated depreciation, would reduce or eliminate the ADIT rate base reduction in future rate cases, and harm customers.

Q. RUCO mentions a 6th PLR that you have not yet referred to, PLR 201418024 ("6th PLR"). What did the IRS rule in this 6th PLR?

A. The IRS ruled that excluding the NOLC did not violate the normalization rules.

Q. Why did you exclude this ruling from your Direct Testimony?

A. This PLR addresses a different situation. Specifically, the method of computing deferred income tax expense in the 6th PLR is not consistent with how UNS Electric computed deferred income tax expense in this rate case or in any prior rate case. In addition, it is inconsistent with how UNS Electric's affiliates, Tucson Electric Power and UNS Gas, have computed deferred income tax expense in prior rate cases. Further, UNS Electric is not aware of the Commission approving deferred income tax expense calculated in the manner presented in the 6th PLR in any rate case.

Q. What does the 6th PLR state with respect to the calculation of deferred income tax expense?

A. The ruling contains the following language:

> "Both Commission and Taxpayer have intended, at all relevant times, to comply with the normalization requirements. Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a

provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates.

Q. If deferred income tax is calculated "based on the entire difference between accelerated depreciation and regulatory depreciation", the ruling allows the NOLC ADIT to be excluded from rate base?

A. Yes. The ruling contains the following language:

> We therefore conclude that the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations."

Q. Did UNS Electric calculate deferred income tax "based on the entire difference between accelerated depreciation and regulatory depreciation?"

A. No, UNS Electric calculates deferred income tax only on the portion of accelerated depreciation that reduces taxable income to $0. As I state later in my Direct Testimony, the deferred income tax on the difference between accelerated depreciation and regulatory depreciation was $0.

Q. Did RUCO calculate deferred income tax "based on the entire difference between accelerated depreciation and regulatory depreciation?"

A. No. RUCO introduces the 6th PLR as support for its position to remove the NOLC ADIT, but then violates the deferred income tax expense calculation requirement of the ruling.

Q. Should the Commission calculate deferred income tax expense "based on the entire difference between accelerated depreciation and regulatory depreciation?"

A. No. Doing so would unnecessarily increase deferred income tax expense and the overall revenue requirement.

Q. What is the deferred income tax expense on "the entire difference between accelerated depreciation and regulatory depreciation"?

A. As shown on page 3 of the Income – Income Taxes.pdf pro forma adjustments workpapers, Deferred Fed column, tax depreciation is $45,579,823 and regulatory depreciation is $13,953,220 resulting in a difference of $31,626,603. The Federal deferred income tax on this difference would be $10,753,045 ($31,626,603 x 34% Federal Tax Rate) on a total company basis, or $8,192,745 on an ACC jurisdiction basis.

Q. How much deferred income tax expense did UNS Electric include in this rate case for "the entire difference between accelerated depreciation and regulatory depreciation".

A. As shown on Schedule C-1 of UNS Electric's filing, the total deferred income tax expense included in this rate case was $1,291,000. Of that amount, $0 relates to the difference between accelerated depreciation and regulatory depreciation. As shown on page 8 of the Income – Income Taxes.pdf pro forma adjustments workpapers UNS Electric had a $35,045,106 loss for income tax purposes. Since the income tax loss exceeds the $31,626,603 difference between tax and regulatory depreciation, the deferred income tax on the depreciation difference was $0. To be in compliance with the 6th PLR, an additional $8,192,745 would need to be added to deferred income tax expense. Clearly, a deferred income tax expense increase of $8,192,745 far exceeds the revenue requirement impact of reducing rate base by the $7,467,062 NOLC ADIT.

Q. Is RUCO's proposal to remove the NOLC ADIT without a corresponding deferred income tax expense adjustment a normalization violation?

A. Yes. RUCO must include the $7,467,062 NOLC ADIT in rate base or it must add $8,192,745 to income tax expense. Excluding both is a normalization violation.

Q. RUCO claims that the Commission is not bound by the IRS code or GAAP. How do you respond to this claim?

A. They are not relevant as it relates to this issue. The issue is how the treatment of the NOLC ADIT in a rate case proceeding impacts the Company's ability to claim accelerated depreciation and maximize tax deductions for the benefit of customers. As I demonstrated above, RUCO's proposal is a normalization violation and would result in a loss of accelerated depreciation tax deductions. It would harm ratepayers.

Q. Does UNS Electric's inclusion of NOLC ADIT in rate base provide the most benefit to customers?

A. Yes. UNS Electric's inclusion of NOLC ADIT is the only way to maximize customer benefits from accelerated depreciation in this rate case and in future rate cases.

III. PROPERTY TAX.

Q. Did RUCO accept the Property Tax Deferral as proposed on pages 15-19 of your Direct Testimony?

A. No. RUCO bifurcates the deferral and rejects the proposal to defer 100% of the Arizona property taxes above or below the test year level caused by changes in the composite tax rate. RUCO recommends a 50/50 sharing between shareholders and ratepayers for the benefits and costs from appealing Gila River property values. In addition, RUCO proposes a cap on the costs associated with the Gila River appeal.

Q. Why does RUCO reject the tax rate component of the deferral?

A. RUCO claims on page 36, line 15 of Mr. Michlik's Direct Testimony that, "There is nothing extraordinary about the Company's request for a deferral of property taxes in this case, other than APS received one."

Q. How do you respond to this claim?

A. RUCO misses the "extraordinary" aspect of the Property Tax Deferral by attempting to bifurcate the deferral into two components. The potential benefits from the Gila River appeal is what makes UNS Electric's total proposal unique and potentially a benefit for ratepayers.

Q. Mr. Michlik claims on page 37, line 6 that the Gila River appeal will save the Company's shareholders money in the long-term. Is this accurate?

A. No. Property taxes are one of expense categories included in cost of service. Shareholders can benefit in between rate cases if property taxes decrease from the test year level. However, that shareholder benefit is short lived. It can help delay the filing of a rate case, but when a rate case is filed those benefits are forever passed onto customer.

Q. In the absence of a deferral mechanism, would shareholders benefit if UNS Electric is successful in its Gila River appeal?

A. Yes, but only until UNS Electric's next rate case. From that point forward, ratepayers would receive 100% of the benefits from lower Gila River property values. If UNS Electric's proposal were approved, customers would start receiving 100% of the benefits immediately and not have to wait until the next rate case.

Q. If UNS Electric loses its appeal, why should ratepayers cover the costs?

A. Since ratepayers will benefit over the entire 35 year remaining life of the Gila River plant with a successful appeal, it is appropriate for the ratepayers to cover 100% of the costs even if UNS Electric is not successful.

Q. RUCO proposes a cap on expenses. Is this reasonable?

A. No. Projecting how hard the Arizona Department of Revenue ("ADOR") will fight and how many levels of court UNS Electric will have to work through would be difficult if not impossible.

Q. What factors should the Commission be aware of that will mitigate costs?

A. UNS Electric is not the first to litigate Gila River property tax values with the ADOR. Sun Devil Holdings, the owners of Gila River Block 1 & 2, are already in Tax Court litigating the same exact issue UNS Electric plans to litigate.

Q. How does the Sun Devil litigation mitigate UNS Electric's costs?

A. If Sun Devil wins its case, the Tax Court should not need to devote as much effort to hearing interpretations of statutes from UNS Electric and the ADOR. Precedent will have been set and UNS Electric's focus would be on proving that its facts are the same as Sun Devil's. If Sun Devil loses, UNS Electric has the opportunity to drop its case and avoid further litigation costs.

Q. If UNS Electric prevails, will its costs be covered by the ADOR?

A. Recovery of legal fees and expenses in tax cases is discretionary under A.R.S. §12-348(B), and is subject to the maximum hourly fee specified in A.R.S. §12-348(E)(3) and the maximum total amounts in A.R.S. §12-348(E)(5), subject to the inflation adjustment specified in A.R.S. §12-348(E)(6). Any amounts that are recovered from the ADOR under these statutes will be included as a credit to the Property Tax Deferral. While some costs may be covered, UNS Electric does not expect 100% of its outside services costs to be recovered from the ADOR.

Q. Should RUCO's Property Tax Deferral changes be accepted?

A. No, the Property Tax Deferral as originally proposed in my Direct Testimony are in the public interest and should be accepted by the Commission.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit JJR-R-1

Private Letter Rulings

Private Letter Ruling 201418024, 05/02/14, IRC Sec(s). 168

UIL No.

Accelerated cost recovery system-rate base calculations-normalization rules-consistency requirements-public utilities.

Headnote:

Commission's reduction of public utility's rate base by full amount of its accumulated deferred income tax without regard to balances in its net operating loss carryforward account and its minimum tax credit carryforward account was consistent with normalization requirements of Code Sec. 168(i)(9); and Reg § 1.167(l)-1 .

Reference(s): Code Sec. 168;

Full Text:

Number: **201418024**

Release Date: 5/2/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-133813-13

Date:

January 27, 2014

LEGEND:

Taxpayer =

Parent =

State =

Commission =

Year A =

Year B =

Year C =

Year D =

Year E =

X =

Y =

Date A =

Date B =

Date C =

Date D =

Date E =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated July 30, 2013, of Taxpayer for a ruling on whether the Commission's treatment of Taxpayer's Accumulated Deferred Income Tax (ADIT) account balance in the context of a rate case is consistent with the requirements of the normalization provisions of the Internal Revenue Code.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State. It is wholly owned by Parent. Taxpayer distributes and sells natural gas to customers in State. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer takes accelerated depreciation where available and, for the period beginning in Year A and ending in Year E, Taxpayer has, in the aggregate, produced more net operating losses (NOL) than taxable income. After application of the carryback and carryforward rules, Taxpayer represents that it has net operating loss carryforward (NOLC), produced in Year C and Year E, of $X as of the end of Year E. The amount of claimed accelerated depreciation in Year C and Year E exceeded the amount of the NOLCs for those years. In Year D, Taxpayer produced regular taxable income as well as alternative minimum taxable income (AMTI); the regular taxable income was offset by the NOLCs from Year B and year C but could not offset the entire alternative minimum tax (AMT) liability due to the limitation in § 56(d). Taxpayer paid $Y of AMT in Year D and had a minimum tax credit carryforward (MTCC) as of the end of year E of $Y.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account and also maintains an offsetting series of entries that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC. With respect to the $Y AMT liability from Year D, Taxpayer carried that amount as an offset to the ADIT because the AMT increased the payment of tax.

Taxpayer filed a general rate case on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In establishing the income tax expense element of its cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission policy and were not flowed thru to ratepayers. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission generally offsets rate base by Taxpayer's plant based ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of NOLCs or the AMT. Commission, in an order issued on Date C, did not use the amounts that Taxpayer calculates did not defer tax due to NOLCs or AMT but only the amount in the ADIT account. Taxpayer filed a petition for reconsideration based on the normalization implications of the order. On Date D, Commission rejected Taxpayer's request. Taxpayer again requested reconsideration and the Commission denied that request on Date E. Commission asserts that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has, such as in this case, an NOLC or AMT. Thus, Commission asserts that it has already recognized the effects of the NOCL in setting rates and there is no need to reduce the ADIT by the other amounts due to NOLCs or AMT.

Taxpayer requests that we rule as follows:

Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 55 of the Code imposes an alternative minimum tax on certain taxpayers, including corporations. Adjustments in computing alternative minimum taxable income are provided in § 56.

Section 56(a)(1) provides for the treatment of depreciation in computing alternative minimum taxable income. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In the rate case at issue, Commission has excluded from the base to which the Taxpayer's rate of return is applied the reserve for deferred taxes, unmodified by the accounts which Taxpayer has designed to calculate the effects of the NOLCs and MTCC. There is little guidance on exactly how an NOLC or MTCC must be taken into account in calculating the reserve for deferred taxes under §§ 1.167(1)-1(h)(1)(iii) and 56(a)(1)(D). However, it is clear that both must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT) for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Both Commission and Taxpayer have intended, at all relevant times, to comply with the normalization requirements. Commission has stated that, in setting rates it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or MTCC. Such a provision allows a utility to collect amounts from ratepayers equal to income taxes that would have been due absent the NOLC and MTCC. Thus, Commission has already taken the NOLC and MTCC into account in setting rates. Because the NOLC and MTCC have been taken into account, Commission's decision to not reduce the amount of the reserve for deferred taxes by these amounts does not result in the amount of that reserve for the period being used in determining the taxpayer's expense in computing cost of service exceeding the proper amount of the reserve and violate the normalization requirements. We therefore conclude that the reduction of Taxpayer's rate base by the full amount of its ADIT account without regard to the balances in its NOLC-related account and its MTCC-related account was consistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above. In particular, while we accept as true for purposes of this ruling Commission's assertions that it includes a provision for deferred taxes based on the entire difference between accelerated tax and regulatory depreciation, including situations in which a utility has an NOLC or AMT, we do not conclude that it has done so and those assertions are subject to verification on audit.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201436037, 09/05/14, IRC Sec(s). 167

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-computation based on with or without basis-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of regulated electric utility's rate base by full amount of its ADIT account balances offset by portion of its NOLC-related account that is less than amount attributable to accelerated depreciation computed on "with or without" basis would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 167; Code Sec. 168;

Full Text:

Number: **201436037**

Release Date: 9/5/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-148310-13

Date:

May 22, 2014

LEGEND:

Taxpayer =

Parent =

State A =

State B =

State C =

Commission A =

Commission B =

Commission C =

Year A =

Year B =

Date A =

Date B =

Date C =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated November 25, 2013, of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State A and State B. It is wholly owned by Parent. Taxpayer is engaged in the transmission, distribution, and supply of electricity in State A and State C. Taxpayer is subject to the regulatory jurisdiction of Commission A, Commission B, and Commission C with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis. Taxpayer takes accelerated depreciation, including "bonus depreciation" where available and, for each year beginning in Year A and ending in Year B, Taxpayer individually (as well as the consolidated return filed by Parent) has or expects to, produce a net operating loss (NOL). On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an net operating loss carryover (NOLC). Taxpayer, for normalization purposes, calculates the portion of the NOLC attributable to accelerated depreciation using a "with or without" methodology, meaning that an NOLC is attributable to accelerated depreciation to the extent of the lesser of the accelerated depreciation or the NOLC.

Taxpayer filed a general rate case with Commission B on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with Commission B policy and were not flowed thru to ratepayers. The data originally filed in Case included six months of forecast data, which the Taxpayer updated with actual data in the course of proceedings. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission B offset rate base by Taxpayer's ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Testimony by various other participants in Case argued against Taxpayer's proposed calculation of ADIT. One proposal made to Commission B was, if Commission B allowed Taxpayer to reduce the ADIT balance as Taxpayer proposed, then Taxpayer's income tax expense element of service should be reduced by that same amount.

Commission B, in an order issued on Date C, allowed Taxpayer to reduce ADIT by the amount that Taxpayer calculates did not actually defer tax due to the presence of the NOLC and ordered Taxpayer to seek a ruling on the effects of an NOLC on ADIT. Rates went into effect on Date C.

Taxpayer proposed, and Commission B accepted, that it be permitted to annualize, rather than average, its reliability plant additions and to extend the period of anticipated reliability plant additions to be included in rate base for an additional quarter. Taxpayer also proposed, and Commission B accepted, that no additional ADIT be reflected as a result of these adjustments inasmuch as any additional book and tax depreciation produced by considering these assets would simply increase Taxpayer's NOLC and thus there would be no net impact on ADIT.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In Case, Commission B has reduced rate base by Taxpayer's ADIT account, as modified by the account which Taxpayer has designed to calculate the effects of the NOLC. Section 1.167(1)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Further, while that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission B is in accord with the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the second issue, § 1.167(1)-(h)(6)(i) provides, as noted above, that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Increasing Taxpayer's ADIT account by an amount representing those taxes that would have been deferred absent the NOLC increases the ADIT reserve account (which will then reduce rate base) beyond the permissible amount.

Regarding the third issue, reduction of Taxpayer's tax expense element of cost of service, we believe that such reduction would, in effect, flow through the tax benefits of accelerated depreciation deductions through to rate payers even though the Taxpayer has not yet realized such benefits. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

3. Under the circumstances described above, any reduction in Taxpayer's tax expense element of cost of service to reflect the tax benefit of its NOLC would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201436038, 09/05/14, IRC Sec(s). 167

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-computation based on "with or without" basis-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/regulated electric utility's rate base by full amount of its ADIT account balances offset by portion of its NOLC-related account that is less than amount attributable to accelerated depreciation computed on "with or without" basis would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 167; Code Sec. 168;

Full Text:

Number: **201436038**

Release Date: 9/5/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-148311-13

Date:

May 22, 2014

LEGEND:

Taxpayer =

Parent =

State A =

State B =

State C =

Commission A =

Commission B =

Commission C =

Year A =

Year B =

Date A =

Date B =

Date C =

Date D =

Date E =

Case =

Director =

Dear ,[Redacted Text]:

This letter responds to the request, dated November 25, 2013, of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated public utility incorporated in State A and State B. It is wholly owned, through a limited liability company, by Parent. Taxpayer is engaged in the transmission, distribution, and supply of electricity in State A and State C. Taxpayer also provides natural gas and natural gas transmission services in State A. Taxpayer is subject to the regulatory jurisdiction of Commission A, Commission B, and Commission C with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis. Taxpayer takes accelerated depreciation, including "bonus depreciation" where available and, for each year beginning in Year A and ending in Year B, Taxpayer individually (as well as the consolidated return filed by Parent) has or expects to, produce a net operating loss (NOL). On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an net operating loss carryover (NOLC). Taxpayer, for normalization purposes, calculates the portion of the NOLC attributable to accelerated depreciation using a "with or without" methodology, meaning that an NOLC is attributable to accelerated depreciation to the extent of the lesser of the accelerated depreciation or the NOLC.

Taxpayer filed a general rate case with Commission B on Date A (Case). The test year used in the Case was the 12 month period ending on Date B. In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized in accordance with

Commission B policy and were not flowed thru to ratepayers. The data originally filed in Case was updated in the course of proceedings. In establishing the rate base on which Taxpayer was to be allowed to earn a return Commission B offset rate base by Taxpayer's ADIT balance, using a 13-month average of the month-end balances of the relevant accounts. Taxpayer argued that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Testimony by various other participants in Case argued against Taxpayer's proposed calculation of ADIT.

On Date C, a settlement agreement was filed with Commission B, incorporating the Taxpayer's proposed treatment of the tax consequences of its NOLC. In an order issued on Date D, Commission B issued an order approving the settlement agreement and also ordered Taxpayer to seek a ruling on the effects of an NOLC on ADIT. Rates went into effect on Date E.

Taxpayer proposed, and Commission B accepted, that it be permitted to annualize, rather than average, its reliability plant additions and to extend the period of anticipated reliability plant additions to be included in rate base for an additional eight months. Taxpayer also proposed, and Commission B accepted, that no additional ADIT be reflected as a result of these adjustments inasmuch as any additional book and tax depreciation produced by considering these assets would simply increase Taxpayer's NOLC and thus there would be no net impact on ADIT.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(1)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(1)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(1)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(1)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(1)-(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(1)-(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(1)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

In Case, Commission B has reduced rate base by Taxpayer's ADIT account, as modified by the account which Taxpayer has designed to calculate the effects of the NOLC. Section 1.167(1)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Further, while that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. Section 1.167(1)-(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission B is in accord with the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the second issue, § 1.167(1)-(h)(6)(i) provides, as noted above, that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Increasing Taxpayer's ADIT account by an amount representing those taxes that would have been deferred absent the NOLC increases the ADIT reserve account (which will then reduce rate base) beyond the permissible amount.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balances offset by a portion of its NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with or without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. The imputation of incremental ADIT on account of the reliability plant addition adjustments described above would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. We are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201438003, 09/19/2014, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/regulated electric utility's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: **201438003**

Release Date: 9/19/2014

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-104157-14

Date:

June 12, 2014

LEGEND:

Taxpayer =

Parent =

State A =

Commission A =

Commission B =

Year A =

Year B =

Year C =

Year D =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated January 24, 2014, and additional submission dated May 19, 2014, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated, investor-owned public utility incorporated under the laws of State A primarily engaged in the business of supplying electricity in State A. Taxpayer is subject to the regulatory jurisdiction of Commission A and Commission B with respect to terms and conditions of service and particularly the rates it may charge for the provision of service. Taxpayer's rates are established on a rate of return basis.

Taxpayer is wholly owned by Parent, and Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent. Taxpayer employs the accrual method of accounting and reports on a calendar year basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer used as its starting point actual data from the historic test period, calendar Year A. It then projected data for Year B through Year C. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. Rates in this proceeding were intended to, and did, go into effect for the period Date B through Date C.

In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized and were not flowed thru to ratepayers.

In its rate case filing, Taxpayer anticipated that it would claim accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available in all years for which data was provided. Additionally, Taxpayer forecasted that it would incur a net operating loss (NOL) in Year D. Taxpayer anticipated that it had the capacity to carry back a portion of this NOL with the remainder producing a net operating loss carryover (NOLC) as of the end of Year D.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those 'tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced as of the end of Year D by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It based this position on its determination that this net amount represented the true measure of federal income taxes deferred on account of its claiming accelerated tax depreciation deductions and, consequently, the actual quantity of "cost-free" capital available to it. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules Testimony by another participant in Case argued against Taxpayer's proposed calculation of ADIT.

Commission A, in an order issued on Date D, held that it is inappropriate to include the NOL in rate base for ratemaking purposes. Commission A further stated that it is the intent of the Commission that Taxpayer comply with the normalization method of accounting and tax normalization regulations. Commission noted that if Taxpayer later obtains a ruling from the IRS which affirms Taxpayer's position, Taxpayer may file seeking an adjustment. Commission A also held that to the extent tax normalization rules require recording the NOL to rate base in the specified years, no rate of return is authorized.

Taxpayer requests that we rule as follows:

> 1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
>
> 2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
>
> 3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission A is not in accord with the normalization requirements.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the third issue, assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would, in effect, flow the tax benefits of accelerated depreciation deductions through to rate payers. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

(Passthroughs & Special Industries)

cc: [Redacted Text]

Private Letter Rulings

Private Letter Ruling 201519021, 05/08/2015, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryover-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/investor-owned public utility's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: **201519021**

Release Date: 5/8/2015

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-136851-14

Date:

February 04, 2015

LEGEND:

Taxpayer =

Parent =

State A =

Commission =

Year A =

Year B =

Year C =

Year D =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated October 1, 2014, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is a regulated, investor-owned public utility incorporated under the laws of State A primarily engaged in the business of supplying natural gas service in State A. Taxpayer is subject to the regulatory jurisdiction of Commission with respect to terms and conditions of service and as to the rates it may charge for the provision of service. Taxpayer's rates are established on a cost of service basis.

Taxpayer is wholly owned by Parent, and Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent. Taxpayer employs the accrual method of accounting and reports on a calendar year basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer used as its starting point actual data from the historic test period, calendar Year A. It then projected data for Year B through Year D. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. Rates in this proceeding were intended to, and did, go into effect for the period Date B through Date C.

In computing its income tax expense element of cost of service, the tax benefits attributable to accelerated depreciation were normalized and were not flowed thru to ratepayers.

In its rate case filing, Taxpayer anticipated that it would claim accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available in all years for which data was provided. Additionally, Taxpayer forecasted that it would incur a net operating loss (NOL) in each of Year B, Year C, and Year D. Taxpayer anticipated that it had the capacity to carry back a portion of this NOL with the remainder producing a net operating loss carryover (NOLC) as of the end of Year C and Year D, the beginning and end of the test period.

On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced as of the end of Year D by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It based this position on its determination that this net amount represented the true measure of federal income taxes deferred on account of its claiming accelerated tax depreciation deductions and, consequently, the actual quantity of "cost-free" capital available to it. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules Testimony by another participant in Case argued against Taxpayer's proposed calculation of ADIT.

Commission, in an order issued on Date D, held that it is inappropriate to include the NOL in rate base for ratemaking purposes. Commission further stated that it is the intent of the Commission that Taxpayer comply with the normalization method of accounting and tax normalization regulations. Commission noted that if Taxpayer later obtains a ruling from the IRS which affirms Taxpayer's position, Taxpayer may file seeking an adjustment. Commission also held that to the extent tax normalization rules require including the NOL in rate base in the specified years, no rate of return is authorized.

Taxpayer requests that we rule as follows:

> 1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
>
> 2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.
>
> 3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, the order by Commission is not in accord with the normalization requirements.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "with or without" methodology employed by Taxpayer is specifically designed to ensure that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these specific facts, any method other than the "with and without" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

Regarding the third issue, assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would, in effect, flow the tax benefits of accelerated depreciation deductions through to rate payers. This would violate the normalization provisions.

We rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account balance that is less than the amount attributable to accelerated depreciation computed on a "with and without" basis would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

3. Under the circumstances described above, the assignment of a zero rate of return to the balance of Taxpayer's NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

Office of the Associate Chief Counsel

(Passthroughs & Special Industries)

Private Letter Rulings

Private Letter Ruling 201534001, 08/21/2015, IRC Sec(s). 168

UIL No. 167.22-01

Accelerated depreciation-accumulated deferred income tax-net operating loss carryforward-normalization-limitations on reasonable allowance in case of property of public utilities.

Headnote:

Reduction of taxpayer/common parent/regulated natural gas distributor's rate base by full amount of its ADIT account balance unreduced by balance of NOLC-related account balance would be inconsistent with Code Sec. 168(i)(9); and Reg § 1.167(l)-1 requirements.

Reference(s): Code Sec. 168; Code Sec. 167;

Full Text:

Number: **201534001**

Release Date: 8/21/2015

Index Number: 167.22-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-103300-15

Date:

May 13, 2015

LEGEND:

Taxpayer =

State A =

State B =

State C =

Commission =

Year A =

Year B =

Date A =

Date B =

Date C =

Date D =

Case =

Director =

Dear [Redacted Text]:

This letter responds to the request, dated January 9, 2015, submitted on behalf of Taxpayer for a ruling on the application of the normalization rules of the Internal Revenue Code to certain accounting and regulatory procedures, described below.

The representations set out in your letter follow.

Taxpayer is the common parent of an affiliated group of corporations and is incorporated under the laws of State A and State B. Taxpayer is engaged primarily in the businesses of regulated natural gas distribution, regulated natural gas transmission, and regulated natural gas storage. Taxpayer's regulated natural gas distribution business delivers gas to customers in several states, including State A. Taxpayer is subject to, as relevant for this ruling, the regulatory jurisdiction of Commission with respect to terms and conditions of service and as to the rates it may charge for the provision of its gas distribution service in State A. Taxpayer's rates are established on a "rate of return" basis.

Taxpayer filed a rate case application on Date A (Case). In its filing, Taxpayer's application was based on a fully forecasted test period consisting of the twelve months ending on Date B. Taxpayer updated, amended, and supplemented its data several times during the course of the proceedings. In a final order dated Date C, rates were approved by Commission for service rendered on or after Date D.

In each year from Year A to Year B, Taxpayer incurred a net operating loss carryforward (NOLC). In each of these years, Taxpayer claimed accelerated depreciation, including "bonus depreciation" on its tax returns to the extent that such depreciation was available. On its regulatory books of account, Taxpayer "normalizes" the differences between regulatory depreciation and tax depreciation. This means that, where accelerated depreciation reduces taxable income, the taxes that a taxpayer would have paid if regulatory depreciation (instead of accelerated tax depreciation) were claimed constitute "cost-free capital" to the taxpayer. A taxpayer that normalizes these differences, like Taxpayer, maintains a reserve account showing the amount of tax liability that is deferred as a result of the accelerated depreciation. This reserve is the accumulated deferred income tax (ADIT) account. Taxpayer maintains an ADIT account. In addition, Taxpayer maintains an offsetting series of entries - a "deferred tax asset" and a "deferred tax expense" - that reflect that portion of those `tax losses' which, while due to accelerated depreciation, did not actually defer tax because of the existence of an NOLC.

In the setting of utility rates in State C, a utility's rate base is offset by its ADIT balance. In its rate case filing and throughout the proceeding, Taxpayer maintained that the ADIT balance should be reduced by the amounts that Taxpayer calculates did not actually defer tax due to the presence of the NOLC, as represented in the deferred tax asset account. Thus, Taxpayer argued that the rate base should be reduced by its federal ADIT balance net of the deferred tax asset account attributable to the federal NOLC. It also asserted that the failure to reduce its rate base offset by the deferred tax asset attributable to the federal NOLC would be inconsistent with the normalization rules. The attorney general for State C argued against Taxpayer's proposed calculation of ADIT.

Commission, in its final order, agreed with Taxpayer but concluded that the ambiguity in the relevant normalization regulations warranted an assessment of the issue by the IRS and this ruling request followed.

Taxpayer requests that we rule as follows:

1. Under the circumstances described above, the reduction of Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

2. For purposes of Ruling 1 above, the use of a balance of Taxpayer's NOLC-related account that is less than the amount attributable to accelerated depreciation computed on a "last dollars deducted" basis would be inconsistent with (and, hence, violative of) the requirements of § 168(i)(9) and § 1.167(l)-1 of the Income Tax regulations.

Law and Analysis

Section 168(f)(2) of the Code provides that the depreciation deduction determined under section 168 shall not apply to any public utility property (within the meaning of section 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, section 168(i)(9)(A)(i) of the Code requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under section 168(i)(9)(A)(ii), if the amount allowable as a deduction under section 168 differs from the amount that-would be allowable as a deduction under section 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under section 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Section 168(i)(9)(B)(i) of the Code provides that one way the requirements of section 168(i)(9)(A) will not be satisfied is if the taxpayer, for ratemaking purposes, uses a procedure or adjustment which is inconsistent with such requirements. Under section 168(i)(9)(B)(ii), such inconsistent procedures and adjustments include the use of an estimate or projection of the taxpayer's tax expense, depreciation expense, or reserve for deferred taxes under section 168(i)(9)(A)(ii), unless such estimate or projection is also used, for ratemaking purposes, with respect to all three of these items and with respect to the rate base.

Former section 167(l) of the Code generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former section 167(l)(3)(G) in a manner consistent with that found in section 168(i)(9)(A). Section 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 1.167(l)-1(h)(1)(i) provides that the reserve established for public utility property should reflect the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes.

Section 1.167(l)-1(h)(1)(iii) provides that the amount of federal income tax liability deferred as a result of the use of different depreciation methods for tax and ratemaking purposes is the excess (computed without regard to credits) of the amount the tax liability would have been had the depreciation method for ratemaking purposes been used over the amount of the actual tax liability. This amount shall be taken into account for the taxable year in which the different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (1) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (1) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

Section 1.167(l)-1(h)(2)(i) provides that the taxpayer must credit this amount of deferred taxes to a reserve for deferred taxes, a depreciation reserve, or other reserve account. This regulation further provides that, with respect to any account, the aggregate amount allocable to deferred tax under section 167(1) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation. That section also notes that the aggregate amount allocable to deferred taxes may be reduced to reflect the amount for any taxable year by which federal income taxes are greater by reason of the prior use of different methods of depreciation under section 1.167(l)-1(h)(1)(i) or to reflect asset retirements or the expiration of the period for depreciation used for determining the allowance for depreciation under section 167(a).

Section 1.167(l)-1(h)(6)(i) provides that, notwithstanding the provisions of subparagraph (1) of that paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking.

Section 1.167(l)-1(h)(6)(ii) provides that, for the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i), above, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for that period is the amount of the reserve (determined under section 1.167(l)-1(h)(2)(i)) at the end of the historical period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period.

Section 1.167(l)-1(h) requires that a utility must maintain a reserve reflecting the total amount of the deferral of federal income tax liability resulting from the taxpayer's use of different depreciation methods for tax and ratemaking purposes. Taxpayer has done so. Section 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Section 56(a)(1)(D) provides that, with respect to public utility property the Secretary shall prescribe the requirements of a normalization method of accounting for that section.

Regarding the first issue, § 1.167(l)-1(h)(6)(i) provides that a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's expense in computing cost of service in such ratemaking. Because the ADIT account, the reserve account for deferred taxes, reduces rate base, it is clear that the portion of an NOLC that is attributable to accelerated depreciation must be taken into account in calculating the amount of the reserve for deferred taxes (ADIT). Thus, to reduce Taxpayer's rate base by the full amount of its ADIT account balance unreduced by the balance of its NOLC-related account balance would be inconsistent with the requirements of § 168(i)(9) and § 1.167(l)-1.

Regarding the second issue, § 1.167(l)-1(h)(1)(iii) makes clear that the effects of an NOLC must be taken into account for normalization purposes. Section 1.167(l)-1(h)(1)(iii) provides generally that, if, in respect of any year, the use of other than regulatory depreciation for tax purposes results in an NOLC carryover (or an increase in an NOLC which would not have arisen had the taxpayer claimed only regulatory depreciation for tax purposes), then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director. While that section provides no specific mandate on methods, it does provide that the Service has discretion to determine whether a particular method satisfies the normalization requirements. The "last dollars deducted" methodology employed by Taxpayer ensures that the portion of the NOLC attributable to accelerated depreciation is correctly taken into account by maximizing the amount of the NOLC attributable to accelerated depreciation. This methodology provides certainty and prevents the possibility of "flow through" of the benefits of accelerated depreciation to ratepayers. Under these specific facts, any method other than the "last dollars deducted" method would not provide the same level of certainty and therefore the use of any other methodology is inconsistent with the normalization rules.

This ruling is based on the representations submitted by Taxpayer and is only valid if those representations are accurate. The accuracy of these representations is subject to verification on audit.

Except as specifically determined above, no opinion is expressed or implied concerning the Federal income tax consequences of the matters described above.

This ruling is directed only to the taxpayer who requested it. Section 6110(k)(3) of the Code provides it may not be used or cited as precedent. In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representative. W e are also sending a copy of this letter ruling to the Director.

Sincerely,

Peter C. Friedman

Senior Technician Reviewer, Branch 6

Office of the Associate Chief Counsel

(Passthroughs & Special Industries)

cc: [Redacted Text]

Rebuttal Testimony of
Michael E. Sheehan

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

Rebuttal Testimony of

Michael E. Sheehan

on Behalf of

UNS Electric, Inc.

January 19, 2016

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Exhibits

Exhibit MES-R-1 Load Factor – 37%
Exhibit MES-R-2 Load Factor – 65%

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Michael E. Sheehan and my business address is 88 East Broadway Blvd., Tucson, Arizona, 85701.

Q. Did you file Direct Testimony on behalf of UNS Electric Inc. ("UNS Electric" or "Company") in this proceeding?

A. Yes.

Q. Which testimony do you address in your Rebuttal Testimony?

A. My Rebuttal Testimony addresses both the Direct Testimony and the Direct Rate Design Testimony of Staff witness Barbara Keene.

Q. What specific issues do you address in your testimony?

A. First, I address Staff's concerns on the Company's methodology for determining the base cost of fuel. Second, I address the Company's proposed Base Rate Annual Adjustment, and lastly, I address the Company's proposed PPFAC Percentage Rate Adjustment.

Q. What objections did Staff raise regarding this issues?

A. For the base cost of fuel, Staff recommended an alternative methodology for calculating the average cost of fuel and purchased power. Regarding the Base Rate Annual Adjustment and the PPFAC Percentage Rate Adjustment, Staff objected to our changes on the basis that the Company's proposal added a great amount complexity to the PPFAC Plan of Administration and the adjustments shifted costs among customer classes.

Q. Does the Company agree with Staff positions?

A. Regarding the alternative methodology for determining the base cost of fuel, the Company agreed with Staff's position. As part of this filing, the Company is providing an updated estimate for the average cost of fuel and purchased power based Staff's methodology. In terms of the two PPFAC adjustments, the Base Rate Annual Adjustment and the PPFAC Percentage Rate Adjustment, the Company concedes that while the proposals add some complexities to the PPFAC Plan of Administration, the Company believes that these proposed changes will provide more accurate and equitable price signals and improve the Company's overall rate design for customers.

II. BASE COST OF FUEL AND PURCHASED POWER UPDATE.

Q. Is the Company proposing a revision to the base cost of fuel and purchased power?

A. Yes. The Company is updating its base cost of fuel and purchased power rate using Staff's calculation methodology[1] and actual costs from 2015.

Q. What was UNSE's average cost of fuel and purchased power in 2015?

A. Using Staff's calculation methodology, UNSE's average cost of fuel and purchased power in 2015 was $0.053689 per kWh. This is based on the actual 2015 fuel and purchased power costs of $87,301,407 and retail sales of 1,626,067,036 kWh.

Q. Do you have any other recommendations regarding the proposed base cost of fuel and purchased power?

A. Yes. The Company is proposing to update the base cost of fuel and purchased power rate based on the Company's actual fuel costs prior to establishing new base fuel rates in this proceeding. This update could potentially provide UNSE customers with a lower base

[1] Staff's calculation methodology is described on Pages 8 and 9 of Direct Testimony of Barbara Keene

cost of fuel and purchased power rate when new rates go into effect. This benefits customers by ensuring that the base cost of fuel and purchase power is reflective of current market conditions.

III. BASE FUEL RATE ANNUAL ADJUSTMENT.

Q. In light of Staff's testimony does the Company still support the Base Rate Annual Adjustment?

A. Yes. The Company believes that the Base Rate Annual Adjustment will provide another tool for the Company to improve its overall rate design for customers. This proposed change will adjust the base cost of fuel and purchased power rate annually resulting in a more accurate and timely recovery of base power supply costs.

Q. What is the purpose of the Base Rate Annual Adjustment?

A. The Base Rate Annual Adjustment is designed to reduce the difference between the actual and approved collections of the base power supply costs related to changes in customer usage patterns relative to the test year.

Q. Can you provide an example on how this adjustment would work?

A. Yes. For example, based on the actual base cost of fuel and purchased power, the Company's 2015 power supply costs were $0.053689 per kWh. However, if over the next 12-months, the changes in customer usage patterns result in the actual recovery of the base power supply costs collecting $0.055218 per kWh (a 2.85% over-recovery of base fuel rates), then the Base Rate Annual Adjustment would be used to adjust all base fuel rates downward by 2.85% to minimize this over recovery in subsequent years. Conversely, if the actual recovery of the base power supply costs had under-recovered by 2.85%, then the Base Rate Annual Adjustment would be used to adjust all base fuel rates upward by 2.85% to minimize this under-recovery. This Base Rate Annual Adjustment would be applied once a year based on 12-months of actual collections.

Q. Doesn't the monthly changes to the PPFAC rate account for this type of variance in the actual base power supply recovery?

A. No. The adjustments to the monthly PPFAC rate only account for changes related to the 12-month rolling average cost of fuel and purchased power. The current UNS Electric PPFAC Plan of Administration currently has no mechanism to deal with the base power supply collection variances caused as a direct result of changing customer composition and usage patterns.

Q. What are the implications of not implementing this Base Rate Annual Adjustment?

A. This difference between the expected recovery based on the base power supply costs established in the rate case and the actual recovery of base power supply costs ends up in the PPFAC bank balance. While the Company will eventually recover or refund this bank balance to customers, this process may take several years to occur. By making an annual adjustment to base power supply rate, any over or under collection will be refunded or charged to customers[2] over the course of the subsequent 12 months.

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[2] In a time of unprecedented change in energy efficiency technologies, distributed generation and a continuing trend of lower use per customer, the Base Rate Annual Adjustment enhances the PPFAC Plan of Administration with an annual mechanism that supports the "Matching Principle" where customers are better aligned to receive the direct cost or benefit based on their actual use of the system. In addition, this matching of fuel and purchased power costs with the rates the Company uses to recover those costs allows rates to reflect the "Cost Causation Principle." Since the PPFAC only recovers changes at the margin, the Base Rate Annual Adjustment reflects the full value of the cost change so that the timing mismatch under the PPFAC is minimized on an annual basis.

IV. PPFAC PERCENTAGE RATE ADJUSTMENT.

Q. Does the Company still support the concept of a PPFAC percentage rate adjustment?

A. Yes. The Company believes that a PPFAC percentage rate adjustment results in an improved allocation of power supply costs by customer class based on the actual cost to serve these customer classes and the structure of their rates.

Q. Please describe the Company's proposal to apply a PPFAC rate as a percentage of base fuel costs?

A. Each customer class rate schedule has a base power supply rate component. These base power supply rate components differ by customer class, by time of use and by season. Currently, the PPFAC rate is applied on a dollar per kWh basis equally across all customer classes and rate schedules and has no relationship to the customer's original base power supply rate. As a result, the Company is proposing to refund or collect the PPFAC as a percentage of each customer's class's underlying base power supply charge.

Q. Would you explain how the PPFAC rate is applied to UNSE customers under the existing PPFAC Plan of Administration?

A. The current PPFAC rate is applied equally on a dollar per kWh basis across all customer rate classes. For example, as shown in Table 1 below, if the actual cost of fuel and purchased power for the total Company was $0.049531 per kWh, and the actual amount collected through base rates was $0.054375 per kWh, the current application of the PPFAC rate would decrease all power supply costs by $0.004844 per kWh for all customer classes.

Table 1 – Power Supply Assumptions (Total Company)[3]

PPFAC Rate Change Assumptions	
Existing PPFAC Rate, $/kWh	$0.054375
New PPFAC Rate, $/kWh	$0.049531

PPFAC Rate, $/KWh	-$0.004844
PPFAC Rate, %	-8.91%

Applying the PPFAC rate for all customers on the same per kWh rate, results in an 8.75% decrease to the base power supply rate for Residential Service class customers and 10.44% decrease to the base power supply rate for Large Power Service class customers. Table 2 below shows the current application of the PPFAC rate change on a dollar per kWh basis by rate class.

Table 2 – Current Rate Change Methodology (By Rate Class)[4]

UNSE Customer Rate Class	Existing Base Power Supply Rate $/kWh	PPFAC Rate $/kWh	Net Power Supply Rate $/kWh	Rate Impact %
Residential Service	$0.055342	-$0.004844	$0.050498	-8.75%
Small General Service	$0.054575	-$0.004844	$0.049732	-8.88%
General Service	$0.054229	-$0.004844	$0.049386	-8.93%
Large Power Service	$0.046384	-$0.004844	$0.041540	-10.44%
Total Company	$0.054375	-$0.004844	$0.049531	-8.91%

Q. Would you explain how the Company's proposed PPFAC percentage rate would be applied to UNSE's customers?

A. Using the same assumptions shown in Table 1 above, the PPFAC percentage rate would result in a decrease of 8.91% applied to the individual base power supply rates for each customer rate class. On a customer class basis, this results in a $0.004930 per kWh decrease for Residential Service customers compared with a $0.004132 per kWh

[3] [Existing Base Power Supply Rate, $/kWh - New Net Power Supply Rate, $/kWh = PPFAC Rate $/kWh]
[New Net Power Supply Rate, $/kWh / Existing Base Power Supply Rate, $/kWh -1 = PPFAC Rate %]

[4] The dollar per kWh numbers shown in Table 2 are representative of UNSE's average fuel and purchased power costs and will differ from the actual numbers presented in the Company's actual cost of service rate design testimony. [Existing Base Power Supply Rate, $/kWh + PPFAC Rate, $/kWh = Net Power Supply Rate, $/kWh]

decrease for Large Power Service customers. Table 3 below shows the application of the PPFAC percentage rate and the resulting dollar per kWh rates by customer class.

Table 3 – Proposed Rate Change Methodology (By Rate Class)[5]

UNSE Customer Rate Class	Base Power Supply Rate $/kWh	PPFAC % Rate Change %	Net Power Supply Rate $/kWh	Rate Impact $/kWh
Residential Service	$0.055342	-8.908%	$0.050412	-$0.004930
Small General Service	$0.054575	-8.908%	$0.049714	-$0.004862
General Service	$0.054229	-8.908%	$0.049399	-$0.004831
Large Power Service	$0.046384	-8.908%	$0.042252	-$0.004132
Total Company	$0.054375	-8.908%	$0.049531	-$0.004844

Q. Why is the Company's proposed PPFAC percentage rate an improvement over the current PPFAC rate calculation?

A. The proposed PPFAC percentage rate applies changes to the PPFAC rate on a more equitable basis across the individual rate classes. The percentage rate applies changes to the PPFAC in a manner that better maintains the original cost of service allocations that are approved as part of a general rate case.

Q. Why is the PPFAC percentage rate more equable by rate class?

A. In comparing the load characteristics of UNSE customers, we observe that Residential Service customers incur higher fuel and purchased power costs on a dollar per kWh basis than Large Power Service customers. This is based on the fact that Residential Service customers have a lower load factor and incur higher distribution losses than Large Power Service customers. This cost differential is represented in the Company's proposed cost of service rate design. Exhibits MES-R-1 and MES-R-2 show the annual hourly load profiles for both the Residential Service and Large Power Service customers. In addition

[5] The dollar per kWh numbers shown in Table 3 are representative of UNSE's average fuel and purchased power costs and will differ from the actual numbers presented in the Company's actual cost of service rate design testimony. [Base Power Supply Rate, $/kWh x PPFAC % Rate = Net Power Supply Rate, $/kWh]

to lower load factors and higher distribution losses, the Residential Service customers, due to summer cooling demand, utilize more expensive summer on-peak power on a weighted average basis relative to the Large Power Service customers, thus contributing to a higher cost per kWh on an annual basis.

As shown in Table 4 below, if we compare the marginal cost of fuel and purchased power to serve Residential Service and Large Power Service customers, we see that in 2015, the marginal cost of fuel and purchased power to serve the Residential Service class customers was $0.27013 per kWh, or 8.34% higher than the $0.024933 per kWh of marginal cost of fuel and purchased power to serve the Large Power Service class customers

Table 4 – UNSE Marginal Cost Comparison

Months	UNSE 2015 Marginal Costs $/kWh	Residential Service $/kWh	Large Power Service $/kWh
January	$0.025215	$0.025619	$0.025263
February	$0.023133	$0.023594	$0.023111
March	$0.022728	$0.023329	$0.022714
April	$0.022628	$0.023508	$0.022813
May	$0.022993	$0.024734	$0.023007
June	$0.027244	$0.029416	$0.027201
July	$0.029155	$0.032133	$0.029177
August	$0.030314	$0.033079	$0.030354
September	$0.027512	$0.029911	$0.027573
October	$0.024438	$0.024850	$0.024362
November	$0.021433	$0.021702	$0.021491
December	$0.020275	$0.020700	$0.020207
Annual	$0.024770	$0.027013	$0.024933

The Company believes that the proposed PPFAC percentage rate will provide more accurate and equitable price signals and improve the Company's overall rate design for customers. The PPFAC percentage rate results in an improved allocation of power supply costs by customer class based on the actual cost to serve these customer classes.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit MES-R-1

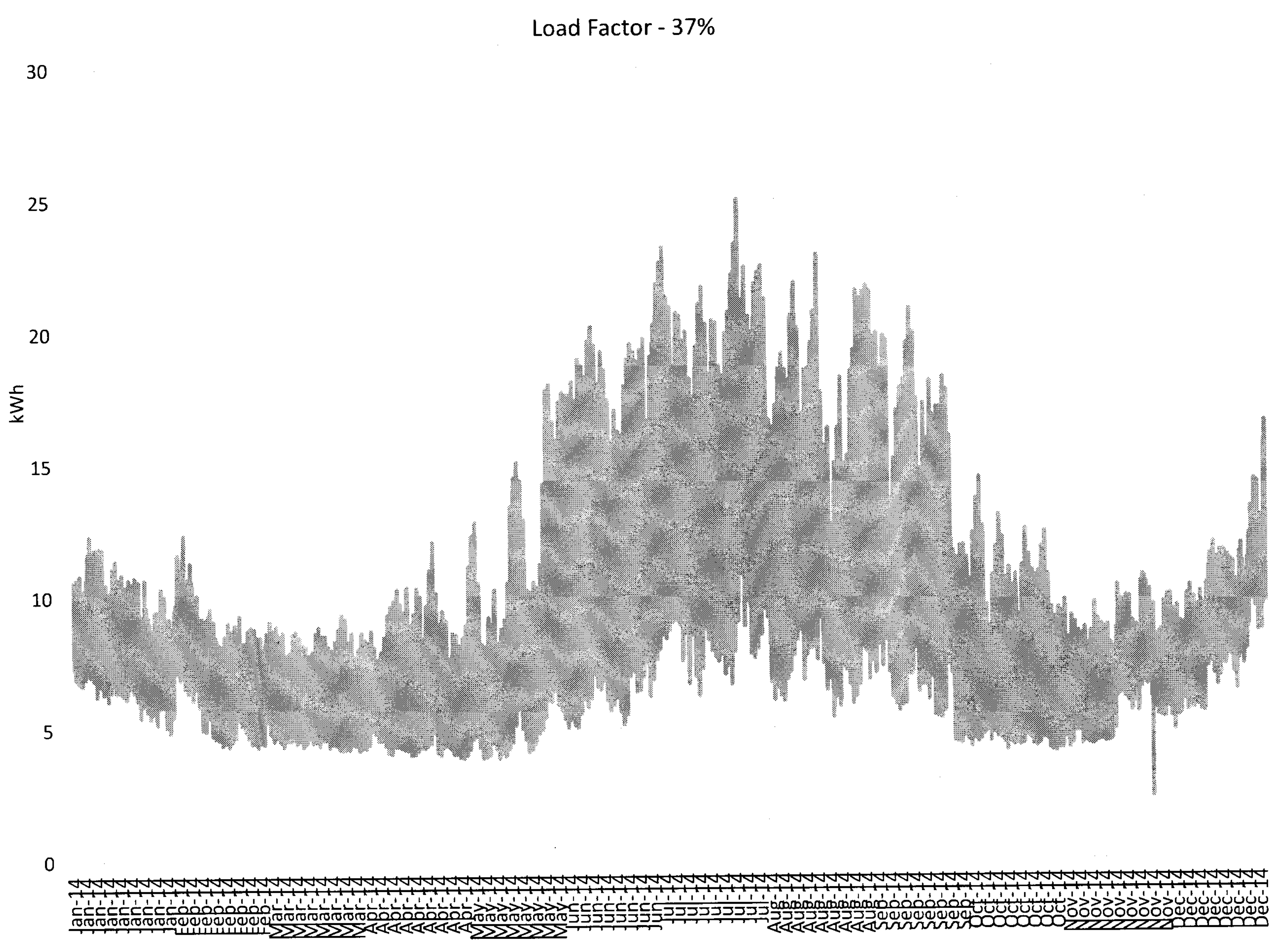
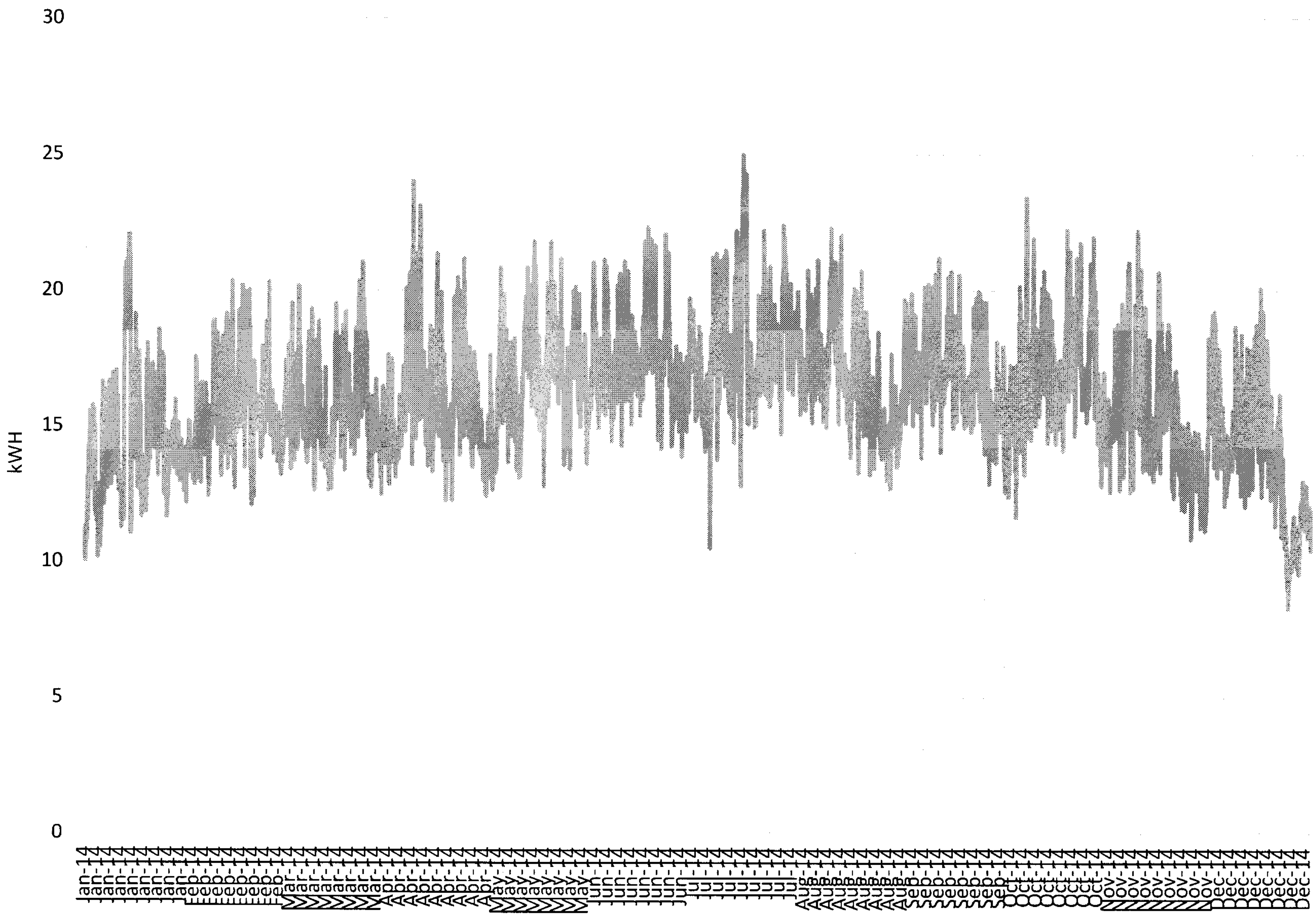

Load Factor - 37%
kWh
30
25
20
15
10
5
0

Exhibit MES-R-2

Load Factor - 65%



Rebuttal Testimony of
Carmine Tilghman

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
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VACANT

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

Rebuttal Testimony of

Carmine A. Tilghman

on Behalf of

UNS Electric, Inc.

January 19, 2016

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I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Carmine Tilghman and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. I will primarily be addressing comments from the testimony of ACC Staff witnessness Howard Solganick and Eric Van Epps, the Residential Utility Consumer Office ("RUCO") witness Lon Huber, Vote Solar ("VS") witness Briana Kobor, Arizona Utility Ratepayer Alliance ("AURA") and TASC witness, Mark Fulmer.

Q. Will you be addressing all of the issues included in testimonies relative to the Company's proposed net metering changes?

A. No, I will be limiting my rebuttal testimony to the following issues:

1. Requests to delay addressing the Company's proposal to modify the Commission's Net Energy Metering policy ("NEM") due to the Commission's pending Docket No. E-0000J-14-0023 (Value and Cost of Distributed Generation).

2. Clarification of the Company's proposal to utilize utility scale pricing as a Renewable Credit Rate, including clarification of Renewable Energy Credit ("REC") ownership and other factors affecting the use of a facility connected to the distribution system of UNSE's affiliate company, TEP.

3. The supposed benefits of distributed generation over centralized PV.

My lack of rebuttal testimony addressing other positions regarding UNSE's NEM proposal taken by Intervenors in their testimonies should not be taken as agreeing with or supporting these positions, and I reserve the right to discuss those issues as they arise during the hearing.

Q. Was there a common theme among the Intervenors' positions regarding the Company's net metering proposal?

A. No. Of the 15 parties in this proceeding that provided written testimony, only six addressed UNSE's proposed changes to the NEM policy in their direct testimonies. TASC, AURA, and Vote Solar oppose any changes to the current subsidies received from retail net metering; and in general, they oppose making any changes to the NEM policy until the Value and Cost of Distributed Generation docket has been completed. Moreover, they opposed demand charges and raising the monthly customer charge and any other proposal designed to mitigate the cost shift caused by current NEM policies and current rate design.

In contrast, RUCO's testimony addressed the need to ensure fairness for all ratepayers and offered several alternatives to the Company's NEM proposal, while the Arizona Investment Council ("AIC") supports UNSE's proposed modifications. ACC Staff testimony states that, for the time being, it does not endorse the Company's NEM proposal, but may update its position during the course of this rate case proceeding.

II. TIMING OF NET METERING MODIFICATIONS.

Q. Does the Company believe it is appropriate to wait until the Value and Cost of Solar docket is completed before considering proposed changes to NEM as part of UNS Electric's rate case?

A. No. Ironically, when the Company proposed addressing NEM as a stand-alone issue in March 2015, many of these same entities strongly argued that this issue must be addressed in a rate case. Their argument was that the Commission should be afforded the opportunity to address all rate design options at once, and that the Company's next general rate case was the appropriate place to do so. Attempting to remove the Company's proposal from consideration in this rate case until the Value of Solar docket is completed is a direct contradiction of their previously stated position.

Q. Have any of the Intervenors proposed rate design structures that either complement or mitigate the need to address modifications to the current NEM policy?

A. Yes, Staff has proposed a three-part rate structure that, if properly designed and implemented in a timely manner, would eliminate the need to specifically address the current NEM policy. However, not all parties support the implementation of a three part rate design that includes a demand component. Given the divergence of positions, the Company believes it is critical to evaluate all potential rate design proposals, including modifications to NEM, in this rate case.

Q. Do you agree with Ms. Kobor's argument that the problem is not large enough to warrant any changes to address the cost-shift due to DG systems?

A. No. Ms. Kobor simply points to a snapshot in time to justify her position. But the fact is that the cost-shift due to DG is a growing problem. Assuming that her conclusion is true (and we are not conceding that at this time) she ignores the increasing amount of DG installations that is and will augment the decline in retail sales beyond 6%. Put simply, the Commission has found that a cost shift exists with non-DG customers subsidizing DG customers. Vote Solar and other parties stated that the rate case is the appropriate forum to address this problem; so now is the time to address this problem while it is at a manageable level.

Moreover, I do not believe it is appropriate to wait until there is a certain level of DG penetration in the market before the Commission addresses an acknowledged problem.

Q. Has the Commission made a specific finding that net metering is causing a cost shift to non-DG customers from DG customers?

A. Yes. Decision No. 74202 (December 3, 2013) recognized that a cost-shift due to net metering exists. Further, while it may have been justified in the past to have in place current net-metering policies to boost the proliferation of DG systems, this is no longer the situation we have. We have reached the point where subsidizing DG customers by crediting excess energy from DG systems at the full retail rate (by the banking of excess generation and rolling over kWh unused to subsequent billing periods) is not necessary, and is not (and never has been) supported by cost-of-service.

Q. Has TASC continued its opposition to any changes to net metering even when there has been substantial increased penetration of DG?

A. Yes. The Hawaii Public Utilities Commission recognized that penetration had reached a level to warrant changes including with its net metering policy - noting that total net metering program capacity had reached between 30% and 53% of each of the HECO Companies system peak load.[1] Keep in mind that UNS Electric is not proposing the changes the Hawaii PUC ultimately adopted, which was to end the current program in

[1] See Decision and Order No. 33258 in Docket No. 2014-0192 (October 12, 2015), pages 160-161(link : http://puc.hawaii.gov/wp-content/uploads/2015/10/2014-0192-Order-Resolving-Phase-1-Issues-final.pdf).

favor of new options for new DG customers. Still, even with that level of penetration, TASC filed suit in Hawaii challenging that Commission's decision that TASC alleges "the state's successful net energy metering program."[2] So even at the level of penetration TASC still opposes changes even when the Hawaii PUC clearly states that the intent of the NEM program was to merely provide "a simple and effective tool to jumpstart the adoption of distributed renewable energy" (as stated on page 162 of the Hawaii PUC's order).

Q. Are there other benefits or reasons to address current NEM policies now?

A. Yes. There is an inherent flaw in the current NEM policy that utilizes retail rates as a "rough justice" for compensation. By failing to send accurate price signals to the customer and the industry, there is little incentive for the industry to evolve its business model and promote new technologies. Rate design structures, including NEM policies, which reflect a more accurate cost of service promote the development of new technologies such as small scale storage and fuel cell technologies. Additionally, flawed and inaccurate price signals such as retail net metering do not promote customer education and do little to promote energy efficiency or demand side management.

Ultimately, most industry experts understand and believe that advanced technologies must be developed and deployed in order to achieve a more interactive grid, also referred to as the "grid of the future" or "grid 2.0". In order to promote the development of the appropriate new technologies, the correct price signals must be sent to the industry. This includes updating antiquated NEM policies that utilize retail rates at the compensation value.

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[2] See Press Release, "TASC Seeks an Injunction on the Decision to Eliminate Solar Net Metering in Hawaii" located at http://allianceforsolarchoice.com/tasc-seeks-an-injunction-on-the-decision-to-eliminate-solar-net-metering-in-hawaii/ (last checked January 13, 2016).

III. RESPONSE TO CONCERNS ABOUT UNS ELECTRIC'S NET METERING PROPOSAL.

Q. Is UNS Electric proposing to eliminate net-metering?

A. No.

Q. Is UNS Electric's proposal consistent with the definition of net metering in the ACC rules?

A. Yes. Amending the excess energy credit does not eliminate the "net" in net metering. Customers still have opportunity to receive a credit for excess energy that offsets energy provided by UNS Electric at the RCR level - in addition to offsetting energy the customer uses from the customer's DG system.

Q. In fact, is UNS Electric proposing to maintain the full retail rate offset for energy that the DG customer consumes from the customer's DG system?

A. Yes. The Company will credit every kWh of energy produced from the DG system that the customer uses at the full retail rate. The only change is with regards to excess energy that flows back onto the grid from the DG customer's system.

Q. Does UNS Electric's proposal eliminate net metering in favor of a "buy all sell all arrangement"?

A. No, because UNS Electric would not be acquiring energy from the DG customer at a specific rate for the energy that DG customer uses in addition to excess energy. And UNS Electric is not selling the excess energy back to the DG customer at the full retail rate. UNS Electric is acquiring the excess energy at a set rate that, while different than the full retail rate, is still offsetting energy provided to the DG customer from UNS Electric.

Q. Can you summarize why UNS Electric believes the Renewable Credit Rate ("RCR") it proposes is in the public interest to adopt for the excess energy credit?

A. Yes. While other UNS Electric witnesses detail the intricacies of cost of service, cost causation and the like, the RCR is a far better reflection of the cost of energy produced by DG than the retail rate. A DG customer does not incur the fixed costs associate with the distribution grid to ensure the deliverability of any energy from the DG system, for example. But those costs are embedded in the volumetric per-kWh retail rate charged to the customer. While UNS Electric's proxy as to the RCR is not perfectly precise, it much better reflects the actual cost to produce the energy.

Q. What issues were raised by Intervenors regarding the use of a utility scale solar price as the proxy for the Company's proposed Renewable Credit Rate?

A. Several Intervenors raised concerns regarding the use of a utility scale PPA price as the proxy for the proposed RCR, including:

1. The use of a Power Purchase Agreement ("PPA") associated with UNSE's sister company, TEP, which has the ability to deliver both energy and REC's to UNSE.
2. PPA price not accounting for transmission or distribution losses.
3. Accounting for potential deferred savings at the distribution level.
4. That a utility scale solar facility is not a fair proxy for Distributed Generation ("DG").
5. Changing or resetting the Renewable Credit Rate.

I will address each of these issues individually. Although there were other issues raised by Intervenors (primarily TASC), they are not significant enough to include in my rebuttal testimony and can be more easily addressed and discussed during the hearing process.

Q. Please discuss the specific issue regarding the use of a PPA price associated with UNSE's sister company TEP, and why the Company still believes it is appropriate to consider.

A. Several Intervenors believe it is inappropriate to establish the Renewable Credit Rate based on a facility that is tied to an expansion of an existing facility, or one that is not directly tied to the UNS Electric system.

For example, Staff argued that it would not be representative of the facilities' actual costs to UNS Electric if the Company were to utilize an existing facility's interconnection and procure solar energy for a lower price (thereby "artificially" lowering the Renewable Credit Rate). It should be noted that, as stated in the Company's response to Staff's data request, the second phase of the TEP facility used in setting the Renewable Credit Rate had its own interconnection costs totaling more than $1.7 million that were included in the contract price.

It should be noted that the Company does, in fact, have the opportunity to take advantage of existing facilities to procure lower priced energy – a benefit which is passed on to the customer. This is the very basis of argument that the Company possesses the ability to procure renewable energy – with arguably equal or superior benefits to customer-sited DG – at a lower cost.

If, in fact, future utility scale projects had a higher price due to interconnection costs, transmission costs, or other variable costs, they would be reflected in a higher PPA price and subsequently in a higher Renewable Credit Rate.

However, at this time, the Company believes that it's inherently unfair that customers should have to pay more than the price at which the Company is currently able to procure solar energy, and the Company fully intends to continue procuring renewable energy at the most cost competitive prices. Moreover, no Intervenor has provided any compelling reason or argument as to why customers should pay more for solar energy.

Several Intervenors question why the Company should be allowed to utilize solar energy from a facility not connected to UNSE's system. The question, however, should be *why wouldn't the Company take advantage of its ability to procure lower cost renewable energy?* The Company's proposal was designed to allow the Company to meet the state's Renewable Portfolio Standard ("RPS") in *the most cost effective manner possible.* Arizona's RPS does not require the renewable energy that serves an affected utility's customers be produced within the company's service territory. The requirement is that the energy be from eligible renewable energy resources (as defined in A.A.C. R14-2-1802) and that these resources *"displace conventional energy resources that would otherwise be used to provide electricity to an affected utility's Arizona customers."* Additionally, the RECs from these resources (except distributed resources) must only demonstrate the delivery of the renewable energy to the affected utility's retail customers (such as through the procurement of transmission rights for the delivery of the energy).

TASC witness Fulmer's testimony states that *"while TEP is an affiliate of UNS, it is not UNS. This begs the question, 'why not Arizona Public Service (APS) or Salt River Project (SRP) or even Nevada Power, whose load center (Las Vegas) is closer to the bulk of UNS's load than Tucson is?'"* UNSE agrees – why not one of those other companies? Any of those companies may very well afford UNSE the opportunity to procure renewable energy for its customers at a *significantly lower cost* than continuing to pay a retail customer approximately double the current rate, all while being able to deliver the energy to the Company's retail customers and satisfying the requirements of the RPS.

While the Company would entertain a much broader discussion in a future rulemaking proceeding regarding the most cost-effective use of regional facilities, the Company's proposal is that avoided cost would be based on a system attached to a "distribution system," which ensures that the facility must be in the State of Arizona and tied to either UNSE's or TEP's distribution system.

Q. Please discuss who owns the RECs associated with the Company's proposal, versus the proposals of the Intervenors.

A. As with all utility scale renewable PPA's – including the proposed project used to establish UNSE's proposed Renewable Credit Rate – the Company's retains all of the RECs. In fact, while Staff witness Solganick expressed concern regarding REC ownership, he also stated that "this is important as REC's have value".

If this concept is to hold true, then it is important to note that the Company retains the right to all RECs associated with the utility scale PPAs. Conversely, and conspicuously missing from all of the Intervenors testimony, is the fact that the Company does not obtain title to the RECs associated with customer-owned renewable DG systems. This further diminishes the value of a customer-owned DG system relative to a utility-scale renewable facility where the utility is able to obtain REC ownership for compliance with the RPS.

Q. Please discuss Intervenors' concerns regarding avoided losses.

A. Several Intervenors expressed concern over not providing the DG customer compensation for avoided losses. This is one area where the Company would concede, with certain caveats, that loss compensation could be considered in the Renewable Credit Rate. Overall, total losses on an electrical grid (transmission, distribution, and conversion) represent approximately 10% of the system cost. As such, even if the entire system losses were deemed to be saved it would only translate into an increased Renewable Credit Rate of about 6.5 cents per kWh, which is still only slightly more than half the current retail rate. However, the Company does not agree that the entire system loss value should be included in the compensation value, and would include the caveats below:

1. Only real losses should be included, and only those losses associated with the distribution system should be included, as the Company's proposal stipulated that the renewable credit rate would be based on a corresponding facility attached to a distribution system. RECs can easily be transferred between companies, and the ability to utilize either company's distribution system benefits UNSE and TEP customers alike. Any concern regarding "significant losses" associated with a third party's transmission system highlights a lack of understanding of the Company's proposal.
2. A reasonable estimate of losses associated with energy pushed back onto the grid should be deducted from any loss compensation adder. While the parties may argue about precise values, it is not uncommon to see approximately 50% of a customer's energy pushed back onto the grid. Many solar proponents argue that energy only "goes to the house next door". However, there are several factors that should be considered when making that as-yet-to-be-proved claim: increasing penetration of DG results in multiple solar customers on each circuit, all pushing energy back into the distribution circuit level; when the solar customer isn't using the energy due to low load, the neighbor often has low load, as well; energy pushed back through the lowest voltage portion of the system has the highest loss percentage (due to the higher current flows at low voltages resulting in higher

eddy current losses). While all of this information is extremely difficult to measure and quantify, it is at the very least necessary to acknowledge the existence of these losses and provide some reduction.

Q. Please address the Intervenors' comments that a utility scale facility is not a fair proxy for distributed generation.

A. Several Intervenors questioned the basis for using a utility scale facility as an equitable proxy for distributed generation. TASC witness Fulmer even went so far as to claim that "the fact that DG is distributed makes it a more reliable and steady source of power than even smaller utility scale projects." In a theoretical world where customer sited DG was evenly distributed throughout the utility's system, it would provide a smoother – yet equally unreliable – power source.

However, we do not live in a theoretical world. The "competitive" solar industry does not install solar in a well-planned, thoughtful manner with an emphasis on improving grid reliability, but rather wherever they find a willing and financially capable customer. As a result of such a random disbursement of DG, which lacks even a hint of thoughtful distribution planning, Mr. Fulmer's and Ms. Kobor's claims that there is a benefit of intermittency smoothing that lacks any credible, real-world evidence. At best, in my experience and observation of the roughly 13,000 DG systems between UNS Electric and TEP, there is no material benefit of randomly sited DG over well-planned, smaller scale centralized PV facilities. In my opinion, Mr. Fulmer's and Ms. Kobor's assertions that the effect of randomly located solar DG is of tremendous value to the utility, simply highlights the witnesses' lack of actual grid management and operational expertise. Mr. Fulmer's additional reliance on the DOE's Solar PEIS study and the assertion that land use impacts such as soil disturbance, habitat fragmentation, noise, and surface water quality prove that DG is more valuable than utility scale PV shows a lack of understanding and ignorance of the Company's long established procedures for siting facilities on previously disturbed or limited use properties. The Company's site selection process either minimizes or eliminates these impacts. Even without the Company's site selection criteria to minimize these impacts, it is irrational to argue that any minimal environmental impact associated with utility scale facilities justifies a solar DG credit equal to twice the cost of energy from utility scale facilities.

TASC witness Fulmer further goes on to claim that the Company's proposal is unfair as the value of renewable power is not the same across technologies, and then proceeds to use the example of the utility procuring a geothermal project with a lower price than solar, or the possibility of a wind facility whose generation profile would be different but again, whose price would be lower. Mr. Fulmer then proceeds to erroneously state that "solar provides power during times of high system load when power is more valuable", once again highlighting his lack of actual operational experience in grid management and relying on an often repeated, yet incorrect, statement that applies to only a few months during the year. The Company has previously shown that at no time during the year does the system peak when solar peaks. In fact, during the winter months when the system peaks before the sun rises and after the sun sets, solar has absolutely zero value during the times of greatest need and when prices are the highest.

The Company questions why Mr. Fulmer would be *concerned* that the Company could procure renewable resources at a lower cost. If, in fact, we could provide our customers with renewable energy from a resource that is a lower cost to the customer, exactly what is the concern? The Company fails to see the logic in TASC's argument that UNSE should be precluded in the future from procuring lower cost resources simply because it makes TASC's member companies' product less economical. Perhaps Mr. Fulmer unintentionally highlights the flaw in TASC's continued fight to preserve the NEM subsidies as they exist today – an acknowledgment that there are cheaper renewable resources available to the utility than customer sited DG.

Q. What is your response to Ms. Kobor's apparent dismissal of DG adversely impacting UNS Electric's grid?

A. As I have stated and based on my experience observing how the growth of DG impacts UNS Electric's grid, the random way by which DG systems are added onto UNS Electric's system will necessitate measures and improvements to address some of the stability issues caused by DG proliferation. If this were a situation that renewable energy systems were placed strategically throughout UNS Electric's service territory, the need for additional improvements of this type could perhaps be minimized. But that is not the case with DG. Like with the intermittency issue (DG systems are not well-planned to cost-effectively reduce intermittency) the need for ancillary services (such as voltage or frequency control) will increase with increased DG proliferation. So, just as widespread proliferation of DG systems is not the sole panacea for intermittency of renewable energy such as solar, the random proliferation of DG results in side effects that adversely impact the grid, where alternative renewable resources strategically placed would lessen such adverse impacts.

Q. What can you tell us about the reverse power flows UNS Electric has experienced with increased DG?

A. Our actual experience operating UNS Electric's distribution grid has shown such reverse power flows during routine or specific testing. The fact is that to put specific monitoring equipment for every one of the hundreds of circuits would be extremely costly if not impossible. But we do know for sure this phenomenon has occurred and exists. As the entity charged with ensuring safe and reliable service, we have to address it.

Q. Mr. Fulmer, at page 9 of his November 6, 2015 Direct Testimony indicates his belief that UNS Electric has not provided sufficient information to demonstrate any integration issues with increased DG. What is your response?

A. Mr. Fulmer ignores the continuing flow of applications that UNS Electric is receiving from customers seeking to install DG. In other words, the number of DG systems interconnected onto UNS Electric's system keeps increasing in response to market opportunities instead of distribution planning. As a result, integration issues arise that require additional equipment that may include smart inverters and other facilities to manage the load and provide stability. I note that UNS Electric continues to receive applications to interconnect DG systems even with notification of the potential changes to rates and the net metering tariff.

Q. Is the Company insistent that the Renewable Credit Rate be reset each year based on the most recent utility scale PV price, or could the Company support a compromise in order to provide some price stability?

A. The Company's proposal is to reset the rate each year. However, the Company would be willing to discuss alternatives in order to provide some price stability, thereby eliminating the concern over changing pricing. These alternatives could include fixing the NEM credit until the Company's next general rate case, or possibly for a longer period of time, when the credit would be recalculated based on more current price information.

IV. <u>RECENT NET METERING POLICY DEVELOPMENTS.</u>

Q. Have there been any regulatory developments or utility commission decisions regarding NEM changes that support the Company's position that the current NEM policy should be changed?

A. Yes, several Public Utility Commissions ("PUCs") have recently made significant policy changes to their states' NEM policies, or have made significant findings in orders regarding net metering. Each of these states have (or had) full retail net metering policies similar to the current Arizona policy. I believe that the PUCs have, in general, correctly identified concerns and problems with NEM policies that are generally applicable in Arizona and that those PUCs have begun the process of making necessary changes in NEM policies to reflect the current - and evolving - circumstances.

In October of 2015, the Hawaii Public Utilities Commission voted to eliminate their retail net metering program in favor of a payment for excess energy pushed back onto the grid that is *less than half of the retail rate* and is based on the avoided cost of fossil fuel during peak generation hours.[3] If UNSE employed this type of payment mechanism, the proposed Renewable Credit Rate would be approximately $0.035-$0.040/kWh rather than the equivalent utility scale price of $0.0584/kWh that the Company proposed. In their decision the Hawaii PUC stated, *"It is abundantly clear that distributed energy resources can provide benefits to Hawaii. It is also clear, for both technical and economic reasons, that the policies established more than a decade ago must be adapted to address the reality of distributed energy resources as they exist today – and as they are likely to develop in the near future."* The Company agrees that, even though there may be different challenges between UNSE and HECO, the idea that policies established a decade ago must be adapted to reflect the current situation and reality of distributed generation resources, particularly in light of the Company's ability to procure lower cost renewable resources in other forms.

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[3] Decision and Order No. 33258 in Docket No. 2014-0192 (October 12, 2015) (link : http://puc.hawaii.gov/wp-content/uploads/2015/10/2014-0192-Order-Resolving-Phase-1-Issues-final.pdf).

In November 2015, the Utah Public Service Commission issued an order in the matter of the investigation of the costs and benefits of PacifiCorp's net metering program.[4] The order is considered the first step in fulfilling a legislative statute and is designed to provide the framework of how to calculate benefits and costs of net metering. The second step, which has not been completed, will address the actual value at which excess energy from NEM customers should be set. What is important in this order is the Utah Commission's rejection of claims made by the Joint Parties (representing several solar entities, including TASC) that a customers' DG equipment is a "free resource to the utility system" and the costs and benefits of net metering are analogous to the analysis used by the utility in its Integrated Resource Planning ("IRP"). In the current UNSE rate case, Intervenors have claimed that energy received by the utility from net metering customers has significant value over well-planned utility-scale PV systems and should be therefore be valued higher. However, the Utah Commission correctly determined a number of fallacies related to this argument, such as:

1. NEM generation results from a voluntary customer decision, and the utility has little, if any, control over the design of systems on the customer side of the meter.
2. Customers own and control their equipment, and customers make decisions about whether to install that equipment and how much capacity to install.
3. The customer is under no obligation to maintain the system.
4. The customer is under no obligation to supply the utility with electricity.
5. If a problem develops that prevents the customer from generating energy, the customer is under no obligation to cure it.
6. A customer is under no contractual obligation to provide any of the power it generates to the utility.

[4] Order in Docket No. 14-035-114 (November 10, 2015) (link: http://www.psc.state.ut.us/utilities/electric/ordersindx/documents/27044914035114o_000.pdf)

All of these observations regarding a customer sited DG system are applicable to every utility with a similar NEM program, including UNSE. However, as PacifiCorp noted and the Utah Commission agreed, the utility's contractual agreements provide for robust credit terms, performance guarantees, step-in rights, and other provisions that ensure the facilities will produce energy for the benefit of all customers. All of UNSE's contracts contain these provisions, along with other valuable attributes such as communications networks for system monitoring, ability to control or shutdown the systems, protection devices, and ownership of the RECs. TASC and other Intervenors' arguments that a customer sited DG system is more valuable ignores all of these circumstances.

Finally, on December 22, 2015 the Nevada Public Utilities Commission voted unanimously to lower the rate applied to net metered energy from distribution generation customers from approximately 11.5 cents per kWh to about 5.5 cents per kWh.[5] This value, calculated by NV Energy in their integrated resource plan, represents the forecasted average annual marginal energy cost (with an adder for avoided distribution line losses). This amount is representative of the value UNSE has proposed through the use of its avoided solar value (the wholesale price for the Renewable Energy Credit rate).

The Nevada PUC also made a number of determinations in support of, and consistent with the Utah PSC's findings, lowering the value associated with energy from NEM customers. Specifically, the Nevada PUC stated:

1. Current rates for NEM ratepayers are not properly aligned with the costs to serve NEM ratepayers. The misalignment can be attributed in part to the NEM policies.
2. Rates are based on marginal (internal utility) costs and do not reflect external benefits or costs for any ratepayer class. External societal costs and benefits are

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[5] Order in Docket Nos. 15-07041 and 15-07042 (December 23, 2015) (link: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2015-7/8412.pdf)

not included in the cost recovery that NV Energy's rates provide for any class. No exception should be made for NEM ratepayers.

3. NEM ratepayers have unique service and cost characteristics, and as such, NEM ratepayers should be placed in a separate rate class in order to allow for alternative rate structures.

4. Separate rate classes will address the inequity between NEM and non-NEM ratepayers that exists under their current NEM structure (which is nearly identical to Arizona's NEM structure).

5. It is in the public interest to take steps to transition to accurate, cost-based, non-discriminatory rates.

6. The value of NEM changes over time based on a variety of factors – relative location and concentration, natural gas prices, and the price of utility-scale renewable amongst other things. Consequently, setting a value for a long period of time is unwise.

7. Banking the net excess energy at the retail rate is not just and reasonable because the energy by the NEM ratepayers is not the same as the energy delivered by NV Energy.

8. NV Energy is required to provide reasonably reliable service at just and reasonable rates. NV Energy is required to provide this service at the times and place and in the volumes required by any ratepayer, including a NEM ratepayer.

9. This requires that the utility adhere to industry standards for the design and operation of its electric system including system reserves and redundancies. Failure to provide this service can result in fines and the revocation of NV Energy's operating certificate.

10. In contrast, NEM ratepayers have no legal requirement to provide any volumes to the grid at any time. NEM provide these volumes solely at the discretion of each

individual NEM ratepayer and are not scheduled in advance and can be withdrawn at any time by the NEM ratepayer.

11. Further, the volumes flow to the grid without consideration for overall grid demand or system reliability which remains the legal responsibility of NV Energy.

12. Ratepayers are smart, capable, and willing to participate in a market that is based on cost causation and fairness.

13. Acknowledges independent analysis conducted by E3, Lawrence Berkeley National Laboratory, and the Massachusetts Institute of Technology support the conclusion that NEM increases utility rates and shifts costs to non-participating ratepayers.

On January 13, 2016, the Nevada Public Utilities Commission unanimously reconfirmed their decision over the objections from several intervenors, including TASC.

While each of these examples are unique in their own right, they highlight the fact that continued use of existing NEM policies such as full retail net metering is unsustainable.

While the Company is open to further discussion regarding the credit rate used for net metered energy and length of time before such rate should be adjusted (annual, in each rate case, etc.), the Company still firmly believes that, in the absence of any significant rate design changes, now is the appropriate time – and this rate case is the appropriate venue – to implement changes to the current retail NEM policy.

V. <u>RESPONSE TO REQUEST FOR REST PLAN OF ADMINISTRATION.</u>

Q. Are there any other issues that you would like to address in this testimony?

A. Yes. The Direct Rate Design Testimony of Eric Van Epps recommends that the Company provide a draft Plan of Administration ("POA") for the REST in the Company's rebuttal testimony. Following discussions to clarify Staff's request for a POA and what additional data is to be included, the Company will draft a POA that is consistent with the requirements set forth in A.A.C. R14-02-1813 governing Affected Utility's renewable implementation plans. Due to the nature of the request and timing associated with the development of the POA, the Company will provide a draft POA prior to the hearing in this matter.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Rebuttal Testimony of

Dallas J. Dukes

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

Rebuttal Testimony of

Dallas J Dukes

on Behalf of

UNS Electric, Inc.

January 19, 2016

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Exhibit:

Exhibit DJD-R-1 - Proposed UNSE Customer Education Campaign for Three-Part Rates

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dallas J. Dukes and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. I am filing Rebuttal Testimony on behalf of UNS Electric, Inc. ("UNS Electric" or the "Company").

Q. How is your Rebuttal Testimony organized?

A. My testimony is organized as follows.

II. Rate Design.

III. Response to Staff's Testimony.

IV. Response to RUCO's Testimony.

V. Response to Other Intervenors.

VI. Net Metering Tariff..

VII. Economic Development Rate.

II. RATE DESIGN

Q. Please briefly summarize the Company's initial proposals regarding three-part rates.

A. The Company's Direct Testimony proposed (i) mandatory three-part rates for all partial requirement residential and small commercial customers who installed distributed generation after June 1, 2015 (collectively, "New DG Customers") and (ii) optional three-part rates for all other residential and small general service customers.

Q. What are the primary reasons for updating UNS Electric's rate design?

A. In this proceeding, the Company is attempting to gradually and fairly modify its rates to (i) reduce intra-class subsidization, (ii) promote fairness and recover costs from cost causers, (iii) provide flexibility to accommodate changing customer usage patterns, (iv) move toward rate structures that encourage the integration of new energy technologies on the electric system, thus promoting more efficient use of the electric system, and (iv) a sustainable rate structure that ensures that the Company can continue delivering safe, reliable and affordable electric services for the benefit of all our customers.

Q. To make it clear, are all of UNS Electric's proposed rate design changes simply to address partial requirement customers, such as solar DG customers?

A. No, and this is something that needs to be clarified. The Company has proposed several rate design changes in this docket. UNS Electric is attempting to address the totality of issues caused by recovering the vast majority of fixed cost with inverted block volumetric pricing, which is exacerbated by declining energy sales. (Please see the Rebuttal Testimony of UNS Electric witness H. Edwin Overcast for a detailed explanation of these issues.) In short, we are trying to gradually shift towards a rate design that more accurately reflects cost causation. Raising the monthly charge to a point where the percentage of recovery of fixed costs increases is one proposal; eliminating the third tier for residential customers is another.

Some of the rate design changes do address the unique subsidization issues related to serving partial requirement customers with two-part rate design and net-metering, but some of which address other inequities. If two-part rate design is retained as an option for UNS Electric's customers, then raising the monthly basic service charge to $20 and eliminating a portion of the inverted rate structure are necessary changes that need to be made to begin addressing the subsidization of inefficient users of the system -low-usage and low load factor customers. That is part of the solution to address subsidization caused by vacant homes and seasonal customers, for example.

Both Staff and RUCO have recognized the need to update rate design and have made proposals that I address below. Other parties have suggested rate design concepts, such as minimum bills, that I believe are not as comprehensive a way to address the issues now or in the long term. Some parties such as Vote Solar and The Alliance for Solar Choice ("TASC") simply oppose all rate design changes without proposing any substantive alternatives, even those that are not targeted to deal with the issues DG specifically causes.

III. RESPONSE TO STAFF'S TESTIMONY.

Q. Have you reviewed Staff's rate design testimony?

A. Yes, I have.

Q. Does the Company support Staff's rate design recommendation to transition all of UNS Electric's residential and small general service ("SGS") customers to a new tariff that includes a demand charge (three-part rates)?

A. Yes, if properly designed, the Company fully supports transitioning all of our residential and SGS customers to three-part rates.

Q. Why didn't the Company propose transitioning all residential and SGS customers to three-part rates in this proceeding?

A. The Company proposed volumetric rates in our initial filing and optional three-part rates that include an increased basic service charges and the elimination of an artificially inflated higher third tier in the volumetric rate design. The proposed changes were designed to (i) mitigate intra-class subsidization, (ii) begin the transition to multi-part rate structures and (iii) move towards more fairly charging customers. My direct testimony was based on the assumption that the approved rate increase and rate design changes would be in effect in mid-2016, as initially requested by the Company. Based on our original plans to complete the installation of our automated meter reading system (in 2017) and implement a customer education and information program, implementing three-part rate design for all customers by mid-2016 seemed somewhat aggressive when we filed our application in May 2015.

Q. How has Staff's proposed rate design addressed transitioning customers to multi-part rates?

A. Staff's proposed long-term rate design plan eliminates the need for multiple rate case proceedings to implement initial three-part rates for all our customers by: including the proposal of transitional volumetric rates, a transition and education period, "<u>first-step</u>" three-part rates (i.e. only collecting a small portion of demand-related costs in this case with a goal of gradually updating the demand rate over the next couple of rate cases); and leaving rate design open for an extended period of time to allow for any significant unintended bill impact and revenue consequences to be addressed. Staff's proposal, in conjunction with accelerating the deployment of our automated meter reading system and the transition plan included as part of my Rebuttal Testimony, enables three-part rate design to be approved for all customers in this proceeding.

Q. What rationale does Staff provide for moving all residential and SGS customers to three-part rates?

A. Staff provides several compelling reasons for its recommendation regarding three-part rates. Mr. Broderick correctly states, among other things, that three-part rates (i) better inform customers considering new technologies, including DG, about the bill impacts of their technology choices, (ii) make significant progress towards all the issues arising from the proliferation of DG, and (iii) reflect cost causation better than rates that rely on energy charges only to recover fixed costs.

Q. Do you agree with Staff's rationale?

A. Yes, I do.

A recent newspaper article in the Kingman Daily Miner (1/8/16) included the following quotes from UNS Electric customers:

> John and Sandi Myers spent about $21,000 to install a new solar unit in their Kingman home in November.
>
> They're hoping to bring their monthly electric bill down to nothing, the way it was at their solar-powered home in Lake Havasu City.

> "We're both retired on a fixed income, so we're looking at not having an electric bill," Sandi said. "We had older panels in Lake Havasu, so they were not as efficient. For nine months, we didn't have a bill. We really liked it. <u>We didn't have to worry about cranking the air conditioning</u>."
>
> Myers said they won't be getting the rebates they had in Lake Havasu. But with the 30 percent tax credit, they won't have to pay any federal taxes for 2015.

This excerpt illustrates a few of the significant issues we're trying to address with the gradual changes proposed by not only the Company, but also by Staff and RUCO such as: 1). It reflects the availability of advancing technologies at reduced costs available to our customers. "We had older panels in Lake Havasu, so they were not as efficient"; 2). That federal tax credits provide significant economic incentives to our customers to invest in these new technologies. "But with the 30 percent tax credit, they won't have to pay any federal taxes for 2015"; 3), that present rate design promotes economic decisions based on false price signals, "<u>we're looking at not having an electric bill</u>;" and 4) that current rate design and rules promote the inefficient use of the system, "<u>We didn't have to worry about cranking the air conditioning</u>".

If customers aren't charged for the costs that they require the Company to incur to provide them with the electricity they need, whenever they need it, customers will never have an incentive to use the system more efficiently. Properly designed three-part rates provide many benefits, ranging from charging customers more equitably for electric service to encouraging more efficient use of the system, to the integration of new technologies.

Q. Does the Company currently have the ability to meter demand for all non-DG customers?

A. No, However, our meter replacement program is on track to have demand reading capability in place for all customers by the by the end of 2016.

Q. Does the Company agree with Staff's proposed residential basic service charge?

A. Staff's proposal to move the residential basic service charge to $15 per month is representative of the customer's direct cost and minimum system cost. However, it is important to note that a $15 basic service charge is still far below the average fixed cost to provide service to a residential customer. The Company supports Staff's proposed basic service charge if the Commission adopts an acceptable three-part rate structure for all residential and SGS customers. However, the Company cannot support this lower customer charge if traditional, two-part volumetric rates are proposed for the Commission's consideration.

Q. Does the Company agree with Staff's proposed Demand Charge?

A. We are materially in agreement with Staff's proposed demand charge with a few minor modifications that are described in greater detail in the Rebuttal Testimonies of Craig A. Jones and H. Edwin Overcast. The primary changes we propose to Staff's proposal are twofold:

1.) The addition of a 15% minimum load factor for purposes of calculating the demand charge.

This temporary measure will address concerns some parties have regarding an atypical customer's usage causing demand charge spikes. Essentially, the billed demand (peak hour usage, during on-peak hours), will be adjusted so as to not be less than the average hourly load of the customer divided by 15%, thereby temporarily protecting certain customers from a higher bill resulting from an inefficient usage of the system until three-part rates are further adjusted in the Company's next rate case.

For example, if a customer used 800 kWh in a 30 day billing period, their average hourly load would be 1.11 kWh or kW [800 kWh / (24hrs x 30 days)]. If their highest hourly usage was 10 kWh or 10kW they would have a measured load factor of 11.1% (1.11 kW avg. load / 10 kW peak load). Without the load factor minimum, this customer would see a demand charge of $50 assuming a $5 per kW rate ($5 per kW x 10 kW peak load). With the minimum load factor the billed demand would be adjusted to 7.4 kW [1.11 kW avg. load / 15% minimum load factor]. Which would lead to an adjusted demand charge of $37 [$5 per kW x 7.4 kW adjusted peak load].

This is described in greater detail in the Rebuttal Testimony of Craig Jones, but is being proposed as an additional safeguard for our customers. Along with Staff's proposal of limiting the amount of demand cost recovered through these "first-step" demand rates, the use of one hour intervals for billed demand measurement and measuring billed demand during on-peak periods only – the load factor minimum will limit the possibilities for adverse and unexpected bill changes as a result of moving customers to three-part rate structures.

2.) Another change the Company is proposing to Staff's three-part rate proposal is to recover generation costs through the demand charge. This will be discussed in more detail in the Rebuttal Testimonies of Craig Jones and H. Edwin Overcast. Staff's proposal to base demand charges on the on-peak usage is directly associated with the cost of generation.

Q. Has the Company anticipated the need for a comprehensive communication and education plan for its customers as three-part rates become available for residential and small general service customers?

A. Absolutely. It has been the Company's objective all along to start communicating about its proposed three-part rate design at the conclusion of the proceeding. Contrary to TASC's erroneous assertion that the Company would not educate customers about three-part rates[1], we will implement a comprehensive communication and outreach plan to educate customers about <u>all</u> important rate and rate design changes that are approved by the Commission at the conclusion of this proceeding. I also strongly disagree with various Intervenors who have suggested that our customers simply will not be able to understand three-part rates, particularly given our plans for extensive outreach and education,

Q. Please describe the Company's education/outreach plans to inform customers about three-part rates.

A. The Company plans to promote awareness about three-part rates through a comprehensive communications campaign. A description of the Company's proposed education campaign is attached as **Exhibit DJD-R-1**. The key elements of the plan are described below.

- **Timing.** The campaign would provide customers with access to information about their individual electric demand at least three months prior to implementing such three-part rates.
- **Messages.** The primary customer messages will focus on the definition of a demand charge, how it is calculated, potential bill impacts and energy efficiency tips aimed at reducing customer demand.

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[1] Direct Testimony of Mark Fulmer (Rate Design and Cost of Service) ("Fulmer"), Page 23, lines 1-7.

- **Communication Channels.** The Company intends to use a variety of communication methods, including focus groups, customer bill messages, UNS Electric's website, social media, the customer electronic newsletter and brochures.
- **New Bill Format.** UNS Electric is in the process of redesigning customer bills. The Company expects to introduce the new bill design to customers at the same time that three-part rates are implemented.

Q. Please discuss Staff's proposed framework for transitioning customers to three-part rates.

A. Staff proposed some general guidelines for a rate migration plan. Staff states the following in its testimony:

- **Usage data.** Rate design should not change until customers can review at least three months of comprehensive usage data. Such usage data should be provided to customers on an ongoing basis.[2]
- **Phase-in.** The transition could start as early as January 1, 2017. The transition should be completed in phases and higher use customers should be transferred first.[3] The transition time for each phase should be at least four months.[4]
- **Unintended consequences.** The rate design portion of the case should remain open for at least 18 months to monitor the transition and deal with problems as they occur.[5]
- **Vulnerable customers.** Potentially vulnerable customers should self-identify; however, existing DG customers do not comprise a vulnerable group.[6]

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[2] Direct Rate Design Testimony of Howard Solganick ("Solganick"), page 13 lines 17-20, page 30 lines 17-26.
[3] Solganick, page 13 lines 22-26, page 14 lines 103.
[4] Solganick, page 32 lines 1-4.
[5] Solganick, page 14 lines 5-10.
[6] Direct Rate Design Testimony of Thomas Broderick ("Broderick"), page 9, lines 14-23, page 10 lines 1-8.

Q. Does the Company's proposed transition plan comport with the rate transition guidelines proposed by Staff?

A. Yes, we generally agree with the guidelines set forth by Staff as summarized above. Our primary difference is with regards to the timing of when customers are transitioned to new rates.

Q. Does the Company have any recommendations regarding the phase-in of three-part rates?

A. Yes. After much consideration, the Company believes that migrating all residential and SGS customers at one time, in February or March of 2017, is preferable to migrating certain customers at different points in time. We would use transitional two-part rates for all residential and SGS customers, including all DG customers, reflecting our new revenue requirement that would be in effect from the decision in this rate case until the migration date.

Q. Why does the Company believe that migrating all customers at once is better than in stages?

A. We think there are a few compelling reasons to migrate all customers at the same time. First and foremost, we think that our customer education and communication plans will be more effective if it is directed at our entire customer base rather than trying to deliver information to different customer groups at different times.

Another consideration is the seasonality of UNS Electric's bills. Implementing three-part rates during a reduced load (shoulder) month, when most bills are lowest for customers, will mitigate initial confusion between bill impacts attributable to the addition of the demand charge, versus a seasonally driven increase. This combined with the minimum load factor and other compromises designed to mitigate initial impacts, should lead to very moderate bill impacts. Please see the Rebuttal Testimony of Craig A. Jones for a more detailed discussion of bill impacts associated with transitioning to the Company's proposed three-part rate structures.

Our customer service performance should also benefit from a one-time implementation rather than a phased in approach. Having all of our customers under a similar rate structure will make it easier for our Customer Service Representatives ("CSRs") to effectively and accurately respond to customer inquiries. We plan to conduct internal training and develop educational materials for our CSRs in order to prepare them for the likely increase in call volume following the implementation of three-part rates.

Q. What can the Company do ahead of time to help mitigate unintended bill impacts resulting from the implementation of three-part rates?

A. The Company is already analyzing data and comparing bill impacts of implementing three-part rates versus current volumetric two-part rates. Once new rates are approved, and prior to implementing the new rate design, we expect to work closely with Staff and RUCO and share bill comparison data to identify and address bill impacts that were not anticipated as part of the approved rate design changes *prior* to implementing the three-part rates. Proactively addressing potential billing issues before even introducing those rates to any of our customers will help ensure a smoother transition and mitigate unintended consequences.

Q. Can you provide an example of when the Company could begin implementing its customer education plan?

A. Yes. For illustrative purposes, the following high-level timeline assumes that the Commission issues a decision in this proceeding in June 2016.

- May - June 2016. The Company implements transitional volumetric rates based on the approved revenue requirement in this case.
- Present – December 2016. UNS Electric will collect and analyze billing data to determine if any rate design changes are necessary prior to billing customers under three-part rates. Essentially comparing customers that we have demand data for under both bill designs throughout this time frame.
- May – October 2016. UNS Electric will begin to roll out its customer education plan.
- Beginning no later than November 2016. UNS Electric provides usage and demand data to customers.
- First Quarter 2017. All residential and SGS customers are migrated to three-part rates. UNS Electric also introduces a redesigned bill.

I would like to emphasize that this high level timeline is preliminary and for discussion purposes only.

Q. Does the Company support Staff's position that existing Net Metering customers should be moved to three-part rates?

A. Yes. But, the Company is also supportive of a properly designed volumetric rate being retained for the period of time initially proposed by the Company (expiring May 31, 2035) for the present customers being billed using Net Metering Rider-4, as defined in my Direct Testimony. In my Direct Testimony, I proposed that Net Metering Rider-4 be retained for all service points being billed with the application of Rider-4 (net metered customers) as of June 1, 2015 and all completed, approved and connected service points – where the Company received applications prior to June 1, 2015.

Q. Does the Company support Staff's position that existing net metering riders should <u>not</u> be modified in this proceeding?

A. No. As discussed in the Rebuttal Testimonies of Carmine Tilghman, Craig A. Jones and H. Edwin Overcast, the Company continues to propose the replacement of the existing Net Metering Rider-4 with the revised Net Metering Rider-10, which eliminates the banking of excess generation (rolling over kWh unused to proceeding billing periods) and credits the customer for excess generation at the applicable Renewable Credit Rate.

All customers, including those who meet the requirements for Net Metering Rider-10 as proposed by the Company, would be on the applicable three-part rate approved for their rate class and would not be eligible for any grandfathered two-part rate designs.

IV. <u>RESPONSE TO RUCO'S TESTIMONY.</u>

Q. Have you reviewed RUCO's rate design testimony?

A. Yes.

Q. Please provide your general thoughts on RUCO's rate design proposals.

A. As discussed by RUCO witness Lon Huber in his direct testimony, his rate design proposals were developed based on four core guidelines. One of those guidelines was to establish rates that both provide more accurate price signals to DG customers and <u>minimize the cost shift</u>. We agree that is an important guideline. We also appreciate RUCO's willingness to offer alternatives to the Company's proposed three-part rate design and net metering rider with regards to partial requirement customers. Unfortunately, we find their various rate proposals to be inadequate (and in some instances confusing) in beginning to address the overall issues surrounding today's antiquated rate design. The proposal offered by the Company in its direct filing and

Staff's proposal as modified in our rebuttal position are superior at beginning to address the foundational problems surrounding the present two-part rate design and the needed modernization of rates.

Q. Please address RUCO's proposed changes for DG customers.

A. RUCO proposes the Company provide new DG customers the option of selecting one of three new rates. RUCO's proposed optional "DG TOU Rate" shares some similarities with the Company and Staff's proposed three-part rate design.

> The three components of this rate are 1) A minimum bill 2) A Variable per kWh energy Charge and 3) a variable per kW Demand Charge covering over peak hours during summer months.[7]

One key difference is that RUCO's proposed demand charge would only apply during summer peak periods.[8] UNS Electric does not support applying demand charges only on a seasonal basis. Moreover, the Company does not support *optional* three-part rates for new DG customers; when coupled with retaining the present two-part rate structure as an option for all other Customers.

Q. Does RUCO support the Company's proposals to increase the monthly basic service charge and eliminate the third tier of its inclining block rate structure?

A. No. RUCO recommends a residential monthly basic service charge of $12.26[9], which is far below the Company's proposed $20 basic service charge. RUCO's proposed monthly basic service charge would collect less than 23% of the Company's average fixed cost to

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[7] Direct Testimony of Lon Huber ("Huber"), page 14 lines 3-5.
[8] Huber, page 15 lines 18-20.
[9] Huber Exhibit 2 page 1.

serve a residential customer. RUCO also opposes the elimination of the third tier of the Company's inclining block rate structure.[10]

Q. Do you agree with RUCO's position regarding basic service charges?

A. No. As I stated in the Company's direct filing, electricity use per residential customer fell by nearly 4% between 2012 and 2014[11]. Waiting for growth in electricity consumption to return to historic levels is simply not an option. We cannot continue to rely on volumetric energy sales to recover the vast majority of our fixed costs and earn an appropriate rate of return in an environment of flat to declining energy usage. Such a small increase is simply inadequate to make meaningful progress towards recovery of fixed costs.

Q. Do you agree with RUCO's position that the third rate tier should remain in the Company's inclining block pricing structure?

A. Absolutely not. As discussed in the Direct and Rebuttal Testimonies of Craig A. Jones and the Rebuttal Testimony of H. Edwin Overcast - there is simply no cost justification for these inverted block tiers which results in an inequitable proportion of cost recovery from higher usage and load factor customers. Accordingly, we are unduly penalizing customers with above average usage or that use the system more efficiently.

This is exasperated by the growing level of low or no usage bills we are seeing on the system. One can simply look at our customer billing data. During the calendar year 2014 (the test year used in this case), the Company issued over 23,000 zero usage bills.[12] This represents a 144% increase over "zero bills" issued during the previous test year (12

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[10] Huber, page 7 lines 19-22.
[11] Direct Testimony of David G. Hutchens, page 5 lines 16-20.
[12] Schedule H-5, page 1 (filed May 4, 2015 with the Company's rate application).

months ended June 30, 2012). It is important to note that these billing statistics do not include our low income customers.

V. RESPONSE TO OTHER INTERVENORS.

Q. How would you respond to TASC and Vote Solar accusing UNS Electric of unfairly discriminating against DG customers by proposing a three-part rate with demand charges?

A. That, quite frankly, is wholly unfounded. There is more than ample justification to put DG customers on a separate rate structure, as the Nevada Public Utilities Commission recently ordered. Further, UNS Electric witness H. Edwin Overcast, , provides detailed Rebuttal Testimony as to why separate rate treatment is appropriate for DG customers, why the current rate structure is not capable of reflecting costs for DG customers (as partial requirements customers) and why a separate rate class for DG customers must include demand charges. In short, and especially given the fact that allocating costs on a two-part rate design for DG customers does not provide the right price signals or properly reflect cost recovery or causation, DG customers should be placed on a separate three-part rate with demand charges. Thus UNS Electric strongly disagrees with any assertion that it is discriminatory to recover the cost of serving a partial requirements customer (DG customer) based on how they use the system - and not doing so based on how a full requirements customer uses the system.

Q. Have other public utility commissions found justification to place DG customers in a separate rate class?

A. Yes. I believe I've detailed the Nevada PUC's decision justifying the placement of DG customers (NEM customers) in a separate rate class. The Utah Public Service Commission, in Docket No. 14-035-114, found reason to order, on November 10, 2015, cost of service studies that segregates DG customers from the class they would otherwise participate in and as part of the Utah PSC's examination of the costs and benefits of net metering. Clearly, utility commissions in other states are finding that DG customers impact the grid differently than traditional full requirements customers.

Q. TASC witness Marc Fulmer alleges, on page 13 of his Direct Testimony on Rate Design, that DG customers' bills would more than double under UNS Electric's proposal versus allowing net metering with banking. How do you respond?

A. First, even if this were the case, the question could easily be turned to ask why non-DG customers should continue to subsidize DG customers to the level that DG customers are allowed to cut their bills by 60% or more.

Q. TASC witness Marc Fulmer notes five main concerns regarding UNS Electric's proposed Rider 11 and the RCR. How do you respond to his concerns?

A. We have already addressed these concerns in our Direct and Rebuttal Testimonies but let me address these concerns succinctly here:

1. Rates are not set based on a benefit-cost analysis. The Commission establishes rates based on cost causation and cost-of-service principles using a historical test year with pro forma adjustments. Resource planning typically uses a cost-benefit approach which then serves as a guideline for the Company's long-term resource decisions.

2. We have already discussed how use of the TEP transaction for a small utility-scale project tied to its distribution system is an acceptable proxy to set the RCR. Mr. Fulmer constantly refers to the benefits of DG over utility-scale solar in justifying his argument. Keep in mind that he provides no empirical evidence to support his position, and testifies on behalf of an entity that was supported by

some of the largest DG leasing entities in the nation (all of which are not based in Arizona).

3. It was never the intent of UNS Electric to have an automatic free-flowing variable RCR. We assumed there would always be Staff review and/or Commission approval of any proposed change to the RCR. This argument is a red herring. I believe TASC's main goal is to keep the subsidy as high as possible to benefit its members' business and financial interests, as opposed to what is best for all of UNS Electric's customers.

4. We agree the value of renewable power may not be the same across all resources. We have not tried to use geothermal or wind as a proxy for the RCR for excess energy from DG systems (which are mainly solar PV).

5. It is not the job of the Commission or UNS Electric to preserve the value of federal solar tax credits for TASC members. Keep in mind that in most solar leasing service arrangements, the TASC members obtain the tax benefits (they do not remain with the DG customer). The goal in this case is to establish just and reasonable rates for all of our customers.

Q. Do you have any specific comments relative to the rate design testimony provided by the Arizona Utility Ratepayer Alliance ("AURA")?

A. AURA's direct testimony opposing demand charges and changes to UNS Electric's net metering tariff largely mirrors the arguments Vote Solar and TASC have set forth. I will not repeat myself here in responding to those same arguments. I will, however, reemphasize that UNS Electric is trying to address *all* ratepayer subsidization in this case, by moving rates closer to cost-of-service. In doing so, we understand that some subsidies will always remain and are deemed to be in the overall public interest - like with those provided to low-income customers. Even under UNS Electric's direct case, DG customers would still retain significant subsidies; although the magnitude of those subsidies would be less. So to the extent AURA suggests that UNS Electric's proposals would end subsidization of DG, that claim is simply false.

VI. NET METERING TARIFF.

Q. Briefly summarize the Company's proposed net metering tariff

A. Under UNS Electric's proposed Net Metering Tariff, New DG Customers, among other things, (i) would not be allowed to "bank" or carry-forward excess kilowatt-hours ("kWh") to offset future electricity consumption and (ii) would be compensated for excess energy at the Renewable Credit Rate.[13]

Q. Is the Company willing to consider other net metering proposals or alternative methodologies of valuing excess generation produced by DG customers?

A. Certainly. However, with the exception of RUCO, none of the other parties in this proceeding provided any new net metering proposals or alternatives in their testimony.

Q. Is the current rate case proceeding the proper venue to approve a new net metering tariff?

A. Yes, without question. I would like to point out that UNS Electric and its sister company, TEP, filed applications in March 2015 to update their net metering tariffs.[14] Although both UNS Electric and TEP believe that the Commission can approve a net metering tariff outside of a rate case, several parties who are Intervenors in this rate case, including TASC[15], Vote Solar[16], the Arizona Solar Deployment Alliance[17] and the Arizona Solar

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[13] Equivalent to the most recent utility-scale renewable purchased power agreement connected to the distribution system of Tucson Electric Power.

[14] March 25, 2015, Docket No. E-04204A-15-0099 (UNS Electric) and Docket No. E-01933A-15-0100 (TEP).

[15] TASC brief (May 15, 2015, Docket No. E-01933A-15-0100), page 1 lines 23-24, page 4 lines 5-6.

[16] Vote Solar brief (May 15, 2015, Docket No. E-01933A-15-0100), page 1 lines 23-24, page 2 line 1 and lines 11-24.

Energy Industry[18], argued that a net metering tariff must be approved in a rate case. In light of the procedural posture in that docket, in June 2015, TEP withdrew its net metering application and accelerated the filing of its rate case.[19] Yet these parties have yet to offer any new net metering proposals in this docket.

While we understand Staff's desire to wait for the outcome of the Commission's investigation of the value and cost of DG (Docket No. E-00000J-14-0023)[20], this proceeding is the proper venue for approval of a new net metering tariff for UNS Electric. It is unclear when that proceeding will conclude and what result it will ultimately produce. On the other hand, this rate proceeding will provide sufficient Company specific data and evidence to support the Commission's approval, modification or rejection of UNS Electric's proposed net metering tariff.

Q. Do you have any estimates of how the Company's proposed three-part rate structure and net metering tariff will impact new DG customers?

A. Yes. The table below demonstrates that new DG customers will continue to see significant savings under the Company's proposed three-part rate structure and net metering tariff. The table shows average pre-tax monthly bills for residential full-requirements and DG customers using an average of 500 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh per month.

[17] Arizona Solar Deployment Alliance brief (May 15, 2015, Docket No. E-01933A-15-0100) page 1 line 16.
[18] Association Arizona Solar Energy Industry Association brief (May 18, 2015, Docket No. E-01933A-15-0100) page 2 line 9.
[19] (Notice of Withdrawal of Application filed June 19, 2015, Docket No. E-01933A-15-0100)
[20] Broderick, Executive Summary; Solganick Rate, page 45 lines 16-25.

Monthly Usage	Transitional 2-part Rate: No DG	Proposed 3-part Rate: No DG	Proposed 3-part Rate: DG with Current Net Metering	Proposed 3-part Rate: DG with Proposed Credit for Export
500 kWh per Month				
Average Monthly Bill (pre-tax)	$ 59.73	$ 63.23	$ 27.84	$ 31.03
Bill Savings from 2-part Rate	NA	$ (3.51)	$ 31.89	$ 28.69
Bill Savings from 3-part Rate	NA	NA	$ 35.40	$ 32.20
900 kWh per Month				
Average Monthly Bill (pre-tax)	$ 100.14	$ 100.08	$ 36.01	$ 41.77
Bill Savings from 2-part Rate	NA	$ 0.06	$ 64.13	$ 58.38
Bill Savings from 3-part Rate	NA	NA	$ 64.07	$ 58.31
1,200 kWh per Month				
Average Monthly Bill (pre-tax)	$ 132.20	$ 122.51	$ 42.05	$ 46.10
Bill Savings from 2-part Rate	NA	$ 9.69	$ 90.15	$ 86.10
Bill Savings from 3-part Rate	NA	NA	$ 80.46	$ 76.40
1,500 kWh per Month				
Average Monthly Bill (pre-tax)	$ 166.00	$ 147.20	$ 47.03	$ 52.23
Bill Savings from 2-part Rate	NA	$ 18.81	$ 118.98	$ 113.77
Bill Savings from 3-part Rate	NA	NA	$ 100.17	$ 94.97

It is evident from the comparisons presented in this table that DG customers on the Company's proposed three-part rate structure and net metering tariff will continue to see significant savings when compared to bills under full requirements utility service. For example, a DG customer under the Company's proposed three-part rate and net metering tariff using an average of 900 kWh per month will save $58.38 monthly compared to the Company's proposed transitional full requirements two-part rate and $58.31 compared to the Company's proposed full requirements three-part rate. This represents monthly bill savings of approximately 58% from full requirements service in both cases. The same residential DG customer on the Company's proposed three-part rate and current net metering tariff would save an average of $64.13 and $64.07 per month from the full requirements transitional two-part rate and proposed three-part rate, respectively.

Q. How do the Company's residential three-part rate design and net metering tariff proposals impact fixed cost recovery from DG customers?

A. Not only will new DG customers continue to realize significant monthly savings under the Company's proposal, they will also contribute more toward the fixed costs of serving them. The table below presents fixed cost recovery for the same customer usage levels as the previous table. As this table shows, a new DG customer using an average of 900 kWh per month on a combination of the Company's proposed three-part rate and net metering tariff will contribute all but $6.76 per month to the fixed costs of service. This represents an increase of $28.37 over an equivalent customer on a two-part rate and the current net metering tariff. As I mentioned earlier, this customer will still be saving $58.38 a month on their electric bill while contributing much more to fixed cost recovery.

Even if this same DG customer using 900 kWh per month takes service under the Company's proposed three-part rate and the current net metering tariff, the contribution to fixed costs increases from $15.43 per month to $35.75 per month compared to service under the transitional two-part rate. The contribution to fixed cost recovery increases by $20.32, while the DG customer realizes savings of $64.13 per month on the monthly electric bill.

Monthly Usage	Transitional 2-part Rate: No DG	Transitional 2-part Rate: DG with Current Net Metering	Proposed 3-part Rate: DG with Current Net Metering	Proposed 3-part Rate: DG with Proposed Credit for Export
500 kWh per Month				
Monthly Fixed Cost Recovery	$ 32.18	$ 15.32	$ 27.64	$ 32.30
Average Monthly Bill (pre-tax)	$ 59.73	$ 15.58	$ 27.84	$ 31.03
Unrecovered Fixed Costs	NA	$ 16.86	$ 4.54	$ (0.12)
Monthly Bill Savings	NA	$ 44.15	$ 31.89	$ 28.69
900 kWh per Month				
Monthly Fixed Cost Recovery	$ 50.56	$ 15.43	$ 35.75	$ 43.80
Average Monthly Bill (pre-tax)	$ 100.14	$ 15.77	$ 36.01	$ 41.77
Unrecovered Fixed Costs	NA	$ 35.13	$ 14.81	$ 6.76
Monthly Bill Savings	NA	$ 84.37	$ 64.13	$ 58.38
1,200 kWh per Month				
Monthly Fixed Cost Recovery	$ 66.10	$ 15.63	$ 41.67	$ 52.13
Average Monthly Bill (pre-tax)	$ 132.20	$ 16.12	$ 42.05	$ 46.10
Unrecovered Fixed Costs	NA	$ 50.47	$ 24.43	$ 13.97
Monthly Bill Savings	NA	$ 116.08	$ 90.15	$ 86.10
1,500 kWh per Month				
Monthly Fixed Cost Recovery	$ 83.37	$ 15.84	$ 46.52	$ 59.60
Average Monthly Bill (pre-tax)	$ 166.00	$ 16.49	$ 47.03	$ 52.23
Unrecovered Fixed Costs	NA	$ 67.53	$ 36.86	$ 23.78
Monthly Bill Savings	NA	$ 149.51	$ 118.98	$ 113.77

VII. <u>ECONOMIC DEVELOPMENT RATE.</u>

Q. Briefly describe the Company's proposed Economic Development Rate ("EDR").

A. As a way to help promote economic development in the Company's service territories, UNS Electric proposed to offer discounted rates to new or existing large business customers that meet certain requirements, including a minimum load factor.

Q. Would you like to make any clarifying remarks about the Company's proposed EDR?

A. Yes. The testimonies of Staff[21], RUCO[22], NUCOR[23], Walmart[24] and AIC[25] generally recognize the merits of UNS Electric's EDR; however, some of these parties express concerns about costs being shifted from EDR customers to other customer classes. I would like to emphasize that the any lost non-fuel revenues resulting from discounts provided to customers through the EDR *will be borne by the Company.* UNS Electric will not seek recovery of any lost non-fuel revenues associated with the EDR in future rate case proceedings. The long-term benefits of attracting or retaining large, high load factor customers greatly outweigh the short-term costs.

Q. Other than concerns about cost shifting, were there any other noteworthy issues addressed by the parties?

A. Yes. NUCOR, AURA, and RUCO recommended changes to or expressed additional concerns with the proposed EDR.

Q. Please address NUCOR's proposals with respect to the Company's proposed EDR.

A. NUCOR generally supports the Company's proposed EDR, but believes that the load factor requirement needs clarification. NUCOR recommends the following language:

> The monthly load factor shall be calculated based upon the *customer's billing demand* and monthly energy usage.[26] [Emphasis added]

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[21] Solganick page 52 lines 5-7
[22] Huber page 8, lines 20-23, page 9 lines 1-6.
[23] Direct Testimony of Dr. Jay Zarnikau ("Zarnikau"), page 30, lines 15-18.
[24] Direct Testimony of Gregory W. Tillman ("Tillman"), page 9 lines 8-19.
[25] Direct Testimony of Gary Yaquinto ("Yaquinto"), pages 8-9, lines 1-22.
[26] Zarnikau, page 31, lines 5-6.

Q. Do you agree with NUCOR's recommendation?

A. No. It is the Company's intent to calculate the load factor requirement for the proposed EDR based on projected measured demand. NUCOR's recommendation to change the load factor requirement in the proposed EDR stems from its position (which the Company opposes) that a LPS customer's billing demand should be calculated as the customer's average demand at the time of the 4 system coincident peaks during the preceding year.[27] This approach would generally reduce this customer's billing demand and increase the resulting load factor calculation making it more likely for this customer to meet the threshold.

The Company's proposed EDR is targeted at new or additional load not currently on the UNS Electric system and there is no billing demand on which to base a load factor calculation. For additional loads associated with new customers on the system and relocations to the UNS Electric service area, basing the monthly load factor calculation on a customer's billing demand would actually increase ambiguity in direct opposition to NUCOR's intent.

Also, if NUCOR's recommendation were adopted, existing customers in rate classes other than NUCOR's whose billing demand is calculated as the Company proposes, along with a demand ratchet, would be less likely to meet the threshold for participation. This is because the demand ratchet generally increases billing demand over actual demand and thereby reduces the calculated load factor. The load factor criteria for the EDR should be based on actual expected demand and not be made contingent on the calculation of billing demand for different rate classes.

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[27] Zarnikau, page 31, lines 7-10.

Q. Please summarize RUCO's proposals with respect to the Company's proposed EDR.

A. RUCO believes that the proposed EDR has some merit but safeguards must be built in to protect non-participating ratepayers. RUCO proposes that (1) total program cost be capped at $3 million, (2) customers receiving EDR discounts participate in DSM programs to lower peak demand needs, and (3) a study be conducted into the systemwide and local economic benefits within three years from approval.[28]

Q. Please address RUCO's proposals.

A. First, because the cost shifting issues were addressed earlier neither a program cost cap nor a study of benefits is necessary. UNS Electric will not seek recovery of any lost non-fuel revenues or under-recovered costs associated with the EDR in future rate case proceedings. Second, requiring EDR participants to also participate in DSM programs is also unnecessary. UNS Electric markets DSM programs to all of its customers and sees no need to single out EDR participants for mandatory participation. Also, the 75% minimum load factor requirement for participation in the program assures that the EDR loads added to the system are the type that will encourage increased energy sales without undue pressure on peak demand needs.

Q. What are the concerns expressed by AURA with respect to the Company's proposed EDR?

A. In addition to the cost shifting concerns addressed above, AURA cites issues with the APS AG-1 program in opposition to the proposed EDR. Specifically, AURA cites the following APS AG-1 program issues:[29]

- Any program with a lottery/cap will leave some qualified customers out of the program.

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[28] Huber, page 8, lines 22-23; page 9, lines 1-6.

[29] Direct Testimony of Patrick J. Quinn, page 5, lines 1-11.

- APS has absorbed lost revenues from the original AG-1 pilot but wants full recovery for the next phase.

Q. Do you find merit in any of AURA's concerns?

A. No. AURA's criticism that a decrease in revenues from one class necessarily shifts costs to other classes is unfounded in relation to the Company's proposed EDR. The EDR will apply only to incremental load on the system, not existing load. The Company has not proposed that it will seek recovery of any non-fuel revenues between those collected and those which would have been collected at full rates, but for the EDR, in a future rate case. In fact, in a future rate case test-year revenues will be calculated based on adjusted test-year billing determinants and full retail rates. There would be no revenue shortfall attributable to EDR customers as a result, only increased sales.

As for AURA's comparisons of the proposed EDR with the APS AG-1 program, Mr. Quinn's criticisms are more apt regarding the Company's proposed buy-through rider, Experimental Rider 14, than the proposed EDR. Both the APS AG-1 program and proposed Rider 14 use a lottery process to select participants. The EDR has no such lottery process. EDR applicants will approach UNS Electric if they have plans to initiate or expand business in the Company's service area. The Company will perform due diligence to determine whether the applicants' expected additional loads and increased business activity meet the EDR criteria. If a prospective EDR participant meets the program criteria and is allowed to participate in the EDR program, the additional electric sales will allow the Company to spread its fixed costs over more output making it possible that costs to other customers on the system are reduced. This is a much different impact than the APS AG-1 and proposed Rider 14 type programs where existing customer loads bypass utility generation service and leave the Company and other customers on the system to pick up the unrecovered fixed costs.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit DJD-R-1

UniSource Energy SERVICES

Proposed Customer Education Campaign for "Three-Part" Electric Rates

Summary

UNS Electric, Inc., which provides electric service under the UniSource Energy Services (UES) brand, has not previously used residential rates that include a "demand charge." If the three-part rate plan proposed in the company's most recent application for new rates is approved, the Company plans to promote awareness of its key elements through a comprehensive communications campaign.

The campaign would provide customers with access to information about their individual electric demand and would continue for at least three months before the new rate design is implemented. The campaign also would promote awareness of energy efficiency tips and programs the Company plans to develop to help customers manage their electric demand.

Our campaign would feature the following key messages and components.

Key Messages

- Explanation of the new rates, including how the demand charge is calculated and the potential bill impact based on customers' individual household electric demand.
- The new rates cover the cost of system upgrades UES has made to provide safe, reliable service.
- Customers can reduce their bills through energy efficiency efforts that reduce electric demand.
- Assistance is available for qualifying low-income customers.
- Explanation of the effective date of the three-part rates and the transition plan

Components

Revised Name – We plan to develop a new, more customer-friendly name for the "demand charge" that would be included in an approved three-part rate plan for residential customers. Although the concept of electric demand is well understood in our industry, we are concerned that residential customers may associate the word with its more common definition and conclude their utility is simply "demanding" more money from them. We will use a customer focus group (see below) to evaluate prospective alternatives and select a name that promotes better understanding. Also, we do not plan to refer to our approved residential tariffs as "three-part rates," as that description is intended for use in regulatory dockets.

Customer Focus Groups – We would conduct a focus group with UNSE residential customers to discuss the prospective rate change and evaluate alternate ways to explain three part rates with a demand component. We expect this meeting would help us select a more customer-friendly name for the "demand charge," refine messages for the communications described below and improve the effectiveness of our outreach.

Customer Bills – We plan to add messages to customer bills alerting them to the impending change and inviting them to visit our website (uesaz.com) or call our customer care center for more details. We also plan to provide customers with a reading of their electric demand from the current billing period, calculated as it would be under the approved three-part rate.

Website Content – We would post an extensive explanation of our approved rates on our website, including details about its rollout, answers to anticipated questions and a link to the approved tariff. Additionally, customers who establish online access to their UNS Electric bill could review the electric demand details presented on their bills, as described above. We would provide information about the assistance available for qualifying low-income customers. Finally, we will prepare and post energy efficiency tips designed to help residential customers manage their electric demand to save energy and save money with three-part rates.

Bill Inserts – We would prepare and distribute two bill inserts to alert residential customers to an impending switch to three-part rates. The first bill insert, delivered in the period before the new rate takes effect, would alert customers to the new rate and direct them to review their bill and visit our website for more information. The second bill insert, distributed with the first bill that includes the new rate, would include graphics and instructions intended to help customers identify and understand the new terms and charges on their bill. Both inserts will invite customers to visit uesaz.com or call our customer care center for more information.

Brochure – Information presented on the bill insert and website will be incorporated into a brochure that will be made available upon customer request and at various locations as needed.

Customer Call Center – Our Customer Care team will be trained extensively to answer customer questions about the new three-part rates, including the "demand charge," based on the material prepared for distribution on our website. Customer Service Representatives will review lists of frequently asked questions and keep such material on hand to ensure accurate, consistent responses. Our representatives may mail brochures to customers or refer them to our website to provide additional information.

Plugged In – We plan to promote awareness of the rate in a "special edition" of Plugged In, our quarterly email newsletter for customers. The special edition will include some of the explanatory content posted on our website, presented in an engaging, easy-to-read format. Plugged In also will provide direct links to our website for additional information. This edition of the newsletter will be distributed in the months before the new rate would take effect. The electronic newsletter is distributed to more than 18,000 UNS Electric residential customers.

News Media – We will work to promote fair, accurate local media coverage of the new rates, including through the preparation and distribution of two press releases about their approval and implementation. The first release, distributed in the period before new rates take effect, would announce the planned rollout of the new rate, provide details about its characteristics, promote awareness of energy efficiency and invite reporters to visit our website or contact a media relations representative for more details. The second would announce the beginning of our implementation of new three-part rates while reinforcing points made in the previous release. Our media relations team also will make itself available to answer any news media questions about the new rates.

Education Outreach – We will incorporate information about new three-part rates and tips for reducing electric demand in our energy efficiency workshops, which are conducted periodically with customer groups in communities across our service territory. These forums provide customers with opportunities for one-on-one interaction with our energy efficiency experts, allowing us to answer unique questions and provide personalized advice for saving energy and money with demand-based rates.

Social Media – We would promote awareness of the new three-part rate online through popular social media channels, including Twitter and Facebook. Questions received on both platforms will be addressed promptly by direct message (Twitter) or publicly available posted responses (on the UES Facebook Page) as appropriate.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

UNS ELECTRIC, INC.

REBUTTAL
TESTIMONY AND EXHIBITS

VOLUME 2 of 2

JANUARY 19, 2016

Rebuttal Testimony of

Craig A. Jones

BEFORE THE ARIZONA CORPORATION COMMISSION

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Rebuttal Testimony of

Craig A. Jones

on Behalf of

UNS Electric, Inc.

January 19, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Craig A. Jones and my business address is 88 East Broadway, Tucson, Arizona, 85702.

Q. Did you file Direct Testimony in this proceeding?

A. Yes.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Rebuttal Testimony is filed on behalf of UNS Electric, Inc. ("Company").

Q. In general, what is the Company's concern with certain positions being expressed by many of the parties in this case?

A. Staff and the Company are the only parties in this case that have an interest that goes beyond a specific customer class, a small group of customers or a narrow special interest. The Company's filed case was an attempt to move to a more equitable rate design that recovers revenues in a manner that minimizes or eliminates intra- or inter-class subsidies where possible. In my rebuttal I will be addressing why certain proposals by many of the parties in this case specifically create either larger or additional subsidies for their specific special interest.

Q. What are the primary reasons for updating UNS Electric's rate design?

A. In this proceeding, the Company is attempting to modify its rates to (i) reduce intra-class subsidization where possible, (ii) promote fairness between like situated customers and recover costs from cost causers, (iii) provide rates designed to promote flexibility which will accommodate changing customer usage patterns while still recovering costs, (iv) promote rate structures that encourage the optimal integration of new energy technologies on the electric system, and (v) ensure that the Company continues delivering safe, reliable and affordable electric services for the benefit of all of our customers.

Q. Which Commission Staff and/or Intervenor testimony do you address in your Rebuttal Testimony?

A. I will be addressing the rate design testimony of most witnesses, including Residential Utility Consumers Office ("RUCO"), Arizonans for Electric Choice & Competition ("AECC"), NUCOR, Arizona Community Action Association ("ACAA"), Southwest Energy Efficiency Project ("SWEEP"), Fresh Produce Association of Arizona ("FPAA"), Walmart, the Vote Solar Initiative ("Vote Solar"), The Alliance for Solar Choice ("TASC"), Western Resource Advocates ("WRA") and Arizona Utility Ratepayer Alliance ("AURA"). I will not have any Rebuttal Testimony for AIC or APS other than to say I support most of their positions.

II. <u>REBUTTAL OF STAFF WITNESSES</u>

Q. Would you summarize the Company's positions as it relates to ACC Staff witness, Mr. Solganick's Direct Testimony in this proceeding?

A. Yes. Mr. Solganick provides a summary of his testimony starting on page 2. In that summary he states that; "Rates should be based on costs and recognize the concepts of customer, demand and energy, including time-of-use ("TOU")." The Company agrees with this general concept.

Staff's revenue allocation proposal does not meet the goals the Company intended in its filing, but in the interest of gradualism and movement in the right direction, the Company is willing to adjust the allocation of revenue between the rate classes using Staff's suggestion as a guide.

The Company supports Staff's recommendation to move all residential and small general service ("SGS") customers to a three-part TOU based rate design. However, the Company believes that certain modifications to Staff's rate design proposal are appropriate and I discuss those modifications in my testimony. The Company is also willing to leave the rate design portion of this proceeding open for a specified period of time in order to make any necessary revenue neutral adjustments to rates to address any significant, unintended consequences that may affect our customers or the Company. Additionally, as explained by David Hutchens and Dallas Dukes in their Rebuttal Testimony, the Company believes that customer engagement and education is an important part of implementing any changes to rate design. Staff's suggestion for the CARES customers is reasonable. The Company strongly supports having CARES customers on the same rate as the standard residential rate, with a discount available to qualifying customers in place of having a special rate for the CARES customers. The specific discount will need to be calculated once final rates are calculated. The Company agrees the total amount of the CARES discount should not be reduced, but believes that any increase in the total amount of the discount should be recovered by adjusting the final rates for other customer classes to capture the added discount, or through a process that allows for timely recovery of the additional discounts.

The Company supports eliminating the current Interruptible Power Service ("IPS") rate in the Company's next rate case, assuming the proposed interruptible Rider R-12 is approved.

The Company disagrees with Staff's position that any changes to the existing net metering tariff or waivers of the net metering rules should not be made at this time. UNS Electric witness Carmine Tilghman, addresses this in his rebuttal testimony.

The Company can accept Staff's recommendation relating to the meter upgrade opt-out and agrees they should be moved to the 3-part rate in the same manner as all other customers, simply without a transmitting meter and at a higher cost for the meter reading and billing.

The Company does not support the Buy-Through offering and opposes any variation that results in costs being shifted to either the Company or the other customers. Consistent with Staff's recommendation, the Company believes any such cost shifts be addressed before the Buy-Through offering is considered.

The Company has not proposed pre-approval of lost non-fuel revenue in its Economic Development Rider ("EDR").

The Company accepts Staff's recommendation to remove the fixed charge option relating to the Lost Fixed Cost Recovery ("LFCR") mechanism; however, we believe Staff's position on the rest of the requested changes guarantees the Company will not be able to recover lost non-fuel revenues associated with complying with the Commission's Energy Efficiency ("EE") and REST rules. Although Staff's proposed three-part rate helps reduce revenues lost due to DG, it certainly does not eliminate it. It is the Company's hope that rate design will evolve over time so that the DG component of the LFCR can be eliminated. However, requiring that the DG component of the LFCR be terminated in UNS Electric's next rate case, without an offsetting requirement that rate design changes will provide an opportunity to recover the lost revenues would be much too soon.

Q. Please provide your response to any specific concerns you have with Mr. Solganick's Direct Testimony.

A. On Page 13, line 1-3, Mr. Solganick mentions that as three part-TOU rates become fully implemented, the magnitude of the LFCR will diminish and can be eliminated for DG. I agree with the statement that properly designed three-part rates will move us in that direction. However, a portion of the fixed costs is still being recovered through volumetric rates, therefore the LFCR still has an important purpose.

Q. Does the demand charge, in combination with the increased basic service charge, allow the Company to recover all of its fixed costs?

A. No. The Company agrees both the Company's and Staff's rate design proposals are a good start in addressing appropriate fixed cost recovery, but the proposals still leave a significant percentage of the Company's fixed costs subject to recovery though volumetric rates. And, especially for DG customers, that will mean a continued under-recovery of the fixed costs required to serve the customer. The Company would still need to recover its lost fixed costs through the LFCR until a future rate design change mitigates those lost revenues in order to provide the Company with a reasonable opportunity to earn its allowed return.

Q. Will you explain what fixed costs you believe will remain under-recovered?

A. Yes. While on Page 45, lines 20-23 of Mr. Solganick's Direct Testimony, Staff has reserved the opportunity to change its position in Sur-rebuttal Testimony, it has recommended no changes be made to the net-metering rules (including the allowance of banking), even for new net-metering customers. If the current net-metering provisions are not, a substantial portion of a DG customer's volumetric consumption will continue to be offset by the combination of instantaneous generation offsets and carried forward banking offsets. Many DG customers offset as much as 100% of their energy volumes.

Based on the bill frequency data developed by the Company over 57% of the DG customers' electric bills are for zero kWh. Under the phased in three-part rates proposed by Staff approximately 27% of the Company's fixed costs will remain in the volumetric energy rate. Therefore, this same percentage of fixed costs will remain unrecovered if a DG customer's system is sized to meet 100% of their annual energy needs. On average, this would equate to approximately $160 per year of unrecovered fixed costs for a typical customer on an annual basis. This amount should still be included in the LFCR as lost fixed costs until rate design can be further modified in future rate proceedings.

Q. Mr. Solganick, on Page 14, line 6, has recommended keeping the rate design portion of the rate case open for some specified period of time to allow for tracking of issues and revenues associated with transitioning to three-part rates. Is this a concern for the Company?

A. While the Company normally prefers closure to all rate case related issues sooner rather than later, the implementation of three-part rates for all customers is a special circumstance which may yield results that were unintended. UNS Electric could support keeping the rate design portion of this rate case open for a period of time in the event that significant unintended consequences arise that adversely affect the Company or its residential or SGS customers. For example, the estimation of monthly billing demands will be difficult because of the potential for customer response and the limited data base used to develop that billing determinant. Mr. Dukes describes the Company's outline of the transitional plan being proposed by the Company to establish the particular steps and processes that will need to be executed during the entire transitional period to make this transition to three-part rates as seamless and issue free as possible.

Q. If the Company agrees with keeping the rate design portion of this case open for a limited period of time, what guidelines would the Company want to be included?

A. The Company believes the following constraints or guidelines should be included:

1) The final transition plan should define how long the rate design remains open, and define the types of adjustments that might be needed to address any potential significant unintended consequences or "extreme" impacts of any "vulnerable customers" (as discussed by Staff). All efforts will be made to minimize or avoid "extreme" impacts or the creation of "vulnerable customers", but the possibility should be considered and any resulting changes be kept to a minimum.
2) The intent of any rate design modification should be limited to mitigating these unintended consequences or "extreme" impacts if they are created and should be open to adjustment of billing determinants and or rates in the specified rate classes if it is determined that the information obtained from the original data used to support the initial three-part rates is either under or over stated. These changes should be addressed if the expected revenues (using all available actual data, adjusted for normal weather) is more (or less) than when the initial rates were created. Any changes should be limited to the residential and SGS rate classes, but may be applied to the other customer classes if needed.
3) Any adjustment to the initial rates should be designed to be revenue neutral to the Company (increased or decreased) with the intended recovery level for the class. This could include adjusting the demand charge up or down based on actual kW data generated during the transition period, with appropriate adjustments to the volumetric rates to maintain a neutral impact. Since the three part rate is a TOU rate and will be expanded to all residential and SGS customers, some modification may need to be made to recover peak versus off-peak fuel costs, on a revenue neutral basis. Other options that could be considered would be the creation of a special group of

"vulnerable customers", if necessary, to be in effect until the next rate case, when they would move to the standard rate and any temporary rate class would be eliminated.

Q. On Page 24, lines 3-7, Mr. Solganick recommends revenues be allocated in a specific manner. Does the Company agree with his recommendations?

A. In general, the Company understands Mr. Solganick's recommendation, which included more cost being allocated to the larger rate classes and less to the residential rate class. The Company can appreciate why the recommendation was made and will adjust its allocation to reflect something closer to what Staff recommends than what was originally proposed by the Company. The Company still believes additional costs should be shifted from certain large classes to the residential and SGS rate classes based on the results of the Company's Class Cost of Service Study ("CCOSS") which indicates the large classes are currently subsidizing the residential and SGS rate classes. The Company does understand Staff's concerns that new rates should be designed to reflect appropriate cost allocation while still setting rates that exhibit the principle of gradualism. While there may be a number of ways to get there, they all involve allocating more cost to the residential and SGS classes and less to the larger rate classes.

The Company recalculated the total revenues to reflect the adjusted total revenue requirement recommended by Staff and as shown in Mr. David Lewis' Rebuttal Testimony to reflect an approximate $18.5 million increase in test year revenues. The Company then reallocated the revenue requirement along the lines suggested by Staff. **Exhibit CAJ-R-1** reflects that proposed reallocation of revenue recovery to each of the rate classes including an adjustment to fuel costs as suggested by Staff witness Barbara Keene.

Once the revenue amounts are allocated to each class, a revised revenue proof was developed that uses the same adjusted test year billing determinants used in the Company's Direct Testimony, while maintaining the current rate design. Staff's recommended basic service charges are reflected in the revenue calculations and any remaining revenue requirement for the specific rate class is applied to an increase to the volumetric charges and/or demand charges as appropriate in existing rates. All of these changes were made with consideration to typical customer bill impacts being kept within an acceptable range, knowing that there will always be a few outliers. Billing determinants for on- and off-peak volumes were used to determine on- and off-peak fuel recoveries. A summary of the resulting bill impacts are reflected in **Exhibit CAJ-R-2**.

Q. Do you have concerns with Mr. Solganick's proposed basic service charges and other pre-transition rates as discussed in his Direct Testimony starting at Page 27?

A. The Company believes that modernizing rate design in a manner that allows for more appropriate recovery of fixed costs is an essential component of this rate case and that its proposed residential basic service charge of $20 per month more appropriately implements this goal. However, the Company is willing to accept Staff's recommended basic service charge of $15 per month in conjunction with the three-part rate as a step in the right direction and has used Staff's proposed basic service charge amounts for all classes in its revised revenue proof.

Further, while the Company is still of the opinion that inverted block rates do not reflect appropriate cost recovery; for purposes of the transition rates only, the Company is willing to accept the retention of the existing residential and SGS rate design for the interim period prior to implementing the three-part rates. If for any reason the three-part rate is not approved by the Commission for all residential and SGS customers, the

Company believes its originally proposed basic service charge and the elimination of the third rate tier for the residential class is the superior rate design.

Q. Did you include bill impact calculations of both the transition rates[1] and the proposed three-part rates once they are applied to the customers?

A. Yes. In addition to the summary of bill impacts provided in **Exhibit CAJ-R-2**, I am attaching a version of the H Schedules as **Exhibit CAJ-R-4**, which provide bill impacts for both the transitional rates being proposed herein, and the impact of the new three-part rate based on a sample of customers with demand data when they migrate from the transitional rates to the 3 part rates. This information can be found in Schedule H-4 of my **Exhibit CAJ-R-4**. The bill impacts of the transitional rates are based on unadjusted test year billing determinants. Since we do not have actual demand data for all residential and SGS customers, the impact of the three-part rate is based on data we have from a load research sample group, which is based on the actual usage data of a sample group of customers.

Q. In the Company's direct case, it was proposed that an approximate $9.5 million credit resulting from the Gila River plant be credited to the customers during the first 12-months these new rates were in effect. Did you provide bill impacts reflecting the impact of this credit?

A. Yes. I have attached as **Exhibit CAJ-R-5** a version of the H-4 schedules that duplicate those I provided in **Exhibit CAJ-R-4**, however, this version reflects the $9.5 million credit being returned over a twelve month period as proposed in the Company's Direct Testimony. These calculations can be found in Schedule H-4-FC of my **Exhibit CAJ-R-5**. The results are also summarized on my **Exhibit CAJ-R-2**.

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[1] Transitional rates are defined as the interim two-part rates (reflecting the revenue requirement approved in this case) that will be in effect until residential and SGS customers are transitioned to three-part rates.

Q. Has the Company provided similar information for the SGS rate class using Staff's recommendations?

A. Yes. Staff's recommended basic service charge and the remaining rates as discussed herein are included in both the residential and SGS portions of revised Schedule H included in both **Exhibit CAJ-R-4** and **Exhibit CAJ-R-5**. The specific rates are reflected in Schedule H-3 and the bill impacts are reflected in Schedule H-4. These exhibits include rates and bill impacts for the other classes as well.

Q. Is the Company proposing to add language to the SGS tariff to address the concern expressed by Mr. Solganick at Page 30, lines 6-9 relating to the movement of an SGS customer from the SGS rate class to the medium general service ("MGS") rate class when the customer uses more than 12,000 kWh in two consecutive months?

A. Yes. That provision will be clearly stated in the final SGS tariff filed in compliance with the final order in this proceeding. The provision currently exists in the SGS tariff so this is not a new concept and therefore the Company did not perform any additional studies or analysis. Prior to the last rate case, customers using more than 7,500 kWh in two consecutive months were automatically moved to the next larger class. This was changed to 12,000 kWh or more in the last rate case. Therefore, it is not expected that customers will be impacted by this provision.

The 12,000 kWh threshold is based on the 20 kW minimum demand for the MGS customer class. A customer would need a load factor greater than 80% to consume 12,000 kWh and not reach a 20 kW demand. Because very few customers in the SGS class would maintain an 80% or greater load factor based on the evaluation of like customers in our load research data and most SGS customers did not have meters to measure demand, the Company felt this was a good way to estimate a customer's demand. This allows a reasonable way for the Company to identify customers with usage levels and demand levels that are more appropriate for the larger rate class and move them into that class.

Q. Since most of the Company's non-fuel costs are fixed, would the Company like to see a higher demand charge for these three-part rates than Mr. Solganick has proposed for the residential and SGS rate classes?

A. Yes. On Page 31, lines 5-10, Mr. Solganick recommends using 75 percent of the unit cost for distribution as the guide for creating the demand charge applicable to the residential and SGS rate classes. This leaves a portion of the distribution related costs, all of the transmission related costs and all of the generation related costs to be recovered in volumetric rates. These are all fixed costs being incurred by the Company to provide service to the customer. The Company believes most, if not all, of these costs should also be reflected in any proposed demand charge.

Q. Is the Company willing to accept Staff's proposal for purposes of implementing a "first-step" demand based rate for customer classes that have not traditionally been accustomed to three-part rates?

A. Yes, with a couple of modifications. For purposes of transitioning into the three-part rate, the Company is willing to agree with this limited level of cost recovery in the demand charge. The Company is willing to agree to this, but believes the reduced demand charge provides justification for maintaining the LFCR mechanism in place until a substantial decrease in the volumetrically recovered costs can be addressed in a future rate case. The other key change the Company is proposing would not change Staff's proposed dollar level of demand charge, but does change the specific costs being recovered through that charge. If the demand charge is based on the customer's on-peak demand, then it should recover the related generation costs. Distribution costs should be associated with the non-coincident peak a customer generates, which would be more appropriately recovered using the customer's individual peak, regardless of when that peak occurs. Since the generation costs are higher than the distribution costs, the initial charge may need to be based on a lower percentage of the total generation unit costs calculated in the CCOSS (say 50%), but that level would be based on calculating a final demand charge that approximates the one proposed by Staff, something close to $5.00 per kW for residential customers in this rate case.

Q. What other modification would the Company propose to Staff's version of the three-part rate?

A. As three-part rates were evaluated, some concerns were brought up relating to what we described as "outlier bills." These bills reflect months where usage habits could cause the bill to be higher when changing from a two-part rate to a three-part rate. The Company is proposing to add a transitional or temporary mitigation adjustment to the calculation of the demand component of the rate. This mitigation adjustment would be built into the billing process and would review each customer's billing determinants before the bill is issued. If the customer's site load and measured kW for the billing period result in a load factor of less than 15%, an algorithm in the billing system will use a billing demand that is lower than the measured demand. The billing demand would be calculated by assuming the site load was utilized at a 15% load factor. This reduces the demand related charges for all customers who have a load factor of less than 15%. Based on the review of our load research group of customers, this moderates the bill impact for nearly all customers. When comparing bills under the two-part rate and a three-part rate on a revenue neutral basis, residential customers generally see bill increases of no more than 3.2%, with over 90% of the customers seeing less than a 13.6% increase. Overall, slightly more than 25% of the customers would see a bill decrease when moving to a three-part rate on a revenue neutral basis.

Q. Would you provide an example of how this mitigation adjustment will work?

A. Yes. First, the definition of Load Factor (LF) is average load divided by maximum load and in formula form for the billing period it is:

LF = site load for billing period in kWh / (billing days * 24 hours/day * kW (measured))

The mitigation adjustment uses this calculation to test for the following:

If LF $\geq$ 15%, no adjustment to the bill calculation,
If LF < 15%, billed kW adjusted to match a LF of 15%

Let's compare the billed demand under two scenarios: 1) total site load of 1,000 kWh in one month with 8 kW of load and 2) total site load of 1,000 kWh in another month, but the customer used a welder one day and produced 14 kW of load, the same kWh usage, but nearly double the system capacity or KW. The system would test month number 1:

LF = 1000 kWh / (30 days * 24 hours/day * 8 kW), or a LF of 17.36%

The first bill would use the measured demand amount of 8 kW and calculate the bill. This is the way nearly 85% of the bills will be calculated. The load factor for the second scenario would be:

LF = 1000 kWh / (30 days * 24 hours/day * 14 kW), or a LF of 9.92%

In this case the system will recognize the LF is below 15% and revert to the algorithm to determine the "billed" demand for this customer in this one month. This time the calculation is done in reverse:

> LF (assumed to be 15%) = 1000 kWh / (30 days * 24 hours/day * x kW), solving for x, gives you a "billed" kW of 9.26 kW

Since the customer's measured demand was 14 kW, but the load factor was less than 15%, the billed demand was adjusted to 9.26 kW. Assuming a $5 per kW demand charge, the customer's bill was reduced by approximately $24. Larger load factor customers save with three-part rates so no adjustment was proposed for the larger customers. The test level of a 15% LF was determined by calculating bills for all customers in the load research group and identifying the level that provided a fair level of protection from large dollar bill impacts.

Q. Does the Company wish to leave this mitigation adjustment in place permanently?

A. No. This proposal was designed to complement the other provisions being proposed with the implementation of three-part rates to mitigate some of the significant bill impacts that may occur, thus allowing the customers to acclimate to the new rate design and adjust their individual usage habits or add new technologies that will allow them to lower their energy costs. It is the Company's position that this mitigation adjustment would be phased out as soon as possible, but no later than the implementation date of the next rate case.

Q. Mr. Solganick has requested the Company provide additional information relating to the proposed basic service charge split for the MGS and LGS rate classes. Will you explain the difference?

A. Yes. In response to Mr. Solganick's request at Page 33, line 20 of his Direct Testimony the Company reviewed its meter cost data. In total, the LGS class will contain only 17 customers. About 40% of that class is moving from the former Large Power Service ("LPS") class. The LPS class required power factor equipment to be in place. Therefore many in the class have higher cost customer related equipment. Additionally, as mentioned in his testimony, the unit cost calculated in the CCOSS for the MGS and LGS rate classes combined is approximately \$265 per month. Since approximately 40% of the LGS customers are moving from a rate class that reflected a \$1,200 monthly basic service charge and 60% were the largest customers in a class with a \$50 basic service charge, the Company felt a \$300 per month basic service charge is a more gradual change in the rate. The MGS customers were formerly paying a \$50 basic service charge therefore a move to a \$100 per month basic service charge seemed reasonable. The Company believes its proposed basic service charges are reasonable and requests that they be approved.

Q. On Page 34, line 8, Mr. Solganick also requests that the Company provide additional support for creating a 750 kW maximum demand amount for an MGS customer to remain on the MGS rate and the proposal that the customer be moved to LGS the month after they attain the 750 kW level. Will you provide additional explanation for the Company's proposed maximum demand amount for this rate class?

A. Yes. The Company did an extensive evaluation of how the various minimum and maximum demand amounts would impact customer bills. The main purpose of creating the additional MGS rate class was to establish classes of service that contained a more homogeneous grouping of customers based on similar usage habits. By establishing minimum and maximum demand amounts for the various classes, this goal is met. While an individual customer's load factor and usage habits will determine what the bill impact will be, the Company reviewed impacts for all migrating customers and settled on a range that did the best job of mitigating those impacts.

In order to respond to Staff's concern the Company queried all anticipated MGS customers with a demand in excess of 400 kW during the test year but did not otherwise reach the 750 kW level (had they reached 750 kW they were already assumed to be included in the LGS rate class). A total of thirty-one customers were identified. To determine the bill impact that would result if any of these customers reached the 750 kW level in a single month, and then returned to their normal (lower than 750 kW per month) test year usage, the first month of the 12-month calculation was reset at 750 kW to determine what the resulting bill would have been. The impact resulted in a bill, during the modeled year, increasing in a range from a 0.3% and 1.1% with no other rate changes. Therefore, it is the Company's opinion that, at most, thirty-one customers could be affected by this provision with a maximum bill impact of less than 1%. In reality, based on our current customers, the level the Company chooses will most likely result in no impact to the customers in this class unless they modify their usage habits substantially and at that point they should change rate classes anyway.

Q. At the bottom of Page 35 of Mr. Solganick's testimony, he requests additional support of the 450 kW minimum demand that the Company is proposing to be included in its LGS rate. Please provide additional information in support of this proposal.

A. Throughout this case, the Company has attempted to propose rate design and conditions relating to providing services to our customers that move toward treating like-situated customers in a similar manner. With that in mind, the Company began looking at the creation of the new service class. Most of the former LGS customers were moved to the MGS class, with a few of the largest former LGS customers and all of the non-69 kV former LPS customers moving into a single rate class, the new LGS class. To maintain a class designed for a homogeneous group of customers, conditions had to be placed on the rate class to maintain that homogeneity. We considered many different caps for the MGS class and floors for the LGS class with the goal of maintaining the homogeneity of the LGS rate class. The MGS cap of 750 kW and the LGS minimum billed demand of 450 kW met this goal. For those customers the Company anticipates moving into the new LGS rate class, their minimum demand was 486 kW. This is above the proposed minimum, thereby confirming that only customers who should be in this class are included and they will not be affected by the 450 kW floor. Also, all of the largest LGS customers that the Company projected would remain in the new LGS class had measured demand of greater than 750 kW during the test year. The ratchet will result in all anticipated LGS customers having a billed demand greater than 450 kW (75% of 750 kW = 563 kW). Therefore, the minimum demand will not impact any of the anticipated LGS customers unless their usage habits change. If that happens, they should move to the MGS class any way.

Q. Staff requested justification for the rates being proposed for the School TOU rates on Page 37, line 6 of Mr. Solganick's Direct Testimony. Please explain the Company's reasoning for the proposed rates.

A. After its prior rate case, the Company worked with Staff and school representatives to create a School TOU rate. It was part of the final order in the rate case and was not originally proposed in the Company's filing. The Company worked with Staff to create a rate that generally modeled the peak periods and design of a school rate that was in place for APS. This tariff was being designed outside of a rate case and the Company was concerned that the final rate be revenue neutral if possible. The peak period is not based on the Company's true peak period and is purely designed to accommodate the needs of a school schedule. As the rates were created after the last case, Staff suggested the rates be slightly higher since the on-peak period was shorter to protect the revenue neutral theory. There have been no customers placed on the tariff so the Company simply used the originally established guidelines to create the new tariff and increased the components proportionally to mirror the standard TOU rate proposed by the Company.

Q. **Does the wattage charge being proposed by the Company in its lighting rate include the ballast load for purposes of determining which wattage the customer will pay?**

A. No. The current wattage charge in the Company's lighting rate is limited to the wattage of the bulb installed. The Company's believes the lighting program today under recovers its fully loaded cost. The Company's intentions prior to the next case is to conduct a cost study of the current program and will have more information on LED lighting to reflect additional cost recovery in the lighting tariff.

Q. **Does the Company agree with Staff's recommendation as it relates to the CARES customers?**

A. Yes. In order to provide CARES customers with the same discount level they currently receive, the Company must provide discounts totaling approximately $1 million to support Staff's position.

In the test year, approximately $600,000 of CARES discounts were allocated other customer classes. This is the discount realized by an average of approximately 6,200 CARES customers during the test year. The additional discount these CARES customers are benefiting from is clouded in the numbers of the revenue proof. Since these CARES customers generate nearly 75,000 bills each year and every bill is discounted by the difference between the residential basic service charge of $10.00 per month and the

CARES customers current basic service charge of $4.90 per month, or a difference of $5.10 per bill, the total additional discount realized by these CARES customers is 75,000 times $5.10 or approximately $380,000 per year. When combined with the approximate $600,000 per year of direct percentage and flat rate discounts realized during the test year, this reaches nearly $1 million of benefits the current CARES customers receive. The method proposed by Staff will need to provide credits reaching nearly $1 million to keep the overall discount about the same as was realized under the rates originally proposed by the Company. This issue will be discussed further when I address the Direct Testimony submitted by ACAA witness Cynthia Zwick.

Staff's position is that CARES customers' bills should be calculated in the same manner as a standard residential customer. This would include each of the rate components, including the basic customer charge, demand charge, volumetric charges and riders. The discount approved by the Commission should be applied to that bill. The Company agrees with this position. UNS Electric supports offering a discount to the bills of low income customer qualifying for the program, but also sending accurate price signals. By moving to a consistent rate design, they receive the same pricing signal as a standard residential customer.

The Company proposes that the CARES discount be applied as a percentage reduction that limits the bill impact on CARES customers to an increase that is in the same general dollar amount as the standard residential customer. Although a single percentage amount would be preferred for all CARES customers, bill impacts may require a different percentage discount for each category of CARES customers (frozen CARES-Medical and Standard CARES customers). If that is the result of this proceeding, future rate cases should seek to move the different percentage discounts to a single discount amount for all CARES customers. And like the current CARES tariffs, once a specific kWh usage has been reached for the month, a fixed credit will be applied instead of the percentage credit. There is no cost basis for maintaining multiple levels of discounts for like situated customers just because some bills were heavily discounted. My **Exhibit CAJ-R-2** also shows the impacts of the transitional rates on the CARES customer using a typical monthly amount of kWh. The monthly dollar change for a typical customer was limited to an amount that was either near or below a standard residential customers monthly bill change.

Q. Please summarize what the Company is proposing for the CARES customers?

A. In summary, the CARES customers should be served under the standard rate they would otherwise qualify for, and if they meet the specified income qualifications, a standard percentage discount would be applied to their total bill before taxes. The Company proposed to keep the current income qualification level, which is 150% of the Federal Poverty level. The percentage discount would be calculated once final rates are decided in this proceeding and will be designed to provide the same benefit, on average, the current CARES customers receive. The total discount would equate to approximately $1 million, in total, for the entire CARES class (both frozen and open) and will be recovered by adding the $1 million to the revenue requirements of the other rate classes.

Q. Mr. Solganick requested the Company provide additional information to verify that the existing IPS customers are subsidized by the LGS customers?

A. First, on Page 52, line 7 of my filed Direct Testimony I do mention that the IPS customer class is subsidized, and I suppose I should have emphasized they are subsidized by all customers not just other LGS customers. To verify that the IPS customers are subsidized is a simple matter of calculating a bill using the existing IPS rate and the existing LGS rate with the same billing determinants. I have provided this calculation as **Exhibit CAJ-R-3**. Referring to this exhibit, you can see, the difference between what the IPS customer pays and what the same level of usage generates as an LGS customer is approximately $2,000 for this one month's bill. It is the Company's opinion that since no interruption has occurred during the test year or any recent years prior to the test year, the level of service these IPS customers are receiving is the same quality as the firm LGS customers. Therefore they are receiving the same level of service for $2,000 less in this example. That means the IPS savings are being shifted to all other rate payers in order to recover the overall revenue requirement authorized for the Company. This type of subsidy is what the Company is trying to either reduce or eliminate with the proposals being made in this proceeding.

Q. Aside from this clarification do you have any additional concerns with Staff's recommendation as it relates to the Interruptible service rate?

A. No. Staff accepted the Company's proposed new Interruptible Rider-12 and has not opposed our freezing the current IPS rate, thereby limiting it to the currently existing customers on this rate. Staff has also recommended the existing IPS tariff be eliminated in the Company's next rate case. The Company agrees to do this in the next rate case.

Q. Do you accept Mr. Solganick's recommendations as it relates to the Service Fee Charges discussed on Pages 46 and 47 and the AMI Opt-out charge discussed on page 48 and 49 of his Direct Testimony?

A. Yes. We will work with Staff to finalize the specific wording necessary to convey the recommendations made, including language to modify how we will charge for requests from the residential and SGS rate classes for interval data during the transition period while customers are trying to figure out how the new three-part rates will be affecting them.

Q. It does not appear that Staff agrees with many of the proposed changes the Company wishes to make to the LFCR mechanism. Would you like to address some of Staff's concerns?

A. Yes. It appears the only change proposed by the Company, relating to the LFCR, that Staff found acceptable is the elimination of the fixed charge option. No customers have participated in the fixed charge option to date and we wish to eliminate it. Staff appears to oppose the Company's other proposals to amend the LFCR. Additionally, for some reason Staff believes the LFCR related lost revenues associated with DG will go away with the first step of proposing its initial demand charge in a three-part rate, thereby justifying the elimination of DG related LFCR recoveries. The Company disagrees with this concept and believes the Staff should reconsider this position.

Q. Why do you believe Staff is wrong as it relates to the LFCR related changes requested by the Company?

A. The first item Staff disagrees with is the Company's proposal to blend the EE and DG percentages that are currently shown as separate entries on the customer's bill into a single adjustment. The primary reason the Company proposed this change is to eliminate confusion and simplify the bill the customer receives. The change does not impact the total amount charged to the customer and it would be one step in the direction of making the bill more customer friendly.

The second item opposed by Staff is the inclusion of fixed generation costs in the LFCR rates. Staff seems to believe the Company has some level of flexibility "to adjust its purchases to match its short-term needs" (Solganick; Page 55, line 4). The Company does not disagree that it can adjust its "purchased" generation if sales change. Adjusting costs associated with "purchased" generation will automatically be reflected in the PPFAC rates and any savings (or costs) will be passed on to the customers as a revised fuel cost.

The Company believes the PPFAC addresses these avoided (or additional) costs in a timely and accurate manner, but does not believe they have anything to do with the LFCR. Staff has provided no evidence or explanation as to how the Company's lost fixed costs are addressed by changes in the PPFAC, when PPFAC revenues are specifically excluded from the LFCR calculations.

Adjustments in "purchased" fuel (generation capacity or otherwise) have no impact on our ability to recover fixed costs that are included in non-fuel related base rates. When rates are created, the fixed cost associated with the Company owned generation facilities and related equipment is included in the costs allocated to the various rate classes. Those costs are then spread over an approved number of billing determinants, either demand or volumetric, depending on the class. Once in the rates, the Company must realize that level of billing determinants in all future years (until rates are reset in a future rate case) to fully recover its fixed cost. Absent a rate case, there is no way to realign the recovery of those lost fixed costs if reduced by DG or EE. The Company does recognize that some level of those costs could be recovered if sales growth returns to a level that sufficiently offsets the revenues lost through DG and EE.

For UNSE, adjusted test year sales in the last rate case were approximately 1,741 GWh for the 12 months ending June 30, 2012. The adjusted test year sales in this case were approximately 1,601 GWh for the 12 months ending December 31, 2014, an approximate decrease of 8%. Even though this reduction is more than DG and EE related reductions, this very clearly shows that during the last 2 ½ years, sales have not increased sufficiently to offset DG or EE losses. The LFCR specifically identifies lost fixed costs associated directly with DG and EE sales reductions and the Company believes it should be allowed to recover those Commission-mandated losses which include fixed generation costs.

The LFCR was supported by all parties in recognition of the fact that recovery of fixed costs are reduced as the result of Commission mandates and that it was fair that a form of recovery be established to offset that. The Company believes generation costs should be included in this amount.

Q. Staff also opposes changing the LFCR provision that only allows recovery of 50% of the non-generation related portion of any demand charge. Why do you believe this provision inappropriately reduces the amount of lost fixed cost revenue the Company should be allowed to recover?

A. The Company believes that this is another arbitrary adjustment to reduce the amount of Commission-mandated lost fixed costs the Company is able to recover. Not only are fixed costs being recovered through the demand charge being reduced by the generation component included in the demand charge, the remaining components in the demand charge are further reduced by 50%.

A simple example may help explain why this is important. Assume a demand charge is $13 per kW. If the generation component is $3, then $10 is left. The current LFCR states the company is only allowed to recover 50% of that. This leaves the LFCR recovering $5 of the $13 demand charge. For every unit of demand the customer avoids due to DG or EE, the Company loses $13 of fixed cost recovery, but is only able to recover $5, or 38%.

As you can see, this leaves a very small portion of the fixed costs assigned to the demand rate to be recovered in the LFCR. Additionally, this arbitrary reduction only applies to verifiable reductions to demand amounts. Specifically, those demand units identified and verified as relating to either demand based EE programs or DG demand reductions coincident with the customers' billing peak. These parameters already create a quantification of lost demand revenues that is very narrowly defined and limited to specifically lost demand revenues resulting from DG and EE mandated activity. Why reduce the lost fixed cost recoveries associated with these vary narrowly defined demand losses by another 50%? In the Company's opinion this is an unfair reduction and should be eliminated.

The Company does recognize that some level of those costs could be recovered if the economy returns and the sales start to increase sufficiently to offset the kW revenues lost through DG and EE, but that has not happened to date. UNS Electric's adjusted test year kW sales in the last rate case were approximately 2.033 GW for the 12 months ending June 30, 2012. The adjusted test year kW sales in this case were approximately 1.880 GW for the 12 months ending December 31, 2014, an approximate decrease of 7.5%. Again, even though this is more than EE and DG related reductions, this very clearly shows that during the last 2 ½ years, sales have not increased sufficiently to offset DG or EE losses.

Based on known and measurable historical data there is no reason to reduce the level of lost fixed cost identified as being related to Commission mandated DG and EE related activity. Therefore the Company recommends that the Commission recognize these losses and add generation related losses and all demand related losses back into the LFCR rates for future recovery of lost fixed costs.

Q. Mr. Solganick also mentions the possibility of double recovering certain lost fixed costs if generation is added back to the LFCR rate and the EDR is approved. Do you agree with this proposal?

A. No. First, as mentioned above, the Company has experienced a loss in sales of over 140 GWh since the last test year. While the Company hopes this trend is not repeated between this rate case and the next, the economy has not made any substantial improvement in this service territory. The rates paid by any qualifying EDR customer would be at the reduced rates specified in the EDR and would be incremental only until the next rate case at those reduced rates. If there is a concern about double recovery of generation costs, the Company would not be opposed to excluding EDR related revenues from any LFCR calculation until the next rate case. The Company only desires to recover quantifiable lost fixed costs associated with Commission mandated DG and EE losses.

Q. Should the LFCR cap be increased from 1% to 2%?

A. Yes. If the Commission accepts the Company's other LFCR recommendations it should increase the cap. The cap may not be reached and if it is not, then the change will have no impact on customers. Even if the Commission does not accept all of the Company's proposals, changing the cap, based on historical LFCR filings, will not have an impact on the customers.

Q. Mr. Solganick also opposes the recovering any lost fixed costs generated by the "Buy-Through" rate in the LFCR. Is that a concern to the Company?

A. Yes, assuming the "Buy-Through" rate is approved in a form that creates lost fixed cost revenue. If the "Buy-Through" rate is denied by the Commission or if the design of the tariff is such that the participating customers pay their full retail rate then no lost fixed cost recoveries will be necessary and there will be no need for this provision to be added to the LFCR. Staff has indicated they have no specific objection to the "Buy-Through" rate as long as no costs are shifted to other customers. As long as that statement is true and includes provisions that costs not be shifted to the Company, the provision may not be needed.

If the Commission approves any variation of the "Buy-Through" rate that results in a reduced (lost) level of fixed cost recovery, lost fixed costs should be eligible for recovery.

The Company would consider other proposals, but the Lost Fixed Cost Recovery mechanism seems to be the most appropriate method to recover any losses.

Q. What is your understanding of the recommendation on Page 57 of Mr. Solganick's Direct Testimony and on Page 10 of Mr. Broderick's Direct Testimony stating that the DG portion of the lost fixed cost included for recovery in the LFCR should be excluded from loss calculations after the effective date of the proposed three-part rates in this proceeding and eliminated from the LFCR altogether with the next rate case?

A. The Company believes both Staff witnesses misunderstand the level of lost revenues DG will still be generating, even if the three-part rate being proposed by Staff and accepted by the Company is put into effect. The Company does agree that a three-part rate will help mitigate some of the losses associated with DG, but it in no way eliminates them. Staff has recommended a relatively low demand charge be initially established for this three-part rate in order to gradually bring customers into a more modern rate design environment. The Company agrees with this strategy. From the standpoint of gradualism, this makes sense; but a lower demand charge means a higher volumetric charge. And as long as solar production reduces overall retail volumes sold, the recovery of fixed costs is avoided. If in future rate cases the demand charge is increased sufficiently the DG related losses will automatically be reduced and when the rates reduce those losses to an insignificant number, then a consideration of removing them would be appropriate. Until then, the calculation of losses should be specified in the LFCR POA, either with the Company's proposed changes or with the existing methods. If the rate design reduces those losses, the amount requested in the LFCR relating to DG will automatically be reduced as part of these calculations. This is a good thing for both other customers and for the Company, but there is no reason to specify an end date until the rate design supports it.

Q. In the above response you refer to the LFCR POA. Will these changes require a revised POA be submitted once the details of these rate design and LFCR issues are resolved?

A. Yes. The Company has proposed a revised LFCR POA reflecting its proposed changes, but any modification to the Company's original proposal could require further revisions to the POA which might include language to address the transition rates and final three-part rates as separate calculations in future LFCR filings. The revised POA could be submitted with the Company's compliance filing that will be submitted at the conclusion of this proceeding.

Q. Do you wish to address any issues expressed by Staff witness Van Epps?

A. Yes. Mr. Van Epps' testimony is primarily expressing a request for either additional or modified Plan(s) of Administration for the DSM, REST and Transmission Cost Adjustor ("TCA"). Company witnesses Ms. Richardson-Smith and Mr. Tilghman will address the issues with submitting the DSM and REST POAs as part of this proceeding. I will discuss the TCA POA below.

Staff's request relating to the TCA POA is designed to clarify and document changes already discussed by Staff and the Company in the Company's last TCA filing. The Company does not object to the changes and has attached an updated TCA POA as **Exhibit CAJ-R-6**.

III. RESPONSE TO RUCO

Q. What concerns does the Company have with the positions expressed by RUCO witness Mr. Huber?

A. The primary concern the Company has with Mr. Huber's recommendations relate to his objection to increasing the basic service charge. The Company dedicated a substantial amount of its Direct Testimony to explaining and supporting its proposed basic service charge. The Company's CCOSS supported a greater charge. RUCO recommended a residential monthly basic service charge of $12.26 for standard customers and a $14 and $13.63 monthly basic service charge for the TOU rate classes without any specific analysis supporting the lower numbers other than RUCO's concern for gradualism. The data supports at least the $15 monthly charge for the residential class proposed by Staff in conjunction with a three-part rate structure. The Company's witness, Mr. Ed Overcast discusses this in more depth.

Q. What is the Company's position on RUCO's proposals for DG related rates?

A. RUCO has suggested a variety of options for DG customers, including a minimum bill, a demand based rate, standard rate with a declining renewable credit rate, and a no export option. The Company believes Staff's recommended three-part TOU rate is the superior rate for all customers, including DG customers. It is a cost based and cost effective proposal. As proposed, none of RUCO's options adequately address the cost shifts associated with net metering. However, a number of RUCO's proposals could be modified to recover a greater portion of the fixed system costs necessary to serve net metering customers. In addition, a demand rate correlated to system peak does not necessarily assist the Company is recovering its fixed delivery costs since those costs do not change from one period to the next. This rate design approach would only make sense for the recovery of fixed generation costs.

IV. RESPONSE TO AECC

Q. AECC witness Mr. Higgins offered both support for certain Company proposals and a couple of concerns. Do you wish to address those concerns?

A. Yes. Mr. Higgins was generally supportive of the Company's proposed revenue allocations, but he did not like the level of subsidy shown by the CCOSS and thinks the ultimate revenue allocation between the rate classes that left certain inter-class subsidies unaddressed. On Page 4 of his Direct Testimony, he suggests that any reduction in overall revenue requirement be apportioned to the various rate classes based on a 50/50 split, with one half going to subsidy paying classes and the other half going to subsidy receiving classes. The Company has chosen to adjust the revenue requirement allocation between the rate classes in a manner more reflective of Staff's proposal as shown in **Exhibit CAJ-R-1**. While the final revenue allocation proposed by the Company does not add the level of cost to the largest rate classes suggested by Staff, it does move further in that direction than what was originally proposed by the Company. The Company believes the allocation proposed in this rebuttal testimony is a fair compromise. More movement is warranted and if the CCOSS results in future rate cases supports it, we will continue to make proposals that will reduce this subsidy.

Q. Mr. Higgins, on Page 4 of his Direct Testimony, also recommended that approximately $908,000 of the reduction allocated to the subsidy-paying classes be held back and used to fund the "Buy-Through" (Experimental Rider 14) rate. Does the Company's proposal allow for this recommendation?

A. No. As discussed in my Direct Testimony and later in this testimony, the Company does not support the approval of the "Buy-Through" Rider. Mr. Higgins' suggestion still results in costs to serve those participating customers to be shifted to remaining customers.

V. RESPONSE TO NUCOR

Q. Mr. Zarnikau submitted Direct Testimony on behalf of NUCOR who is a customer of the Company. Do you have any concerns with the suggested changes he has offered in that testimony?

A. Yes I do. The specific objections to NUCOR's proposals are as follows:

1. **NUCOR does not agree with the way the LPS demand rates are designed.** Demand rates should be a combination of costs being recovered based on the system's non-coincident peak and its coincident peak depending on the cost. Further review of how these costs should be recovered may justify more costs being allocated to the off-peak period instead of less as NUCOR proposes, especially for the largest TOU rate class. Since the current differential was agreed to in the last rate case, the Company believes its current design is appropriate and is willing to leave the differential as it is in current rates for purposes of this rate case.
2. **NUCOR does not agree with reducing the on and off peak price differential.** The Company does not currently incur a substantial difference in the marginal cost of energy purchased on peak, versus off-peak. Therefore, the Company believes its proposed differential between on- and off-peak fuel prices is appropriate. In fact, the actual difference in marginal costs associated with the on- and off-peak period may justify a smaller differential. But for purposes of this case, the Company is willing to leave the differential as proposed in the Company's direct rate case.
3. **NUCOR believes the Interruptible rate should be redesigned.**

   The interruptible rate has not provided benefit to the system or other rate payers in the last few years and the capacity needs of the Company do not justify offering any discount for the interruptible service currently being provided. The Company has proposed a new Interruptible Rider and proposed to freeze the current IPS rate. Staff has agreed to this proposal. Without a need to interrupt during the peak load timeframe, the Company does not see any value in creating a special deal that allows for a discount if the customer can interrupt during the off-peak period.

NUCOR wants the load factor associated with the EDR to be calculated based on the customer's billing demand and monthly usage. The Company's proposal simply states the customer must have a load factor of greater than 75% to qualify. The Company proposed this provision to encourage only the customers with the highest load factor to participate. Changing the parameters in the tariff may result in less efficient use of the system and may result in capacity issues. Therefore the Company does not believe that any changes to the proposed tariff are necessary or appropriate.

The Company has put together a set of proposals in its rate case that are designed to offer a balanced allocation of costs and the recovery of those costs. The Company has suggested many changes to its current tariffs and overall rate design in an attempt to reduce intra- and inter-class subsidies. As circumstances change, many specialty provisions are created that tend to favor a specific group or class of customers. The Company prefers to minimize the occurrence of situations where customers receive special treatment. Some of these situations are warranted and in those cases the Company would like to minimize the subsidies where possible. The Company has attempted to create a CCOSS that fairly allocates costs between the general rate classes. It understands that occasionally specific groups may need special attention, such as low income customers. That being said, the Company does not wish to encourage situations where customers seek special treatment to make their rates lower at the expense of other customers.

Staff is tasked with creating a fair set of rates that are justified and non-discriminatory. Staff is also tasked with creating rates that allow the Company a reasonable opportunity to realize its approved return on the plant it has in service to provide energy and other services to its customers. The Company has proposed a revenue requirement it believes is representative of the amount necessary to achieve that goal. It has also calculated a CCOSS that should be used as a guide to allocate costs to each rate class. With that as the starting point, the Commission must review all of the evidence in the record and decide if it agrees with any individual party or any combination of parties based on that evidence. As that evidence is considered, some thought must be given to the specific parties who express a special interest. This includes the low income customers, solar providers, specific customers such as NUCOR, WalMart, the Fresh Produce customers, and other groups like SWEEP and WRA. All of these groups want the general rate design and cost recovery allocation to benefit their individual interests. The Commission must decide if creating a group of "winners" at the expense of the "losers" (i.e. remaining customers) is in the best interest of the customer base, the service territory or even the State of Arizona. If the Commission believes that allowing a subsidy or special rate design that creates "winners" is in the best interest of their constituents, then they will do so. NUCOR's proposals seem to fall into this special interest category.

The Company recognizes NUCOR is an important customer and as such has proposed a reduced increase to its rate class and has agreed to special provisions that benefitted them in the past. However, in this case the Company does not believe special consideration is justified beyond what was proposed in its original filing, along with any adjustments made to accommodate Staff's recommendations.

As such the Company believes that it is not appropriate or fair to modify the rates and cost allocation for NUCOR.

Q. NUCOR has suggested substantial changes be applied to how the customers in this LPS-TOU rate class are billed demand related charges starting on Page 8, line 4 of Mr. Zarnikau's testimony. Do you agree with his recommended changes?

A. No. As NUCOR's witness states and as Company rebuttal witness Mr. Overcast states, the generation and transmission costs should be based on the capacity needs the customer contributes to the system peak. Even though NUCOR states that the existing tariffs are poorly designed, they do exactly what he suggests. The only concern Mr. Zarnikau has expressed relates to how the demand charge is calculated and the test to determine how the customer should be billed. The peak period demand calculation already reflect his theory and an alternate test allows for one-half of the off peak demand to be used in calculating a customer's bill. This alternate is designed to allow some benefit to customers who peak during the system's off peak period. Billing determinants are based on this theory and have been the guideline in place for this class in all recent rate cases. With only four customers in the LPS rate class this cost allocation and method of recovery is reasonable. NUCOR fails to recognize that through the cost of service process a level of costs is identified and is allocated to the customers in that rate class. NUCOR is the only customer in the TOU class and is currently the Company's largest consumer. Therefore the Company is of the opinion that its allocation of demand related costs is reasonable and any change to how it is recovered would not change the total cost allocated to that class, only how that TOU customer would pay the same total amount. Therefore no change in how demand charges are recovered is warranted.

VI. RESPONSE TO FPAA

Q. Does the Company wish to address concerns expressed by the Fresh Produce witnesses on behalf of customers who take service from the Company in the Nogales area?

A. Yes. The Company recognizes that the Fresh Produce group is important to the Company. Fresh Produce witnesses Jungmeyer and Simer have requested that the ratchet, applicable to the demand charge, be reduced or eliminated in order to reduce what their members pay during their off season.

As also discussed earlier in my testimony, the Company has proposed many changes in this case in an attempt to mitigate inter- and intra-class subsidies. The ratchet was added in the last rate case to help mitigate the intra-class subsidy and is a common method of assigning the actual demand that a customer places on the system. Many times that ratchet is 100%. The Company's current 75% ratchet is a compromise and moves the rates in the direction that improves the allocation and cost recovery from customers within the rate class. If the rate was changed to a more seasonal design that allowed these customers to avoid paying for the cost of their system during the two or three months they operate at a reduced load, any new design would require that they pay more when they place load on the system. If not, the cost of the system used to serve them will be paid by other customers. The Company believes this proposal does just the opposite of what it desires to accomplish in this proceeding, which is to design rates that better allocate cost recovery to the cost causer.

Q. Fresh Produce witness, Mr. Simer also requests that the ratchet be removed. Are his arguments any more compelling?

A. No. Our rebuttal positions apply to his arguments as well. The Company understands this is an important group of customers and considered them when the 75% ratchet was established in the last rate case. Even the witness' graph, on Page 9 of his testimony, shows that for the select group of customers, three of the six peak months the group is at or near 75% of the combined peak of 2700 kW. And the group peaks in June which is coincident with the typical system peak in the Santa Cruz territory. By only allocating demand costs based on 75% of the customer's 11 prior peaks in those three off months, the Company has designed a reasonable compromise in rate design. Any additional movement of costs to other customers would mean the Fresh Produce customers would be subsidized by all other customers in the class during the other nine months of the year. The Company believes the 75% ratchet is appropriate and should remain part of the rate design for this customer class.

VII. RESPONSE TO ACAA AND CARES ISSUES

Q. Ms. Cynthia Zwick, who is testifying on behalf of the ACAA has expressed concerns with how the Company is currently serving the CARES customers and the proposals the Company has made regarding discounts. Would you please respond to these concerns?

A. Yes. Ms. Zwick has discussed the hardships low income customers experience and the Company is sympathetic to these challenges. Under the Company's proposal, CARES customers will receive bill reductions of approximately $1,000,000 annually which maintains the existing discount level. The actual dollar impact on the typical CARES customer is shown on my **Exhibit CAJ-2** to my Direct Testimony and reflects a dollar change that averaged $5.75 for the Standard CARES customer and $6.23 for a CARES medical customer.

Ms. Zwick also suggested the eligibility be expanded to an income level representing 200% of the Federal government's poverty level. The Company proposed to keep the current income qualification level, which is 150% of the Federal Poverty level. She did not specify how many eligible customers would be added, but if this expansion doubled the number of CARES customers from approximately 6,200 to over 12,000, the discounts would also double to approximately $2 million per year. If the Commission approves Ms. Zwick's proposals, the Company would seek to recover those bill discounts exceeding $1 million from other customers through an adjustor mechanism. The Commission could also consider applying the CAREs discount to the base cost of fuel and PPFAC only, resulting in those customers paying lower fuel and purchased power costs. This would result in any incremental costs being shifted to non-CARES customer's through the PPFAC adjustment.

The Company believes Staff's recommendation is the best solution for providing discounts available to CARES customers. The Company would propose provisions consistent with Staff's suggestions, while maintaining the current $1,000,000 discount to the CARES customers and current eligibility criteria. As a result, between rate cases, any increase in participation resulting in discounts above $1 million annually would be incurred by the Company.

Q. Didn't Staff's witness, Mr. Solganick indicate the CARES discount should remain at the current level of just under $600,000 per year?

A. Yes, he did. That amount is reflected in the Company's revenue proof as the percentage and flat discounts included in rates. However, Staff's recommendation, which the

Company agrees to adopt, will be built to offer discounts off of the existing standard residential rate once the proposed three-part rate is approved. This means there is also an increase in the basic service charge from the Company's originally proposed $9.00 per month to $15.00 per month. For approximately 6,200 CARES customer being billed 12 months per year this is another $446,000 of discounts that would need to be added to the current $585,000 of discounts reflected in the revenue proof for total CARES discounts of just over $1,000,000 to keep the customers at the same level as today.

Q. How would the Company design the method to offer discounts to the CARES customers?

A. The numbers will vary depending on the final outcome of this proceeding, but based on the current numbers, the Company is proposing to offer a flat percentage discount to all standard CARES customers of 18% with a flat $16 discount applied for bills reflecting more than 1,000 kWh of consumption and a flat percentage discount to all CARES-Medical customers of 24% with the same flat $16 discount applied for bills reflecting more than 2,000 kWh. The CARES-Medical rate would continue to be frozen so no new customers would be added. The Company calculates that a typical CARES customer using 753 kWh of consumption monthly would see an increase of approximately $5.75 per month. The CARES-Medical increase would be slightly higher at $6.23 per month. The standard CARES customer's bill would still be approximately $170 less per year than the standard residential customer's bill using approximately the same amount of energy. The CARES-Medical bill will be closer to the standard residential customer's annual bill. Even though their typical usage is over 200 kWh more per month the total bill is approximately the same.

Q. Do you believe Staff's proposal is fair to the CARES customers?

A. Yes. Staff suggested this method as a compromise that will let the CARES customers see the amount of their undiscounted bill, even when the new three-part rates become effective. This provides customers with the appropriate pricing signals and will allow them to more easily adapt to the three-part rates when they become effective. The Company believes it is a good solution and still provides a meaningful discount in the CARES customers' bills. By basing a CARES customer's bill on the exact same rates as a standard residential customer, the CARES customers will be included with the rest of the residential class that pay the DSM surcharge as proposed by the Company in it direct case.

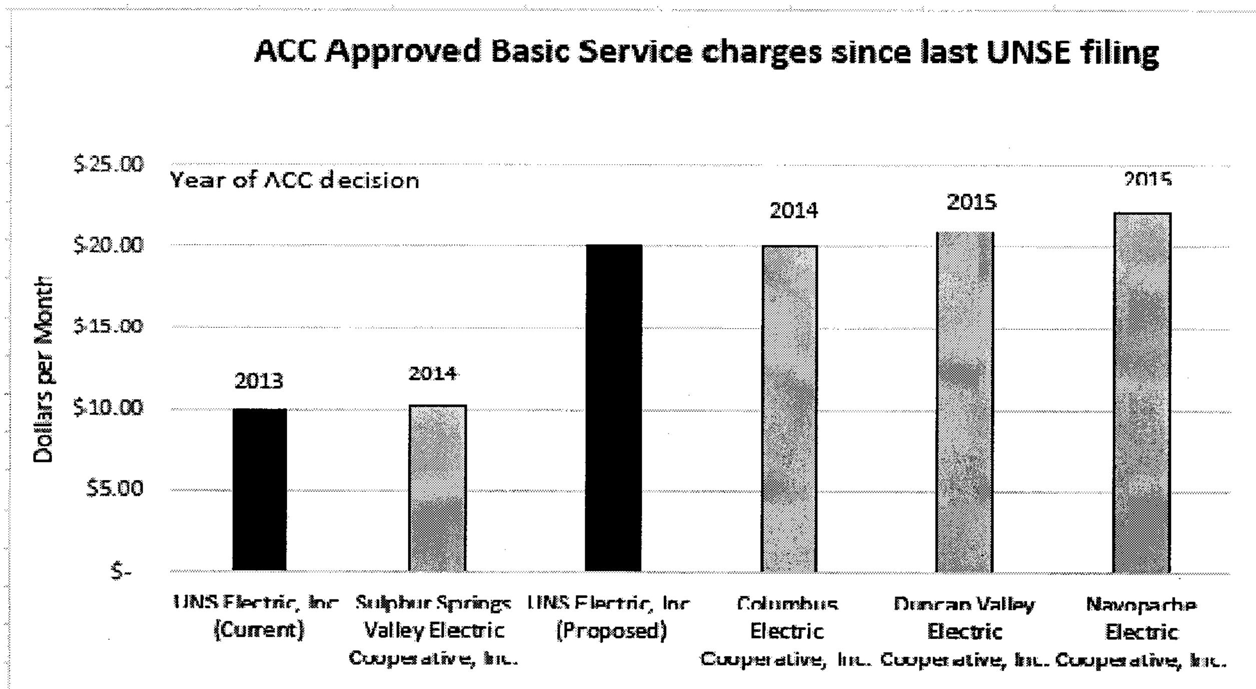
Q. Will the proposed CARES discount method work with the three-part rate the Company has proposed for the residential customers?

A. Yes. However, if after the new rates become effective and an issue is identified, changes can be made during the window created to leave rate design open.

VIII. RESPONSE TO SWEEP

Q. SWEEP witness Mr. Schlegel has filed testimony in opposition to a number of the Company's proposals. Would you like to address his objections?

A. Yes. The Company's rebuttal witness Mr. Overcast does an excellent job of explaining why the increased basic service charge and the elimination of the third tier are appropriate. Also, Mr. Schlegel, on Page 8, line 25 of his testimony indicated the Company's proposed $20 per month basic service charge will be one of the highest in the region. Based on the Company's research, recent Commission actions have approved a number of basic service charges at least as high as the one the Company is requesting. Please refer to the following table:



Q. What other issues expressed by Mr. Schlegel do you wish to address?

A. I have already addressed Mr. Schlegel's suggestion to not include generation in the LFCR, and his recommendation to maintain the 1% cap in my testimony rebutting Staff witness Mr. Solganick so I will not discuss it further here. I will also mention that the Company appreciates Mr. Schlegel's testimony justifying a full decoupling mechanism, but believes fixing the LFCR by correcting it in accordance with the changes suggested by the Company in my Direct Testimony will provide the Company with sufficient incentive to continue to promote DG and EE.

IX. <u>RESPONSE TO VOTE SOLAR AND TASC</u>

Q. Vote Solar witness Ms. Kobor and TASC witness Mr. Fulmer oppose many of the Company's proposals. Did you wish to discuss some of those issues?

A. Yes. I will address a few of their concerns. The Company's witnesses' Mr. Dukes, Mr. Tilghman, and Mr. Overcast have done a very good job of explaining the flaws in both

Ms. Kobor and Mr. Fulmer's misguided evaluation of how DG customers impact the Company's system and the "real" value they bring to the system.

Q. Ms. Kobor on Page 44 indicates that the LFCR is a better way to recover lost fixed cost than correcting antiquated rate design. Do you agree?

A. No. While I agree that the LFCR is a necessary mechanism while we are transitioning our rates to a more equitable and more modern design, I see the LFCR as a mechanism that furthers the cross subsidy between DG customers and full requirements customers because it transfers the volumetric recovery of costs incurred for DG customers to other customers. The best long-term way to address the lost fixed costs is to get the rate design right. As appropriate rate design is placed into effect, and customers are contributing more appropriately to their portion of the fixed costs, the need for the LFCR will be reduced or it may no longer be necessary for DG related lost fixed cost revenue. Additionally, Ms. Kobor fails to mention that the lost fixed costs generated by the DG customers are not charged back to the DG customers; it is paid by all remaining customers, thereby making the subsidy worse. Unfortunately, until rate design is corrected, recovery through the LFCR is our best option between rate cases.

Q. On Page 50 of Ms. Kobor's testimony she indicates she believes a cost of service study is necessary to increase a net metering customer's rates. Did the Company file a CCOSS in this proceeding?

A. Yes. I find it rather interesting that Vote Solar believes it is necessary to have CCOSS supported information to justify placing DG customers on a three-part rate, given that there was no cost-based justification for providing the net metering customer the subsidized rate that they currently enjoy.

Q. Mr. Fulmer indicates on Page 24 of his Direct Testimony that a minimum bill is a better way of addressing low use customers. RUCO witness Mr. Huber on page 8 of his Direct Testimony and WRA witness Mr. Wilson also suggest a form of minimum bill in their testimony. Is this something the Company would consider?

A. The Company supports the three-part rate for our residential and SGS customers. This is the best option for our customers and moves us further toward appropriate cost recovery. Absent the superior three-part rate as an option, the minimum bill proposal may be something the Company would consider. Even though it is a better option than the current two-part rate, there are issues with the minimum bill as well. These include not sending the right price signals regarding basic service charges or energy charges, bill impacts for low use customers, no signals to incent capacity conservation which potentially results in reduced future adoption of technology to reduce capacity, etc. With appropriate design, it can still be a move in the right direction though.

X. AGS EXPERIMENTAL RIDER 14 ("BUY-THROUGH")

Q. Which Commission Staff and/or Intervenor parties addressed the Company's proposed Experimental Rider 14 in their Rate Design testimony?

A. Commission Staff, AECC, Walmart, and AIC addressed the issue.

Q. Please summarize the Intervenor Parties positions regarding the Company's proposed Experimental Rider 14.

A. Staff is neutral on adoption of Experimental Rider 14 and does not object to its adoption if there are no adverse impacts on non-participating customers. AECC and Walmart support adoption of Experimental Rider 14 with recommended revisions that I will discuss in more detail.

AIC opposes adoption of the Rider because it benefits only the customers fortunate enough to be chosen to participate and shifts costs to non-participating customers. Also, AIC notes that a similar program (AG-1) was implemented by APS in 2012 and the potential effects of that program on the company and its customers are uncertain. AIC recommends that the Commission should wait until it is able to analyze the performance of the APS AG-1 rate program before requiring the implementation of a similar program by UNS Electric.

a. <u>Commission Staff</u>

Q. Please summarize ACC Staff comments on the Company's proposed Experimental Rider 14.

A. Mr. Solganick stated that Staff looks forward to the input of other parties and does not object to the implementation of Experimental Rider 14 if there are no adverse impacts or costs to other customers. In particular, Staff opposes recouping any lost revenue in the LFCR and opposes any deferral of lost revenue.

Q. Do you agree with Staff's position that no lost revenue resulting from the implementation of Experimental Rider 14 should be recovered in the LFCR or deferred for recovery at a later date?

A. As clearly stated in my Direct Testimony, the Company is not supportive of the "Buy-Through" rate. I will discuss the Company's concerns and objections to this rate later in my Rebuttal Testimony. Staff indicated they do not object to a "Buy-Through" mechanism if there are no adverse impacts and no costs to the other customers. This includes not allowing any identified costs to be recovered through the Company proposed method of including it in the LFCR mechanism.

As stated in my Direct Testimony, with regards to the "Buy-Through" rate since UNSE does not have anyone on staff to offer this type of service, providing it will require additional personnel, additional processes to track and verify the flow of energy, incremental Transmission balancing services, additional billing equipment and billing processes, among other things. This will all be required to offer a special deal to a few large customers to gain the opportunity to save on energy while the market is down, only to come back for full retail service when the market returns. Since the fixed cost of the Company's generation facilities are included in base rates and recovered on a test year assumed level of sales, all lost sales due to this program will produce lost fixed cost recovery. We would prefer not creating a potentially subsidized rate for a few select large customers just to create more lost revenues. Therefore, without charging the full retail non-fuel rates while the customer was participating in the "Buy-Through" rate, a loss in revenues will occur. If the rate is approved, there will be a cost. That cost will fall on someone. The Company's goal in this case is to address and minimize subsidized pockets of customers, not create more.

b. <u>AECC</u>

Q. Please summarize AECC's recommendations for proposed Experimental Rider14.

A. AECC witness Kevin Higgins recommends adoption of a buy-through program "that is as similar as reasonably possible to the APS AG-1 program approved for APS."[2] Mr. Higgins favors adopting some of the features of the buy-through program presented by the Company, but recommends changes to program eligibility, the proposed monthly management fee, the mechanics of fixed generation cost recovery, and the terms of return to standard generation service. He also recommends clarification of the program term.

Q. Do you agree with AECC's recommendations for Experimental Rider 14?

A. No. I will address each of AECC's recommendations individually.

[2] Higgins Direct, p. 17, ll. 1-2.

Q. Please summarize AECC's recommendations related to Rider 14 program eligibility.

A. AECC agrees that the Company's proposed program cap of 10 MW should be retained. However, AECC recommends broadening the range of customers eligible to participate by reducing the minimum load size from 2.5 MW to 1 MW (peak demand) and allowing aggregation of smaller loads in the MGS/LGS classes owned by the same corporate entity to achieve the 1 MW threshold. Each single entity aggregated to reach the 1 MW threshold should have experienced a billing demand of at least 200 kW in the previous year to be eligible.

In support of the AECC position, Mr. Higgins cites the APS AG-1 program participation limits as they apply to minimum customer load and aggregation. The APS AG-1 program sets a total participation limit of 200 MW and requires a minimum aggregated peak load of 10 MW or more for customer eligibility. The APS AG-1 program allows customers on its Rate Schedule E32-L to participate through aggregation even though they cannot meet the 10 MW minimum individually and has set aside 50% of the initial capacity for those customers. Mr. Higgins states that the customers on APS Schedule E32-L "roughly corresponds to the UNSE MGS and LGS classes"[3] and uses this as support for his recommendation.

Q. Do you agree with the AECC recommendation to reduce the minimum load size for participation and allow aggregation of corporate loads?

A. No. While the APS AG-1 program can serve as a model for certain elements of a similar program for the Company, the proposal should not be identical to the APS AG-1 program. The Company and APS are utilities of much different size, generating capacity and customer characteristics. In 2014, the APS system had a peak demand approximately 17 times larger than that of the Company. As a result, APS is most likely able to take

[3] Higgins Direct, p. 18, ll. 6-7.

advantage of economies of scale that are not available to a company the size of UNS Electric. The Company does not currently have personnel on staff to manage a program like that proposed in Experimental Rider 14, much less to manage aggregation of corporate loads for such a program as Mr. Higgins is proposing.

Also, APS Schedule E32-L is applicable to customers whose average monthly maximum demand is greater than 400 kW and the Company's MGS tariff specifies a minimum monthly billing demand of 20 kW. A minimum size customer on APS Schedule E32-L is 20 times larger than a minimum size customer in the Company's MGS rate class. The APS E32-L rate class in no way corresponds to the MGS rate class.

Finally, the order in the Fortis acquisition of UNS Energy, parent of TEP and the Company specifies that in their next rate cases "TEP and UNS Electric will propose a pilot program for a "buy through" tariff available to Large Light and Power Service and Large Power Service customers, respectively."[4] As mentioned earlier, the Company is proposing Experimental Rider 14 as a condition of the Fortis merger settlement agreement, but is not supporting its adoption. Therefore, the Company sees no reason to expand the availability of Experimental Rider 14 beyond the customer classes specified in the Fortis merger settlement agreement.

Q. Do you agree with AECC that the Company's proposed monthly management fee should be reduced from the \$0.004/MWh to \$0.0006/MWh which is the management fee specified in the APS AG-1 rate rider?

A. No. The only reason Mr. Higgins gives for the Company's proposed management fee being "unreasonable and exorbitant" is that it is "six times greater" than the APS

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[4] ACC Decision No. 74689, Opinion and Order in Docket No. E-04230A-14-0011, Attachment A, p. 5, August 12, 2014.

management fee. As mentioned earlier, APS and the Company are much different companies especially where size is concerned. APS, with a 2014 peak demand roughly 17 times that of the Company, likely has scale economies that do not exist for the Company. Therefore, a higher charge for the service is reasonable.

Furthermore, APS has indicated that the net impact of the AG-1 program has been losses in the range of $10 million annually.[5] Rather than the proposed management fee being "unreasonable and exorbitant" it is highly likely that the APS AG-1 management fee is inadequate and partly responsible for the AG-1 program losses.

Q. Please summarize Mr. Higgins recommendations regarding the Company's fixed generation cost recovery.

A. The Company proposed that participating customers pay 100% of the customer's generation-related demand component for all billing demand for the first twelve months of service and 25% for the remainder of service under the Rider. Mr. Higgins recommends that charges for generation-related services should be limited to a charge for reserve capacity applied to 15% of the customer's billed demand priced at the unbundled generation demand charge. Essentially, Mr. Higgins is recommending that the recovery of generation-related fixed costs from participating customers be reduced from the Company's proposal of 100% in the first year, and 25% thereafter to 15% for the entire term of service under the Rider.

Q. What are AECC's objections to the Company's proposed recovery of fixed generation costs from participating customers?

A. Mr. Higgins argues that while some assignment of cost for generation reserves may be appropriate, the Company's proposal is excessive and is more comparable to a stranded

[5] ACC Decision No. 75322, Order in Docket No. E-01345A-11-0224, p. 2, November 25, 2015.

cost charge. He argues that the stranded cost approach should be rejected unless the customers are being provided with an opportunity to transition permanently to market pricing. Mr. Higgins bases his recommendation of 15% on the Company's planning reserve margin.

Q. Do you agree that the Company's proposal is comparable to a stranded cost charge?

A. No. Stranded cost is defined as the net present value difference between the market value of an asset and the book value. If the market value is less than book, stranded costs result. In other words, a stranded cost calculation would look at the entire value of the asset up to the time the asset is retired. The Company has invested in generation assets to serve all customers on the system including those who might participate in the Rider 14 program. The capital costs related to these generation assets are collected from the customers served by them over the useful life of the assets. A recovery of 100% of fixed generation costs for one year is not equivalent to a stranded cost charge, which would be calculated over the entire remaining life of the asset. In fact, the fixed generation costs reflected in rates are set to recover that assets depreciation expense and return for the life of generation assets on a monthly basis over the life of those assets. Recovering 100% of those costs over a 12-month period would be much less than a system exit fee based on stranded costs.

Q. Do you agree with Mr. Higgins' suggestion that the first $908,000 of any revenue requirement reduction should be apportioned to "subsidy-paying" classes to help absorb any UNS Electric revenue deficiency ascribed to lost generation revenues?

A. No. As discussed in my Direct Testimony and in this Rebuttal Testimony, the Company does not support the approval of the "Buy-Through" Rider 14. Mr. Higgins' suggestion is innovative on the surface, but still results in the costs associated with providing the "Buy Through" option to a select few customers coming out of the Company's total revenue requirement and thereby being paid for by the remaining customers.

Q. Do you agree with Mr. Higgins that the price for returning to full utility service should be lowered from the Company's proposed Dow Jones Palo Verde Index plus $20/MWh to the Index plus a maximum of $4/MWh?

A. No. This charge is being proposed to discourage this from happening. Therefore the penalty charge needs to be large enough to make that happen. Hopefully, the charge will never be applied, but if it is it needs to be a true penalty. The APS AG-1 program specifies the Dow Jones Palo Verde Index plus $10/MWh. Reducing the adder to $4/MWh has no justification. Again, UNS Electric wants to protect itself and its customers from the types of losses that APS has experienced as a result of its AG-1 program.

Q. What are AECC's recommendations with respect to clarification of the Experimental Rider 14 program term?

A. AECC recommends that the program term should be restated to indicate that Rider 14 will continue to be available at least until the start of the first rate-effective period following a general rate case occurring no less than four years from the program start date.

Q. What is AECC's justification for this recommendation?

A. While Mr. Higgins states that he does not disagree with the Company's proposal to target a four-year period for the program term, he believes it is important that any program extension or modification be considered in the context of a future general rate case prior to termination of the program.

Q. Do you agree with the AECC recommendation to extend the program term at least until the start of the first rate-effective period following a general rate case occurring no less than four years from the program start date?

A. No. If the Company is ordered to implement Rider 14 it should be for a maximum of the four years specified in the tariff. AECC seems to want the best of both worlds with this recommendation.

c. <u>Walmart</u>

Q. Please summarize Walmart's recommendations for proposed Experimental Rider 14.

A. Walmart witness Chris Hendrix recommends approval of Experimental Rider 14 with the following changes:

- UNS Electric's proposed management fee of $0.004/kWh should be rejected and the Company should be required to file a cost-justified management fee proposal.
- The minimum participation level should be reduced to 1,000 kW and corporate aggregation should be allowed to meet the limit.
- All rate classes should be allowed to participate in the program.
- The total participation limit should be raised to 150 MW, based on the amount of wholesale electricity purchases currently undertaken by UNS Electric.
- Experimental Rider 14 customers should not be responsible for any of the Company's generation related charges because the program is simply replacing market purchases.
- There should be no limit on the term of the program.

Q. Do you agree with Walmart's recommendations for Experimental Rider 14?

A. No. I will address Walmart's recommendations individually.

Q. Do you agree with the Walmart's recommendation to reject the Company's proposed management fee and require UNS Electric to file a cost-justified management fee proposal?

A. No. Proposed Experimental Rider 14 is an optional program. If any potential participants believe the management fee is too high, they can elect not to participate. Since the level of participation and therefor the level of personnel necessary to monitor the program, nor the equipment or software needs are known at this time, the initial charge should be large enough to capture any and all possible costs. The Company believe the proposed $0.004 per kWh meets those needs.

Q. Do you agree that the minimum participation level should be reduced to 1,000 kW and corporate aggregation should be allowed to meet the limit?

A. No. As I addressed in the rebuttal to AECC concerning this issue, UNS Electric does not have the resources to deal with smaller customer sizes than specified in the proposed Rider 14 or aggregation of loads.

Q. Do you agree with Walmart's recommendation that all rate classes be allowed to participate?

A. No. As mentioned earlier, the Fortis acquisition settlement agreement specified only that UNS Electric make a program like that proposed in Rider 14 available to customers in the Large Power Service rate class.

Q. What is Walmart's basis for recommending that the total participation cap be raised to 150 MW?

A. Mr. Hendrix notes that according to the Direct Testimony of UNS Electric witness Michael E. Sheehan, the Company will be purchasing 175 MW of Market Based Resources after the Gila River Acquisition. Mr. Hendrix bases the 150 MW cap recommendation on that number and argues that removing that 150 MW from the Company's market purchases would "significantly reduce the Company's reliance on the wholesale market and transfer the market risk to customers who are willingly participating in the AGS program."[6]

Q. Do you agree with Mr. Hendrix that the total participation cap should be raised to 150 MW?

A. No. Mr. Hendrix's recommendation ignores the entire process of Integrated Resource Planning. An Integrated Resource Plan ("IRP") is a utility plan for meeting forecasted annual peak and energy demand, plus an established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. It is a dynamic process and a utility's IRP will typically be examined, modified, and acknowledged in a proceeding before a regulatory commission.

The Company's IRP was developed via extensive modeling and dynamic optimization to select the best combination of supply and demand-side resources to serve projected Company loads plus a reserve margin. Also, the Company's IRP has been reviewed and acknowledged in a separate IRP proceeding by the Commission. Mr. Hendrix proposes to throw out that entire process and make ad hoc adjustments to the Company's IRP in a rate case, not in a proceeding where these planning issues are more closely examined.

Finally, the 175 MW of market power purchases cited earlier in the Company's IRP has not been planned for the sole benefit and use of prospective Rider 14 customers. In the same vein, the Gila River Acquisition was undertaken to benefit all customers on the system. Prospective Rider 14 customers should not be allowed to evade their responsibility for cost recovery of the utility's fixed generation assets that were procured to their benefit under an obligation to serve.

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[6] Walmart-Hendrix Direct, pp. 7-8, ll. 20-1.

Q. Do you agree with Walmart's statement that Experimental Rider 14 customers should not be responsible for any of Company's generation related charges because the program is simply replacing wholesale market purchases?

A. No. The generation related charges included in rates are not avoidable. For the same reasons that I believe the generation costs should be included in the LFCR rates, I believe these customers should be required to pay the level of generation costs they were allocated in the most recent rate case. All resources that the Company relies on to serve loads on the system are procured for the benefit of all customers. All customers should therefore be responsible for their share of allocated costs.

Q. Do you agree that the program term should be unlimited?

A. No. "Experimental" means a program that has to be tested and evaluated to determine whether it merits becoming a permanent rate structure. As mentioned earlier, the Fortis Acquisition Settlement specified that UNS Electric propose a pilot program for a buy-through tariff. Pilot programs by definition are of limited duration.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

Exhibit CAJ-R-1

UNS Electric, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Test Year Present Net Revenue	Net Change	Proposed % Increase to Test Year	Adjusted TY Revenue	Proposed Dollar Increase (a)	Proposed Percent Increase to Adjusted Test Year Revenues (a)	Proposed Net Revenue
1	Residential Service	$83,768,709	$10,172,880	12.1%	$78,169,265	$15,928,289	20.38%	$94,097,555
2	Small General Service	12,922,488	1,355,249	10.5%	12,461,200	1,816,538	14.58%	14,277,738
3	Interruptible Power Service	2,920,047	277,930	9.5%	3,111,532	86,446	2.78%	3,197,977
4	Medium General Serive	0	45,117,600	0.0%	0	45,117,600	0.0%	45,117,600
5	Large General Service	46,292,475	-37,043,568	-80.0%	43,498,604	-34,243,500	-78.72%	9,255,104
6	Large Power Service	21,454,373	-14,756,700	-68.8%	17,170,539	-10,393,742	-60.53%	6,776,797
7	Lighting	528,359	94,271	17.8%	547,038	75,592	13.82%	622,630
8	Subtotal	$167,886,452	$5,217,663	3.11%	$154,958,178	$18,387,223	11.87%	$173,345,402
9	Other Operating Revenue	1,734,044	95,034	N/A	1,829,078	N/A	N/A	1,829,078
10	Total	$169,620,496	$5,312,697	3.13%	$156,787,256	$18,387,223	11.73%	$175,174,479

Total Electric Retail Service
(a) H-2 (P2)

Recap Schedules
A-1

Exhibit CAJ-R-2

Exhibit CAJ-R-2

UNS Electric Inc.
Bill Impacts
Test Period Ending December 31, 2014

Line No.	Class Description	Customer Counts To-date (Dec 2015)	TEST YEAR ADJUSTED WITH MARGIN INCREASE, FUEL/PPAFC TRUE-UP AND TCA: Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase	TEST YEAR ADJUSTED WITH MARGIN INCREASE, FUEL/PPAFC TRUE-UP, TCA AND DEFERRED CREDIT: Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase	COS RETURNS
1	Residential	75,504	$79.24	$6.60	**7.78%**	$18.34	$1.53	**1.76%**	
2	Residential CARES	5,904	$69.00	$5.75	**9.04%**	$23.52	$1.96	**3.01%**	
3	Residential CARES-M	251	$74.78	$6.23	**7.96%**	$19.15	$1.60	**1.99%**	6.45%
4	Residential TOU	266	$102.04	$8.50	**8.61%**	$27.82	$2.32	**2.29%**	
5	Residential TOU Super Peak	5	$102.76	$8.56	**8.92%**	$28.66	$2.39	**2.43%**	
6	Small General Service	8,839	$155.11	$12.93	**10.67%**	$74.65	$6.22	**5.02%**	6.34%
7	Small General Service TOU	14	$219.45	$18.29	**9.31%**	$75.09	$6.26	**3.11%**	
8	Interruptible Service	25	$14,823.67	$1,235.31	**16.99%**	$7,865.17	$655.43	**8.72%**	
9	Medium General Service	1279	$909.85	$75.82	**2.79%**	($1,002.53)	($83.54)	**-3.00%**	
10	Medium General Service TOU	9	$1,855.86	$154.66	**2.29%**	($2,868.72)	($239.06)	**-3.44%**	18.59%
11	Large General Service	10	($2,353.68)	($196.14)	**-0.47%**	($35,891.52)	($2,990.96)	**-6.99%**	
12	Large General Service (Formally LPS)	7	($14,102.18)	($1,175.18)	**-2.77%**	($47,640.02)	($3,970.00)	**-9.07%**	
13	Large General Service TOU	2	$15,412.80	$1,284.40	**2.29%**	($30,637.62)	($2,553.14)	**-4.41%**	
14	Large Power Service	3	$31,961.74	$2,663.48	**2.37%**	($69,774.86)	($5,814.57)	**-4.99%**	17.18%
15	Large Power Service TOU	1	$55,198.74	$4,599.90	**2.61%**	($94,037.58)	($7,836.47)	**-4.32%**	
16	Lighting Service	1,922	$31.80	$2.65	**19.94%**	$28.92	$2.41	**18.13%**	10.41%

Exhibit CAJ-R-2

UNS Electric Inc.
Bill Impacts
Test Period Ending December 31, 2014

Line No.	Class Description	Customer Counts To-date (Mar 2015)	New Summer Month A	Total Summer Change B	Summer Change C=(B*6)	New Winter Month D	Total Winter Change E	Winter Change F=(E*6)	Annual Bill G=(A*6+D*6)	TEST YEAR ADJUSTED - FUEL TRUE-UP AND MARGIN INCREASE Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase
1	Residential	75,504	$100.68	$0.48	$2.88	$76.17	$2.58	$15.46	$1,061.11	$18.34	$1.53	**1.76%**
2	Residential Demand		$103.59	($4.25)	($25.52)	$76.26	($4.41)	($26.45)	$1,079.10	($51.97)	($4.33)	**-4.59%**
3	Residential CARES	5,904	$75.38	$1.89	$11.34	$58.93	$2.03	$12.18	$805.84	$23.52	$1.96	**3.01%**
4	Residential Cares Demand		$76.61	($2.82)	($16.92)	$60.37	($1.49)	($8.94)	$821.88	($25.86)	($2.16)	**-3.05%**
5	Residential CARES-M	251	$92.35	$1.51	$9.07	$71.22	$1.68	$10.08	$981.46	$19.15	$1.60	**1.99%**
6	CARES Medical Demand		$92.23	($5.09)	($30.54)	$71.30	($3.63)	($21.78)	$981.18	($52.32)	($4.36)	**-5.06%**
7	Residential TOU	266	$121.20	$2.60	$15.58	$85.62	$2.04	$12.24	$1,240.92	$27.82	$2.32	**2.29%**
8	Residential TOU Demand		$121.29	($7.70)	($46.20)	$82.49	($3.13)	($18.78)	$1,222.68	($64.98)	($5.42)	**-5.05%**
9	Residential TOU Super Peak	5	$117.12	($0.22)	($1.34)	$84.32	$5.00	$30.00	$1,208.64	$28.66	$2.39	**2.43%**
10	Small General Service	8,839	$140.64	$4.95	$29.72	$119.82	$7.49	$44.93	$1,562.76	$74.65	$6.22	**5.02%**
11	Small General Service Demand		$139.11	($9.11)	($54.67)	$118.34	($7.30)	($43.80)	$1,544.70	($98.47)	($8.21)	**-5.99%**
12	Small General Service TOU	14	$236.59	$4.21	$25.24	$178.40	$8.31	$49.85	$2,489.94	$75.09	$6.26	**3.11%**
13	Small General Service TOU Demand		$211.89	($39.11)	($234.66)	$153.40	($25.00)	($150.00)	$2,191.74	($384.66)	($32.06)	**-14.93%**
14	Interruptible Service	25	$9,012.88	$745.31	$4,471.84	$7,333.76	$565.56	$3,393.33	$98,079.85	$7,865.17	$655.43	**8.72%**
15	Medium General Service	1279	$2,946.29	($100.05)	($600.28)	$2,459.78	($67.04)	($402.25)	$32,436.42	($1,002.53)	($83.54)	**-3.00%**
16	Medium General Service TOU	9	$6,818.46	($421.68)	($2,530.08)	$6,591.53	($56.44)	($338.64)	$80,459.94	($2,868.72)	($239.06)	**-3.44%**
17	Large General Service	10	$38,400.51	($2,990.96)	($17,945.76)	$41,195.33	($2,990.96)	($17,945.76)	$477,575.09	($35,891.52)	($2,990.96)	**-6.99%**
18	Large General Service (Formally LPS)	7	$38,400.51	($3,970.00)	($23,820.01)	$41,195.33	($3,970.00)	($23,820.01)	$477,575.09	($47,640.02)	($3,970.00)	**-9.07%**
19	Large General Service TOU	2	$55,512.50	($3,597.95)	($21,587.70)	$55,112.87	($1,508.32)	($9,049.92)	$663,752.22	($30,637.62)	($2,553.14)	**-4.41%**
20	Large Power Service	3	$106,491.04	($5,814.57)	($34,887.43)	$114,969.09	($5,814.57)	($34,887.43)	$1,328,760.75	($69,774.86)	($5,814.57)	**-4.99%**
21	Large Power Service TOU	1	$177,202.48	($7,693.78)	($46,162.68)	$170,341.02	($7,979.15)	($47,874.90)	$2,085,261.00	($94,037.58)	($7,836.47)	**-4.32%**
22	Lighting Service	1,922	$15.70	$2.41	$14.46	$15.70	$2.41	$14.46	$188.40	$28.92	$2.41	**18.13%**

Exhibit CAJ-R-3

UNS Electric Inc.
IPS VS. LGS BILL
Test Period Ending December 31, 2014

Exhibit CAJ-R-3

Billing Determinants

	LF	
kWh		98,000
kW	0.50	268

INTERRUPTIBLE POWER SERVICE	***Rates***	***Revenue***
Basic Service Charge	$18.00	$18.00
Demand Charge, per kW	$5.00	$1,342.47
Energy Charge, per kWh	$0.019408	$1,901.98
TCA, per kW	$1.229700	$330.17
Base Power	$0.043760	$4,288.48
Net Bill		$7,881.10
5713 LARGE GENERAL SERVICE		
Basic Service Charge	$50.00	$50.00
Demand Charge, per kW	$12.81	$3,439.40
Energy Charge, per kWh	$0.005470	$536.06
TCA, per kW	$1.229700	$330.17
Base Power	$0.056603	$5,547.09
Net Bill		$9,902.72
Subsidy		**$2,021.62**

Exhibit CAJ-R-4

UNS Electric, Inc.
Summary of Revenues by Customer Classifications
Adjusted Present Rates And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Test Year Present Net Revenue	Net Change	Proposed % Increase to Test Year	Adjusted TY Revenue	Proposed Dollar Increase (a)	Proposed Percent Increase to Adjusted Test Year Revenues (a)	Proposed Net Revenue
1	Residential Service	$83,768,709	$10,172,880	12.1%	$78,169,265	$15,928,289	20.38%	$94,097,555
2	Small General Service	12,922,488	1,355,249	10.5%	12,461,200	1,816,538	14.58%	14,277,738
3	Interruptible Power Service	2,920,047	277,930	9.5%	3,111,532	86,446	2.78%	3,197,977
4	Medium General Serive	0	45,117,600	0.0%	0	45,117,600	0.0%	45,117,600
5	Large General Service	46,292,475	-37,043,568	-80.0%	43,498,604	-34,243,500	-78.72%	9,255,104
6	Large Power Service	21,454,373	-14,756,700	-68.8%	17,170,539	-10,393,742	-60.53%	6,776,797
7	Lighting	528,359	94,271	17.8%	547,038	75,592	13.82%	622,630
8	Subtotal	$167,886,452	$5,217,663	3.11%	$154,958,178	$18,387,223	11.87%	$173,345,402
9	Other Operating Revenue	1,734,044	95,034	N/A	1,829,078	N/A	N/A	1,829,078
10	Total	$169,620,496	$5,312,697	3.13%	$156,787,256	$18,387,223	11.73%	$175,174,479

Total Electric Retail Service
(a) H-2 (P2)

Recap Schedules
A-1

UNS Electric, Inc.
Comparisons of Sales by Rate Schedules
Present And Proposed Rates
Test Period Ended December 31, 2014

				Actual				Adjusted			Tariff Changes		
Line No.	Class of Service	Rate Schedule Present	Proposed [1]	kWh Sales	Average Number of Customers	Average kWh per Customer	Test Year End Sales Adjustments	kWh Sales	Average Number of Customers	Average Sales per Customer	kWh Sales	Average Number of Customers	Average Sales per Customer
1	Residential Cares	CARES	NC	57,138,737	6,112	9,349	1,701,588	58,840,325	6,236	9,436	58,840,325	6,236	9,436
2	Residential Service	RES-01	NC	755,005,617	75,847	9,954	6,209,782	761,215,400	76,035	10,011	761,215,400	76,035	10,011
3	Residential Service TOU	RES-TOU	NC	2,731,217	230	11,892	321,911	3,053,127	257	11,880	3,053,127	257	11,880
4	Res Bright Community Solar	RES-BC	NC	844,333	79	10,733	0	844,333	79	10,733	844,333	79	10,733
5	Residential Unbilled			(484,060)	0			0	0		0	0	
6	Small General Service	SGS-10	NC	118,754,401	8,704	13,643	(253,035)	118,501,366	8,750	13,543	118,501,366	8,750	13,543
7	Small General Service TOU	SGS-TOU	NC	170,628	8	22,750	11,802	182,430	8	22,804	182,430	8	22,804
8	Interruptible Power Service	IPS	NC	38,106,302	32	1,193,931	(2,538,461)	35,567,841	29	1,226,477	35,567,841	29	1,226,477
9	Medium General Service		MGS	0	0	0	0	0	0	0	408,462,296	1,331	306,884
10	Medium General Service TOU		MGS-TOU	0	0	0	0	0	0	0	7,718,956	8	964,869
11	Large General Service	LGS	LGS	448,678,574	1,361	329,688	(2,896,080)	445,782,493	1,341	332,425	95,412,304	17	5,612,488
12	Large General Service TOU	LGS-TOU	LGS TOU	3,834,211	5	821,617	3,884,745	7,718,956	8	964,869	15,418,264	2	7,709,132
13	LGS Bright Community Solar	LGS-BC	MGSBC	16,769	3	5,590	(16,769)	0	0	0	0	0	0
14	Large General Service Unbilled			384,473	0			0	0		0	0	
15	Large Power Service & TOU <69 kV	LPS/LPS TOU	LGS/LGS TOU	92,705,606	12	7,672,188	(19,195,235)	73,510,371	9	8,167,819	0	0	0
16	LPS Standard/Mining & TOU >69 kV	LPS/LPSM/ LPS TOU	NC	157,107,744	6	26,184,624	(64,342,470)	92,765,274	4	23,191,318	92,765,274	4	23,191,318
17	Large Power Service Unbilled			(369,148)	0			0	0		0	0	
18	Lighting	LTG	NC	2,820,013	2,388	1,181	7,237	2,827,250	2,388	1,184	2,827,250	2,388	1,184
19	Total Electric Retail Service			1,677,445,418	94,785	17,697	(77,104,986)	1,600,809,167	95,144	16,825	1,600,809,167	95,144	16,825

Note:
[1] NC equals No Change

UNS Electric, Inc.
Comparisons of Revenues by Rate Schedules
Present And Proposed Rates
Test Period Ended December 31, 2014

Line No.	Class of Service	Proposed	Unadjusted [1] Margin Revenue	Unadjusted [2] Fuel & PPFAC Revenue	Margin Pro Forma Adjustment	Fuel & PPFAC [3] Pro Forma Adjustment	Adjusted Margin Revenue	Adjusted Fuel & PPFAC Revenue	Adjusted TY Revenues	Proposed Revenue	Proposed Increase To TY Revenue $	Proposed Increase To TY Revenue %	Proposed Increase to Adjusted Revenue [4] $	Proposed Increase to Adjusted Revenue [4] %
1	Residential Cares	RES-01	$1,779,128	$3,029,378	$0	$0	$1,793,740	$2,585,159	$4,378,898	$5,495,550	$687,045	14.29%	$1,116,652	20.32%
2	Residential Service	RES-01	31,759,612	46,999,721	0	0	31,469,845	41,935,733	73,405,578	88,170,239	9,410,907	11.95%	14,764,661	16.75%
3	Residential Service TOU	RES-TOU	116,271	152,725	0	0	128,000	169,535	297,536	328,290	59,294	22.04%	30,754	9.37%
4	Res Bright Community Solar	RES-BC	34,190	53,651	0	0	33,602	53,651	87,253	103,476	15,635	17.80%	16,223	15.68%
5	Residential Unbilled		110,955	-266,920	0	0	0	0	0	0	0	0.00%	0	0.00%
6	Small General Service	SGS-10	6,255,704	6,650,173	0	0	6,127,602	6,314,938	12,442,540	14,257,815	1,351,938	10.48%	1,815,275	12.73%
7	Small General Service TOU	SGS-TOU	8,527	8,085	0	0	8,992	9,668	18,660	19,923	3,311	19.93%	1,263	6.34%
8	Interruptible Power Service	IPS	1,335,391	1,584,656	0	0	1,223,235	1,888,297	3,111,532	3,197,977	277,930	9.52%	86,446	2.70%
9	Medium General Service	MGS	0	0	0	0	0	0	0	44,466,094	44,466,094	n/a	44,466,094	100.00%
10	Medium General Service TOU	MGS-TOU	0	0	0	0	0	0	0	651,506	651,506	n/a	651,506	100.00%
11	LGS Bright Community Solar	LGS-BC	898	976	0	0	0	0	0	0	0	0.00%	0	0.00%
12	Large General Service	LGS	21,574,476	24,416,757	0	0	21,103,440	21,766,956	42,870,396	7,890,233	(38,101,000)	-82.84%	(34,980,163)	-443.33%
13	Large General Service TOU	LGS - TOU	121,380	186,059	0	0	254,632	373,576	628,208	1,364,871	1,057,432	343.95%	736,663	53.97%
14	General Service Unbilled		138,446	-146,516	0	0	0	0	0	0	0	0.00%	0	0.00%
15	Large Power Service & LPS TOU <69 kV	LPS <69	5,072,348	3,652,261	0	0	3,813,388	5,910,483	9,723,871	0	(8,724,609)	-100.00%	(9,723,871)	0.00%
16	Large Power Service Unbilled		-31,928	-47,197	0	0	0	0	0	0	0	0.00%	0	0.00%
17	Large Power Service & LPS TOU >69 kV	LPS >69	6,894,832	5,914,057	0	0	3,191,840	4,254,829	7,446,668	6,776,797	(6,032,091)	-47.09%	(669,871)	-9.88%
18	Lighting	LTG	505,944	22,415	0	0	505,944	41,094	547,038	622,630	94,271	17.84%	75,592	12.14%
19	Total Electric Service		$75,676,172	$92,210,280	$0	$0	$69,654,260	$85,303,919	$154,958,178	$173,345,402	$5,217,663	3.11%	$18,387,223	11.87%

Note:
[1] Test Year Billed Margin Revenues calculated $69,916 more than Booked Revenues.
[2] Test Year Billed Fuel and PPFAC revenues calculated $175,930 less than Booked Revenues.
[3] Test Fuel and PPFAC Test Year True-up includes a Billed to Book adjustment of $175,930.
[4] Total increase is $69,916 less than Schedule A1, Line 10 due to difference from Test Year billed to booked revenues.

	Present Rate	Proposed Rate	Increase $	Increase %
Residential Service - CARES - *Transition Rates*				
Basic Service Charge	$4.90	$9.00	$4.10	83.67%
Energy Charge 1st 400 kWhs	$0.018973	$0.030800	$0.011827	62.34%
Energy Charge, all additional kWhs	$0.035400	$0.050800	$0.015400	43.50%
Base Power Supply Charge, all kWhs	$0.061700	$0.050260	-$0.011440	-18.54%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service CARES Demand				
Basic Service Charge	N/A	$15.00	N/A	N/A
Demand Charge, per kW	N/A	$5.15	N/A	N/A
Energy Charge (kWhs)	N/A	$0.016760	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.102251	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.042830	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.082800	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.038610	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Residential Service - *Transition Rates*				
Basic Service Charge	$10.00	$15.00	$5.00	50.00%
Energy Charge 1st 400 kWhs	$0.019300	$0.032258	$0.012958	67.14%
Energy Charge 401-1,000 kWhs	$0.034350	$0.042258	$0.007908	23.02%
Energy Charge, all additional kWhs	$0.038499	$0.060258	$0.021759	56.52%
Base Power Supply Charge, all kWhs	$0.064510	$0.055090	-$0.009420	-14.60%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service Time-of-Use - *Transition Rates*				
Basic Service Charge	$11.50	$15.00	$3.50	30.43%
Energy Charge 1st 400 kWhs	$0.030350	$0.036900	$0.006550	21.58%
Energy Charge 401-1,000 kWhs	$0.030350	$0.036900	$0.006550	21.58%
Energy Charge, all additional kWhs	$0.030350	$0.036900	$0.006550	21.58%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.129605	$0.111001	-$0.018604	-14.35%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039605	$0.042830	$0.003225	8.14%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.129605	$0.091550	-$0.038055	-29.36%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.031385	$0.038610	$0.007225	23.02%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Residential Service Demand				
Basic Service Charge	N/A	$15.00	N/A	N/A
Demand Charge, per kW	N/A	$5.15	N/A	N/A
Energy Charge (kWhs)	N/A	$0.016760	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.102251	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.042830	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.082800	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.038610	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Residential Service Time-of-Use Super Peak - *Transition Rates*				
Basic Service Charge	$11.50	$15.00	$3.50	30.43%
Energy Charge 1st 400 kWhs	$0.025000	$0.032258	$0.007258	29.03%
Energy Charge, all additional kWhs	$0.035000	$0.042258	$0.007258	20.74%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.170000	$0.159790	-$0.010210	-6.01%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039700	$0.040810	$0.001110	2.80%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.150000	$0.159790	$0.009790	6.53%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.038700	$0.040810	$0.002110	5.45%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Small General Service - ***Transition Rates***				
Basic Service Charge	$14.50	$30.00	$15.50	106.90%
Energy Charge 1st 400 kWh	$0.030176	$0.032400	$0.002224	7.37%
Energy Charge 401 -7,500 kWh	$0.041042	$0.042400	$0.001358	3.31%
Energy Charge >7,500 kWh	$0.076042	$0.077400	$0.001358	1.79%
Base Power Supply Charge, all kWhs	$0.058241	$0.053290	-$0.004951	-8.50%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Small General Service Demand				
Basic Service Charge	N/A	$30.00	N/A	N/A
Demand Charge, per kW	N/A	$5.49	N/A	N/A
Energy Charge (kWhs)	N/A	$0.016680	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.084570	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.045800	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.083570	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.040036	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Small General Service Time-of-Use - ***Transition Rates***				
Basic Service Charge	$16.50	$30.00	$13.50	81.82%
Energy Charge 1st 400 kWh	$0.030176	$0.032400	$0.002224	7.37%
Energy Charge 401 -7,500 kWh	$0.043176	$0.042400	-$0.000776	-1.80%
Energy Charge >7,500 kWh	$0.076042	$0.077400	$0.001358	1.79%
Base Power Supply Charges				
Base Power Supply Charge, Summer On-Peak all kWhs	$0.129605	$0.109800	-$0.019805	-15.28%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.039605	$0.045800	$0.006195	15.64%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.129605	$0.108800	-$0.020805	-16.05%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.031385	$0.040036	$0.008651	27.56%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Small General Service Demand Time-of-Use				
Basic Service Charge	N/A	$30.00	N/A	N/A
Demand Charge, per kW	N/A	$5.49	N/A	N/A
Energy Charge (kWhs)	N/A	$0.016680	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.084570	N/A	N/A
Base Power Supply Charge, Summer Off-Peak all kWhs	N/A	$0.045800	N/A	N/A
Base Power Supply Charge, Winter On-Peak all kWhs	N/A	$0.083570	N/A	N/A
Base Power Supply Charge, Winter Off-Peak all kWhs	N/A	$0.040036	N/A	N/A
PPFAC[1]	N/A	$0.000000	N/A	N/A
Medium General Service[2]				
Basic Service Charge	$50.00	$100.00	$50.00	100.00%
Demand Charge, per kW	$12.81	$13.95	$1.14	8.90%
Energy Charge (kWhs)	$0.005470	$0.005500	$0.000030	0.55%
Base Power Supply Charge, all kWhs	$0.056603	$0.053290	-$0.003313	-5.85%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Medium General Service Time-of-Use[2]				
Basic Service Charge	$52.00	$100.00	$48.00	92.31%
Demand Charge, per kW	$12.81	$13.95	$1.14	8.90%
Energy Charge (kWhs)	$0.005470	$0.005500	$0.000030	0.55%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.114886	$0.114886	$0.000000	0.00%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039886	$0.033500	-$0.006386	-16.01%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.114886	$0.101047	-$0.013839	-12.05%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.026168	$0.031690	$0.005522	21.10%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

UNS Electric, Inc.
Comparison of Present and Proposed Rates
Test Year Ended December 31, 2014

	Present Rate	Proposed Rate	Increase $	Increase %
Large General Service				
Basic Service Charge	$50.00	$300.00	$250.00	500.00%
Demand Charge, per kW	$12.81	$13.35	$0.54	4.22%
Energy Charge (kWhs)	$0.005470	$0.005470	$0.000000	0.00%
Base Power Supply Charge, all kWhs	$0.056603	$0.053290	-$0.003313	-5.85%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Large General Service Time-of-Use				
Basic Service Charge	$52.00	$300.00	$248.00	476.92%
Demand Charge, per kW	$12.81	$13.35	$0.54	4.22%
Energy Charge (kWhs)	$0.005470	$0.005470	$0.000000	0.00%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.114886	$0.143771	$0.028885	25.14%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.039886	$0.038600	-$0.001286	-3.22%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.114886	$0.139880	$0.024994	21.76%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.026168	$0.034927	$0.008759	33.47%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service[3]				
Basic Service Charge <69 kV	$1,200.00	$300.00	-$900.00	-75.00%
Basic Service Charge ≥69 kV	$1,200.00	$1,500.00	$300.00	25.00%
Demand Charge <69kV, per kW	$22.00	$13.35	-$8.65	-39.32%
Demand Charge ≥69kV, per kW	$17.00	$13.00	-$4.00	-23.53%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005470	$0.005008	1083.98%
Energy Charge (kWhs) ≥69 kV	$0.000462	$0.000500	$0.000038	8.23%
Base Power Supply Charge, all kWhs <69 kV	$0.041880	$0.053290	$0.011410	27.24%
Base Power Supply Charge, all kWhs ≥69 kV	$0.041880	$0.049332	$0.007452	17.79%
PPFAC[1] <69kV	($0.002139)	$0.000000	$0.002139	100.00%
PPFAC[1] ≥69kV	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service Time-of-Use[3]				
Basic Service Charge <69 kV	$1,200.00	$300.00	-$900.00	-75.00%
Basic Service Charge ≥69 kV	$1,200.00	$1,500.00	$300.00	25.00%
Demand Charge <69kV, per kW	$22.00	$13.35	-$8.65	-39.32%
Demand Charge ≥69kV, per kW	$17.00	$13.00	-$4.00	-23.53%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005470	$0.005008	1083.98%
Energy Charge (kWhs) ≥69 kV	$0.000462	$0.000500	$0.000038	8.23%
Base Power Supply Charge <69 kV				
Base Power Supply Charge, Summer On-Peak all kWhs	$0.123580	$0.143771	$0.020191	16.34%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.024716	$0.038600	$0.013884	56.17%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.093880	$0.139880	$0.046000	49.00%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.022105	$0.034927	$0.012822	58.00%
Base Power Supply Charge ≥69 kV				
Base Power Supply Charge, Summer On-Peak all kWhs	$0.123580	$0.125155	$0.001575	1.27%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.024716	$0.033410	$0.008694	35.18%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.093880	$0.092110	-$0.001770	-1.89%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.022105	$0.030410	$0.008305	37.57%
PPFAC[1] <69kV	($0.002139)	$0.000000	$0.002139	100.00%
PPFAC[1] ≥69kV	($0.002139)	$0.000000	$0.002139	100.00%
Large Power Service Mining (≥69kV)				
Basic Service Charge	$1,200.00	$1,500.00	$300.00	25.00%
Demand Charge, per kW	$17.00	$13.00	-$4.00	-23.53%
Energy Charge (kWhs)	$0.000462	$0.000500	$0.000038	8.23%
Base Power Supply Charge, all kWhs	$0.041880	$0.049332	$0.007452	17.79%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%

	Present Rate	Proposed Rate	Increase $	Increase %
Interruptible Power Service				
Basic Service Charge	$18.00	$75.00	$57.00	316.67%
Demand Charge, per kW	$5.00	$5.50	$0.50	10.00%
Energy Charge (kWhs)	$0.019408	$0.019800	$0.000392	2.02%
Base Power Supply Charge, all kWhs	$0.043760	$0.053090	$0.009330	21.32%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
Lighting Dusk to Dawn				
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.68	$0.34	7.83%
New 30' Metal or Fiberglass - Overhead	$8.66	$9.35	$0.69	7.97%
Existing Wood Pole - Underground	$2.18	$2.35	$0.17	7.80%
New 30' Wood Pole (Class 6) - Underground	$6.52	$7.04	$0.52	7.98%
New 30' Metal or Fiberglass - Underground	$10.81	$11.67	$0.86	7.96%
Wattage, per Watt	$0.051681	$0.060516	$0.008835	17.10%
Lighting Base Power Supply Charge, per kWh	$0.010113	$0.014535	$0.004422	43.73%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
TOU - Medium General Service Schools (Formally TOU - Small General Service Schools)				
Basic Service Charge	$16.50	$100.00	$83.50	506.06%
Demand Charge, per kW	N/A	$13.95	N/A	N/A
Energy Charge 1st 400 kWh	$0.030176	$0.005500	-$0.024676	-81.77%
Energy Charge 401 -7,500 kWh	$0.043176	$0.005500	-$0.037676	-87.26%
Energy Charge >7,500 kWh	$0.076042	$0.005500	-$0.070542	-92.77%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.137405	$0.120586	-$0.016819	-12.24%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.047405	$0.039200	-$0.008205	-17.31%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.137405	$0.106747	-$0.030658	-22.31%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.039185	$0.037390	-$0.001795	-4.58%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
TOU - Large General Service Schools				
Basic Service Charge	$52.00	$300.00	$248.00	476.92%
Demand Charge, per kW	$12.81	$13.35	$0.54	4.22%
Energy Charge (kWhs)	$0.005470	$0.005470	$0.000000	0.00%
Base Power Supply Charge, Summer On-Peak all kWhs	$0.120586	$0.148471	$0.027885	23.12%
Base Power Supply Charge, Summer Off-Peak all kWhs	$0.045586	$0.043300	-$0.002286	-5.01%
Base Power Supply Charge, Winter On-Peak all kWhs	$0.120586	$0.144580	$0.023994	19.90%
Base Power Supply Charge, Winter Off-Peak all kWhs	$0.031868	$0.039627	$0.007759	24.35%
PPFAC[1]	($0.002139)	$0.000000	$0.002139	100.00%
RIDER R-5 ELECTRIC SERVICE SOLAR RIDER (BRIGHT ARIZONA COMMUNITY SOLAR™)				
Residential Electric, Rate R-01	$0.084510	$0.075090	-$0.009420	-11.15%
General Service, Rate SGS-10	$0.078241	$0.073290	-$0.004951	-6.33%
Medium General Service, R-MGS (Former LGS)	$0.076603	$0.073290	-$0.003313	-4.32%

[1] The Present Rate for the PPFAC is the Test Year average PPFAC, since the rate varies by month. The Proposed Rate is $0.00, since the PPFAC rate will be reset to zero for one month when the new base rates become effective. However, the PPFAC rate will change monthly in all subsequent months by an amount defined in the proposed PPFAC POA. The Company has proposed the PPFAC be a percentage based adjustment that will be recalculated monthly and reflected as a single percentage based adjustment applied to base fuel cost for each rate class (e.g. the percentage adjustment will be the same percentage value regardless of the rate class).

[2] For the new Medium General Service and Medium General Service Time-of-Use rates, the Present Rate column is populated with the currently existing rates for Large General Service and Large General Service Time-of-Use, respectively, since these two new Medium General Service classes will be comparable to the former Large General Service classes.

	Present Rate	Proposed Rate	Increase $	Increase %

3 The proposed Large Power Service rate classes will be restricted to customers with ≥69kV service. The Proposed Rate column for <69kV service is populated with the Proposed Rates from the corresponding Large General Service rate classes.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$15.00	$0.032258	$0.042258	$0.060258	$0.000000	$0.055090	0.000%			
Xsmall	111	111	0	0	$15.00	$3.58	$0.00	$0.00	$0.00	$6.12	$0.00	$24.70	$5.51	28.7%
Small	330	330	0	0	$15.00	$10.65	$0.00	$0.00	$0.00	$18.18	$0.00	$43.83	$6.49	17.4%
Medium	664	400	264	0	$15.00	$12.90	$11.16	$0.00	$0.00	$36.58	$0.00	$75.64	$6.68	9.7%
Large	1,144	400	600	144	$15.00	$12.90	$25.35	$8.68	$0.00	$63.02	$0.00	$124.96	$8.43	7.2%
Xlarge	2,162	400	600	1,162	$15.00	$12.90	$25.35	$70.02	$0.00	$119.11	$0.00	$242.39	$22.02	10.0%
Mean	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.00	$45.70	$0.00	$91.75	$6.59	7.7%
Sum	983	400	583	0	$15.00	$12.90	$24.65	$0.00	$0.00	$54.17	$0.00	$106.72	$6.52	6.5%
Win	669	400	269	0	$15.00	$12.90	$11.38	$0.00	$0.00	$36.88	$0.00	$76.17	$6.69	9.6%
Annual												$1,097.35	$79.24	7.8%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

WINTER

	BILL IMPACTS PROPOSED TRANSITION RATES													
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh				
							$15.00	$0.032258	$0.042258	$0.060258	$0.000000	$0.055090	$0.000000	
Xsm	19%	0.7	100	100	0	0	$15.00	$3.23	$0.00	$0.00	$0.00	$5.51	$0.00	$23.74
Small	24%	1.7	294	294	0	0	$15.00	$9.48	$0.00	$0.00	$0.00	$16.20	$0.00	$40.68
Medium	28%	2.8	560	400	160	0	$15.00	$12.90	$6.76	$0.00	$0.00	$30.85	$0.00	$65.51
Large	31%	4.1	914	400	514	0	$15.00	$12.90	$21.72	$0.00	$0.00	$50.35	$0.00	$99.97
XLg	35%	6.5	1,653	400	600	653	$15.00	$12.90	$25.35	$39.35	$0.00	$91.06	$0.00	$183.67
AnnAvg	30%	3.8	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.00	$45.70	$0.00	$91.75
WinAvg	29%	3.2	669	400	269	0	$15.00	$12.90	$11.38	$0.00	$0.00	$36.88	$0.00	$76.17

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak			All kW	All kWh							
							$15.00	$5.15	$0.01676	$0.000000						
Winter				0.26	0.74						$0.082800	$0.038610	0.000%			
Summer											$0.102251	$0.042830				
Xsm	19%	0.7	100	26	74		$15.00	$3.61	$1.68	$0.00	$2.15	$2.86	$0.00	$25.30	$1.56	6.59%
Small	24%	1.7	294	76	218		$15.00	$8.76	$4.93	$0.00	$6.29	$8.42	$0.00	$43.40	$2.72	6.68%
Medium	28%	2.8	560	145	415		$15.00	$14.42	$9.39	$0.00	$12.01	$16.02	$0.00	$66.84	$1.33	2.02%
Large	31%	4.1	914	237	677		$15.00	$21.12	$15.32	$0.00	$19.62	$26.14	$0.00	$97.20	-$2.77	-2.77%
XLg	35%	6.5	1,653	429	1,224		$15.00	$33.48	$27.70	$0.00	$35.52	$47.26	$0.00	$158.96	-$24.71	-13.45%
AnnAvg	30%	3.8	830	215	614		$15.00	$19.57	$13.90	$0.00	$17.80	$23.71	$0.00	$89.98	-$1.77	-1.93%
WinAvg	29%	3.2	669	174	496		$15.00	$16.48	$11.22	$0.00	$14.41	$19.15	$0.00	$76.26	$0.09	0.12%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
								0-400 kWh	401-1,000 kWh	1,000+ kWh				
				0-400	401-1,000	1,000+	$15.00	$0.032258	$0.042258	$0.060258	$0.000000	$0.055090	$0.000000	
Xsm	20%	0.8	117	117	0	0	$15.00	$3.77	$0.00	$0.00	$0.00	$6.45	$0.00	$25.22
Small	25%	2.1	386	386	0	0	$15.00	$12.45	$0.00	$0.00	$0.00	$21.26	$0.00	$48.71
Medium	30%	3.7	813	400	413	0	$15.00	$12.90	$17.45	$0.00	$0.00	$44.79	$0.00	$90.15
Large	34%	5.7	1,395	400	600	395	$15.00	$12.90	$25.35	$23.80	$0.00	$76.85	$0.00	$153.91
XLg	38%	9.0	2,471	400	600	1,471	$15.00	$12.90	$25.35	$88.64	$0.00	$136.13	$0.00	$278.03
AnnAvg	30%	3.8	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.00	$45.70	$0.00	$91.75
SumAvg	31%	4.3	983	400	583	0	$15.00	$12.90	$24.65	$0.00	$0.00	$54.17	$0.00	$106.72

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
								All kW	All kWh							
				On-Peak	Off-Peak		$15.00	$5.15	$0.01676	$0.000000						
Winter											$0.082800	$0.038610				
Summer				0.24	0.76						$0.102251	$0.042830	0.000%			
Xsm	20%	0.8	117	28	89		$15.00	$4.12	$1.96	$0.00	$2.86	$3.81	$0.00	$27.75	$2.53	10.01%
Small	25%	2.1	386	93	293		$15.00	$10.82	$6.47	$0.00	$9.51	$12.55	$0.00	$54.35	$5.64	11.57%
Medium	30%	3.7	813	196	617		$15.00	$19.06	$13.63	$0.00	$20.04	$26.43	$0.00	$94.16	$4.01	4.45%
Large	34%	5.7	1,395	336	1,059		$15.00	$29.36	$23.38	$0.00	$34.36	$45.36	$0.00	$147.46	-$6.45	-4.19%
XLg	38%	9.0	2,471	595	1,876		$15.00	$46.35	$41.41	$0.00	$60.84	$80.35	$0.00	$243.95	-$34.08	-12.26%
AnnAvg	30%	3.8	830	200	630		$15.00	$19.57	$13.90	$0.00	$20.45	$26.98	$0.00	$95.90	$4.15	4.52%
SumAvg	31%	4.3	983	237	747		$15.00	$22.15	$16.48	$0.00	$24.23	$31.99	$0.00	$109.85	$3.13	2.93%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	220	220	0	$4.90	$4.17	$0.00	$0.25	$13.57	-$0.47	$15.69	30.00%
Small	360	360	0	$4.90	$6.83	$0.00	$0.41	$22.21	-$0.77	$26.86	20.00%
Medium	607	400	207	$4.90	$7.59	$7.33	$0.69	$37.45	-$1.30	$50.99	10.00%
Large	990	400	590	$4.90	$7.59	$20.89	$1.13	$61.08	-$2.12	$84.12	10.00%
Xlarge	1,843	400	1,443	$4.90	$7.59	$51.08	$2.10	$113.71	-$3.94	$167.44	$8.00
Mean	753	400	353	$4.90	$7.59	$12.49	$0.86	$46.45	-$1.61	$63.61	10.00%
Sum	867	400	467	$4.90	$7.59	$16.53	$0.99	$53.49	-$1.85	$73.49	10.00%
Win	638	400	238	$4.90	$7.59	$8.43	$0.73	$39.37	-$1.37	$53.69	10.00%
Annual										$763.08	

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change	
		1-400	401+	$9.00	$0.030800	$0.050800	$0.000000	$0.050260	0.000%				
Xsmall	220	220	0	$9.00	$6.78	$0.00	$0.00	$11.06	$0.00	$18.79	$3.10	19.75%	30.00%
Small	360	360	0	$9.00	$11.09	$0.00	$0.00	$18.09	$0.00	$30.54	$3.68	13.72%	20.00%
Medium	607	400	207	$9.00	$12.32	$10.52	$0.00	$30.51	$0.00	$56.12	$5.13	10.05%	10.00%
Large	990	400	590	$9.00	$12.32	$29.97	$0.00	$49.76	$0.00	$90.95	$6.82	8.11%	10.00%
Xlarge	1,843	400	1,443	$9.00	$12.32	$73.30	$0.00	$92.63	$0.00	$179.25	$11.81	7.05%	$8.00
Mean	753	400	353	$9.00	$12.32	$17.93	$0.00	$37.84	$0.00	$69.38	$5.77	9.07%	10.00%
Sum	867	400	467	$9.00	$12.32	$23.72	$0.00	$43.57	$0.00	$79.75	$6.26	8.52%	10.00%
Win	638	400	238	$9.00	$12.32	$12.09	$0.00	$32.07	$0.00	$58.93	$5.24	9.76%	10.00%
Annual										$832.09	$69.01	9.04%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES MEDICAL

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	365	365	0	$4.90	$6.93	$0.00	$0.42	$22.52	-$0.78	$23.79	30.00%
Small	564	400	164	$4.90	$7.59	$5.81	$0.64	$34.80	-$1.21	$36.77	30.00%
Medium	878	400	478	$4.90	$7.59	$16.92	$1.00	$54.17	-$1.88	$66.16	20.00%
Large	1,340	400	940	$4.90	$7.59	$33.28	$1.53	$82.68	-$2.87	$114.40	10.00%
Xlarge	2,304	400	1,904	$4.90	$7.59	$67.40	$2.63	$142.16	-$4.93	$211.75	$8.00
Mean	1,034	400	634	$4.90	$7.59	$22.43	$1.18	$63.78	-$2.21	$78.13	20.00%
sum	1,199	400	799	$4.90	$7.59	$28.28	$1.37	$73.97	-$2.56	$90.84	20.00%
win	871	400	471	$4.90	$7.59	$16.68	$0.99	$53.75	-$1.86	$65.64	20.00%
Annual										$938.88	

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	$ Change	% Change	Discounts
		1-400	401+	$9.00	$0.030800	$0.050800	$0.000000	$0.050260	0.000%				
Xsmall	365	365	0	$9.00	$11.24	$0.00	$0.00	$18.34	$0.00	$27.01	$3.22	13.5%	30.00%
Small	564	400	164	$9.00	$12.32	$8.33	$0.00	$28.35	$0.00	$40.60	$3.83	10.4%	30.00%
Medium	878	400	478	$9.00	$12.32	$24.28	$0.00	$44.13	$0.00	$71.78	$5.62	8.5%	20.00%
Large	1,340	400	940	$9.00	$12.32	$47.75	$0.00	$67.35	$0.00	$136.32	$21.92	19.2%	10.00%
Xlarge	2,304	400	1,904	$9.00	$12.32	$96.72	$0.00	$115.80	$0.00	$225.84	$14.09	6.7%	$8.00
Mean	1,034	400	634	$9.00	$12.32	$32.19	$0.00	$51.95	$0.00	$84.37	$6.24	8.0%	20.00%
sum	1,199	400	799	$9.00	$12.32	$40.58	$0.00	$60.25	$0.00	$97.72	$6.88	7.6%	20.00%
win	871	400	471	$9.00	$12.32	$23.93	$0.00	$43.78	$0.00	$71.22	$5.58	8.5%	20.00%
Annual										$1,013.66	$74.78	8.0%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+	$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	22%	1.2	198	198	0	0	$9.00	$6.10	$0.00	$0.00	$0.00	$9.95	$0.00	$17.53	30.00%
Small	25%	1.8	324	324	0	0	$9.00	$9.98	$0.00	$0.00	$0.00	$16.28	$0.00	$28.21	20.00%
Medium	27%	2.7	525	400	125	0	$9.00	$12.32	$6.35	$0.00	$0.00	$26.39	$0.00	$48.65	10.00%
Large	30%	3.8	831	400	431	0	$9.00	$12.32	$21.89	$0.00	$0.00	$41.77	$0.00	$76.49	10.00%
XLg	34%	6.0	1,496	400	600	496	$9.00	$12.32	$30.48	$25.20	$0.00	$75.19	$0.00	$144.19	$8.00
AnnAvg	30%	3.9	867	400	467	0	$9.00	$12.32	$23.72	$0.00	$0.00	$43.57	$0.00	$79.75	10.00%
WinAvg	28%	3.1	638	400	238	0	$9.00	$12.32	$12.09	$0.00	$0.00	$32.07	$0.00	$58.94	10.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		15.00	5.15	$0.01676	$0.000000							
Winter				0.26	0.74						$0.082800	$0.038610	0.000%				
Summer											$0.102251	$0.042830					
Xsm	22%	1.2	198	51	147		$15.00	$6.18	$3.32	$0.00	$4.22	$5.68	$0.00	$28.21	$10.68	60.9%	18.00%
Small	25%	1.8	324	84	240		$15.00	$9.27	$5.43	$0.00	$6.96	$9.27	$0.00	$37.66	$9.45	33.5%	18.00%
Medium	27%	2.7	525	136	389		$15.00	$13.91	$8.80	$0.00	$11.26	$15.02	$0.00	$52.47	$3.82	7.9%	18.00%
Large	30%	3.8	831	216	615		$15.00	$19.57	$13.93	$0.00	$17.88	$23.75	$0.00	$73.91	-$2.58	-3.4%	18.00%
XLg	34%	6.0	1,496	388	1,108		$15.00	$30.90	$25.07	$0.00	$32.13	$42.78	$0.00	$129.88	-$14.31	-9.9%	$16.00
AnnAvg	30%	3.9	867	225	642		$15.00	$20.09	$14.53	$0.00	$18.63	$24.79	$0.00	$76.29	-$3.46	-4.3%	18.00%
WinAvg	28%	3.1	638	166	472		$15.00	$15.97	$10.69	$0.00	$13.74	$18.22	$0.00	$60.37	$1.43	2.4%	18.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+	$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	23%	1.4	243	243	0	0	$9.00	$7.48	$0.00	$0.00	$0.00	$12.21	$0.00	$20.09	30.00%
Small	26%	2.2	413	400	13	0	$9.00	$12.32	$0.66	$0.00	$0.00	$20.76	$0.00	$34.19	20.00%
Medium	29%	3.4	709	400	309	0	$9.00	$12.32	$15.70	$0.00	$0.00	$35.63	$0.00	$65.38	10.00%
Large	32%	4.9	1,161	400	600	161	$9.00	$12.32	$30.48	$8.18	$0.00	$58.35	$0.00	$110.33	$8.00
XLg	37%	7.8	2,078	400	600	1,078	$9.00	$12.32	$30.48	$54.76	$0.00	$104.44	$0.00	$203.00	$8.00
AnnAvg	30%	3.9	867	400	467	0	$9.00	$12.32	$23.72	$0.00	$0.00	$43.57	$0.00	$79.75	10.00%
SumAvg	30%	3.9	863	400	463	0	$9.00	$12.32	$23.54	$0.00	$0.00	$43.39	$0.00	$79.43	10.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak	$15.00	$5.15	$0.01676	$0.000000							
Winter										$0.082800	$0.038610					
Summer				0.24	0.76					$0.102251	$0.042830	0.000%				
Xsm	23%	1.4	243	58	185	$15.00	$7.21	$4.07	$0.00	$5.93	$7.92	$0.00	$32.91	$12.82	63.8%	18.00%
Small	26%	2.2	413	99	314	$15.00	$11.33	$6.92	$0.00	$10.12	$13.45	$0.00	$46.59	$12.40	36.3%	18.00%
Medium	29%	3.4	709	171	538	$15.00	$17.51	$11.88	$0.00	$17.48	$23.04	$0.00	$69.63	$4.25	6.5%	18.00%
Large	32%	4.9	1,161	279	882	$15.00	$25.24	$19.46	$0.00	$28.53	$37.78	$0.00	$110.01	-$0.32	-0.3%	$16.00
XLg	37%	7.8	2,078	500	1,578	$15.00	$40.17	$34.83	$0.00	$51.13	$67.59	$0.00	$192.72	-$10.28	-5.1%	$16.00
AnnAvg	30%	3.9	867	209	658	$15.00	$20.09	$14.53	$0.00	$21.37	$28.18	$0.00	$81.32	$1.57	2.0%	18.00%
SumAvg	30%	3.9	863	208	656	$15.00	$20.09	$14.47	$0.00	$21.27	$28.10	$0.00	$81.12	$1.69	2.1%	18.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

WINTER

	BILL IMPACTS PROPOSED TRANSITION RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
								0-400 kWh	401-1,000 kWh	1,000+ kWh					
				0-400	401-1,000	1,000+	$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	24%	1.8	323	323	0	0	$9.00	$9.95	$0.00	$0.00	$0.00	$16.23	$0.00	$24.62	30.00%
Small	27%	2.5	495	400	95	0	$9.00	$12.32	$4.83	$0.00	$0.00	$24.88	$0.00	$35.72	30.00%
Medium	29%	3.6	763	400	363	0	$9.00	$12.32	$18.44	$0.00	$0.00	$38.35	$0.00	$62.49	20.00%
Large	32%	4.8	1,115	400	600	115	$9.00	$12.32	$30.48	$5.84	$0.00	$56.04	$0.00	$90.95	20.00%
XLg	36%	7.2	1,887	400	600	887	$9.00	$12.32	$30.48	$45.06	$0.00	$94.84	$0.00	$172.53	10.00%
AnnAvg	32%	5.1	1,199	400	600	199	$9.00	$12.32	$30.48	$10.10	$0.00	$60.25	$0.00	$97.72	20.00%
WinAvg	30%	4.0	871	400	471	0	$9.00	$12.32	$23.93	$0.00	$0.00	$43.78	$0.00	$71.23	20.00%

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
							All kW	All kWh								
				On-Peak	Off-Peak	15.00	5.15	$0.01676	$0.000000							
Winter				0.26	0.74					$0.082800	$0.038610	0.000%				
Summer										$0.102251	$0.042830					
Xsm	24%	1.8	323	84	239	$15.00	$9.27	$5.41	$0.00	$6.96	$9.23	$0.00	$34.86	$10.24	41.6%	24.00%
Small	27%	2.5	495	128	367	$15.00	$12.88	$8.30	$0.00	$10.60	$14.17	$0.00	$46.32	$10.60	29.7%	24.00%
Medium	29%	3.6	763	198	565	$15.00	$18.54	$12.79	$0.00	$16.39	$21.81	$0.00	$64.24	$1.75	2.8%	24.00%
Large	32%	4.8	1,115	289	826	$15.00	$24.72	$18.69	$0.00	$23.93	$31.89	$0.00	$86.81	-$4.14	-4.6%	24.00%
XLg	36%	7.2	1,887	490	1,397	$15.00	$37.08	$31.63	$0.00	$40.57	$53.94	$0.00	$135.45	-$37.08	-21.5%	24.00%
AnnAvg	32%	5.1	1,199	311	888	$15.00	$26.27	$20.09	$0.00	$25.75	$34.29	$0.00	$92.26	-$5.46	-5.6%	24.00%
WinAvg	30%	4.0	871	226	645	$15.00	$20.60	$14.60	$0.00	$18.71	$24.90	$0.00	$71.30	$0.07	0.1%	24.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
								0-400 kWh	401-1,000 kWh	1,000+ kWh					
				0-400	401-1,000	1,000+	$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	26%	2.2	414	400	14	0	$9.00	$12.32	$0.71	$0.00	$0.00	$20.81	$0.00	$29.99	30.00%
Small	29%	3.2	663	400	263	0	$9.00	$12.32	$13.34	$0.00	$0.00	$33.30	$0.00	$54.36	20.00%
Medium	31%	4.5	1,035	400	600	35	$9.00	$12.32	$30.48	$1.78	$0.00	$52.02	$0.00	$84.48	20.00%
Large	34%	6.3	1,572	400	600	572	$9.00	$12.32	$30.48	$29.03	$0.00	$78.98	$0.00	$143.83	10.00%
XLg	38%	9.3	2,601	400	600	1,601	$9.00	$12.32	$30.48	$81.33	$0.00	$130.73	$0.00	$255.86	$8.00
AnnAvg	32%	5.1	1,199	400	600	199	$9.00	$12.32	$30.48	$10.10	$0.00	$60.25	$0.00	$97.72	20.00%
SumAvg	32%	5.0	1,194	400	600	194	$9.00	$12.32	$30.48	$9.84	$0.00	$60.00	$0.00	$97.32	20.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		All kW	All kWh								
						$15.00	$5.15	$0.01676	$0.000000							
Winter										$0.082800	$0.038610					
Summer				0.24	0.76					$0.102251	$0.042830	0.000%				
Xsm	26%	2.2	414	100	314	$15.00	$11.33	$6.94	$0.00	$10.23	$13.45	$0.00	$43.28	$13.29	44.3%	24.00%
Small	29%	3.2	663	159	503	$15.00	$16.48	$11.10	$0.00	$16.26	$21.54	$0.00	$61.09	$6.73	12.4%	24.00%
Medium	31%	4.5	1,035	249	786	$15.00	$23.18	$17.35	$0.00	$25.46	$33.66	$0.00	$87.13	$2.65	3.1%	24.00%
Large	34%	6.3	1,572	378	1,193	$15.00	$32.45	$26.34	$0.00	$38.65	$51.10	$0.00	$124.29	-$19.54	-13.6%	24.00%
XLg	38%	9.3	2,601	626	1,975	$15.00	$47.90	$43.59	$0.00	$64.01	$84.59	$0.00	$239.09	-$16.77	-6.6%	$16.00
AnnAvg	32%	5.1	1,199	288	910	$15.00	$26.27	$20.09	$0.00	$29.45	$38.98	$0.00	$98.64	$0.92	0.9%	24.00%
SumAvg	32%	5.0	1,194	287	907	$15.00	$25.75	$20.01	$0.00	$29.35	$38.85	$0.00	$98.01	$0.69	0.7%	24.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter	0.24	0.76				$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer									$0.129605	$0.039605		
Xsm	150	36	114	150	0	0	$11.50	$4.55	$0.17	$4.67	$3.58	-$0.32	$24.15
Small	286	69	217	286	0	0	$11.50	$8.68	$0.33	$8.90	$6.82	-$0.61	$35.62
Medium	641	154	487	400	241	0	$11.50	$19.45	$0.73	$19.94	$15.29	-$1.37	$65.54
Large	1,043	250	793	400	600	43	$11.50	$31.66	$1.19	$32.44	$24.88	-$2.23	$99.44
XLg	1,810	434	1,376	400	600	810	$11.50	$54.93	$2.06	$56.30	$43.17	-$3.87	$164.09
AnnAvg	1,008	242	766	400	600	8	$11.50	$30.59	$1.15	$31.36	$24.05	-$2.16	$96.49
Avg Win	801	192	608	400	401	0	$11.50	$24.30	$0.91	$24.90	$19.10	-$1.71	$79.00

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610	0.000%			
	Summer											$0.111001	$0.042830			$ Change	% Change
Xsm	150	36	114	150	0	0	$15.00	$5.54	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.24	$4.09	16.94%
Small	286	69	217	286	0	0	$15.00	$10.55	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$40.22	$4.60	12.91%
Medium	641	154	487	400	241	0	$15.00	$14.76	$8.89	$0.00	- $0.00	$14.08	$18.81	$0.00	$71.54	$6.00	9.15%
Large	1,043	250	793	400	600	43	$15.00	$14.76	$22.14	$1.59	$0.00	$22.92	$30.61	$0.00	$107.02	$7.58	7.62%
XLg	1,810	434	1,376	400	600	810	$15.00	$14.76	$22.14	$29.89	$0.00	$39.77	$53.11	$0.00	$174.67	$10.58	6.45%
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$22.15	$29.58	$0.00	$103.93	$7.44	7.71%
Avg Win	801	192	608	400	401	0	$15.00	$14.76	$14.78	$0.00	$0.00	$17.59	$23.49	$0.00	$85.62	$6.62	8.38%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter						$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.23	0.77							$0.129605	$0.039605		
Xsm	261	60	201	261	0	0	$11.50	$7.92	$0.30	$7.78	$7.96	-$0.56	$34.90
Small	525	121	404	400	125	0	$11.50	$15.93	$0.60	$15.65	$16.01	-$1.12	$58.57
Medium	983	226	757	400	583	0	$11.50	$29.83	$1.12	$29.30	$29.98	-$2.10	$99.63
Large	1,611	371	1,240	400	600	611	$11.50	$48.89	$1.84	$48.02	$49.13	-$3.45	$155.93
XLg	2,681	617	2,064	400	600	1,681	$11.50	$81.37	$3.06	$79.92	$81.76	-$5.74	$251.87
AnnAvg	1,008	232	776	400	600	8	$11.50	$30.59	$1.15	$30.05	$30.74	-$2.16	$101.87
Avg Sum	1,195	275	920	400	600	195	$11.50	$36.26	$1.36	$35.61	$36.43	-$2.56	$118.60

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610				
	Summer											$0.111001	$0.042830	0.000%		$ Change	% Change
Xsm	261	60	201	261	0	0	$15.00	$9.63	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.90	$5.00	14.32%
Small	525	121	404	400	125	0	$15.00	$14.76	$4.61	$0.00	$0.00	$13.40	$17.31	$0.00	$65.08	$6.51	11.12%
Medium	983	226	757	400	583	0	$15.00	$14.76	$21.51	$0.00	$0.00	$25.10	$32.42	$0.00	$108.79	$9.16	9.20%
Large	1,611	371	1,240	400	600	611	$15.00	$14.76	$22.14	$22.55	$0.00	$41.13	$53.13	$0.00	$168.71	$12.78	8.19%
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.76	$22.14	$62.03	$0.00	$68.45	$88.42	$0.00	$270.80	$18.93	7.51%
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$25.74	$33.25	$0.00	$111.19	$9.32	9.15%
Avg Sum	1,195	275	920	400	600	195	$15.00	$14.76	$22.14	$7.19	$0.00	$30.50	$39.40	$0.00	$128.99	$10.39	8.76%

															$ Change	% Change
Current Annual														$1,185.62		
Proposed Annual														$1,287.66	$102.04	8.61%

Exhibit CAJ-R-4

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Schedule H-4

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS PROPOSED RES-TOU RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.24	0.76				$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610	0.000%	
	Summer											$0.111001	$0.042830		
Xsm	150	36	114	150	0	0	$15.00	$5.54	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.24
Small	286	69	217	286	0	0	$15.00	$10.55	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$40.22
Medium	641	154	487	400	241	0	$15.00	$14.76	$8.89	$0.00	$0.00	$14.08	$18.81	$0.00	$71.54
Large	1,043	250	793	400	600	43	$15.00	$14.76	$22.14	$1.59	$0.00	$22.92	$30.61	$0.00	$107.02
XLg	1,810	434	1,376	400	600	810	$15.00	$14.76	$22.14	$29.89	$0.00	$39.77	$53.11	$0.00	$174.67
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$22.15	$29.58	$0.00	$103.93
WinAvg	801	192	608	400	401	0	$15.00	$14.76	$14.78	$0.00	$0.00	$17.59	$23.49	$0.00	$85.62

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
								All kW	All kWh							
		On-Peak	Off-Peak				$15.00	$5.15	$0.01676	$0.000000						
Winter		0.24	0.76								$0.082800	$0.038610	0.000%			
Summer											$0.102251	$0.042830				
Xsm	150	36	114	21%	1.0		$15.00	$5.15	$2.51	$0.00	$2.98	$4.40	$0.00	$30.04	$1.80	6.37%
Small	286	69	217	24%	1.6		$15.00	$8.24	$4.79	$0.00	$5.68	$8.39	$0.00	$42.10	$1.88	4.67%
Medium	641	154	487	28%	3.1		$15.00	$15.97	$10.74	$0.00	$12.74	$18.81	$0.00	$73.26	$1.72	2.40%
Large	1,043	250	793	31%	4.5		$15.00	$23.18	$17.48	$0.00	$20.73	$30.61	$0.00	$107.00	-$0.02	-0.02%
XLg	1,810	434	1,376	35%	7.0		$15.00	$36.05	$30.34	$0.00	$35.97	$53.11	$0.00	$170.47	-$4.20	-2.40%
AnnAvg	1,008	242	766	31%	4.4		$15.00	$22.66	$16.90	$0.00	$20.03	$29.58	$0.00	$104.17	$0.24	0.23%
WinAvg	801	192	608	30%	3.7		$15.00	$19.06	$13.42	$0.00	$15.91	$23.49	$0.00	$86.88	$1.26	1.47%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED RES-TOU RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610		
	Summer	0.23	0.77									$0.111001	$0.042830	0.000%	
Xsm	261	60	201	261	0	0	$15.00	$9.63	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.90
Small	525	121	404	400	125	0	$15.00	$14.76	$4.61	$0.00	$0.00	$13.40	$17.31	$0.00	$65.08
Medium	983	226	757	400	583	0	$15.00	$14.76	$21.51	$0.00	$0.00	$25.10	$32.42	$0.00	$108.79
Large	1,611	371	1,240	400	600	611	$15.00	$14.76	$22.14	$22.55	$0.00	$41.13	$53.13	$0.00	$168.71
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.76	$22.14	$62.03	$0.00	$68.45	$88.42	$0.00	$270.80
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$25.74	$33.25	$0.00	$111.19
SumAvg	1,195	275	920	400	600	195	$15.00	$14.76	$22.14	$7.19	$0.00	$30.50	$39.40	$0.00	$128.99

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak					All kW	All kWh							
							$15.00	$5.15	$0.01676	$0.000000						
Winter											$0.082800	$0.038610				
Summer		0.23	0.77								$0.102251	$0.042830	0.000%			
Xsm	261	60	201	23%	1.5		$15.00	$7.73	$4.37	$0.00	$6.14	$8.61	$0.00	$41.85	$1.95	4.89%
Small	525	121	404	27%	2.7		$15.00	$13.91	$8.80	$0.00	$12.37	$17.30	$0.00	$67.38	$2.30	3.53%
Medium	983	226	757	31%	4.3		$15.00	$22.15	$16.48	$0.00	$23.11	$32.42	$0.00	$109.16	$0.37	0.34%
Large	1,611	371	1,240	35%	6.4		$15.00	$32.96	$27.00	$0.00	$37.94	$53.11	$0.00	$166.01	-$2.70	-1.60%
XLg	2,681	617	2,064	39%	9.5		$15.00	$48.93	$44.93	$0.00	$63.09	$88.40	$0.00	$260.35	-$10.45	-3.86%
AnnAvg	1,008	232	776	31%	4.4		$15.00	$22.66	$16.90	$0.00	$23.72	$33.24	$0.00	$111.52	$0.33	0.30%
SumAvg	1,195	275	920	32%	5.1		$15.00	$26.27	$20.02	$0.00	$28.12	$39.40	$0.00	$128.81	-$0.18	-0.14%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.1	0.9				$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer											$0.170000	$0.039700		
Xsm	150	15	135	150	0	0	$11.50	$3.75	$0.00	$0.00	$0.17	$2.25	$5.22	-$0.32	$22.57
Small	286	29	257	286	0	0	$11.50	$7.15	$0.00	$0.00	$0.33	$4.29	$9.96	-$0.61	$32.62
Medium	641	64	577	400	241	0	$11.50	$10.00	$8.44	$0.00	$0.73	$9.62	$22.33	-$1.37	$61.25
Large	1,043	104	939	400	600	43	$11.50	$10.00	$21.00	$1.51	$1.19	$15.65	$36.33	-$2.23	$94.95
XLg	1,810	181	1,629	400	600	810	$11.50	$10.00	$21.00	$28.35	$2.06	$27.15	$63.04	-$3.87	$159.23
AnnAvg	1,008	101	907	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$15.12	$35.11	-$2.16	$92.00
Avg Win	801	80	721	400	401	0	$11.50	$10.00	$14.02	$0.00	$0.91	$12.01	$27.89	-$1.71	$74.62

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.032258	$0.035500	$0.035500	$0.000000	$0.159790	$0.040810	0.000%			
	Summer											$0.159790	$0.040810			$ Change	% Change
Xsm	150	15	135	150	0	0	$15.00	$4.84	$0.00	$0.00	$0.00	$2.40	$5.51	$0.00	$27.75	$5.18	22.95%
Small	286	29	257	286	0	0	$15.00	$9.23	$0.00	$0.00	$0.00	$4.57	$10.50	$0.00	$39.30	$6.68	20.48%
Medium	641	64	577	400	241	0	$15.00	$12.90	$8.56	$0.00	$0.00	$10.24	$23.54	$0.00	$70.24	$8.99	14.68%
Large	1,043	104	939	400	600	43	$15.00	$12.90	$21.30	$1.53	$0.00	$16.67	$38.31	$0.00	$105.71	$10.76	11.33%
XLg	1,810	181	1,629	400	600	810	$15.00	$12.90	$21.30	$28.76	$0.00	$28.92	$66.48	$0.00	$173.36	$14.13	8.87%
AnnAvg	1,008	101	907	400	600	8	$15.00	$12.90	$21.30	$0.29	$0.00	$16.11	$37.03	$0.00	$102.63	$10.63	11.55%
AvgWin	801	80	721	400	401	0	$15.00	$12.90	$14.22	$0.00	$0.00	$12.79	$29.41	$0.00	$84.32	$9.70	13.00%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter						$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer	0.14	0.86									$0.170000	$0.039700		
Xsm	261	37	224	261	0	0	$11.50	$6.53	$0.00	$0.00	$0.30	$6.21	$8.91	-$0.56	$32.89
Small	525	74	452	400	125	0	$11.50	$10.00	$4.38	$0.00	$0.60	$12.50	$17.92	-$1.12	$55.78
Medium	983	138	845	400	583	0	$11.50	$10.00	$20.41	$0.00	$1.12	$23.40	$33.56	-$2.10	$97.89
Large	1,611	226	1,385	400	600	611	$11.50	$10.00	$21.00	$21.39	$1.84	$38.34	$55.00	-$3.45	$155.62
XLg	2,681	375	2,306	400	600	1,681	$11.50	$10.00	$21.00	$58.84	$3.06	$63.81	$91.53	-$5.74	$254.00
AnnAvg	1,008	141	867	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$23.99	$34.42	-$2.16	$100.18
AvgSum	1,195	167	1,027	400	600	195	$11.50	$10.00	$21.00	$6.82	$1.36	$28.43	$40.79	-$2.56	$117.34

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.032258	$0.035500	$0.035500	$0.000000	$0.159790	$0.040810				
	Summer	0.14	0.86									$0.159790	$0.040810	0.000%		$ Change	% Change
Xsm	261	37	224	261	0	0	$15.00	$8.42	$0.00	$0.00	$0.00	$5.84	$9.16	$0.00	$38.42	$5.53	16.81%
Small	525	74	452	400	125	0	$15.00	$12.90	$4.44	$0.00	$0.00	$11.74	$18.43	$0.00	$62.51	$6.73	12.07%
Medium	983	138	845	400	583	0	$15.00	$12.90	$20.70	$0.00	$0.00	$21.99	$34.50	$0.00	$105.09	$7.20	7.36%
Large	1,611	226	1,385	400	600	611	$15.00	$12.90	$21.30	$21.69	$0.00	$36.04	$56.54	$0.00	$163.47	$7.85	5.04%
XLg	2,681	375	2,306	400	600	1,681	$15.00	$12.90	$21.30	$59.68	$0.00	$59.98	$94.09	$0.00	$262.95	$8.95	3.52%
AnnAvg	1,008	141	867	400	600	8	$15.00	$12.90	$21.30	$0.29	$0.00	$22.55	$35.38	$0.00	$107.42	$7.24	7.22%
AvgSum	1,195	167	1,027	400	600	195	$15.00	$12.90	$21.30	$6.91	$0.00	$26.73	$41.93	$0.00	$124.77	$7.43	6.33%

	Net Bill	$ Change	% Change
Current Annual	$1,151.78		
Proposed Annual	$1,254.54	$102.76	8.92%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

SMALL GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery kWh 1-400	Delivery kWh 401-7500	Delivery kWh 7501+	Basic Service Charge	Delivery (kWh) 1-400	Delivery (kWh) 401-7500	Delivery (kWh) 7501+	TCA	Base Fuel	PPFAC	Net Bill
					$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	200	200	0	0	$14.50	$6.04	$0.00	$0.00	$0.23	$11.65	-$0.43	$31.99
Small	350	350	0	0	$14.50	$10.56	$0.00	$0.00	$0.40	$20.38	-$0.75	$45.09
Medium	561	400	161	0	$14.50	$12.07	$6.61	$0.00	$0.64	$32.67	-$1.20	$65.29
Large	1,447	400	1,047	0	$14.50	$12.07	$42.97	$0.00	$1.65	$84.27	-$3.10	$152.36
XLg	4,078	400	3,678	0	$14.50	$12.07	$150.95	$0.00	$4.65	$237.51	-$8.72	$410.96
Mean	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
sum	1,277	400	877	0	$14.50	$12.07	$36.00	$0.00	$1.46	$74.39	-$2.73	$135.69
win	980	400	580	0	$14.50	$12.07	$23.82	$0.00	$1.12	$57.10	-$2.10	$106.51
Annual												$1,453.20

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery kWh 1-400	Delivery kWh 401-7500	Delivery kWh 7501+	Basic Service Charge	Delivery (kWh) 1-400	Delivery (kWh) 401-7500	Delivery (kWh) 7501+	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	0.000%			
Xsm	200	200	0	0	$30.00	$6.48	$0.00	$0.00	$0.00	$10.66	$0.00	$47.14	$15.15	47.35%
Small	350	350	0	0	$30.00	$11.34	$0.00	$0.00	$0.00	$18.65	$0.00	$59.99	$14.90	33.04%
Medium	561	400	161	0	$30.00	$12.96	$6.83	$0.00	$0.00	$29.90	$0.00	$79.69	$14.40	22.06%
Large	1,447	400	1,047	0	$30.00	$12.96	$44.39	$0.00	$0.00	$77.11	$0.00	$164.46	$12.10	7.94%
XLg	4,078	400	3,678	0	$30.00	$12.96	$155.95	$0.00	$0.00	$217.32	$0.00	$416.23	$5.27	1.28%
Mean	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22	$12.91	10.64%
sum	1,277	400	877	0	$30.00	$12.96	$37.20	$0.00	$0.00	$68.07	$0.00	$148.23	$12.54	9.24%
win	980	400	580	0	$30.00	$12.96	$24.61	$0.00	$0.00	$52.25	$0.00	$119.82	$13.31	12.49%
Annual												$1,608.30	$155.10	10.67%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE DEMAND

WINTER

	BILL IMPACTS PROPOSED TRANSITION RATES													
	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
				1-400	401-7500	7501+		1-400	401-7500	7501+				
							$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	$0.000000	
Xsm	27%	0.9	173	173	0	0	$30.00	$5.61	$0.00	$0.00	$0.00	$9.22	$0.00	$44.82
Small	30%	1.4	303	303	0	0	$30.00	$9.82	$0.00	$0.00	$0.00	$16.15	$0.00	$55.96
Medium	33%	2.0	486	400	86	0	$30.00	$12.96	$3.65	$0.00	$0.00	$25.90	$0.00	$72.51
Large	40%	4.3	1,254	400	854	0	$30.00	$12.96	$36.21	$0.00	$0.00	$66.83	$0.00	$146.00
XLg	48%	10.1	3,535	400	3,135	0	$30.00	$12.96	$132.92	$0.00	$0.00	$188.38	$0.00	$364.26
AnnAvg	39%	4.0	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22
WinAvg	38%	3.6	980	400	580	0	$30.00	$12.96	$24.61	$0.00	$0.00	$52.25	$0.00	$119.82

	BILL IMPACTS PROPOSED RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
						30.00	5.49	$0.016680	$0.000000	On-Peak	Off-Peak				
	Winter			0.30	0.70					$0.083570	$0.040036	0.000%			
	Summer									$0.084570	$0.045800				
Xsm	27%	0.9	173	53	120	$30.00	$4.94	$2.89	$0.00	$4.39	$4.82	$0.00	$47.04	$2.22	4.94%
Small	30%	1.4	303	92	211	$30.00	$7.69	$5.05	$0.00	$7.70	$8.44	$0.00	$58.88	$2.92	5.21%
Medium	33%	2.0	486	148	338	$30.00	$10.98	$8.11	$0.00	$12.35	$13.54	$0.00	$74.98	$2.47	3.41%
Large	40%	4.3	1,254	381	873	$30.00	$23.61	$20.92	$0.00	$31.86	$34.94	$0.00	$141.33	-$4.67	-3.20%
XLg	48%	10.1	3,535	1,075	2,460	$30.00	$55.45	$58.96	$0.00	$89.80	$98.50	$0.00	$332.71	-$31.55	-8.66%
AnnAvg	39%	4.0	1,131	344	787	$30.00	$21.96	$18.86	$0.00	$28.73	$31.52	$0.00	$131.07	-$3.15	-2.35%
WinAvg	38%	3.6	980	298	682	$30.00	$19.76	$16.35	$0.00	$24.91	$27.32	$0.00	$118.34	-$1.48	-1.23%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE DEMAND

SUMMER

	BILL IMPACTS PROPOSED TRANSITION RATES													
	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
				1-400	401-7500	7501+		1-400	401-7500	7501+				
							$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	$0.000000	
Xsm	29%	1.1	226	226	0	0	$30.00	$7.32	$0.00	$0.00	$0.00	$12.04	$0.00	$49.37
Small	32%	1.7	395	395	0	0	$30.00	$12.80	$0.00	$0.00	$0.00	$21.05	$0.00	$63.85
Medium	35%	2.5	634	400	234	0	$30.00	$12.96	$9.92	$0.00	$0.00	$33.79	$0.00	$86.67
Large	42%	5.4	1,634	400	1,234	0	$30.00	$12.96	$52.32	$0.00	$0.00	$87.08	$0.00	$182.36
XLg	51%	12.5	4,605	400	4,205	0	$30.00	$12.96	$178.29	$0.00	$0.00	$245.40	$0.00	$466.65
AnnAvg	39%	4.0	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22
SumAvg	40%	4.4	1,277	400	877	0	$30.00	$12.96	$37.20	$0.00	$0.00	$68.07	$0.00	$148.22

	BILL IMPACTS PROPOSED RATES															
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
								All kW	All kWh							
				On-Peak	Off-Peak		30.00	5.49	$0.016680	$0.000000	On-Peak	Off-Peak				
	Winter										$0.083570	$0.040036				
	Summer			0.27	0.73						$0.084570	$0.045800	0.000%			
Xsm	29%	1.1	226	60	166		$30.00	$6.04	$3.77	$0.00	$5.07	$7.61	$0.00	$52.49	$3.12	6.33%
Small	32%	1.7	395	105	290		$30.00	$9.33	$6.59	$0.00	$8.85	$13.30	$0.00	$68.07	$4.22	6.61%
Medium	35%	2.5	634	168	466		$30.00	$13.73	$10.58	$0.00	$14.21	$21.34	$0.00	$89.86	$3.19	3.68%
Large	42%	5.4	1,634	433	1,201		$30.00	$29.65	$27.26	$0.00	$36.62	$55.00	$0.00	$178.53	-$3.83	-2.10%
XLg	51%	12.5	4,605	1,220	3,385		$30.00	$68.63	$76.81	$0.00	$103.21	$155.01	$0.00	$433.66	-$32.99	-7.07%
AnnAvg	39%	4.0	1,131	300	831		$30.00	$21.96	$18.86	$0.00	$25.35	$38.07	$0.00	$134.24	$0.02	0.01%
SumAvg	40%	4.4	1,277	339	939		$30.00	$24.16	$21.30	$0.00	$28.63	$43.00	$0.00	$147.09	-$1.13	-0.76%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	394	91	303	394	0	0	$16.50	$11.87	$0.00	$0.00	$0.45	$11.73	$9.51	-$0.84	$49.22
Small	636	146	490	400	236	0	$16.50	$12.07	$10.19	$0.00	$0.73	$18.96	$15.37	-$1.36	$72.46
Medium	1633	376	1,257	400	1,233	0	$16.50	$12.07	$53.24	$0.00	$1.86	$48.68	$39.46	-$3.49	$168.32
Large	2,328	535	1,793	400	1,928	0	$16.50	$12.07	$83.24	$0.00	$2.65	$69.40	$56.26	-$4.98	$235.14
XLg	3,091	711	2,380	400	2,691	0	$16.50	$12.07	$116.19	$0.00	$3.52	$92.14	$74.70	-$6.61	$308.51
WinAvg	1,551	357	1,194	400	1,151	0	$16.50	$12.07	$49.70	$0.00	$1.77	$46.24	$37.48	-$3.32	$160.44

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036	0.000%			
	Summer	0.18										$0.109800	$0.045800			$ Change	% Change
Xsm	394	91	303	394	0	0	$30.00	$12.75	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$64.73	$15.51	31.52%
Small	636	146	490	400	236	0	$30.00	$12.96	$10.01	$0.00	$0.00	$15.92	$19.61	$0.00	$88.50	$16.04	22.14%
Medium	1,633	376	1,257	400	1,233	0	$30.00	$12.96	$52.28	$0.00	$0.00	$40.86	$50.34	$0.00	$186.44	$18.12	10.77%
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.96	$81.75	$0.00	$0.00	$58.26	$71.77	$0.00	$254.74	$19.60	8.34%
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.96	$114.10	$0.00	$0.00	$77.35	$95.29	$0.00	$329.70	$21.19	6.87%
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.96	$48.81	$0.00	$0.00	$38.81	$47.82	$0.00	$178.40	$17.96	11.19%

Exhibit CAJ-R-4

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Schedule H-4

SMALL GENERAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	781	141	640	400	381	0	$16.50	$12.07	$16.45	$0.00	$0.89	$18.22	$25.36	-$1.67	$87.82
Small	1220	220	1,000	400	820	0	$16.50	$12.07	$35.40	$0.00	$1.39	$28.46	$39.62	-$2.61	$130.83
Medium	2350	423	1,927	400	1,950	0	$16.50	$12.07	$84.17	$0.00	$2.68	$54.81	$76.30	-$5.03	$241.50
Large	3,078	554	2,524	400	2,678	0	$16.50	$12.07	$115.63	$0.00	$3.51	$71.81	$99.96	-$6.58	$312.90
XLg	3,640	655	2,985	400	3,240	0	$16.50	$12.07	$139.89	$0.00	$4.15	$84.92	$118.21	-$7.79	$367.95
SumAvg	2,256	406	1,850	400	1,856	0	$16.50	$12.07	$80.15	$0.00	$2.57	$52.64	$73.28	-$4.83	$232.38

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036				
	Summer	0.18										$0.109800	$0.045800	0.000%		$ Change	% Change
Xsm	781	141	640	400	381	0	$30.00	$12.96	$16.15	$0.00	$0.00	$15.44	$29.33	$0.00	$103.88	$16.06	18.29%
Small	1,220	220	1,000	400	820	0	$30.00	$12.96	$34.77	$0.00	$0.00	$24.11	$45.82	$0.00	$147.66	$16.83	12.86%
Medium	2,350	423	1,927	400	1,950	0	$30.00	$12.96	$82.66	$0.00	$0.00	$46.44	$88.24	$0.00	$260.30	$18.80	7.78%
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.96	$113.55	$0.00	$0.00	$60.83	$115.60	$0.00	$332.94	$20.04	6.41%
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.96	$137.38	$0.00	$0.00	$71.94	$136.70	$0.00	$388.98	$21.03	5.71%
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.96	$78.71	$0.00	$0.00	$44.59	$84.74	$0.00	$251.00	$18.62	8.01%

															$ Change	% Change
Current Annual														$2,356.95		
Proposed Annual														$2,576.40	$219.45	9.31%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS PROPOSED SGS-TOU RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036	0.000%	
	Summer	0.18										$0.109800	$0.045800		
Xsm	394	91	303	394	0	0	$30.00	$12.75	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$64.73
Small	636	146	490	400	236	0	$30.00	$12.96	$10.01	$0.00	$0.00	$15.92	$19.61	$0.00	$88.50
Medium	1633	376	1,257	400	1,233	0	$30.00	$12.96	$52.28	$0.00	$0.00	$40.86	$50.34	$0.00	$186.44
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.96	$81.75	$0.00	$0.00	$58.26	$71.77	$0.00	$254.74
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.96	$114.10	$0.00	$0.00	$77.35	$95.29	$0.00	$329.70
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.96	$48.81	$0.00	$0.00	$38.81	$47.82	$0.00	$178.40

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak					30.00	5.49	$0.016680	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.083570	$0.040036	0.000%			
	Summer	0.18										$0.084570	$0.045800				
Xsm	394	91	303	32%	1.7			$30.00	$9.33	$6.56	$0.00	$7.56	$12.13	$0.00	$65.58	$0.85	1.31%
Small	636	146	490	35%	2.5			$30.00	$13.73	$10.61	$0.00	$12.22	$19.61	$0.00	$86.17	-$2.33	-2.63%
Medium	1633	376	1,257	42%	5.4			$30.00	$29.65	$27.24	$0.00	$31.39	$50.34	$0.00	$168.62	-$17.82	-9.56%
Large	2,328	535	1,793	44%	7.2			$30.00	$39.53	$38.83	$0.00	$44.75	$71.77	$0.00	$224.88	-$29.86	-11.72%
XLg	3,091	711	2,380	47%	9.0			$30.00	$49.41	$51.56	$0.00	$59.41	$95.29	$0.00	$285.67	-$44.03	-13.35%
WinAvg	1,551	357	1,194	41%	5.2			$30.00	$28.55	$25.87	$0.00	$29.81	$47.82	$0.00	$162.05	-$16.35	-9.16%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED SGS-TOU RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036		
	Summer	0.18										$0.109800	$0.045800	0.000%	
Xsm	781	141	640	400	381	0	$30.00	$12.96	$16.15	$0.00	$0.00	$15.44	$29.33	$0.00	$103.88
Small	1220	220	1,000	400	820	0	$30.00	$12.96	$34.77	$0.00	$0.00	$24.11	$45.82	$0.00	$147.66
Medium	2350	423	1,927	400	1,950	0	$30.00	$12.96	$82.66	$0.00	$0.00	$46.44	$88.24	$0.00	$260.30
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.96	$113.55	$0.00	$0.00	$60.83	$115.60	$0.00	$332.94
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.96	$137.38	$0.00	$0.00	$71.94	$136.70	$0.00	$388.98
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.96	$78.71	$0.00	$0.00	$44.59	$84.74	$0.00	$251.00

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
									All kW	All kWh							
		On-Peak	Off-Peak					30.00	5.49	$0.016680	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.083570	$0.040036				
	Summer	0.18										$0.084570	$0.045800	0.000%			
Xsm	781	141	640	36%	3.0			$30.00	$16.47	$13.03	$0.00	$11.89	$29.33	$0.00	$100.72	-$3.16	-3.04%
Small	1,220	220	1,000	39%	4.3			$30.00	$23.61	$20.35	$0.00	$18.57	$45.82	$0.00	$138.35	-$9.31	-6.31%
Medium	2,350	423	1,927	45%	7.2			$30.00	$39.53	$39.19	$0.00	$35.77	$88.24	$0.00	$232.73	-$27.57	-10.59%
Large	3,078	554	2,524	47%	9.0			$30.00	$49.41	$51.34	$0.00	$46.86	$115.60	$0.00	$293.21	-$39.73	-11.93%
XLg	3,640	655	2,985	48%	10.3			$30.00	$56.55	$60.72	$0.00	$55.41	$136.70	$0.00	$339.38	-$49.60	-12.75%
SumAvg	2,256	406	1,850	44%	7.0			$30.00	$38.43	$37.64	$0.00	$34.35	$84.74	$0.00	$225.16	-$25.84	-10.29%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

		$ Change	% Change
Current Annual	$2,576.40		
Proposed Annual	$2,323.26	($253.14)	-9.83%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

INTERRUPTIBLE POWER SERVICE

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$18.00	$5.00	$0.019408	$0.432900	0.043760	-$0.002139	
Xsm	40.3%	1,116	66	$18.00	$331.53	$21.65	$28.70	$48.82	-$2.39	$446.32
Small	27.4%	14,651	108	$18.00	$541.23	$284.34	$46.86	$641.11	-$31.34	$1,500.20
Medium	30.7%	29,389	154	$18.00	$768.97	$570.39	$66.58	$1,286.08	-$62.87	$2,647.15
Large	44.3%	71,334	237	$18.00	$1,183.91	$1,384.44	$102.50	$3,121.55	-$152.61	$5,657.79
XLg	58.4%	384,599	887	$18.00	$4,432.94	$7,464.30	$383.80	$16,830.06	-$822.79	$28,306.31
AnnAvg	56.0%	97,708	239	$18.00	$1,195.06	$1,896.33	$103.47	$4,275.72	-$209.03	$7,279.55
AvgWin	52.0%	83,072	219	$18.00	$1,094.21	$1,612.26	$94.74	$3,635.24	-$177.72	$6,276.73
AvgSum	62.0%	112,958	250	$18.00	$1,247.88	$2,192.29	$108.04	$4,943.03	-$241.65	$8,267.58
Annual										$87,265.86

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$75.00	$5.50	$0.019800	$0.000000	$0.053090	0.000%			
Xsm	40.3%	1,116	66	$75.00	$364.69	$22.09	$0.00	$59.23	$0.00	$521.01	$74.69	16.73%
Small	27.4%	14,651	108	$75.00	$595.36	$290.08	$0.00	$777.80	$0.00	$1,738.24	$238.04	15.87%
Medium	30.7%	29,389	154	$75.00	$845.87	$581.91	$0.00	$1,560.28	$0.00	$3,063.06	$415.91	15.71%
Large	44.3%	71,334	237	$75.00	$1,302.30	$1,412.40	$0.00	$3,787.10	$0.00	$6,576.80	$919.01	16.24%
XLg	58.4%	384,599	887	$75.00	$4,876.23	$7,615.06	$0.00	$20,418.37	$0.00	$32,984.66	$4,678.35	16.53%
AnnAvg	56.0%	97,708	239	$75.00	$1,314.57	$1,934.63	$0.00	$5,187.34	$0.00	$8,511.54	$1,231.99	16.92%
AvgWin	52.0%	83,072	219	$75.00	$1,203.63	$1,644.83	$0.00	$4,410.30	$0.00	$7,333.76	$1,057.03	16.84%
AvgSum	62.0%	112,958	250	$75.00	$1,372.66	$2,236.57	$0.00	$5,996.93	$0.00	$9,681.16	$1,413.59	17.10%
Annual										$102,089.53	$14,823.67	16.99%

MEDIUM GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.432900	$0.056603	-$0.002139	
Xsm	0.46	20	4,040	$50.00	$256.20	$22.10	$8.66	$228.68	-$8.64	$557.00
Small	0.46	20	6,400	$50.00	$256.20	$35.01	$8.66	$362.26	-$13.69	$698.44
Medium	0.46	36	12,160	$50.00	$463.88	$66.52	$15.68	$688.29	-$26.01	$1,258.36
Large	0.46	80	26,880	$50.00	$1,025.41	$147.03	$34.65	$1,521.49	-$57.51	$2,721.07
Xlarge	0.46	294	98,640	$50.00	$3,762.89	$539.56	$127.16	$5,583.32	-$211.02	$9,851.91
AnnAvg	0.46	80	26,796	$50.00	$1,022.22	$146.58	$34.54	$1,516.76	-$57.33	$2,712.77
sum	0.46	90	30,153	$50.00	$1,150.28	$164.94	$38.87	$1,706.76	-$64.51	$3,046.34
win	0.46	70	23,520	$50.00	$897.22	$128.65	$30.32	$1,331.28	-$50.32	$2,387.15
Annual										$32,600.94

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$100.00	$13.95	$0.005500	$0.000000	$0.053290	0.000%			
Xsm	0.46	20	4,040	$100.00	$279.00	$22.22	$0.00	$215.29	$0.00	$616.51	$59.51	10.7%
Small	0.46	20	6,400	$100.00	$279.00	$35.20	$0.00	$341.06	$0.00	$755.26	$56.82	8.1%
Medium	0.46	36	12,160	$100.00	$505.16	$66.88	$0.00	$648.01	$0.00	$1,320.05	$61.69	4.9%
Large	0.46	80	26,880	$100.00	$1,116.66	$147.84	$0.00	$1,432.44	$0.00	$2,796.94	$75.87	2.8%
Xlarge	0.46	294	98,640	$100.00	$4,097.76	$542.52	$0.00	$5,256.53	$0.00	$9,996.81	$144.90	1.5%
AnnAvg	0.46	80	26,796	$100.00	$1,113.19	$147.38	$0.00	$1,427.98	$0.00	$2,788.55	$75.78	2.8%
sum	0.46	90	30,153	$100.00	$1,252.64	$165.84	$0.00	$1,606.87	$0.00	$3,125.35	$79.01	2.6%
win	0.46	70	23,520	$100.00	$977.06	$129.36	$0.00	$1,253.36	$0.00	$2,459.78	$72.63	3.0%
Annual										$33,510.78	$909.84	2.8%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

WINTER

	BILL IMPACTS CURRENT RATES												
	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168	-$0.002139	
		Summer		0.20						0.114886	0.039886		
Xsm	0.46	27,974	83	8,112	19,862	$52.00	$1,067.14	$153.02	$36.06	$932.01	$519.74	-$59.85	$2,700.12
Small	0.46	28,067	84	8,139	19,928	$52.00	$1,070.69	$153.53	$36.18	$935.11	$521.46	-$60.04	$2,708.93
Medium	0.46	48,453	144	14,051	34,402	$52.00	$1,848.37	$265.04	$62.46	$1,614.31	$900.22	-$103.66	$4,638.74
Large	0.56	62,572	186	18,146	44,426	$52.00	$2,386.98	$342.27	$80.67	$2,084.71	$1,162.54	-$133.86	$5,975.31
XLg	0.66	193,470	576	56,106	137,364	$52.00	$7,380.44	$1,058.28	$249.41	$6,445.83	$3,594.53	-$413.90	$18,366.59
AnnAvg	0.58	69,713	208	20,217	49,496	$52.00	$2,659.39	$381.33	$89.87	$2,322.62	$1,295.22	-$149.14	$6,651.29
AvgWin	0.56	65,673	196	19,045	46,628	$52.00	$2,505.28	$359.23	$84.66	$2,188.02	$1,220.16	-$140.50	$6,268.85

	BILL IMPACTS PROPOSED RATES														
	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.95	$0.005500	$0.00000	0.101047	0.031690	0.000%			
		Summer								0.114886	0.033500				
Xsm	0.46	27,974	83	8,112	19,862	$100.00	$1,162.11	$153.86	$0.00	$819.74	$629.41	$0.00	$2,865.12	$165.00	6.1%
Small	0.46	28,067	84	8,139	19,928	$100.00	$1,165.98	$154.37	$0.00	$822.46	$631.50	$0.00	$2,874.31	$165.38	6.1%
Medium	0.46	48,453	144	14,051	34,402	$100.00	$2,012.86	$266.49	$0.00	$1,419.85	$1,090.19	$0.00	$4,889.39	$250.65	5.4%
Large	0.56	62,572	186	18,146	44,426	$100.00	$2,599.40	$344.15	$0.00	$1,833.59	$1,407.86	$0.00	$6,285.00	$309.69	5.2%
XLg	0.66	193,470	576	56,106	137,364	$100.00	$8,037.24	$1,064.09	$0.00	$5,669.37	$4,353.06	$0.00	$19,223.76	$857.17	4.7%
AnnAvg	0.58	69,713	208	20,217	49,496	$100.00	$2,896.06	$383.42	$0.00	$2,042.84	$1,568.53	$0.00	$6,990.85	$339.56	5.1%
AvgWin	0.56	65,673	196	19,045	46,628	$100.00	$2,728.23	$361.20	$0.00	$1,924.46	$1,477.64	$0.00	$6,591.53	$322.68	5.1%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168		
		Summer		0.20						0.114886	0.039886	-$0.002139	
Xsm	0.46	27,974	83	5,595	22,379	$52.00	$1,067.14	$153.02	$36.06	$642.76	$892.62	-$59.85	$2,783.75
Small	0.46	28,067	84	5,613	22,454	$52.00	$1,070.69	$153.53	$36.18	$644.90	$895.58	-$60.04	$2,792.84
Medium	0.46	48,453	144	9,691	38,762	$52.00	$1,848.37	$265.04	$62.46	$1,113.31	$1,546.08	-$103.66	$4,783.60
Large	0.56	62,572	186	12,514	50,058	$52.00	$2,386.98	$342.27	$80.67	$1,437.73	$1,996.60	-$133.86	$6,162.39
XLg	0.66	193,470	576	38,694	154,776	$52.00	$7,380.44	$1,058.28	$249.41	$4,445.40	$6,173.40	-$413.90	$18,945.03
AnnAvg	0.58	69,713	208	13,943	55,770	$52.00	$2,659.39	$381.33	$89.87	$1,601.81	$2,224.46	-$149.14	$6,859.72
AvgSum	0.56	73,609	219	14,722	58,887	$52.00	$2,808.00	$402.64	$94.89	$1,691.32	$2,348.76	-$157.47	$7,240.14

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.95	$0.005500	$0.00000	0.101047	0.031690				
		Summer								0.114886	0.033500	0.000%			
Xsm	0.46	27,974	83	5,595	22,379	$100.00	$1,162.11	$153.86	$0.00	$642.76	$749.70	$0.00	$2,808.43	$24.68	0.9%
Small	0.46	28,067	84	5,613	22,454	$100.00	$1,165.98	$154.37	$0.00	$644.90	$752.20	$0.00	$2,817.45	$24.61	0.9%
Medium	0.46	48,453	144	9,691	38,762	$100.00	$2,012.86	$266.49	$0.00	$1,113.31	$1,298.54	$0.00	$4,791.20	$7.60	0.2%
Large	0.56	62,572	186	12,514	50,058	$100.00	$2,599.40	$344.15	$0.00	$1,437.73	$1,676.93	$0.00	$6,158.21	-$4.18	-0.1%
XLg	0.66	193,470	576	38,694	154,776	$100.00	$8,037.24	$1,064.09	$0.00	$4,445.40	$5,185.00	$0.00	$18,831.73	-$113.30	-0.6%
AnnAvg	0.58	69,713	208	13,943	55,770	$100.00	$2,896.06	$383.42	$0.00	$1,601.81	$1,868.31	$0.00	$6,849.60	-$10.12	-0.1%
AvgSum	0.56	73,609	219	14,722	58,887	$100.00	$3,057.89	$404.85	$0.00	$1,691.32	$1,972.71	$0.00	$7,226.77	-$13.37	-0.2%

	$ Change	% Change	
Current Annual	$81,053.94		
Proposed Annual	$82,909.80	$1,855.86	2.3%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE GENERAL SERVICE TO NEW LARGE GENERAL SERVICE

BILL IMPACTS CURRENT RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.43290	0.056603	-$0.002139	
Xsm	30%	205	45,000	$50.00	$2,632.19	$246.15	$88.95	$2,547.14	-$96.27	$5,468.16
Small	46%	194	65,000	$50.00	$2,479.60	$355.55	$83.80	$3,679.20	-$139.06	$6,509.09
Medium	66%	844	406,600	$50.00	$10,810.60	$2,224.10	$365.33	$23,014.78	-$869.85	$35,594.96
Large	75%	174	95,000	$50.00	$2,222.74	$519.65	$75.12	$5,377.29	-$203.24	$8,041.56
XLg	95%	1,875	1,300,500	$50.00	$24,022.21	$7,113.74	$811.80	$73,612.20	-$2,782.20	$102,827.75
AnnAvg	65%	992	470,630	$50.00	$12,705.52	$2,574.35	$429.37	$26,639.07	-$1,006.83	$41,391.47

BILL IMPACTS PROPOSED RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$13.35	$0.005470	$0.00000	$0.053290	0.000%			
Xsm	30%	450	45,000	$300.00	$6,007.50	$246.15	$0.00	$2,398.05	$0.00	$8,951.70	$3,483.54	63.7%
Small	46%	450	65,000	$300.00	$6,007.50	$355.55	$0.00	$3,463.85	$0.00	$10,126.90	$3,617.81	55.6%
Medium	66%	844	406,600	$300.00	$11,266.31	$2,224.10	$0.00	$21,667.71	$0.00	$35,458.13	-$136.83	-0.4%
Large	75%	450	95,000	$300.00	$6,007.50	$519.65	$0.00	$5,062.55	$0.00	$11,889.70	$3,848.14	47.9%
XLg	95%	1,875	1,300,500	$300.00	$25,034.86	$7,113.74	$0.00	$69,303.65	$0.00	$101,752.24	-$1,075.50	-1.0%
AnnAvg	65%	992	470,630	$300.00	$13,241.12	$2,574.35	$0.00	$25,079.87	$0.00	$41,195.33	-$196.14	-0.5%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE <69kV TO NEW LARGE GENERAL SERVICE

BILL IMPACTS CURRENT RATES - LPS <69kV

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$22.00	$0.000462	$0.43290	$0.04188	-$0.002139	
Xsm	44%	747	240,000	$1,200.00	$16,438.36	$110.88	$323.46	$10,051.20	-$513.44	$27,610.46
Small	46%	893	300,000	$1,200.00	$19,654.56	$138.60	$386.75	$12,564.00	-$641.80	$33,302.11
Medium	66%	844	406,600	$1,200.00	$18,566.21	$187.85	$365.33	$17,028.41	-$869.85	$36,477.95
Large	75%	1,553	850,000	$1,200.00	$34,155.25	$392.70	$672.08	$35,598.00	-$1,818.43	$70,199.60
XLg	75%	2,192	1,200,000	$1,200.00	$48,219.18	$554.40	$948.82	$50,256.00	-$2,567.20	$98,611.20
AnnAvg	65%	992	470,630	$1,200.00	$21,820.57	$217.43	$429.37	$19,709.98	-$1,006.83	$42,370.52

BILL IMPACTS PROPOSED RATES - LPS <69 kV

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$13.35	$0.005470	$0.00000	$0.053290	0.000%			
Xsm	44%	747	240,000	$300.00	$9,975.09	$1,312.80	$0.00	$12,789.60	$0.00	$24,377.49	-$3,232.96	-11.7%
Small	46%	893	300,000	$300.00	$11,926.74	$1,641.00	$0.00	$15,987.00	$0.00	$29,854.74	-$3,447.36	-10.4%
Medium	66%	844	406,600	$300.00	$11,266.31	$2,224.10	$0.00	$21,667.71	$0.00	$35,458.13	-$1,019.82	-2.8%
Large	75%	1,553	850,000	$300.00	$20,726.03	$4,649.50	$0.00	$45,296.50	$0.00	$70,972.03	$772.43	1.1%
XLg	75%	2,192	1,200,000	$300.00	$29,260.27	$6,564.00	$0.00	$63,948.00	$0.00	$100,072.27	$1,461.08	1.5%
AnnAvg	65%	992	470,630	$300.00	$13,241.12	$2,574.35	$0.00	$25,079.87	$0.00	$41,195.33	-$1,175.18	-2.8%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.16						$0.123580	$0.024716		
Small	433,335	1,281	69,334	364,001	$1,200.00	$28,182.00	$200.20	$554.54	$6,509.04	$8,046.25	-$927.05	$43,764.98
Medium	517,000	1,380	82,720	434,280	$1,200.00	$30,360.00	$238.85	$597.40	$7,765.75	$9,599.76	-$1,106.04	$48,655.72
Large	600,000	1,400	96,000	504,000	$1,200.00	$30,800.00	$277.20	$606.06	$9,012.48	$11,140.92	-$1,283.60	$51,753.06
XLg	775,000	1,570	124,000	651,000	$1,200.00	$34,540.00	$358.05	$679.65	$11,641.12	$14,390.36	-$1,657.98	$61,151.20
Mean	642,400	1,430	102,784	539,616	$1,200.00	$31,460.00	$296.79	$619.05	$9,649.36	$11,928.21	-$1,374.31	$53,779.10
AvgWin	627,900	1,416	100,464	527,436	$1,200.00	$31,152.00	$290.09	$612.99	$9,431.56	$11,658.97	-$1,343.29	$53,002.32

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$13.35	$0.005470	$0.00000	$0.139880	$0.034927	0.000%			
	Summer								$0.143771	$0.038600				
Small	433,335	1,281	69,334	364,001	$300.00	$17,101.35	$2,370.34	$0.00	$9,698.38	$12,713.48	$0.00	$42,183.55	-$1,581.43	-3.6%
Medium	517,000	1,380	82,720	434,280	$300.00	$18,423.00	$2,827.99	$0.00	$11,570.87	$15,168.10	$0.00	$48,289.96	-$365.76	-0.8%
Large	600,000	1,400	96,000	504,000	$300.00	$18,690.00	$3,282.00	$0.00	$13,428.48	$17,603.21	$0.00	$53,303.69	$1,550.63	3.0%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,959.50	$4,239.25	$0.00	$17,345.12	$22,737.48	$0.00	$65,581.35	$4,430.15	7.2%
Mean	642,400	1,430	102,784	539,616	$300.00	$19,090.50	$3,513.93	$0.00	$14,377.43	$18,847.17	$0.00	$56,129.03	$2,349.93	4.4%
AvgWin	627,900	1,416	100,464	527,436	$300.00	$18,903.60	$3,434.61	$0.00	$14,052.90	$18,421.76	$0.00	$55,112.87	$2,110.55	4.0%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

SUMMER

	BILL IMPACTS CURRENT RATES											
	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105		
	Summer		0.16						$0.123580	$0.024716	-$0.002139	
Small	433,335	1,281	69,334	364,001	$1,200	$28,182.00	$200.20	$554.54	$8,568.25	$8,996.66	-$927.05	$46,774.60
Medium	517,000	1,380	82,720	434,280	$1,200	$30,360.00	$238.85	$597.40	$10,222.54	$10,733.66	-$1,106.04	$52,246.41
Large	600,000	1,400	96,000	504,000	$1,200	$30,800.00	$277.20	$606.06	$11,863.68	$12,456.86	-$1,283.60	$55,920.20
XLg	775,000	1,570	124,000	651,000	$1,200	$34,540.00	$358.05	$679.65	$15,323.92	$16,090.12	-$1,657.98	$66,533.76
Mean	642,400	1,430	102,784	539,616	$1,200	$31,460.00	$296.79	$619.05	$12,702.05	$13,337.15	-$1,374.31	$58,240.73
AvgSum	656,700	1,444	105,072	551,628	$1,200	$31,768.00	$303.40	$625.11	$12,984.80	$13,634.04	-$1,404.90	$59,110.45

	BILL IMPACTS PROPOSED RATES													
	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$13.35	$0.005470	$0.00000	$0.139880	$0.034927				
	Summer								$0.143771	$0.038600	0.000%			
Small	433,335	1,281	69,334	364,001	$300.00	$17,101.35	$2,370.34	$0.00	$9,968.16	$14,050.45	$0.00	$43,790.30	-$2,984.30	-6.4%
Medium	517,000	1,380	82,720	434,280	$300.00	$18,423.00	$2,827.99	$0.00	$11,892.74	$16,763.21	$0.00	$50,206.94	-$2,039.47	-3.9%
Large	600,000	1,400	96,000	504,000	$300.00	$18,690.00	$3,282.00	$0.00	$13,802.02	$19,454.40	$0.00	$55,528.42	-$391.78	-0.7%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,959.50	$4,239.25	$0.00	$17,827.60	$25,128.60	$0.00	$68,454.95	$1,921.19	2.9%
Mean	642,400	1,430	102,784	539,616	$300.00	$19,090.50	$3,513.93	$0.00	$14,777.36	$20,829.18	$0.00	$58,510.97	$270.24	0.5%
AvgSum	656,700	1,444	105,072	551,628	$300.00	$19,277.40	$3,592.15	$0.00	$15,106.31	$21,292.84	$0.00	$59,568.70	$458.25	0.8%

		$ Change	% Change
Current Annual	$672,676.62		
Proposed Annual	$688,089.42	$15,412.80	2.29%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE - TRANSMISSION VOLTAGE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$17.00	$0.000462	$0.43290	$0.041880	-$0.002139	
Xsm	0.42	506	155,000	$1,200.00	$8,594.26	$71.61	$218.85	$6,491.40	-$331.60	$16,244.52
Small	0.42	1,267	388,500	$1,200.00	$21,541.10	$179.49	$548.54	$16,270.38	-$831.13	$38,908.37
Small	0.46	1,336	448,600	$1,200.00	$22,710.54	$207.25	$578.32	$18,787.37	-$959.70	$42,523.79
Medium	0.75	2,416	1,322,700	$1,200.00	$41,070.14	$611.09	$1,045.84	$55,394.68	-$2,829.70	$96,492.04
Medium	0.75	2,817	1,542,200	$1,200.00	$47,885.66	$712.50	$1,219.39	$64,587.34	-$3,299.28	$112,305.61
Large	0.89	4,775	3,102,500	$1,200.00	$81,179.78	$1,433.36	$2,067.22	$129,932.70	-$6,637.28	$209,175.77
Large	0.89	5,379	3,494,900	$1,200.00	$91,447.28	$1,614.64	$2,328.68	$146,366.41	-$7,476.76	$235,480.26

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$1,500.00	$13.00	$0.000500	$0.00000	$0.049332	0.000%			
Xsm	0.42	506	155,000	$1,500.00	$6,572.08	$77.50	$0.00	$7,646.43	$0.00	$15,796.01	-$448.51	-2.8%
Small	0.42	1,267	388,500	$1,500.00	$16,472.60	$194.25	$0.00	$19,165.41	$0.00	$37,332.26	-$1,576.11	-4.1%
Small	0.46	1,336	448,600	$1,500.00	$17,366.89	$224.30	$0.00	$22,130.26	$0.00	$41,221.45	-$1,302.34	-3.1%
Medium	0.75	2,416	1,322,700	$1,500.00	$31,406.58	$661.35	$0.00	$65,251.21	$0.00	$98,819.14	$2,327.09	2.4%
Medium	0.75	2,817	1,542,200	$1,500.00	$36,618.45	$771.10	$0.00	$76,079.54	$0.00	$114,969.09	$2,663.48	2.4%
Large	0.89	4,775	3,102,500	$1,500.00	$62,078.65	$1,551.25	$0.00	$153,051.99	$0.00	$218,181.89	$9,006.12	4.3%
Large	0.89	5,379	3,494,900	$1,500.00	$69,930.28	$1,747.45	$0.00	$172,409.80	$0.00	$245,587.53	$10,107.27	4.3%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE >69kV

WINTER

	BILL IMPACTS CURRENT RATES											
	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.11	0.89					$0.123580	$0.024716		
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$28,811.77	$54,888.93	-$5,967.81	$168,833.30
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$32,529.42	$61,971.37	-$6,737.85	$179,029.67
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$21,841.18	$41,609.35	-$4,523.99	$149,715.10
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$28,057.92	$53,452.76	-$5,811.66	$166,765.70
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,200.00	$86,411.00	$1,259.41	$2,200.43	$28,150.86	$53,629.82	-$5,830.91	$167,020.61

	BILL IMPACTS PROPOSED RATES													
	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,500.00	$13.00	$0.000500	$0.00000	$0.092110	$0.030410	0.000%			
	Summer								$0.125155	$0.033410				
Small	2,790,000	5,083	306,900	2,483,100	$1,500.00	$66,079.00	$1,395.00	$0.00	$28,268.56	$75,511.07	$0.00	$172,753.63	$3,920.33	2.32%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500.00	$66,079.00	$1,575.00	$0.00	$31,916.12	$85,254.44	$0.00	$186,324.56	$7,294.89	4.07%
Large	2,115,000	5,083	232,650	1,882,350	$1,500.00	$66,079.00	$1,057.50	$0.00	$21,429.39	$57,242.26	$0.00	$147,308.15	-$2,406.95	-1.61%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500.00	$66,079.00	$1,358.50	$0.00	$27,528.92	$73,535.33	$0.00	$170,001.75	$3,236.05	1.94%
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,500.00	$66,079.00	$1,363.00	$0.00	$27,620.10	$73,778.92	$0.00	$170,341.02	$3,320.41	1.99%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE >69kV

SUMMER

	BILL IMPACTS CURRENT RATES											
	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105		
	Summer		0.11	0.89					$0.123580	$0.024716	-$0.002139	
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$37,926.70	$61,372.30	-$5,967.81	$184,431.60
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$42,820.47	$69,291.31	-$6,737.85	$196,640.66
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$28,750.89	$46,524.16	-$4,523.99	$161,539.62
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$36,934.35	$59,766.50	-$5,811.66	$181,955.87
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$38,507.53	$61,256.13	-$5,967.81	$184,896.26

	BILL IMPACTS PROPOSED RATES													
	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,500.00	$13.00	$0.000500	$0.00000	$0.092110	$0.030410				
	Summer								$0.125155	$0.033410	0.000%			
Small	2,790,000	5,083	306,900	2,483,100	$1,500	$66,079	$1,395	$0.00	$38,410.07	$82,960.37	$0.00	$190,344	$5,912.84	3.21%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500	$66,079	$1,575	$0.00	$43,366.21	$93,664.94	$0.00	$206,185	$9,544.49	4.85%
Large	2,115,000	5,083	232,650	1,882,350	$1,500	$66,079	$1,058	$0.00	$29,117.31	$62,889.31	$0.00	$160,643	-$896.50	-0.55%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500	$66,079	$1,359	$0.00	$37,405.07	$80,789.72	$0.00	$187,132	$5,176.42	2.84%
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,500	$66,079	$1,395	$0.00	$38,998.30	$82,803.34	$0.00	$190,776	$5,879.38	3.18%

												$ Change	% Change
Current Annual											$2,111,501		
Proposed Annual											$2,166,700	$55,199	2.61%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

LIGHTING SERVICE

Description	Old Rate	New Rate
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.68
New 30' Metal or Fiberglass - Overhead	$8.66	$9.35
Existing Wood Pole - Underground	$2.18	$2.35
New 30' Wood Pole (Class 6) - Underground	$6.52	$7.04
New 30' Metal or Fiberglass - Underground	$10.81	$11.67
Wattage, per Watt	$0.051681	$0.060516
Base Power Supply	$0.010113	$0.014535
PPFAC	-$0.002139	0.000%

		Proration
New Rate Days	28	100%
Old Rate Days	0	0%

Total Days	28
Total kWh billed	150

Customer Bill	Current Rates	Proposed Rates	$Change	%Change
100 Watt	$5.17	$6.05	$0.88	17.02%
150 Watt	$7.75	$9.08	$1.33	17.16%
200 Watt	$10.34	$12.10	$1.76	17.02%
250 Watt	$12.92	$15.13	$2.21	17.11%
400 Watt	$20.67	$24.21	$3.54	17.13%
Existing Wood Pole OH	$4.34	$4.68	$0.34	7.83%
New 30' Wood Pole OH	$8.66	$9.35	$0.69	7.97%
New 30' Metal or FG OH	$2.18	$2.35	$0.17	7.80%
Existing Wood Pole UG	$6.52	$7.04	$0.52	7.98%
New 30' Wood Pole UG	$10.81	$11.67	$0.86	7.96%
New 30' Metal or FG UG	$0.05	$0.06	$0.01	17.10%
Base Power Supply	$1.52	$2.18	$0.66	43.42%
PPFAC	($0.32)	$0.00	$0.32	-100.00%
Typical	$13.29	$15.94	$2.65	19.94%

Detail of Services Billed	Wattage	Units Billed
100 Watt	100	1
150 Watt	150	1
200 Watt	200	1
250 Watt	250	1
400 Watt	400	1
Existing Wood Pole OH		5
New 30' Wood Pole OH		0
New 30' Metal or FG OH		0
Existing Wood Pole UG		0
New 30' Wood Pole UG		0
New 30' Metal or FG UG		0

Exhibit CAJ-R-5

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
		0-400	401-1,000	1,000+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsmall	111	111	0	0	$10.00	$2.14	$0.00	$0.00	$0.13	$7.16	-$0.24	$19.19
Small	330	330	0	0	$10.00	$6.37	$0.00	$0.00	$0.38	$21.29	-$0.71	$37.33
Medium	664	400	264	0	$10.00	$7.72	$9.07	$0.00	$0.76	$42.83	-$1.42	$68.96
Large	1,144	400	600	144	$10.00	$7.72	$20.61	$5.54	$1.30	$73.80	-$2.45	$116.53
Xlarge	2,162	400	600	1,162	$10.00	$7.72	$20.61	$44.74	$2.46	$139.47	-$4.63	$220.37
Mean	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
Sum	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20
Win	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48
Annual												$1,018.12

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		0-400	401-1,000	1,000+	$15.00	$0.032258	$0.042258	$0.060258	$0.000000	$0.055090	-11.144%			
Xsmall	111	111	0	0	$15.00	$3.58	$0.00	$0.00	$0.00	$6.12	($0.68)	$24.02	$4.83	25.1%
Small	330	330	0	0	$15.00	$10.65	$0.00	$0.00	$0.00	$18.18	($2.03)	$41.80	$4.46	12.0%
Medium	664	400	264	0	$15.00	$12.90	$11.16	$0.00	$0.00	$36.58	($4.08)	$71.56	$2.60	3.8%
Large	1,144	400	600	144	$15.00	$12.90	$25.35	$8.68	$0.00	$63.02	($7.02)	$117.94	$1.41	1.2%
Xlarge	2,162	400	600	1,162	$15.00	$12.90	$25.35	$70.02	$0.00	$119.11	($13.27)	$229.12	$8.75	4.0%
Mean	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.00	$45.70	($5.09)	$86.66	$1.50	1.8%
Sum	983	400	583	0	$15.00	$12.90	$24.65	$0.00	$0.00	$54.17	($6.04)	$100.68	$0.48	0.5%
Win	669	400	269	0	$15.00	$12.90	$11.38	$0.00	$0.00	$36.88	($4.11)	$72.06	$2.58	3.7%
Annual												$1,036.45	$18.34	1.8%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

WINTER

	BILL IMPACTS PROPOSED TRANSITION RATES													
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	401-1,000 kWh	1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+	$15.00	$0.032258	$0.042258	$0.060258	$0.001140	$0.055090	$0.000000	
Xsm	19%	0.7	100	100	0	0	$15.00	$3.23	$0.00	$0.00	$0.11	$5.51	$0.00	$23.85
Small	24%	1.7	294	294	0	0	$15.00	$9.48	$0.00	$0.00	$0.34	$16.20	$0.00	$41.02
Medium	28%	2.8	560	400	160	0	$15.00	$12.90	$6.76	$0.00	$0.64	$30.85	$0.00	$66.15
Large	31%	4.1	914	400	514	0	$15.00	$12.90	$21.72	$0.00	$1.04	$50.35	$0.00	$101.01
XLg	35%	6.5	1,653	400	600	653	$15.00	$12.90	$25.35	$39.35	$1.88	$91.06	$0.00	$185.55
AnnAvg	30%	3.8	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.95	$45.70	$0.00	$92.70
WinAvg	29%	3.2	669	400	269	0	$15.00	$12.90	$11.38	$0.00	$0.76	$36.88	$0.00	$76.93

	BILL IMPACTS PROPOSED RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery All kW	All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak										
Winter				0.26	0.74	$15.00	$5.15	$0.01676	$0.000000	$0.082800	$0.038610	-11.144%			
Summer										$0.102251	$0.042830				
Xsm	19%	0.7	100	26	74	$15.00	$3.61	$1.68	$0.00	$2.15	$2.86	($0.56)	$24.74	$0.89	3.75%
Small	24%	1.7	294	76	218	$15.00	$8.76	$4.93	$0.00	$6.29	$8.42	($1.64)	$41.76	$0.74	1.79%
Medium	28%	2.8	560	145	415	$15.00	$14.42	$9.39	$0.00	$12.01	$16.02	($3.12)	$63.72	-$2.43	-3.68%
Large	31%	4.1	914	237	677	$15.00	$21.12	$15.32	$0.00	$19.62	$26.14	($5.10)	$92.10	-$8.91	-8.82%
XLg	35%	6.5	1,653	429	1,224	$15.00	$33.48	$27.70	$0.00	$35.52	$47.26	($9.22)	$149.74	-$35.81	-19.30%
AnnAvg	30%	3.8	830	215	614	$15.00	$19.57	$13.90	$0.00	$17.80	$23.71	($4.63)	$85.35	-$7.35	-7.93%
WinAvg	29%	3.2	669	174	496	$15.00	$16.48	$11.22	$0.00	$14.41	$19.15	($3.74)	$72.52	-$4.41	-5.73%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh				
							$15.00	$0.032258	$0.042258	$0.060258	$0.001140	$0.055090	$0.000000	
Xsm	20%	0.8	117	117	0	0	$15.00	$3.77	$0.00	$0.00	$0.13	$6.45	$0.00	$25.35
Small	25%	2.1	386	386	0	0	$15.00	$12.45	$0.00	$0.00	$0.44	$21.26	$0.00	$49.15
Medium	30%	3.7	813	400	413	0	$15.00	$12.90	$17.45	$0.00	$0.93	$44.79	$0.00	$91.08
Large	34%	5.7	1,395	400	600	395	$15.00	$12.90	$25.35	$23.80	$1.59	$76.85	$0.00	$155.50
XLg	38%	9.0	2,471	400	600	1,471	$15.00	$12.90	$25.35	$88.64	$2.82	$136.13	$0.00	$280.85
AnnAvg	30%	3.8	830	400	430	0	$15.00	$12.90	$18.15	$0.00	$0.95	$45.70	$0.00	$92.70
SumAvg	31%	4.3	983	400	583	0	$15.00	$12.90	$24.65	$0.00	$1.12	$54.17	$0.00	$107.84

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak		All kW	All kWh							
Winter										$0.082800	$0.038610				
Summer				0.24	0.76	$15.00	$5.15	$0.01676	$0.000000	$0.102251	$0.042830	-11.144%			
Xsm	20%	0.8	117	28	89	$15.00	$4.12	$1.96	$0.00	$2.86	$3.81	($0.74)	$27.01	$1.66	6.53%
Small	25%	2.1	386	93	293	$15.00	$10.82	$6.47	$0.00	$9.51	$12.55	($2.46)	$51.89	$2.74	5.57%
Medium	30%	3.7	813	196	617	$15.00	$19.06	$13.63	$0.00	$20.04	$26.43	($5.18)	$88.98	-$2.10	-2.30%
Large	34%	5.7	1,395	336	1,059	$15.00	$29.36	$23.38	$0.00	$34.36	$45.36	($8.88)	$138.58	-$16.92	-10.88%
XLg	38%	9.0	2,471	595	1,876	$15.00	$46.35	$41.41	$0.00	$60.84	$80.35	($15.73)	$228.22	-$52.63	-18.74%
AnnAvg	30%	3.8	830	200	630	$15.00	$19.57	$13.90	$0.00	$20.45	$26.98	($5.29)	$90.61	-$2.09	-2.26%
SumAvg	31%	4.3	983	237	747	$15.00	$22.15	$16.48	$0.00	$24.23	$31.99	($6.26)	$103.59	-$4.25	-3.94%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	220	220	0	$4.90	$4.17	$0.00	$0.25	$13.57	-$0.47	$15.69	30.00%
Small	360	360	0	$4.90	$6.83	$0.00	$0.41	$22.21	-$0.77	$26.86	20.00%
Medium	607	400	207	$4.90	$7.59	$7.33	$0.69	$37.45	-$1.30	$50.99	10.00%
Large	990	400	590	$4.90	$7.59	$20.89	$1.13	$61.08	-$2.12	$84.12	10.00%
Xlarge	1,843	400	1,443	$4.90	$7.59	$51.08	$2.10	$113.71	-$3.94	$167.44	$8.00
Mean	753	400	353	$4.90	$7.59	$12.49	$0.86	$46.45	-$1.61	$63.61	10.00%
Sum	867	400	467	$4.90	$7.59	$16.53	$0.99	$53.49	-$1.85	$73.49	10.00%
Win	638	400	238	$4.90	$7.59	$8.43	$0.73	$39.37	-$1.37	$53.69	10.00%
Annual										$763.08	

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change	Discounts
		1-400	401+	$9.00	$0.030800	$0.050800	$0.000000	$0.050260	-11.144%				
Xsmall	220	220	0	$9.00	$6.78	$0.00	$0.00	$11.06	($1.23)	$17.93	$2.24	14.26%	30.00%
Small	360	360	0	$9.00	$11.09	$0.00	$0.00	$18.09	($2.02)	$28.93	$2.07	7.70%	20.00%
Medium	607	400	207	$9.00	$12.32	$10.52	$0.00	$30.51	($3.40)	$53.06	$2.07	4.05%	10.00%
Large	990	400	590	$9.00	$12.32	$29.97	$0.00	$49.76	($5.55)	$85.95	$1.83	2.18%	10.00%
Xlarge	1,843	400	1,443	$9.00	$12.32	$73.30	$0.00	$92.63	($10.32)	$168.93	$1.49	0.89%	$8.00
Mean	753	400	353	$9.00	$12.32	$17.93	$0.00	$37.84	($4.22)	$65.58	$1.97	3.10%	10.00%
Sum	867	400	467	$9.00	$12.32	$23.72	$0.00	$43.57	($4.86)	$75.38	$1.89	2.56%	10.00%
Win	638	400	238	$9.00	$12.32	$12.09	$0.00	$32.07	($3.57)	$55.72	$2.03	3.78%	10.00%
Annual										$786.56	$23.48	3.08%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE CARES MEDICAL

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	Discounts
		1-400	401+	$4.90	$0.018973	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsmall	365	365	0	$4.90	$6.93	$0.00	$0.42	$22.52	-$0.78	$23.79	30.00%
Small	564	400	164	$4.90	$7.59	$5.81	$0.64	$34.80	-$1.21	$36.77	30.00%
Medium	878	400	478	$4.90	$7.59	$16.92	$1.00	$54.17	-$1.88	$66.16	20.00%
Large	1,340	400	940	$4.90	$7.59	$33.28	$1.53	$82.68	-$2.87	$114.40	10.00%
Xlarge	2,304	400	1,904	$4.90	$7.59	$67.40	$2.63	$142.16	-$4.93	$211.75	$8.00
Mean	1,034	400	634	$4.90	$7.59	$22.43	$1.18	$63.78	-$2.21	$78.13	20.00%
sum	1,199	400	799	$4.90	$7.59	$28.28	$1.37	$73.97	-$2.56	$90.84	20.00%
win	871	400	471	$4.90	$7.59	$16.68	$0.99	$53.75	-$1.86	$65.64	20.00%
Annual										$938.88	

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Basic Service Charge	Delivery 0-400 kWh	Delivery 400+ kWh	TCA	Base Fuel	PPFAC	Net Revenue	$ Change	% Change	
		1-400	401+	$9.00	$0.030800	$0.050800	$0.000000	$0.050260	-11.144%				
Xsmall	365	365	0	$9.00	$11.24	$0.00	$0.00	$18.34	($2.04)	$25.58	$1.79	7.5%	30.00%
Small	564	400	164	$9.00	$12.32	$8.33	$0.00	$28.35	($3.16)	$38.39	$1.62	4.4%	30.00%
Medium	878	400	478	$9.00	$12.32	$24.28	$0.00	$44.13	($4.92)	$67.85	$1.69	2.6%	20.00%
Large	1,340	400	940	$9.00	$12.32	$47.75	$0.00	$67.35	($7.51)	$128.81	$14.41	12.6%	10.00%
Xlarge	2,304	400	1,904	$9.00	$12.32	$96.72	$0.00	$115.80	($12.90)	$212.94	$1.19	0.6%	$8.00
Mean	1,034	400	634	$9.00	$12.32	$32.19	$0.00	$51.95	($5.79)	$79.74	$1.61	2.1%	20.00%
sum	1,199	400	799	$9.00	$12.32	$40.58	$0.00	$60.25	($6.71)	$92.35	$1.51	1.7%	20.00%
win	871	400	471	$9.00	$12.32	$23.93	$0.00	$43.78	($4.88)	$67.32	$1.68	2.6%	20.00%
Annual										$958.03	$19.15	2.0%	

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

WINTER

	BILL IMPACTS PROPOSED TRANSITION RATES														
								Delivery							
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	0-400 kWh	401-1,000 kWh	1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+	$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	22%	1.2	198	198	0	0	$9.00	$6.10	$0.00	$0.00	$0.00	$9.95	$0.00	$17.53	30.00%
Small	25%	1.8	324	324	0	0	$9.00	$9.98	$0.00	$0.00	$0.00	$16.28	$0.00	$28.21	20.00%
Medium	27%	2.7	525	400	125	0	$9.00	$12.32	$6.35	$0.00	$0.00	$26.39	$0.00	$48.65	10.00%
Large	30%	3.8	831	400	431	0	$9.00	$12.32	$21.89	$0.00	$0.00	$41.77	$0.00	$76.49	10.00%
XLg	34%	6.0	1,496	400	600	496	$9.00	$12.32	$30.48	$25.20	$0.00	$75.19	$0.00	$144.19	$8.00
AnnAvg	30%	3.9	867	400	467	0	$9.00	$12.32	$23.72	$0.00	$0.00	$43.57	$0.00	$79.75	10.00%
WinAvg	28%	3.1	638	400	238	0	$9.00	$12.32	$12.09	$0.00	$0.00	$32.07	$0.00	$58.94	10.00%

	BILL IMPACTS PROPOSED RATES																
								Delivery									
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	All kW	All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak		15.00	5.15	$0.01676	$0.000000							
Winter				0.26	0.74						$0.082800	$0.038610	-11.144%				
Summer											$0.102251	$0.042830					
Xsm	22%	1.2	198	51	147		$15.00	$6.18	$3.32	$0.00	$4.22	$5.68	($1.10)	$27.31	$9.78	55.8%	18.00%
Small	25%	1.8	324	84	240		$15.00	$9.27	$5.43	$0.00	$6.96	$9.27	($1.81)	$36.18	$7.97	28.3%	18.00%
Medium	27%	2.7	525	136	389		$15.00	$13.91	$8.80	$0.00	$11.26	$15.02	($2.93)	$50.07	$1.42	2.9%	18.00%
Large	30%	3.8	831	216	615		$15.00	$19.57	$13.93	$0.00	$17.88	$23.75	($4.64)	$70.10	-$6.39	-8.4%	18.00%
XLg	34%	6.0	1,496	388	1,108		$15.00	$30.90	$25.07	$0.00	$32.13	$42.78	($8.35)	$121.53	-$22.66	-15.7%	$16.00
AnnAvg	30%	3.9	867	225	642		$15.00	$20.09	$14.53	$0.00	$18.63	$24.79	($4.84)	$72.32	-$7.43	-9.3%	18.00%
WinAvg	28%	3.1	638	166	472		$15.00	$15.97	$10.69	$0.00	$13.74	$18.22	($3.56)	$57.45	-$1.49	-2.5%	18.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES

SUMMER

	BILL IMPACTS PROPOSED TRANSITION RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+	$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	23%	1.4	243	243	0	0	$9.00	$7.48	$0.00	$0.00	$0.00	$12.21	$0.00	$20.09	30.00%
Small	26%	2.2	413	400	13	0	$9.00	$12.32	$0.66	$0.00	$0.00	$20.76	$0.00	$34.19	20.00%
Medium	29%	3.4	709	400	309	0	$9.00	$12.32	$15.70	$0.00	$0.00	$35.63	$0.00	$65.38	10.00%
Large	32%	4.9	1,161	400	600	161	$9.00	$12.32	$30.48	$8.18	$0.00	$58.35	$0.00	$110.33	$8.00
XLg	37%	7.8	2,078	400	600	1,078	$9.00	$12.32	$30.48	$54.76	$0.00	$104.44	$0.00	$203.00	$8.00
AnnAvg	30%	3.9	867	400	467	0	$9.00	$12.32	$23.72	$0.00	$0.00	$43.57	$0.00	$79.75	10.00%
SumAvg	30%	3.9	863	400	463	0	$9.00	$12.32	$23.54	$0.00	$0.00	$43.39	$0.00	$79.43	10.00%

	BILL IMPACTS PROPOSED RATES																
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
				On-Peak	Off-Peak												
Winter											$0.082800	$0.038610					
Summer				0.24	0.76		$15.00	$5.15	$0.01676	$0.000000	$0.102251	$0.042830	-11.144%				
Xsm	23%	1.4	243	58	185		$15.00	$7.21	$4.07	$0.00	$5.93	$7.92	($1.54)	$31.64	$11.55	57.5%	18.00%
Small	26%	2.2	413	99	314		$15.00	$11.33	$6.92	$0.00	$10.12	$13.45	($2.63)	$44.44	$10.25	30.0%	18.00%
Medium	29%	3.4	709	171	538		$15.00	$17.51	$11.88	$0.00	$17.48	$23.04	($4.52)	$65.92	$0.54	0.8%	18.00%
Large	32%	4.9	1,161	279	882		$15.00	$25.24	$19.46	$0.00	$28.53	$37.78	($7.39)	$102.62	-$7.71	-7.0%	$16.00
XLg	37%	7.8	2,078	500	1,578		$15.00	$40.17	$34.83	$0.00	$51.13	$67.59	($13.23)	$179.49	-$23.51	-11.6%	$16.00
AnnAvg	30%	3.9	867	209	658		$15.00	$20.09	$14.53	$0.00	$21.37	$28.18	($5.52)	$76.79	-$2.96	-3.7%	18.00%
SumAvg	30%	3.9	863	208	656		$15.00	$20.09	$14.47	$0.00	$21.27	$28.10	($5.50)	$76.61	-$2.82	-3.6%	18.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+	$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	24%	1.8	323	323	0	0	$9.00	$9.95	$0.00	$0.00	$0.00	$16.23	$0.00	$24.62	30.00%
Small	27%	2.5	495	400	95	0	$9.00	$12.32	$4.83	$0.00	$0.00	$24.88	$0.00	$35.72	30.00%
Medium	29%	3.6	763	400	363	0	$9.00	$12.32	$18.44	$0.00	$0.00	$38.35	$0.00	$62.49	20.00%
Large	32%	4.8	1,115	400	600	115	$9.00	$12.32	$30.48	$5.84	$0.00	$56.04	$0.00	$90.95	20.00%
XLg	36%	7.2	1,887	400	600	887	$9.00	$12.32	$30.48	$45.06	$0.00	$94.84	$0.00	$172.53	10.00%
AnnAvg	32%	5.1	1,199	400	600	199	$9.00	$12.32	$30.48	$10.10	$0.00	$60.25	$0.00	$97.72	20.00%
WinAvg	30%	4.0	871	400	471	0	$9.00	$12.32	$23.93	$0.00	$0.00	$43.78	$0.00	$71.23	20.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	Discounts
				On-Peak	Off-Peak		15.00	5.15	$0.01676	$0.000000							
Winter				0.26	0.74						$0.082800	$0.038610	-11.144%				
Summer											$0.102251	$0.042830					
Xsm	24%	1.8	323	84	239		$15.00	$9.27	$5.41	$0.00	$6.96	$9.23	($1.80)	$33.49	$8.87	36.0%	24.00%
Small	27%	2.5	495	128	367		$15.00	$12.88	$8.30	$0.00	$10.60	$14.17	($2.76)	$44.22	$8.50	23.8%	24.00%
Medium	29%	3.6	763	198	565		$15.00	$18.54	$12.79	$0.00	$16.39	$21.81	($4.26)	$61.01	-$1.48	-2.4%	24.00%
Large	32%	4.8	1,115	289	826		$15.00	$24.72	$18.69	$0.00	$23.93	$31.89	($6.22)	$82.09	-$8.86	-9.7%	24.00%
XLg	36%	7.2	1,887	490	1,397		$15.00	$37.08	$31.63	$0.00	$40.57	$53.94	($10.53)	$127.44	-$45.09	-26.1%	24.00%
AnnAvg	32%	5.1	1,199	311	888		$15.00	$26.27	$20.09	$0.00	$25.75	$34.29	($6.69)	$87.18	-$10.54	-10.8%	24.00%
WinAvg	30%	4.0	871	226	645		$15.00	$20.60	$14.60	$0.00	$18.71	$24.90	($4.86)	$67.60	-$3.63	-5.1%	24.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

SUMMER

	BILL IMPACTS PROPOSED TRANSITION RATES														
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
								0-400 kWh	401-1,000 kWh	1,000+ kWh					
				0-400	401-1,000	1,000+	$9.00	$0.030800	$0.050800	$0.050800	$0.000000	$0.050260	$0.000000		
Xsm	26%	2.2	414	400	14	0	$9.00	$12.32	$0.71	$0.00	$0.00	$20.81	$0.00	$29.99	30.00%
Small	29%	3.2	663	400	263	0	$9.00	$12.32	$13.34	$0.00	$0.00	$33.30	$0.00	$54.36	20.00%
Medium	31%	4.5	1,035	400	600	35	$9.00	$12.32	$30.48	$1.78	$0.00	$52.02	$0.00	$84.48	20.00%
Large	34%	6.3	1,572	400	600	572	$9.00	$12.32	$30.48	$29.03	$0.00	$78.98	$0.00	$143.83	10.00%
XLg	38%	9.3	2,601	400	600	1,601	$9.00	$12.32	$30.48	$81.33	$0.00	$130.73	$0.00	$255.86	$8.00
AnnAvg	32%	5.1	1,199	400	600	199	$9.00	$12.32	$30.48	$10.10	$0.00	$60.25	$0.00	$97.72	20.00%
SumAvg	32%	5.0	1,194	400	600	194	$9.00	$12.32	$30.48	$9.84	$0.00	$60.00	$0.00	$97.32	20.00%

	BILL IMPACTS PROPOSED RATES																
	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
								All kW	All kWh								
				On-Peak	Off-Peak												
Winter											$0.082800	$0.038610					
Summer				0.24	0.76		$15.00	$5.15	$0.01676	$0.000000	$0.102251	$0.042830	-11.144%				
Xsm	26%	2.2	414	100	314		$15.00	$11.33	$6.94	$0.00	$10.23	$13.45	($2.64)	$41.28	$11.29	37.6%	24.00%
Small	29%	3.2	663	159	503		$15.00	$16.48	$11.10	$0.00	$16.26	$21.54	($4.21)	$57.89	$3.53	6.5%	24.00%
Medium	31%	4.5	1,035	249	786		$15.00	$23.18	$17.35	$0.00	$25.46	$33.66	($6.59)	$82.13	-$2.35	-2.8%	24.00%
Large	34%	6.3	1,572	378	1,193		$15.00	$32.45	$26.34	$0.00	$38.65	$51.10	($10.00)	$116.69	-$27.14	-18.9%	24.00%
XLg	38%	9.3	2,601	626	1,975		$15.00	$47.90	$43.59	$0.00	$64.01	$84.59	($16.56)	$222.53	-$33.33	-13.0%	$16.00
AnnAvg	32%	5.1	1,199	288	910		$15.00	$26.27	$20.09	$0.00	$29.45	$38.98	($7.63)	$92.84	-$4.88	-5.0%	24.00%
SumAvg	32%	5.0	1,194	287	907		$15.00	$25.75	$20.01	$0.00	$29.35	$38.85	($7.60)	$92.23	-$5.09	-5.2%	24.00%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+							
	Winter	0.24	0.76				$11.50	$0.030350	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer									$0.129605	$0.039605		
Xsm	150	36	114	150	0	0	$11.50	$4.55	$0.17	$4.67	$3.58	-$0.32	$24.15
Small	286	69	217	286	0	0	$11.50	$8.68	$0.33	$8.90	$6.82	-$0.61	$35.62
Medium	641	154	487	400	241	0	$11.50	$19.45	$0.73	$19.94	$15.29	-$1.37	$65.54
Large	1,043	250	793	400	600	43	$11.50	$31.66	$1.19	$32.44	$24.88	-$2.23	$99.44
XLg	1,810	434	1,376	400	600	810	$11.50	$54.93	$2.06	$56.30	$43.17	-$3.87	$164.09
AnnAvg	1,008	242	766	400	600	8	$11.50	$30.59	$1.15	$31.36	$24.05	-$2.16	$96.49
Avg Win	801	192	608	400	401	0	$11.50	$24.30	$0.91	$24.90	$19.10	-$1.71	$79.00

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610	-11.144%			
	Summer											$0.111001	$0.042830			$ Change	% Change
Xsm	150	36	114	150	0	0	$15.00	$5.54	$0.00	$0.00	$0.00	$3.30	$4.40	($0.86)	$27.38	$3.23	13.37%
Small	286	69	217	286	0	0	$15.00	$10.55	$0.00	$0.00	$0.00	$6.28	$8.39	($1.63)	$38.59	$2.97	8.34%
Medium	641	154	487	400	241	0	$15.00	$14.76	$8.89	$0.00	$0.00	$14.08	$18.81	($3.67)	$67.87	$2.33	3.56%
Large	1,043	250	793	400	600	43	$15.00	$14.76	$22.14	$1.59	$0.00	$22.92	$30.61	($5.97)	$101.05	$1.61	1.62%
XLg	1,810	434	1,376	400	600	810	$15.00	$14.76	$22.14	$29.89	$0.00	$39.77	$53.11	($10.35)	$164.32	$0.23	0.14%
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$22.15	$29.58	($5.76)	$98.17	$1.68	1.74%
Avg Win	801	192	608	400	401	0	$15.00	$14.76	$14.78	$0.00	$0.00	$17.59	$23.49	($4.58)	$81.04	$2.04	2.58%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Delivery (kWh) TIERS 0-400	401-1,000	1,000+	Basic Service Charge	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
Winter		0.23	0.77										
Summer							$11.50	$0.030350	$0.001140	$0.129605	$0.031385		
										$0.129605	$0.039605	-$0.002139	
Xsm	261	60	201	261	0	0	$11.50	$7.92	$0.30	$7.78	$7.96	-$0.56	$34.90
Small	525	121	404	400	125	0	$11.50	$15.93	$0.60	$15.65	$16.01	-$1.12	$58.57
Medium	983	226	757	400	583	0	$11.50	$29.83	$1.12	$29.30	$29.98	-$2.10	$99.63
Large	1,611	371	1,240	400	600	611	$11.50	$48.89	$1.84	$48.02	$49.13	-$3.45	$155.93
XLg	2,681	617	2,064	400	600	1,681	$11.50	$81.37	$3.06	$79.92	$81.76	-$5.74	$251.87
AnnAvg	1,008	232	776	400	600	8	$11.50	$30.59	$1.15	$30.05	$30.74	-$2.16	$101.87
Avg Sum	1,195	275	920	400	600	195	$11.50	$36.26	$1.36	$35.61	$36.43	-$2.56	$118.60

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak	Delivery (kWh) TIERS 0-400	401-1,000	1,000+	Basic Service Charge	Delivery All kWh 0-400	401-1,000	1,000+	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
Winter																	
Summer							$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610				
												$0.111001	$0.042830	-11.144%			
Xsm	261	60	201	261	0	0	$15.00	$9.63	$0.00	$0.00	$0.00	$6.66	$8.61	($1.70)	$38.20	$3.30	9.45%
Small	525	121	404	400	125	0	$15.00	$14.76	$4.61	$0.00	$0.00	$13.40	$17.31	($3.42)	$61.66	$3.09	5.28%
Medium	983	226	757	400	583	0	$15.00	$14.76	$21.51	$0.00	$0.00	$25.10	$32.42	($6.41)	$102.38	$2.75	2.76%
Large	1,611	371	1,240	400	600	611	$15.00	$14.76	$22.14	$22.55	$0.00	$41.13	$53.13	($10.50)	$158.21	$2.28	1.46%
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.76	$22.14	$62.03	$0.00	$68.45	$88.42	($17.48)	$253.32	$1.45	0.57%
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$25.74	$33.25	($6.57)	$104.62	$2.75	2.70%
Avg Sum	1,195	275	920	400	600	195	$15.00	$14.76	$22.14	$7.19	$0.00	$30.50	$39.40	($7.79)	$121.20	$2.60	2.19%

		$ Change	% Change
Current Annual	$1,185.62		
Proposed Annual	$1,213.44	$27.82	2.35%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES - RES TOU

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.24	0.76				$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610	0.000%	
	Summer											$0.111001	$0.042830		
Xsm	150	36	114	150	0	0	$15.00	$5.54	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.24
Small	286	69	217	286	0	0	$15.00	$10.55	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$40.22
Medium	641	154	487	400	241	0	$15.00	$14.76	$8.89	$0.00	$0.00	$14.08	$18.81	$0.00	$71.54
Large	1,043	250	793	400	600	43	$15.00	$14.76	$22.14	$1.59	$0.00	$22.92	$30.61	$0.00	$107.02
XLg	1,810	434	1,376	400	600	810	$15.00	$14.76	$22.14	$29.89	$0.00	$39.77	$53.11	$0.00	$174.67
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$22.15	$29.58	$0.00	$103.93
Avg Win	801	192	608	400	401	0	$15.00	$14.76	$14.78	$0.00	$0.00	$17.59	$23.49	$0.00	$85.62

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)	Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak			$15.00	All kW	All kWh	$0.000000						
							$5.15	$0.01676							
Winter		0.24	0.76							$0.082800	$0.038610	-11.144%			
Summer										$0.102251	$0.042830				
Xsm	150	36	114	21%	1.0	$15.00	$5.15	$2.51	$0.00	$2.98	$4.40	($0.82)	$29.22	$0.98	3.47%
Small	286	69	217	24%	1.6	$15.00	$8.24	$4.79	$0.00	$5.68	$8.39	($1.57)	$40.53	$0.31	0.77%
Medium	641	154	487	28%	3.1	$15.00	$15.97	$10.74	$0.00	$12.74	$18.81	($3.52)	$69.74	-$1.80	-2.52%
Large	1,043	250	793	31%	4.5	$15.00	$23.18	$17.48	$0.00	$20.73	$30.61	($5.72)	$101.28	-$5.74	-5.36%
XLg	1,810	434	1,376	35%	7.0	$15.00	$36.05	$30.34	$0.00	$35.97	$53.11	($9.93)	$160.54	-$14.13	-8.09%
AnnAvg	1,008	242	766	31%	4.4	$15.00	$22.66	$16.90	$0.00	$20.03	$29.58	($5.53)	$98.64	-$5.29	-5.09%
WinAvg	801	192	608	30%	3.7	$15.00	$19.06	$13.42	$0.00	$15.91	$23.49	($4.39)	$82.49	-$3.13	-3.66%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED TRANSITION RATES - RES TOU

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
Winter							$15.00	$0.036900	$0.036900	$0.036900	$0.000000	$0.091550	$0.038610		
Summer		0.23	0.77									$0.111001	$0.042830	0.000%	
Xsm	261	60	201	261	0	0	$15.00	$9.63	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.90
Small	525	121	404	400	125	0	$15.00	$14.76	$4.61	$0.00	$0.00	$13.40	$17.31	$0.00	$65.08
Medium	983	226	757	400	583	0	$15.00	$14.76	$21.51	$0.00	$0.00	$25.10	$32.42	$0.00	$108.79
Large	1,611	371	1,240	400	600	611	$15.00	$14.76	$22.14	$22.55	$0.00	$41.13	$53.13	$0.00	$168.71
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.76	$22.14	$62.03	$0.00	$68.45	$88.42	$0.00	$270.80
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.76	$22.14	$0.30	$0.00	$25.74	$33.25	$0.00	$111.19
Avg Win	1,195	275	920	400	600	195	$15.00	$14.76	$22.14	$7.19	$0.00	$30.50	$39.40	$0.00	$128.99

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		Basic Service Charge	Delivery		TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak					All kW	All kWh							
							$15.00	$5.15	$0.01676	$0.000000						
Winter											$0.082800	$0.038610				
Summer		0.23	0.77								$0.102251	$0.042830	-11.144%			
Xsm	261	60	201	23%	1.5		$15.00	$7.73	$4.37	$0.00	$6.14	$8.61	($1.64)	$40.21	$0.31	0.78%
Small	525	121	404	27%	2.7		$15.00	$13.91	$8.80	$0.00	$12.37	$17.30	($3.31)	$64.07	-$1.01	-1.55%
Medium	983	226	757	31%	4.3		$15.00	$22.15	$16.48	$0.00	$23.11	$32.42	($6.19)	$102.97	-$5.82	-5.35%
Large	1,611	371	1,240	35%	6.4		$15.00	$32.96	$27.00	$0.00	$37.94	$53.11	($10.15)	$155.86	-$12.85	-7.62%
XLg	2,681	617	2,064	39%	9.5		$15.00	$48.93	$44.93	$0.00	$63.09	$88.40	($16.88)	$243.47	-$27.33	-10.09%
AnnAvg	1,008	232	776	31%	4.4		$15.00	$22.66	$16.90	$0.00	$23.72	$33.24	($6.35)	$105.17	-$6.02	-5.41%
WinAvg	1,195	275	920	32%	5.1		$15.00	$26.27	$20.02	$0.00	$28.12	$39.40	($7.52)	$121.29	-$7.70	-5.97%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter	0.1	0.9				$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer											$0.170000	$0.039700		
Xsm	150	15	135	150	0	0	$11.50	$3.75	$0.00	$0.00	$0.17	$2.25	$5.22	-$0.32	$22.57
Small	286	29	257	286	0	0	$11.50	$7.15	$0.00	$0.00	$0.33	$4.29	$9.96	-$0.61	$32.62
Medium	641	64	577	400	241	0	$11.50	$10.00	$8.44	$0.00	$0.73	$9.62	$22.33	-$1.37	$61.25
Large	1,043	104	939	400	600	43	$11.50	$10.00	$21.00	$1.51	$1.19	$15.65	$36.33	-$2.23	$94.95
XLg	1,810	181	1,629	400	600	810	$11.50	$10.00	$21.00	$28.35	$2.06	$27.15	$63.04	-$3.87	$159.23
AnnAvg	1,008	101	907	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$15.12	$35.11	-$2.16	$92.00
Avg Win	801	80	721	400	401	0	$11.50	$10.00	$14.02	$0.00	$0.91	$12.01	$27.89	-$1.71	$74.62

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+							
	Winter						$15.00	$0.032258	$0.035500	$0.035500	$0.000000	$0.159790	$0.040810	-11.144%			
	Summer											$0.159790	$0.040810				
Xsm	150	15	135	150	0	0	$15.00	$4.84	$0.00	$0.00	$0.00	$2.40	$5.51	($0.88)	$26.87	$4.30	19.05%
Small	286	29	257	286	0	0	$15.00	$9.23	$0.00	$0.00	$0.00	$4.57	$10.50	($1.68)	$37.62	$5.00	15.33%
Medium	641	64	577	400	241	0	$15.00	$12.90	$8.56	$0.00	$0.00	$10.24	$23.54	($3.76)	$66.48	$5.23	8.54%
Large	1,043	104	939	400	600	43	$15.00	$12.90	$21.30	$1.53	$0.00	$16.67	$38.31	($6.13)	$99.58	$4.63	4.88%
XLg	1,810	181	1,629	400	600	810	$15.00	$12.90	$21.30	$28.76	$0.00	$28.92	$66.48	($10.63)	$162.73	$3.50	2.20%
AnnAvg	1,008	101	907	400	600	8	$15.00	$12.90	$21.30	$0.29	$0.00	$16.11	$37.03	($5.92)	$96.71	$4.71	5.12%
AvgWin	801	80	721	400	401	0	$15.00	$12.90	$14.22	$0.00	$0.00	$12.79	$29.41	($4.70)	$79.62	$5.00	6.70%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

RESIDENTIAL SERVICE RATE TIME OF USE - SUPER PEAK

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-1,000	1,000+		0-400	401-1,000	1,000+					
	Winter						$11.50	$0.025000	$0.035000	$0.035000	$0.001140	$0.150000	$0.038700	-$0.002139	
	Summer	0.14	0.86									$0.170000	$0.039700		
Xsm	261	37	224	261	0	0	$11.50	$6.53	$0.00	$0.00	$0.30	$6.21	$8.91	-$0.56	$32.89
Small	525	74	452	400	125	0	$11.50	$10.00	$4.38	$0.00	$0.60	$12.50	$17.92	-$1.12	$55.78
Medium	983	138	845	400	583	0	$11.50	$10.00	$20.41	$0.00	$1.12	$23.40	$33.56	-$2.10	$97.89
Large	1,611	226	1,385	400	600	611	$11.50	$10.00	$21.00	$21.39	$1.84	$38.34	$55.00	-$3.45	$155.62
XLg	2,681	375	2,306	400	600	1,681	$11.50	$10.00	$21.00	$58.84	$3.06	$63.81	$91.53	-$5.74	$254.00
AnnAvg	1,008	141	867	400	600	8	$11.50	$10.00	$21.00	$0.28	$1.15	$23.99	$34.42	-$2.16	$100.18
AvgSum	1,195	167	1,027	400	600	195	$11.50	$10.00	$21.00	$6.82	$1.36	$28.43	$40.79	-$2.56	$117.34

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-1,000	1,000+	$15.00	0-400	401-1,000	1,000+							
	Winter							$0.032258	$0.035500	$0.035500	$0.000000	$0.159790	$0.040810				
	Summer	0.14	0.86									$0.159790	$0.040810	-11.144%		$ Change	% Change
Xsm	261	37	224	261	0	0	$15.00	$8.42	$0.00	$0.00	$0.00	$5.84	$9.16	($1.67)	$36.75	$3.86	11.73%
Small	525	74	452	400	125	0	$15.00	$12.90	$4.44	$0.00	$0.00	$11.74	$18.43	($3.36)	$59.15	$3.37	6.05%
Medium	983	138	845	400	583	0	$15.00	$12.90	$20.70	$0.00	$0.00	$21.99	$34.50	($6.30)	$98.79	$0.90	0.92%
Large	1,611	226	1,385	400	600	611	$15.00	$12.90	$21.30	$21.69	$0.00	$36.04	$56.54	($10.32)	$153.15	($2.47)	-1.59%
XLg	2,681	375	2,306	400	600	1,681	$15.00	$12.90	$21.30	$59.68	$0.00	$59.98	$94.09	($17.17)	$245.78	($8.22)	-3.24%
AnnAvg	1,008	141	867	400	600	8	$15.00	$12.90	$21.30	$0.29	$0.00	$22.55	$35.38	($6.46)	$100.96	$0.78	0.78%
AvgSum	1,195	167	1,027	400	600	195	$15.00	$12.90	$21.30	$6.91	$0.00	$26.73	$41.93	($7.65)	$117.12	($0.22)	-0.19%

	Net Bill	$ Change	% Change
Current Annual	$1,151.78		
Proposed Annual	$1,180.44	$28.66	2.49%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

SMALL GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
						1-400	401-7500	7501+				
		1-400	401-7500	7501+	$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	200	200	0	0	$14.50	$6.04	$0.00	$0.00	$0.23	$11.65	-$0.43	$31.99
Small	350	350	0	0	$14.50	$10.56	$0.00	$0.00	$0.40	$20.38	-$0.75	$45.09
Medium	561	400	161	0	$14.50	$12.07	$6.61	$0.00	$0.64	$32.67	-$1.20	$65.29
Large	1,447	400	1,047	0	$14.50	$12.07	$42.97	$0.00	$1.65	$84.27	-$3.10	$152.36
XLg	4,078	400	3,678	0	$14.50	$12.07	$150.95	$0.00	$4.65	$237.51	-$8.72	$410.96
Mean	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
sum	1,277	400	877	0	$14.50	$12.07	$36.00	$0.00	$1.46	$74.39	-$2.73	$135.69
win	980	400	580	0	$14.50	$12.07	$23.82	$0.00	$1.12	$57.10	-$2.10	$106.51
Annual												$1,453.20

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
						1-400	401-7500	7501+						
		1-400	401-7500	7501+	$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	-11.144%			
Xsm	200	200	0	0	$30.00	$6.48	$0.00	$0.00	$0.00	$10.66	($1.19)	$45.95	$13.96	43.63%
Small	350	350	0	0	$30.00	$11.34	$0.00	$0.00	$0.00	$18.65	($2.08)	$57.91	$12.82	28.43%
Medium	561	400	161	0	$30.00	$12.96	$6.83	$0.00	$0.00	$29.90	($3.33)	$76.36	$11.07	16.96%
Large	1,447	400	1,047	0	$30.00	$12.96	$44.39	$0.00	$0.00	$77.11	($8.59)	$155.87	$3.51	2.30%
XLg	4,078	400	3,678	0	$30.00	$12.96	$155.95	$0.00	$0.00	$217.32	($24.22)	$392.01	-$18.95	-4.61%
Mean	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	($6.72)	$127.50	$6.19	5.10%
sum	1,277	400	877	0	$30.00	$12.96	$37.20	$0.00	$0.00	$68.07	($7.59)	$140.64	$4.95	3.65%
win	980	400	580	0	$30.00	$12.96	$24.61	$0.00	$0.00	$52.25	($5.82)	$114.00	$7.49	7.03%
Annual												$1,527.84	$74.64	5.14%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE DEMAND

WINTER

BILL IMPACTS PROPOSED TRANSITION RATES

	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh) 1-400	Delivery (kWh) 401-7500	Delivery (kWh) 7501+	TCA	Base Fuel	PPFAC	Net Bill
				1-400	401-7500	7501+	$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	$0.000000	
Xsm	27%	0.9	173	173	0	0	$30.00	$5.61	$0.00	$0.00	$0.00	$9.22	$0.00	$44.82
Small	30%	1.4	303	303	0	0	$30.00	$9.82	$0.00	$0.00	$0.00	$16.15	$0.00	$55.96
Medium	33%	2.0	486	400	86	0	$30.00	$12.96	$3.65	$0.00	$0.00	$25.90	$0.00	$72.51
Large	40%	4.3	1,254	400	854	0	$30.00	$12.96	$36.21	$0.00	$0.00	$66.83	$0.00	$146.00
XLg	48%	10.1	3,535	400	3,135	0	$30.00	$12.96	$132.92	$0.00	$0.00	$188.38	$0.00	$364.26
AnnAvg	39%	4.0	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22
WinAvg	38%	3.6	980	400	580	0	$30.00	$12.96	$24.61	$0.00	$0.00	$52.25	$0.00	$119.82

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) On-Peak	Delivery (kWh) Off-Peak		Basic Service Charge	Delivery All kW	Delivery All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
							30.00	5.49	$0.016680	$0.000000						
	Winter			0.30	0.70						$0.083570	$0.040036	-11.144%			
	Summer										$0.084570	$0.045800				
Xsm	27%	0.9	173	53	120		$30.00	$4.94	$2.89	$0.00	$4.39	$4.82	($1.03)	$46.01	$1.19	2.65%
Small	30%	1.4	303	92	211		$30.00	$7.69	$5.05	$0.00	$7.70	$8.44	($1.80)	$57.08	$1.12	1.99%
Medium	33%	2.0	486	148	338		$30.00	$10.98	$8.11	$0.00	$12.35	$13.54	($2.89)	$72.09	-$0.42	-0.57%
Large	40%	4.3	1,254	381	873		$30.00	$23.61	$20.92	$0.00	$31.86	$34.94	($7.44)	$133.89	-$12.11	-8.29%
XLg	48%	10.1	3,535	1,075	2,460		$30.00	$55.45	$58.96	$0.00	$89.80	$98.50	($20.98)	$311.73	-$52.53	-14.42%
AnnAvg	39%	4.0	1,131	344	787		$30.00	$21.96	$18.86	$0.00	$28.73	$31.52	($6.71)	$124.36	-$9.86	-7.35%
WinAvg	38%	3.6	980	298	682		$30.00	$19.76	$16.35	$0.00	$24.91	$27.32	($5.82)	$112.52	-$7.30	-6.09%

Notes: 1. This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE DEMAND

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Total kWh	Delivery kWh			Basic Service Charge	Delivery (kWh)			TCA	Base Fuel	PPFAC	Net Bill
				1-400	401-7500	7501+		1-400	401-7500	7501+				
							$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.053290	$0.000000	
Xsm	29%	1.1	226	226	0	0	$30.00	$7.32	$0.00	$0.00	$0.00	$12.04	$0.00	$49.37
Small	32%	1.7	395	395	0	0	$30.00	$12.80	$0.00	$0.00	$0.00	$21.05	$0.00	$63.85
Medium	35%	2.5	634	400	234	0	$30.00	$12.96	$9.92	$0.00	$0.00	$33.79	$0.00	$86.67
Large	42%	5.4	1,634	400	1,234	0	$30.00	$12.96	$52.32	$0.00	$0.00	$87.08	$0.00	$182.36
XLg	51%	12.5	4,605	400	4,205	0	$30.00	$12.96	$178.29	$0.00	$0.00	$245.40	$0.00	$466.65
AnnAvg	39%	4.0	1,131	400	731	0	$30.00	$12.96	$30.99	$0.00	$0.00	$60.27	$0.00	$134.22
SumAvg	40%	4.4	1,277	400	877	0	$30.00	$12.96	$37.20	$0.00	$0.00	$68.07	$0.00	$148.22

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
				On-Peak	Off-Peak			All kW	All kWh		On-Peak	Off-Peak				
							30.00	5.49	$0.016680	$0.000000						
	Winter										$0.083570	$0.040036				
	Summer			0.27	0.73						$0.084570	$0.045800	-11.144%			
Xsm	29%	1.1	226	60	166		$30.00	$6.04	$3.77	$0.00	$5.07	$7.61	($1.41)	$51.08	$1.71	3.47%
Small	32%	1.7	395	105	290		$30.00	$9.33	$6.59	$0.00	$8.85	$13.30	($2.47)	$65.60	$1.75	2.74%
Medium	35%	2.5	634	168	466		$30.00	$13.73	$10.58	$0.00	$14.21	$21.34	($3.96)	$85.90	-$0.77	-0.89%
Large	42%	5.4	1,634	433	1,201		$30.00	$29.65	$27.26	$0.00	$36.62	$55.00	($10.21)	$168.32	-$14.04	-7.70%
XLg	51%	12.5	4,605	1,220	3,385		$30.00	$68.63	$76.81	$0.00	$103.21	$155.01	($28.78)	$404.88	-$61.77	-13.24%
AnnAvg	39%	4.0	1,131	300	831		$30.00	$21.96	$18.86	$0.00	$25.35	$38.07	($7.07)	$127.17	-$7.05	-5.26%
SumAvg	40%	4.4	1,277	339	939		$30.00	$24.16	$21.30	$0.00	$28.63	$43.00	($7.98)	$139.11	-$9.11	-6.15%

Notes: 1. This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE

WINTER

	BILL IMPACTS CURRENT RATES														
	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385	-$0.002139	
	Summer	0.18										$0.129605	$0.039605		
Xsm	394	91	303	394	0	0	$16.50	$11.87	$0.00	$0.00	$0.45	$11.73	$9.51	-$0.84	$49.22
Small	636	146	490	400	236	0	$16.50	$12.07	$10.19	$0.00	$0.73	$18.96	$15.37	-$1.36	$72.46
Medium	1633	376	1,257	400	1,233	0	$16.50	$12.07	$53.24	$0.00	$1.86	$48.68	$39.46	-$3.49	$168.32
Large	2,328	535	1,793	400	1,928	0	$16.50	$12.07	$83.24	$0.00	$2.65	$69.40	$56.26	-$4.98	$235.14
XLg	3,091	711	2,380	400	2,691	0	$16.50	$12.07	$116.19	$0.00	$3.52	$92.14	$74.70	-$6.61	$308.51
WinAvg	1,551	357	1,194	400	1,151	0	$16.50	$12.07	$49.70	$0.00	$1.77	$46.24	$37.48	-$3.32	$160.44

	BILL IMPACTS PROPOSED RATES																
	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036	-11.144%			
	Summer	0.18										$0.109800	$0.045800			$ Change	% Change
Xsm	394	91	303	394	0	0	$30.00	$12.75	$0.00	$0.00	$0.00	$9.85	$12.13	($2.45)	$62.28	$13.06	26.54%
Small	636	146	490	400	236	0	$30.00	$12.96	$10.01	$0.00	$0.00	$15.92	$19.61	($3.96)	$84.54	$12.08	16.67%
Medium	1,633	376	1,257	400	1,233	0	$30.00	$12.96	$52.28	$0.00	$0.00	$40.86	$50.34	($10.16)	$176.28	$7.96	4.73%
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.96	$81.75	$0.00	$0.00	$58.26	$71.77	($14.49)	$240.25	$5.11	2.17%
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.96	$114.10	$0.00	$0.00	$77.35	$95.29	($19.24)	$310.46	$1.95	0.63%
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.96	$48.81	$0.00	$0.00	$38.81	$47.82	($9.65)	$168.75	$8.31	5.18%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23										$0.129605	$0.031385		
	Summer	0.18					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.039605	-$0.002139	
Xsm	781	141	640	400	381	0	$16.50	$12.07	$16.45	$0.00	$0.89	$18.22	$25.36	-$1.67	$87.82
Small	1220	220	1,000	400	820	0	$16.50	$12.07	$35.40	$0.00	$1.39	$28.46	$39.62	-$2.61	$130.83
Medium	2350	423	1,927	400	1,950	0	$16.50	$12.07	$84.17	$0.00	$2.68	$54.81	$76.30	-$5.03	$241.50
Large	3,078	554	2,524	400	2,678	0	$16.50	$12.07	$115.63	$0.00	$3.51	$71.81	$99.96	-$6.58	$312.90
XLg	3,640	655	2,985	400	3,240	0	$16.50	$12.07	$139.89	$0.00	$4.15	$84.92	$118.21	-$7.79	$367.95
SumAvg	2,256	406	1,850	400	1,856	0	$16.50	$12.07	$80.15	$0.00	$2.57	$52.64	$73.28	-$4.83	$232.38

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill		
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036				
	Summer	0.18										$0.109800	$0.045800	-11.144%		$ Change	% Change
Xsm	781	141	640	400	381	0	$30.00	$12.96	$16.15	$0.00	$0.00	$15.44	$29.33	($4.99)	$98.89	$11.07	12.61%
Small	1,220	220	1,000	400	820	0	$30.00	$12.96	$34.77	$0.00	$0.00	$24.11	$45.82	($7.79)	$139.87	$9.04	6.91%
Medium	2,350	423	1,927	400	1,950	0	$30.00	$12.96	$82.66	$0.00	$0.00	$46.44	$88.24	($15.01)	$245.29	$3.79	1.57%
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.96	$113.55	$0.00	$0.00	$60.83	$115.60	($19.66)	$313.28	$0.38	0.12%
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.96	$137.38	$0.00	$0.00	$71.94	$136.70	($23.25)	$365.73	($2.22)	-0.60%
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.96	$78.71	$0.00	$0.00	$44.59	$84.74	($14.41)	$236.59	$4.21	1.81%

															$ Change	% Change
Current Annual														$2,356.95		
Proposed Annual														$2,432.04	$75.09	3.19%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

WINTER

BILL IMPACTS PROPOSED SGS-TOU RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036	0.000%	
	Summer	0.18										$0.109800	$0.045800		
Xsm	394	91	303	394	0	0	$30.00	$12.75	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$64.73
Small	636	146	490	400	236	0	$30.00	$12.96	$10.01	$0.00	$0.00	$15.92	$19.61	$0.00	$88.50
Medium	1633	376	1,257	400	1,233	0	$30.00	$12.96	$52.28	$0.00	$0.00	$40.86	$50.34	$0.00	$186.44
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.96	$81.75	$0.00	$0.00	$58.26	$71.77	$0.00	$254.74
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.96	$114.10	$0.00	$0.00	$77.35	$95.29	$0.00	$329.70
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.96	$48.81	$0.00	$0.00	$38.81	$47.82	$0.00	$178.40

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
									All kW	All kWh							
		On-Peak	Off-Peak					30.00	5.49	$0.016680	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.083570	$0.040036	-11.144%			
	Summer	0.18										$0.084570	$0.045800				
Xsm	394	91	303	32%	1.7			$30.00	$9.33	$6.56	$0.00	$7.56	$12.13	($2.19)	$63.39	-$1.34	-2.07%
Small	636	146	490	35%	2.5			$30.00	$13.73	$10.61	$0.00	$12.22	$19.61	($3.55)	$82.62	-$5.88	-6.64%
Medium	1633	376	1,257	42%	5.4			$30.00	$29.65	$27.24	$0.00	$31.39	$50.34	($9.11)	$159.51	-$26.93	-14.44%
Large	2,328	535	1,793	44%	7.2			$30.00	$39.53	$38.83	$0.00	$44.75	$71.77	($12.98)	$211.90	-$42.84	-16.82%
XLg	3,091	711	2,380	47%	9.0			$30.00	$49.41	$51.56	$0.00	$59.41	$95.29	($17.24)	$268.43	-$61.27	-18.58%
WinAvg	1,551	357	1,194	41%	5.2			$30.00	$28.55	$25.87	$0.00	$29.81	$47.82	($8.65)	$153.40	-$25.00	-14.01%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

SMALL GENERAL SERVICE RATE TIME OF USE DEMAND

SUMMER

BILL IMPACTS PROPOSED SGS-TOU RATES

	Energy (kWh)	Delivery (kWh)		Delivery (kWh) TIERS			Basic Service Charge	Delivery All kWh			TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+					
	Winter	0.23					$30.00	$0.032400	$0.042400	$0.077400	$0.000000	$0.108800	$0.040036		
	Summer	0.18										$0.109800	$0.045800	0.000%	
Xsm	781	141	640	400	381	0	$30.00	$12.96	$16.15	$0.00	$0.00	$15.44	$29.33	$0.00	$103.88
Small	1220	220	1,000	400	820	0	$30.00	$12.96	$34.77	$0.00	$0.00	$24.11	$45.82	$0.00	$147.66
Medium	2350	423	1,927	400	1,950	0	$30.00	$12.96	$82.66	$0.00	$0.00	$46.44	$88.24	$0.00	$260.30
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.96	$113.55	$0.00	$0.00	$60.83	$115.60	$0.00	$332.94
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.96	$137.38	$0.00	$0.00	$71.94	$136.70	$0.00	$388.98
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.96	$78.71	$0.00	$0.00	$44.59	$84.74	$0.00	$251.00

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
									All kW	All kWh							
	·	On-Peak	Off-Peak					30.00	5.49	$0.016680	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.083570	$0.040036				
	Summer	0.18										$0.084570	$0.045800	-11.144%			
Xsm	781	141	640	36%	3.0			$30.00	$16.47	$13.03	$0.00	$11.89	$29.33	($4.59)	$96.13	-$7.75	-7.46%
Small	1,220	220	1,000	39%	4.3			$30.00	$23.61	$20.35	$0.00	$18.57	$45.82	($7.18)	$131.17	-$16.49	-11.17%
Medium	2,350	423	1,927	45%	7.2			$30.00	$39.53	$39.19	$0.00	$35.77	$88.24	($13.82)	$218.91	-$41.39	-15.90%
Large	3,078	554	2,524	47%	9.0			$30.00	$49.41	$51.34	$0.00	$46.86	$115.60	($18.10)	$275.11	-$57.83	-17.37%
XLg	3,640	655	2,985	48%	10.3			$30.00	$56.55	$60.72	$0.00	$55.41	$136.70	($21.41)	$317.97	-$71.01	-18.26%
SumAvg	2,256	406	1,850	44%	7.0			$30.00	$38.43	$37.64	$0.00	$34.35	$84.74	($13.27)	$211.89	-$39.11	-15.58%

Notes: 1.This is a new proposed rate and there are currently no customers on the rate.

2. Assumed load factors and billing determinants were obtained from UNS Electric billing and load research data.

		$ Change	% Change
Current Annual	$2,576.40		
Proposed Annual	$2,191.74	($384.66)	-14.93%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

INTERRUPTIBLE POWER SERVICE

	BILL IMPACTS CURRENT RATES									
	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$18.00	$5.00	$0.019408	$0.432900	0.043760	-$0.002139	
Xsm	40.3%	1,116	66	$18.00	$331.53	$21.65	$28.70	$48.82	-$2.39	$446.32
Small	27.4%	14,651	108	$18.00	$541.23	$284.34	$46.86	$641.11	-$31.34	$1,500.20
Medium	30.7%	29,389	154	$18.00	$768.97	$570.39	$66.58	$1,286.08	-$62.87	$2,647.15
Large	44.3%	71,334	237	$18.00	$1,183.91	$1,384.44	$102.50	$3,121.55	-$152.61	$5,657.79
XLg	58.4%	384,599	887	$18.00	$4,432.94	$7,464.30	$383.80	$16,830.06	-$822.79	$28,306.31
AnnAvg	56.0%	97,708	239	$18.00	$1,195.06	$1,896.33	$103.47	$4,275.72	-$209.03	$7,279.55
AvgWin	52.0%	83,072	219	$18.00	$1,094.21	$1,612.26	$94.74	$3,635.24	-$177.72	$6,276.73
AvgSum	62.0%	112,958	250	$18.00	$1,247.88	$2,192.29	$108.04	$4,943.03	-$241.65	$8,267.58
Annual										$87,265.86

	BILL IMPACTS PROPOSED RATES											
	Load Factor	Total kWh	Demand (kW)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$75.00	$5.50	$0.019800	$0.000000	$0.053090	-11.144%			
Xsm	40.3%	1,116	66	$75.00	$364.69	$22.09	$0.00	$59.23	($6.60)	$514.41	$68.09	15.26%
Small	27.4%	14,651	108	$75.00	$595.36	$290.08	$0.00	$777.80	($86.68)	$1,651.56	$151.36	10.09%
Medium	30.7%	29,389	154	$75.00	$845.87	$581.91	$0.00	$1,560.28	($173.87)	$2,889.19	$242.04	9.14%
Large	44.3%	71,334	237	$75.00	$1,302.30	$1,412.40	$0.00	$3,787.10	($422.02)	$6,154.78	$496.99	8.78%
XLg	58.4%	384,599	887	$75.00	$4,876.23	$7,615.06	$0.00	$20,418.37	($2,275.35)	$30,709.31	$2,403.00	8.49%
AnnAvg	56.0%	97,708	239	$75.00	$1,314.57	$1,934.63	$0.00	$5,187.34	($578.06)	$7,933.48	$653.93	8.98%
AvgWin	52.0%	83,072	219	$75.00	$1,203.63	$1,644.83	$0.00	$4,410.30	($491.47)	$6,842.29	$565.56	9.01%
AvgSum	62.0%	112,958	250	$75.00	$1,372.66	$2,236.57	$0.00	$5,996.93	($668.28)	$9,012.88	$745.31	9.01%
Annual										$95,131.03	$7,865.17	9.01%

MEDIUM GENERAL SERVICE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.432900	$0.056603	-$0.002139	
Xsm	0.46	20	4,040	$50.00	$256.20	$22.10	$8.66	$228.68	-$8.64	$557.00
Small	0.46	20	6,400	$50.00	$256.20	$35.01	$8.66	$362.26	-$13.69	$698.44
Medium	0.46	36	12,160	$50.00	$463.88	$66.52	$15.68	$688.29	-$26.01	$1,258.36
Large	0.46	80	26,880	$50.00	$1,025.41	$147.03	$34.65	$1,521.49	-$57.51	$2,721.07
Xlarge	0.46	294	98,640	$50.00	$3,762.89	$539.56	$127.16	$5,583.32	-$211.02	$9,851.91
AnnAvg	0.46	80	26,796	$50.00	$1,022.22	$146.58	$34.54	$1,516.76	-$57.33	$2,712.77
sum	0.46	90	30,153	$50.00	$1,150.28	$164.94	$38.87	$1,706.76	-$64.51	$3,046.34
win	0.46	70	23,520	$50.00	$897.22	$128.65	$30.32	$1,331.28	-$50.32	$2,387.15
Annual										$32,600.94

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$100.00	$13.95	$0.005500	$0.000000	$0.053290	-11.144%			
Xsm	0.46	20	4,040	$100.00	$279.00	$22.22	$0.00	$215.29	($23.99)	$592.52	$35.52	6.4%
Small	0.46	20	6,400	$100.00	$279.00	$35.20	$0.00	$341.06	($38.01)	$717.25	$18.81	2.7%
Medium	0.46	36	12,160	$100.00	$505.16	$66.88	$0.00	$648.01	($72.21)	$1,247.84	-$10.52	-0.8%
Large	0.46	80	26,880	$100.00	$1,116.66	$147.84	$0.00	$1,432.44	($159.63)	$2,637.31	-$83.76	-3.1%
Xlarge	0.46	294	98,640	$100.00	$4,097.76	$542.52	$0.00	$5,256.53	($585.77)	$9,411.04	-$440.87	-4.5%
AnnAvg	0.46	80	26,796	$100.00	$1,113.19	$147.38	$0.00	$1,427.98	($159.13)	$2,629.42	-$83.35	-3.1%
sum	0.46	90	30,153	$100.00	$1,252.64	$165.84	$0.00	$1,606.87	($179.06)	$2,946.29	-$100.05	-3.3%
win	0.46	70	23,520	$100.00	$977.06	$129.36	$0.00	$1,253.36	($139.67)	$2,320.11	-$67.04	-2.8%
Annual										$31,598.40	-$1,002.54	-3.1%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

WINTER

	BILL IMPACTS CURRENT RATES												
	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168	-$0.002139	
		Summer		0.20						0.114886	0.039886		
Xsm	0.46	27,974	83	8,112	19,862	$52.00	$1,067.14	$153.02	$36.06	$932.01	$519.74	-$59.85	$2,700.12
Small	0.46	28,067	84	8,139	19,928	$52.00	$1,070.69	$153.53	$36.18	$935.11	$521.46	-$60.04	$2,708.93
Medium	0.46	48,453	144	14,051	34,402	$52.00	$1,848.37	$265.04	$62.46	$1,614.31	$900.22	-$103.66	$4,638.74
Large	0.56	62,572	186	18,146	44,426	$52.00	$2,386.98	$342.27	$80.67	$2,084.71	$1,162.54	-$133.86	$5,975.31
XLg	0.66	193,470	576	56,106	137,364	$52.00	$7,380.44	$1,058.28	$249.41	$6,445.83	$3,594.53	-$413.90	$18,366.59
AnnAvg	0.58	69,713	208	20,217	49,496	$52.00	$2,659.39	$381.33	$89.87	$2,322.62	$1,295.22	-$149.14	$6,651.29
AvgWin	0.56	65,673	196	19,045	46,628	$52.00	$2,505.28	$359.23	$84.66	$2,188.02	$1,220.16	-$140.50	$6,268.85

	BILL IMPACTS PROPOSED RATES														
	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.95	$0.005500	$0.00000	0.101047	0.031690	-11.144%			
		Summer								0.114886	0.033500				
Xsm	0.46	27,974	83	8,112	19,862	$100.00	$1,162.11	$153.86	$0.00	$819.74	$629.41	($161.49)	$2,703.63	$3.51	0.1%
Small	0.46	28,067	84	8,139	19,928	$100.00	$1,165.98	$154.37	$0.00	$822.46	$631.50	($162.02)	$2,712.29	$3.36	0.1%
Medium	0.46	48,453	144	14,051	34,402	$100.00	$2,012.86	$266.49	$0.00	$1,419.85	$1,090.19	($279.71)	$4,609.68	-$29.06	-0.6%
Large	0.56	62,572	186	18,146	44,426	$100.00	$2,599.40	$344.15	$0.00	$1,833.59	$1,407.86	($361.22)	$5,923.78	-$51.53	-0.9%
XLg	0.66	193,470	576	56,106	137,364	$100.00	$8,037.24	$1,064.09	$0.00	$5,669.37	$4,353.06	($1,116.87)	$18,106.89	-$259.70	-1.4%
AnnAvg	0.58	69,713	208	20,217	49,496	$100.00	$2,896.06	$383.42	$0.00	$2,042.84	$1,568.53	($402.44)	$6,588.41	-$62.88	-0.9%
AvgWin	0.56	65,673	196	19,045	46,628	$100.00	$2,728.23	$361.20	$0.00	$1,924.46	$1,477.64	($379.12)	$6,212.41	-$56.44	-0.9%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

MEDIUM GENERAL SERVICE TIME OF USE

SUMMER

BILL IMPACTS CURRENT RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
		Winter		0.29		$52.00	$12.81	$0.005470	$0.43290	0.114886	0.026168		
		Summer		0.20						0.114886	0.039886	-$0.002139	
Xsm	0.46	27,974	83	5,595	22,379	$52.00	$1,067.14	$153.02	$36.06	$642.76	$892.62	-$59.85	$2,783.75
Small	0.46	28,067	84	5,613	22,454	$52.00	$1,070.69	$153.53	$36.18	$644.90	$895.58	-$60.04	$2,792.84
Medium	0.46	48,453	144	9,691	38,762	$52.00	$1,848.37	$265.04	$62.46	$1,113.31	$1,546.08	-$103.66	$4,783.60
Large	0.56	62,572	186	12,514	50,058	$52.00	$2,386.98	$342.27	$80.67	$1,437.73	$1,996.60	-$133.86	$6,162.39
XLg	0.66	193,470	576	38,694	154,776	$52.00	$7,380.44	$1,058.28	$249.41	$4,445.40	$6,173.40	-$413.90	$18,945.03
AnnAvg	0.58	69,713	208	13,943	55,770	$52.00	$2,659.39	$381.33	$89.87	$1,601.81	$2,224.46	-$149.14	$6,859.72
AvgSum	0.56	73,609	219	14,722	58,887	$52.00	$2,808.00	$402.64	$94.89	$1,691.32	$2,348.76	-$157.47	$7,240.14

BILL IMPACTS PROPOSED RATES

	Load Factor	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
		Winter				$100.00	$13.95	$0.005500	$0.00000	0.101047	0.031690				
		Summer								0.114886	0.033500	-11.144%			
Xsm	0.46	27,974	83	5,595	22,379	$100.00	$1,162.11	$153.86	$0.00	$642.76	$749.70	($155.17)	$2,653.26	-$130.49	-4.7%
Small	0.46	28,067	84	5,613	22,454	$100.00	$1,165.98	$154.37	$0.00	$644.90	$752.20	($155.69)	$2,661.76	-$131.08	-4.7%
Medium	0.46	48,453	144	9,691	38,762	$100.00	$2,012.86	$266.49	$0.00	$1,113.31	$1,298.54	($268.77)	$4,522.43	-$261.17	-5.5%
Large	0.56	62,572	186	12,514	50,058	$100.00	$2,599.40	$344.15	$0.00	$1,437.73	$1,676.93	($347.09)	$5,811.12	-$351.27	-5.7%
XLg	0.66	193,470	576	38,694	154,776	$100.00	$8,037.24	$1,064.09	$0.00	$4,445.40	$5,185.00	($1,073.18)	$17,758.55	-$1,186.48	-6.3%
AnnAvg	0.58	69,713	208	13,943	55,770	$100.00	$2,896.06	$383.42	$0.00	$1,601.81	$1,868.31	($386.70)	$6,462.90	-$396.82	-5.8%
AvgSum	0.56	73,609	219	14,722	58,887	$100.00	$3,057.89	$404.85	$0.00	$1,691.32	$1,972.71	($408.31)	$6,818.46	-$421.68	-5.8%

												$ Change	% Change	
Current Annual												$81,053.94		
Proposed Annual												$78,185.22	-$2,868.72	-3.5%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE GENERAL SERVICE TO NEW LARGE GENERAL SERVICE

BILL IMPACTS CURRENT RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$50.00	$12.81	$0.005470	$0.43290	0.056603	-$0.002139	
Xsm	30%	205	45,000	$50.00	$2,632.19	$246.15	$88.95	$2,547.14	-$96.27	$5,468.16
Small	46%	194	65,000	$50.00	$2,479.60	$355.55	$83.80	$3,679.20	-$139.06	$6,509.09
Medium	66%	844	406,600	$50.00	$10,810.60	$2,224.10	$365.33	$23,014.78	-$869.85	$35,594.96
Large	75%	174	95,000	$50.00	$2,222.74	$519.65	$75.12	$5,377.29	-$203.24	$8,041.56
XLg	95%	1,875	1,300,500	$50.00	$24,022.21	$7,113.74	$811.80	$73,612.20	-$2,782.20	$102,827.75
AnnAvg	65%	992	470,630	$50.00	$12,705.52	$2,574.35	$429.37	$26,639.07	-$1,006.83	$41,391.47

BILL IMPACTS PROPOSED RATES - LGS

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$13.35	$0.005470	$0.00000	$0.053290	-11.144%			
Xsm	30%	450	45,000	$300.00	$6,007.50	$246.15	$0.00	$2,398.05	($267.23)	$8,684.47	$3,216.31	58.8%
Small	46%	450	65,000	$300.00	$6,007.50	$355.55	$0.00	$3,463.85	($386.00)	$9,740.90	$3,231.81	49.7%
Medium	66%	844	406,600	$300.00	$11,266.31	$2,224.10	$0.00	$21,667.71	($2,414.58)	$33,043.55	-$2,551.41	-7.2%
Large	75%	450	95,000	$300.00	$6,007.50	$519.65	$0.00	$5,062.55	($564.15)	$11,325.55	$3,283.99	40.8%
XLg	95%	1,875	1,300,500	$300.00	$25,034.86	$7,113.74	$0.00	$69,303.65	($7,722.96)	$94,029.28	-$8,798.46	-8.6%
AnnAvg	65%	992	470,630	$300.00	$13,241.12	$2,574.35	$0.00	$25,079.87	($2,794.82)	$38,400.51	-$2,990.96	-7.2%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE <69kV TO NEW LARGE GENERAL SERVICE

	BILL IMPACTS CURRENT RATES - LPS <69kV									
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$22.00	$0.000462	$0.43290	$0.04188	-$0.002139	
Xsm	44%	747	240,000	$1,200.00	$16,438.36	$110.88	$323.46	$10,051.20	-$513.44	$27,610.46
Small	46%	893	300,000	$1,200.00	$19,654.56	$138.60	$386.75	$12,564.00	-$641.80	$33,302.11
Medium	66%	844	406,600	$1,200.00	$18,566.21	$187.85	$365.33	$17,028.41	-$869.85	$36,477.95
Large	75%	1,553	850,000	$1,200.00	$34,155.25	$392.70	$672.08	$35,598.00	-$1,818.43	$70,199.60
XLg	75%	2,192	1,200,000	$1,200.00	$48,219.18	$554.40	$948.82	$50,256.00	-$2,567.20	$98,611.20
AnnAvg	65%	992	470,630	$1,200.00	$21,820.57	$217.43	$429.37	$19,709.98	-$1,006.83	$42,370.52

	BILL IMPACTS PROPOSED RATES - LPS <69 kV											
	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$300.00	$13.35	$0.005470	$0.00000	$0.053290	-11.144%			
Xsm	44%	747	240,000	$300.00	$9,975.09	$1,312.80	$0.00	$12,789.60	($1,425.23)	$22,952.26	-$4,658.19	-16.9%
Small	46%	893	300,000	$300.00	$11,926.74	$1,641.00	$0.00	$15,987.00	($1,781.54)	$28,073.20	-$5,228.90	-15.7%
Medium	66%	844	406,600	$300.00	$11,266.31	$2,224.10	$0.00	$21,667.71	($2,414.58)	$33,043.55	-$3,434.40	-9.4%
Large	75%	1,553	850,000	$300.00	$20,726.03	$4,649.50	$0.00	$45,296.50	($5,047.69)	$65,924.34	-$4,275.26	-6.1%
XLg	75%	2,192	1,200,000	$300.00	$29,260.27	$6,564.00	$0.00	$63,948.00	($7,126.15)	$92,946.12	-$5,665.07	-5.7%
AnnAvg	65%	992	470,630	$300.00	$13,241.12	$2,574.35	$0.00	$25,079.87	($2,794.82)	$38,400.51	-$3,970.00	-9.4%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

WINTER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.16						$0.123580	$0.024716		
Small	433,335	1,281	69,334	364,001	$1,200.00	$28,182.00	$200.20	$554.54	$6,509.04	$8,046.25	-$927.05	$43,764.98
Medium	517,000	1,380	82,720	434,280	$1,200.00	$30,360.00	$238.85	$597.40	$7,765.75	$9,599.76	-$1,106.04	$48,655.72
Large	600,000	1,400	96,000	504,000	$1,200.00	$30,800.00	$277.20	$606.06	$9,012.48	$11,140.92	-$1,283.60	$51,753.06
XLg	775,000	1,570	124,000	651,000	$1,200.00	$34,540.00	$358.05	$679.65	$11,641.12	$14,390.36	-$1,657.98	$61,151.20
Mean	642,400	1,430	102,784	539,616	$1,200.00	$31,460.00	$296.79	$619.05	$9,649.36	$11,928.21	-$1,374.31	$53,779.10
AvgWin	627,900	1,416	100,464	527,436	$1,200.00	$31,152.00	$290.09	$612.99	$9,431.56	$11,658.97	-$1,343.29	$53,002.32

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$13.35	$0.005470	$0.00000	$0.139880	$0.034927	-11.144%			
	Summer								$0.143771	$0.038600				
Small	433,335	1,281	69,334	364,001	$300.00	$17,101.35	$2,370.34	$0.00	$9,698.38	$12,713.48	($2,497.50)	$39,686.05	-$4,078.93	-9.3%
Medium	517,000	1,380	82,720	434,280	$300.00	$18,423.00	$2,827.99	$0.00	$11,570.87	$15,168.10	($2,979.70)	$45,310.26	-$3,345.46	-6.9%
Large	600,000	1,400	96,000	504,000	$300.00	$18,690.00	$3,282.00	$0.00	$13,428.48	$17,603.21	($3,458.07)	$49,845.62	-$1,907.44	-3.7%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,959.50	$4,239.25	$0.00	$17,345.12	$22,737.48	($4,466.67)	$61,114.68	-$36.52	-0.1%
Mean	642,400	1,430	102,784	539,616	$300.00	$19,090.50	$3,513.93	$0.00	$14,377.43	$18,847.17	($3,702.44)	$52,426.59	-$1,352.51	-2.5%
AvgWin	627,900	1,416	100,464	527,436	$300.00	$18,903.60	$3,434.61	$0.00	$14,052.90	$18,421.76	($3,618.87)	$51,494.00	-$1,508.32	-2.8%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE <69kV TO NEW LARGE GENERAL SERVICE TIME OF USE

SUMMER

	BILL IMPACTS CURRENT RATES											
	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill
	Winter		0.16		$1,200.00	$22.00	$0.000462	$0.43290	$0.093880	$0.022105		
	Summer		0.16						$0.123580	$0.024716	-$0.002139	
Small	433,335	1,281	69,334	364,001	$1,200	$28,182.00	$200.20	$554.54	$8,568.25	$8,996.66	-$927.05	$46,774.60
Medium	517,000	1,380	82,720	434,280	$1,200	$30,360.00	$238.85	$597.40	$10,222.54	$10,733.66	-$1,106.04	$52,246.41
Large	600,000	1,400	96,000	504,000	$1,200	$30,800.00	$277.20	$606.06	$11,863.68	$12,456.86	-$1,283.60	$55,920.20
XLg	775,000	1,570	124,000	651,000	$1,200	$34,540.00	$358.05	$679.65	$15,323.92	$16,090.12	-$1,657.98	$66,533.76
Mean	642,400	1,430	102,784	539,616	$1,200	$31,460.00	$296.79	$619.05	$12,702.05	$13,337.15	-$1,374.31	$58,240.73
AvgSum	656,700	1,444	105,072	551,628	$1,200	$31,768.00	$303.40	$625.11	$12,984.80	$13,634.04	-$1,404.90	$59,110.45

	BILL IMPACTS PROPOSED RATES													
	Total kWh	Demand (kW)	Delivery On-Peak (kWh)	Delivery Off-Peak (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Net Bill	$ Change	% Change
	Winter				$300.00	$13.35	$0.005470	$0.00000	$0.139880	$0.034927				
	Summer								$0.143771	$0.038600	-11.144%			
Small	433,335	1,281	69,334	364,001	$300.00	$17,101.35	$2,370.34	$0.00	$9,968.16	$14,050.45	($2,676.55)	$41,113.75	-$5,660.85	-12.1%
Medium	517,000	1,380	82,720	434,280	$300.00	$18,423.00	$2,827.99	$0.00	$11,892.74	$16,763.21	($3,193.32)	$47,013.62	-$5,232.79	-10.0%
Large	600,000	1,400	96,000	504,000	$300.00	$18,690.00	$3,282.00	$0.00	$13,802.02	$19,454.40	($3,705.98)	$51,822.44	-$4,097.76	-7.3%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,959.50	$4,239.25	$0.00	$17,827.60	$25,128.60	($4,786.89)	$63,668.06	-$2,865.70	-4.3%
Mean	642,400	1,430	102,784	539,616	$300.00	$19,090.50	$3,513.93	$0.00	$14,777.36	$20,829.18	($3,967.87)	$54,543.10	-$3,697.63	-6.3%
AvgSum	656,700	1,444	105,072	551,628	$300.00	$19,277.40	$3,592.15	$0.00	$15,106.31	$21,292.84	($4,056.20)	$55,512.50	-$3,597.95	-6.1%

	Net Bill	$ Change	% Change
Current Annual	$672,676.62		
Proposed Annual	$642,039.00	-$30,637.62	-4.55%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE - TRANSMISSION VOLTAGE

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill
				$1,200.00	$17.00	$0.000462	$0.43290	$0.041880	-$0.002139	
Xsm	0.42	506	155,000	$1,200.00	$8,594.26	$71.61	$218.85	$6,491.40	-$331.60	$16,244.52
Small	0.42	1,267	388,500	$1,200.00	$21,541.10	$179.49	$548.54	$16,270.38	-$831.13	$38,908.37
Small	0.46	1,336	448,600	$1,200.00	$22,710.54	$207.25	$578.32	$18,787.37	-$959.70	$42,523.79
Medium	0.75	2,416	1,322,700	$1,200.00	$41,070.14	$611.09	$1,045.84	$55,394.68	-$2,829.70	$96,492.04
Medium	0.75	2,817	1,542,200	$1,200.00	$47,885.66	$712.50	$1,219.39	$64,587.34	-$3,299.28	$112,305.61
Large	0.89	4,775	3,102,500	$1,200.00	$81,179.78	$1,433.36	$2,067.22	$129,932.70	-$6,637.28	$209,175.77
Large	0.89	5,379	3,494,900	$1,200.00	$91,447.28	$1,614.64	$2,328.68	$146,366.41	-$7,476.76	$235,480.26

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Delivery (kWh)	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
				$1,500.00	$13.00	$0.000500	$0.00000	$0.049332	-11.144%			
Xsm	0.42	506	155,000	$1,500.00	$6,572.08	$77.50	$0.00	$7,646.43	($852.09)	$14,943.92	-$1,300.60	-8.0%
Small	0.42	1,267	388,500	$1,500.00	$16,472.60	$194.25	$0.00	$19,165.41	($2,135.73)	$35,196.53	-$3,711.84	-9.5%
Small	0.46	1,336	448,600	$1,500.00	$17,366.89	$224.30	$0.00	$22,130.26	($2,466.12)	$38,755.33	-$3,768.46	-8.9%
Medium	0.75	2,416	1,322,700	$1,500.00	$31,406.58	$661.35	$0.00	$65,251.21	($7,271.37)	$91,547.77	-$4,944.28	-5.1%
Medium	0.75	2,817	1,542,200	$1,500.00	$36,618.45	$771.10	$0.00	$76,079.54	($8,478.05)	$106,491.04	-$5,814.57	-5.2%
Large	0.89	4,775	3,102,500	$1,500.00	$62,078.65	$1,551.25	$0.00	$153,051.99	($17,055.59)	$201,126.30	-$8,049.47	-3.8%
Large	0.89	5,379	3,494,900	$1,500.00	$69,930.28	$1,747.45	$0.00	$172,409.80	($19,212.76)	$226,374.77	-$9,105.49	-3.9%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE >69kV

WINTER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter				$1,200.00	$17.00	$0.000462	$0.43290	$0.093880	$0.022105	-$0.002139	
	Summer		0.11	0.89					$0.123580	$0.024716		
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$28,811.77	$54,888.93	-$5,967.81	$168,833.30
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$32,529.42	$61,971.37	-$6,737.85	$179,029.67
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$21,841.18	$41,609.35	-$4,523.99	$149,715.10
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$28,057.92	$53,452.76	-$5,811.66	$166,765.70
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,200.00	$86,411.00	$1,259.41	$2,200.43	$28,150.86	$53,629.82	-$5,830.91	$167,020.61

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter				$1,500.00	$13.00	$0.000500	$0.00000	$0.092110	$0.030410	-11.144%			
	Summer								$0.125155	$0.033410				
Small	2,790,000	5,083	306,900	2,483,100	$1,500.00	$66,079.00	$1,395.00	$0.00	$28,268.56	$75,511.07	($11,564.85)	$161,188.78	-$7,644.52	-4.53%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500.00	$66,079.00	$1,575.00	$0.00	$31,916.12	$85,254.44	($13,057.09)	$173,267.47	-$5,762.20	-3.22%
Large	2,115,000	5,083	232,650	1,882,350	$1,500.00	$66,079.00	$1,057.50	$0.00	$21,429.39	$57,242.26	($8,766.90)	$138,541.25	-$11,173.85	-7.46%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500.00	$66,079.00	$1,358.50	$0.00	$27,528.92	$73,535.33	($11,262.26)	$158,739.49	-$8,026.21	-4.81%
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,500.00	$66,079.00	$1,363.00	$0.00	$27,620.10	$73,778.92	($11,299.56)	$159,041.46	-$7,979.15	-4.78%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

LARGE POWER SERVICE TIME OF USE >69kV

SUMMER

BILL IMPACTS CURRENT RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill
	Winter								$0.093880	$0.022105		
	Summer		0.11	0.89	$1,200.00	$17.00	$0.000462	$0.43290	$0.123580	$0.024716	-$0.002139	
Small	2,790,000	5,083	306,900	2,483,100	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$37,926.70	$61,372.30	-$5,967.81	$184,431.60
Medium	3,150,000	5,083	346,500	2,803,500	$1,200.00	$86,411.00	$1,455.30	$2,200.43	$42,820.47	$69,291.31	-$6,737.85	$196,640.66
Large	2,115,000	5,083	232,650	1,882,350	$1,200.00	$86,411.00	$977.13	$2,200.43	$28,750.89	$46,524.16	-$4,523.99	$161,539.62
Mean	2,717,000	5,083	298,870	2,418,130	$1,200.00	$86,411.00	$1,255.25	$2,200.43	$36,934.35	$59,766.50	-$5,811.66	$181,955.87
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,200.00	$86,411.00	$1,288.98	$2,200.43	$38,507.53	$61,256.13	-$5,967.81	$184,896.26

BILL IMPACTS PROPOSED RATES

	Total kWh	Demand (kW)	Delivery On-Peak kWh	Delivery Off-Peak kWh	Basic Service Charge	Delivery (kW)	Delivery (kWh)	TCA /kW	Base Fuel On-Peak	Base Fuel Off-Peak	PPFAC	Total Net Bill	$ Change	% Change
	Winter								$0.092110	$0.030410				
	Summer				$1,500.00	$13.00	$0.000500	$0.00000	$0.125155	$0.033410	-11.144%			
Small	2,790,000	5,083	306,900	2,483,100	$1,500	$66,079	$1,395	$0.00	$38,410.07	$82,960.37	($13,525.11)	$176,819	-$7,612.27	-4.13%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500	$66,079	$1,575	$0.00	$43,366.21	$93,664.94	($15,270.29)	$190,915	-$5,725.80	-2.91%
Large	2,115,000	5,083	232,650	1,882,350	$1,500	$66,079	$1,058	$0.00	$29,117.31	$62,889.31	($10,252.90)	$150,390	-$11,149.40	-6.90%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500	$66,079	$1,359	$0.00	$37,405.07	$80,789.72	($13,171.23)	$173,961	-$7,994.81	-4.39%
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,500	$66,079	$1,395	$0.00	$38,998.30	$82,803.34	($13,573.16)	$177,202	-$7,693.78	-4.16%

											Total	$ Change	% Change
Current Annual											$2,111,501		
Proposed Annual											$2,017,464	($94,038)	-4.45%

UNS Electric, Inc.
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending December 31, 2014

LIGHTING SERVICE

Description	Old Rate	New Rate
New 30' Wood Pole (Class 6) - Overhead	$4.34	$4.68
New 30' Metal or Fiberglass - Overhead	$8.66	$9.35
Existing Wood Pole - Underground	$2.18	$2.35
New 30' Wood Pole (Class 6) - Underground	$6.52	$7.04
New 30' Metal or Fiberglass - Underground	$10.81	$11.67
Wattage, per Watt	$0.051681	$0.060516
		0
Base Power Supply	$0.010113	$0.014535
PPFAC	-$0.002139	-11.144%

		Proration
New Rate Days	28	100%
Old Rate Days	0	0%

Total Days	28
Total kWh billed	150

Customer Bill	Current Rates	Proposed Rates	$Change	%Change
100 Watt	$5.17	$6.05	$0.88	17.02%
150 Watt	$7.75	$9.08	$1.33	17.16%
200 Watt	$10.34	$12.10	$1.76	17.02%
250 Watt	$12.92	$15.13	$2.21	17.11%
400 Watt	$20.67	$24.21	$3.54	17.13%
Existing Wood Pole OH	$4.34	$4.68	$0.34	7.83%
New 30' Wood Pole OH	$8.66	$9.35	$0.69	7.97%
New 30' Metal or FG OH	$2.18	$2.35	$0.17	7.80%
Existing Wood Pole UG	$6.52	$7.04	$0.52	7.98%
New 30' Wood Pole UG	$10.81	$11.67	$0.86	7.96%
New 30' Metal or FG UG	$0.05	$0.06	$0.01	17.10%
Base Power Supply	$1.52	$2.18	$0.66	43.42%
PPFAC	($0.32)	($0.24)	$0.08	-25.00%
Typical	$13.29	$15.70	$2.41	18.13%

Detail of Services Billed	Wattage	Units Billed
100 Watt	100	1
150 Watt	150	1
200 Watt	200	1
250 Watt	250	1
400 Watt	400	1
Existing Wood Pole OH		5
New 30' Wood Pole OH		0
New 30' Metal or FG OH		0
Existing Wood Pole UG		0
New 30' Wood Pole UG		0
New 30' Metal or FG UG		0

Exhibit CAJ-R-6

Clean

UNS Electric, Inc.
Transmission Cost Adjustor
Plan of Administration

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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 make an annual filing with Docket Control that includes its revised TCA based on the Company's updated transmission service rates calculated pursuant to the Company's Open Access Transmission Tariff ("OATT"), including all supporting data and documentation used in calculating the formula rate ("Informational Filing") and the TCA. This Informational Filing shall be filed with the Commission no later than May 1.

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 in June 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:

Demand Billed Customers
Non-Demand Billed Customers

In addition to the Transmission Rate, UNS Electric will charge retail customers for other transmission-related services ("ancillary services") in accordance with its OATT ("Ancillary Services Rates") at such time that the Company provides these services. 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, 20xx.

Line	Service Type		
		\$/kWh	\$/kW
		(A)	(B)
1.	Transmission Rate	\$0.xxxx	\$x.xxxx
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.xxxx	\$x.xxxx
8.	Included in Retail Base Rates per OATT	\$0.xxxx	\$x.xxxx
9.	TCA (Line 7) – (Line 8)	\$0.xxxx	\$x.xxxx

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, which includes the revised TCA and all supporting data and documentation used in calculating the formula rate with the Commission each year no later than May 1. The Commission Staff and interested parties shall have the opportunity to review UNS Electric's Informational Filing.

The new TCA rates proposed by UNS Electric shall be effective in first billing cycle in June unless Staff requests Commission review or otherwise ordered by the Commission. The TCA rates are not prorated.

UNS Electric, Inc.
Rates for Transmission Cost Adjustor For June 1, 20xx Through May 31, 20xx
Data For Period Ending December 31, 20xx

Line	Service Type		
		$/kWh	$/kW
		(A)	(B)
1	Transmission Rate	$x.xxxx	$x.xxxx
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	$x.xxxx	$x.xxxx
8	Included in Retail Base Rates per OATT	$x.xxxx	$x.xxxx
9	TCA (Line 7) – (Line 8)	$x.xxxx	$x.xxxx

Redline

UNS Electric, Inc.
Transmission Cost Adjustor
Plan of Administration

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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 make an annual filing with Docket Control that includes its revised TCA based on the Company's updated transmission service rates calculated pursuant to the Company's Open Access Transmission Tariff ("OATT"), including all supporting data and documentation used in calculating the formula rate ("Informational Filing") and the TCA. This Informational Filing shall be filed with the Commission no later than May 1.

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 in June 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.

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The calculated Transmission Rates will be set forth in UNS Electric's Informational Filing. Transmission Rates are determined for the following classes:

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In addition to the Transmission Rate, UNS Electric will charge retail customers for other transmission-related services ("ancillary services") in accordance with its OATT ("Ancillary Services Rates") at such time that the Company provides these services. These additional ancillary services could include:

Scheduling, System Control and Dispatch Service

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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~~20xx.

Line	Service Type		
		$/kWh	$/kW
		(A)	(B)
1.	Transmission Rate	$0.~~0059~~xxxx	$~~2.3022~~x.xxxx
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~~xxxx	$~~2.3022~~x.xxxx
8.	Included in Retail Base Rates per OATT	$0.~~0059~~xxxx	$~~2.3022~~x.xxxx
9.	TCA (Line 7) – (Line 8)	$0.~~0000~~xxxx	$~~0.0000~~x.xxxx

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, which includes the revised TCA and all supporting data and documentation used in calculating the formula rate with the Commission each year no later than May 1. The Commission Staff and interested parties shall have the opportunity to review UNS Electric's Informational Filing.

The new TCA rates proposed by UNS Electric shall be effective in first billing cycle in June unless Staff requests Commission review or otherwise ordered by the Commission. The TCA rates are not prorated.

Rebuttal Testimony of

H. Edwin Overcast

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE - INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

Rebuttal Testimony of

H. Edwin Overcast

on Behalf of

UNS Electric, Inc.

January 19, 2016

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Appendix A Educational Background and Professional Experience

Appendix B Smart Rates for Smart Utilities

Exhibits:

Exhibit HEO-1 Part 1 La Senita Monthly Curves.pdf

Exhibit HEO -1 Part 2 Rio Monthly Curves.pdf

Exhibit HEO-2 Part 1 La Senita Production vs MC.pdf

HEO Exhibit 2 - Part 2 Rio Production vs MC.pdf

Exhibit HEO-3 Part 1 Senita Seasonal Curves.pdf

HEO Exhibit 3 - Part 2 Rio Seasonal Curves.pdf

Exhibit HEO- 4 Full vs NEM.pdf

Exhibit HEO-5 Part 2 Manager's Report.pdf

Exhibit HEO 5 Part 1 Make Free Demand Work.pdf

Exhibit HEO -6 Cumulative Full vs CARES.pdf

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

Q. BY WHOM AND IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am a Director, Black & Veatch Management Consulting, LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. A detailed summary of my educational and professional experience is provided in Appendix A to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. My fields of study include microeconomic theory, industrial organization and public finance. I have been employed in the energy industry for more than 40 years in various rate, regulatory and planning positions. My industry employers include the Tennessee Valley Authority, Northeast Utilities (an electric and gas holding company) and AGL Resources (a gas holding company). I have been employed as a utility consultant since 1998 providing rate, regulatory, strategic and other consulting services to utility clients. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. I have previously testified before the Federal Energy Regulatory Commission ("FERC") on a number of electric, gas pipeline and oil pipeline issues.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am testifying on behalf of UNS Electric (UNSE or the Company)

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?

A. No.

Q. PLEASE PROVIDE A LIST OF STATE AND CANADIAN JURISDICTIONS IN WHICH YOU HAVE TESTIFIED.

A. I have testified in Connecticut, Massachusetts, Georgia, Tennessee, Montana, Missouri, New York, Ohio, Michigan, Arkansas, New Jersey, Oklahoma, Kansas and Maryland. In Canada I have testified before the Ontario Energy Board, the Alberta Energy and Utilities Board, the New Brunswick Energy and Utilities Board and the British Columbia Utilities Commission. My testimony has been related to issues such as cost of service, rate design, prudence, rate of return, regulatory risk, performance based regulation, competition and unbundling.

Q. DURING YOUR CAREER HAVE YOU MADE PRESENTATIONS TO ENERGY RELATED TRAINING AND OTHER PROGRAMS?

A. Yes. I have been an instructor for the Edison Electric Institute's Rate Fundamentals and Advanced Rate School related to cost of service. I have been an instructor in both the American Gas Association's Rate Fundamentals and Advanced Rate courses. I have been an instructor for the Southern Gas Association's Intermediate Rate Course and for the RMEL providing training related to regulation. I have made numerous presentations to trade association meetings including the EEI Rate Committee, the AGA Rate Committee, the AEIC Load Research Committee, SURFA and other industry sponsored programs. I have made presentations to NARUC events and events sponsored by academic institutions. I have also written broadly on various subjects related to utility regulation, including issues related to the integration of distributed generation into a utility system and the design of rates for the 21st century.

Q. HAVE YOU PROVIDED EXPERT TESTIMONY ON COST OF SERVICE AND RATE DESIGN RELATED TO NET METERING, RATES FOR DISTRIBUTED GENERATION (DG) CUSTOMERS AND DEVELOPMENT OF RATES FOR PURCHASE OF ENERGY FROM DG CUSTOMERS?

A. Yes. My testimony in Maryland addressed these issues and more related to cost of service, rate design, net metering impacts and the impact of purchasing excess generation at the full SOS rate. In that testimony, I developed specific measures of the level of subsidy created by net metering and demonstrated that the Commission's net metering rule resulted in undue discrimination based on the factual circumstances for the utility.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. My rebuttal testimony addresses a number of areas related to the economics of DG from the perspective of the utility, its customers and economic efficiency. Specifically, I respond to issues raised by the Commission Staff, Vote Solar (VS), Western Resource Advocates (WRA), The Alliance for Solar Choice (TASC), Residential Utility Consumer Office (RUCO), Southwest Energy Efficiency Project (SWEEP) and Arizona Utility Ratepayers Alliance (AURA). I address the following issues as discussed by some or all of these parties:

- the cost to serve a partial requirements DG customer – specifically a Solar DG customer compared to a full requirements customer in the residential class;
- the subsidies being provided to DG customers under the current rate design and net metering tariff;
- the economic and regulatory rationale for a separate rate for a DG customer that requires different treatment than a standard customer until such time as utility rates are fully unbundled and customers are classed based on the cost causing characteristics of their service;
- the economic and regulatory basis for multi-part rates including customer charges, demand charges and time differentiated energy charges;
- the efficacy of demand based rates for all customer classes and how such rates will impact customers;
- the ability of customers to respond to more complex price signals,
- the role of fairness, efficiency and gradualism in developing and implementing new mandatory rate designs; mitigation of adverse impacts during the rate design transition;
- the reason all customers should be on the same rates with any special considerations (CARES customers for example) should have mitigation outside of the rate structure per se;
- the customers who choose to use the utility system in ways that result in high unit costs (low load factor customers for example) should pay the full costs imposed on the system under the cost causation principle and the matching principle of rates;

- the importance of multi-step transition plans to assure timely and efficient implementation of the best rate design for all customer classes in an expeditious manner; and

Finally, I provide support for the central themes in the Staff's proposal while at the same timing recommending transition steps necessary to that proposal to match costs and revenues and to minimize the impact of changes over time. Although these issues as they relate to net metering, three part rates and the inefficiency and intraclass subsidy from inverted block rates are all closely intertwined as is evident in the various sections, I have discussed the topics in separate sections to identify the focus on a particular issue.

Q. HOW IS YOUR REBUTTAL TESTIMONY ORGANIZED?

A. My testimony is organized in sections beginning with this introduction that includes a summary of my recommendations and the individual sections as follows:

II. Economics of Serving Full and Partial Requirements Service Customers

III. Separate Rate Treatment for DG Customers

IV. The Economic Rationale for Multi-Part Rates

V. Customer Response to More Complex Price Signals

VI. Customer Cost Analysis

VII. The Concepts of Fairness, Efficiency and Gradualism

VIII. Serving All Customers in a Class under the Same Rate Schedule

IX. Conclusions

Q. PLEASE BRIEFLY SUMMARIZE THE EVIDENCE YOU HAVE PROVIDED IN THIS REBUTTAL TESTIMONY.

A. My evidence shows that the combination of two-part rate with a low customer charge and inclining block rates coupled with the banking provision of net metering for residential DG customers results in customers with equal costs paying far different annual bills for the services they use. The subsidy to residential DG customers results from both fixed costs and variable energy costs. The magnitude of the subsidy totals about $91 per kW of installed solar DG annually under UNS Electric's current rates.

I explain why the two-part rate cannot be just and reasonable when serving both full requirements customers and partial requirements customers such as DG. I use metered data from two solar facilities to show that solar customers generation patterns result in more off-peak energy on an annual basis than on peak and do not even avoid the average cost of energy much less the full cost of Base Power and the associated PPFAC adjustments. I show how a multi-part rate reflects cost causation more accurately and when unbundled will be consistent with the principles of cost causation and matching costs and revenues with a proper design.

I show how a separate rate for solar DG customers is not discriminatory and in fact is the best option for eliminating the current undue discrimination that favors these customers. The separate rate is necessary for all new solar customers even if the Commission accepts the Staff proposal for a three-part rate because the issue of unjust subsidy will continue until the rate is fully implemented.

I provide a discussion of the appropriate components of customer costs that include much more than what some witnesses refer to as the Basic Customer Method. I note that this method is not even discussed as an option in the NARUC Electric Cost Allocation Manual and with good reason. It is simply not a reflection of costs caused by customers. Using the minimum system as UNSE has done in its cost study results in class costs that more closely match cost causation. Rates should reflect the higher customer charges that result from the cost of service study and more where marginal cost based price signals do not produce the revenue requirements.

Finally, I provide a discussion of the appropriate rate for CARES customers and discuss the adverse impact on low income customers from proposals that collect fixed customer related costs in kWh charges.

II. ECONOMICS OF SERVING FULL AND PARTIAL REQUIREMENTS SERVICE CUSTOMERS

Q. PLEASE DEFINE THE TERMS FULL AND PARTIAL REQUIREMENTS CUSTOMERS.

A. A full requirements service customer is a customer who elects to use the full bundle of utility services on a continuous basis and acquires no utility related services from another provider. In the case of an electric customer this means that the customer uses the full scope of production, transmission, distribution and customer services from the utility in a seamless package represented by the delivery of capacity and energy to the customer as required by the customer. A partial requirements service customer is a customer who elects to select the particular components of the utility service to be used when the customer elects to use the utility service and to use other non-utility sources for all or a portion of the some of the standard utility services to meet his demand for energy or capacity or some combination of the two requirements.

Partial requirements customers essentially are former full requirements customers who elect to use the utility for services such as back-up/standby service, maintenance service or supplemental service or some combination of all of these services. Partial requirements customers differ both from full requirements customers and from each other depending on the non-utility services they purchase because the demand and energy load shapes the utility must stand ready to serve differ and in some case differ dramatically. For example, some partial requirements services provide baseload service leaving the utility to provide supplemental peaking services and may be viewed as low load factor customers for the utility. Other partial requirements services are peaking in nature and leave the utility to provide baseload service and may be viewed as high load factor customers for the utility. Each different service has different cost characteristics based on the cost the utility incurs to serve the customer.

Every solar DG customer differs from customers who use cogeneration and cogeneration customers differ based on technology. They also differ based on the underlying total hourly demand for electricity. For example, when a residential customer changes from full requirements to partial requirements the underlying load of the dwelling does not change nor do the local facilities installed to serve that customer. As an example, the utility cannot change the service line or the transformer to serve that customer because those were sized to serve the maximum load of the customer whenever it occurs. The load measured in kWh and kW imposed on the utility does change however. The customer may use less energy but may still require the same kW capacity for delivery service and may even require the same capacity for production and transmission depending on a number of factors associated with the customer's non-utility supply source. Since different technologies have different supply characteristics every different source will have a different impact. In some cases, that impact is a function of system characteristics in others it is a function of technology or some of both. If a new customer comes on the system as a partial requirements customer, the utility system planners must provide for the maximum service that a partial requirements customer may impose when the customer's non-utility source of supply is not available. The important point is that one cannot assume that cost causation for the selected utility services will change when the customer elects partial requirements service and in some cases it may even increase. To determine cost causation requires an understanding of the type and timing of the services provided by the utility. Finally, it is critically important to recognize that utility capacity requirements are not the same for each component of utility service. Appendix B to this rebuttal testimony is a copy of my white paper "*Smart Rates for Smart Utilities*" that provides a detailed discussion of many of the concepts related to unbundled rates and the necessity for each rate component.

Several examples will illustrate this point. For a utility that is winter peaking the peaks occur either in the early morning driven by electric heating load or in the evening driven by miscellaneous appliance load. In either case solar DG contributes nothing to reducing any of the capacity requirements of the utility. If the utility was winter peaking for load but summer peaking for capacity the solar facilities would contribute to the summer peak capacity based on the expected peak load hour occurring typically in the afternoon. Solar DG would have no impact of the capacity cost for distribution and portions of transmission plant. The summer peak load contribution may or may not have a capacity value depending on whether the net peak load demand actually shifts to a later hour. This is the concept labeled as the "Duck Curve" in California where the peak load shifts to a later hour in the day where there is no solar generation.

Since the issue of capacity savings cannot be determined based solely on one measure of capacity as discussed later in this rebuttal testimony, it is impossible to conclude that there are capacity benefits for each measure of capacity- production, transmission and distribution- for partial requirements service. The capacity obligation associated with delivery to the DG customer is typically the same as for a full requirements customer and is based on the expected load of the premise which may and usually does occur outside the peak load period.

Q. HAVE YOU DEVELOPED DATA TO SHOW HOW THE SOLAR DG CUSTOMERS OUTPUT COMPARES WITH THE SYSTEM LOAD ON A MONTHLY BASIS?

A. Yes. I have attached Exhibit HEO-1 that provides a month by month comparison of system loads and solar output based on actual metered load data for two different solar power facilities-a single axis tracking solar generating facility (La Senita) and a fixed axis south facing facility (Rio Rico) and the retail load of UNSE Electric during 2015. As the exhibit shows production in the winter months of November to April uniformly misses the high load hours and tends to be the highest in the load valleys. In the summer months for the tracking facility, solar production declines as load rises in the afternoon and since the system peak hour occurs at 5 PM, solar output is uniformly declining at that hour for both facilities. The data also shows that the tracking facility has both longer hours of production and a higher rate of production in the summer hours near the peak than the south facing facility which is more consistent with a rooftop solar DG facility. Finally, as solar penetration continues to increase the potential for the Duck Curve impact to shift the evening peak hour as it does in California also grows thus assuring no distribution capacity peak savings and potentially no transmission or generation capacity savings for solar generation. I should also point out that increased solar penetration also reduces avoided energy costs.

I have also prepared Exhibit HEO-2 that shows for the same two facilities that the hours of maximum output occur in hours other than the highest marginal cost hours in both the winter and the summer. This means that excess generation sold back to the utility occurs on average at times when the avoided energy cost is less than the average energy cost and less than the marginal cost of energy used by solar DG customers to meet the load in excess of solar DG. Exhibit HEO-3 shows that in the winter and the summer (2015) the value of the energy avoided cost for these two facilities is uniformly less than the Base Power Costs (the unbundled rate component for energy) plus PPFAC determined under the actual PPFAC calculation on an hourly basis in every hour of the day on average. For UNSE the gap in energy cost is at least $16 per MWh in the summer and over $24 dollars per MWh in the winter. Added to this difference is the fact that on the peak day in the summer the ambient temperature is so high that the efficiency of the solar generation is reduced by over 7% in the Nogales and Kingman areas and by over 10% in Havasu. We also know that the maximum solar output actually occurs in the shoulder months (when customer loads are lowest) so there is a further subsidy associated with the banking provision. Under the banking provision the subsidy is the difference between the avoided marginal cost and the Base Power plus the PPFAC rate applied when those kWh are actually consumed by the customer and when the excess kWhs are produced. That subsidy is in excess of three cents per kWh. This evidence not only shows that net metering creates large subsidies with respect to energy costs but that without modifications to net metering and separate rate treatment for partial requirements DG customers there is no opportunity for rates to be just and reasonable and not unduly discriminatory.

III. SEPARATE RATE TREATMENT FOR DG CUSTOMERS

Q. WHAT IS THE RATIONALE FOR TREATING PARTIAL REQUIREMENTS CUSTOMERS IN A SEPARATE CLASS FROM FULL REQUIREMENTS CUSTOMERS?

A. Under two-part rates the assumption that is required for rates to reflect cost causation is that load characteristics are relatively homogeneous as to cost causation and to load patterns. Relative homogeneity existed when kWh rates were first used for residential customers in the late 19th century because the only electric load was lighting. The demand was a function of the number of fixtures and kWh consumption was a function of average operating hours. Thus a simple two-part rate with a customer or access charge and a flat kWh charge represented a reasonable rate because the cause of cost and the load characteristics were the same. Over time, the end use load profiles of residential customers has changed and electric rates evolved to reflect different load characteristics through declining block rates and through separate rate classes for different end-use residential loads such as all electric rates or special provisions for specific end-uses such as a water heating block for customers with electric water heating. The trend away from these rate provisions to flat and inverted rate designs and fewer special provisions made rates less cost based as end-use load profiles continued to be more diverse because larger groups of customers were served under rates that were simple but not capable of reflecting costs for less homogeneous groups. With the addition of partial requirements customers within a class, customers are no longer homogeneous as the following table illustrates by comparing two identical premises with the same demographic characteristics:

Table 1

Comparison of Full and Partial Requirements Customers

Measures	Full Requirements	Partial Requirements
Customer Maximum Demand	10 kW	10 kW
Annual Energy Consumption	35,040 kWh	35,040 kWh
Annual Billed kWh	35,040 kWh	17,047 kWh*
Load Factor	40 %	19.4%

* Based on 35,040 kWh less the energy produced by a 10 kW Solar PV system operating at a 20.54% annual capacity factor.

From a cost perspective the delivery cost is the same for these two customers. The difference in cost recovery under the current UNSE Electric rates is calculated in Table 2 below based on the current local delivery component (Delivery Service- Energy) of the current unbundled rate alone.

Table 2

Customer Revenue Under Rate Res-01

Billing Determinants	Local Delivery	Full Requirements	Partial Requirements
Customer	12	$120.00	$120.00
0-400 kWh	4800	$25.30	$25.30
401-1000 kWh	7200	$146.31	$146.31
Over 1000 kWh			
Full Requirements	23040	$563.79	
Partial Requirements	5047		$123.50
Total Bill		$855.40	$415.11
Difference		$440.29	

Total Bill is the annual bill for the Delivery Service- Energy rate only.

Table 2 shows that the annual delivery subsidy under current rates is over $44 per kW of installed solar capacity. This subsidy is based on equal treatment for equal cost causing delivery characteristics and is not tied directly to a measure of the cost subsidy which may be even larger as a result of the inverted block rate where excess costs are recovered from the largest no-DG customers. In addition, on the basis of cost causation there will be subsidy in the generation and transmission portion of the rate simply because the solar PV capacity of 10 kW will not be coincident with the system peak demand as shown by the monthly charts in Exhibit HEO-1. Instead, only a portion of the installed kW will be coincident with an afternoon peak. The coincident amount will be between 2% and 24% of the installed kW on average and even lower on a peak day because of the extreme temperature. This implies a further subsidy for the remainder of the base charge. It should be noted that this result occurs because of the current price signal based on energy that incents the customer to install a system that maximizes energy production without regard to the capacity value of the solar facility[1]. This means that solar panels would face south in the Northern Hemisphere to maximize energy production instead of west to maximize summer peaking capacity contribution.[2] In that event the capacity contribution of solar and the later timing of the solar customers class NCP would result in no distribution cost savings and potentially even higher distribution costs associated with the class NCP for DG customers occurring at a later hour. Under the most favorable circumstances a 5 kW solar facility would reduce the class NCP by about 0.5 kW and that would not be enough to result in smaller distribution facilities such as a transformer or conductor even if all of the customers using the same equipment had installed solar DG.

There is also the issue of a potential subsidy under the energy cost component of the base rate. That subsidy would result from the load pattern of the solar power delivery that does not occur in uniform high cost hours. In fact, solar output is maximized in hours outside the peak period as defined in the residential TOU rate in both the winter and the summer. Since the winter off-peak period represents the majority of operating hours in that season and represents only 33% of the summer peak operating hours it is reasonable to conclude that the solar energy value is less that the base energy charge.

[1] A generation and transmission on-peak demand charge would provide an incentive to consider both the capacity and the energy value when installing solar and also for investments in EE.

[2] See for example "9% of solar homes are doing something utilities love. Will others follow?", OPOWER Blog December 1, 2014.

The average hourly marginal cost for UNSE in 2015 was also well below the average fuel and purchased power costs and lower than the total fuel and related costs reflected in the Base Power portion of the rate as shown in Table 3.

Table 3

Fuel and Purchased Power Cost Comparisons 2015

Cost Category	Cost per MWH
Marginal Cost	$24.77
Rio Rico Solar Avoided Energy Cost	$27.00
La Senita Avoided Energy Cost	$27.40
Average Fuel and Purchased Power Cost	$37.43
Actual Base plus PPFAC Cost	$53.53

Table 3 also includes the average avoided energy cost for hourly metered solar facilities that further demonstrates that solar DG does not avoid the average cost of energy but a lesser amount because of the effort to maximize energy rather than the capacity value of generation for Rio Rico. La Senita has a higher capacity value because it is a single axis tracking facility and even then still avoids less than the average energy costs. The avoided generation capacity cost for solar DG assuming capacity was needed immediately is less than one cent per kWh and far less than that if capacity is needed further out in the future. Since marginal cost is the measure of the avoided costs and the average fuel and purchased power cost represents the energy component of power costs the $10 difference represents a subsidy in the energy component of the base energy costs. The full subsidy based on Base Power plus PPFAC is the difference between the

Rio Rico avoided cost of $27 per MWh and the Base Power plus PPFAC of $53.53 or $26.53 per MWh. The subsidy is larger for the full Base Power plus PPFAC because that includes fixed costs for purchased power that are not avoided and hedging costs as well. The energy related subsidy based on the fixed axis solar DG would be about $47.72 per kW of solar capacity[3]. This subsidy also creates arbitrage for solar DG customers who consume energy in high cost summer hours and sell energy in low cost, off-peak winter, spring and fall hours as discussed above. The impact would be a subsidy larger than the difference between average energy costs and marginal energy costs on an annual basis.

Q. PLEASE SUMMARIZE THE TOTAL SUBSIDY RECEIVED BY A RESIDENTIAL DG CUSTOMER.

A. The total subsidy from the Delivery Services rate and the Base Power is over $91[4] per kW and more than $642 per year for the average 7 kW solar DG facility. This amount does not include the arbitrage benefit noted above when customers consume solar DG customers consume power in summer periods and deliver the energy in low cost daylight hours in the winter season.

All of this evidence suggests that with a two part rate and net metering with banking can never result in just and reasonable rates for partial requirement DG customers. The only possible alternative to treat partial requirements, DG customers equitably is a separate rate class with a three-part rate. Further, the excess kWhs should not be banked but should be purchased at a market based rate. This solution is practical

[3] 8760 hours times a capacity factor of 20.54% times $26.53

[4] Delivery subsidy of $44.03 plus energy subsidy of $47.72 is $91.75

immediately and need not wait until there is a general rate redesign for all residential customers. It also illustrates that there is a substantial subsidy inherent in net metering because the use of self-generated kWhs saves the DG customer more than the system saves by an amount that over-values the DG contribution. This is part of the reason that commissions and others are developing Value of Solar (VOS) and a buy all sell all rate as a substitute for net metering. I might also note that from an economic perspective solar DG is not a least cost solution for the utility and its customers when community solar has much lower installed capacity costs because of economies of scale. Furthermore, I disagree with any of the critics of this approach that may suggest that eliminating the banking feature is in effect violating the concept of "netting" which is fundamental to the net metering concept. The fact that the Company is simply crediting back energy produced by DG at a market value different from the total delivered cost of power to the customer does not change the net metering that the customer sees relative to its own use of energy. There are valid cost based reasons including the provision under PURPA that makes adoption of any standard including net metering satisfy the principle of equitable rate treatment for customers.

Q. ARE THERE OTHER ISSUES THAT MAKE THE SEPARATE TREATMENT OF DG CUSTOMERS NECESSARY IN THE CURRENT PROCEEDING?

A. Yes. The unequal treatment of customers who have the same costs but provide very different levels of revenue to recover those costs is a perfect demonstration of undue discrimination and that the current rates are no longer just and reasonable as the result of a combination of the net metering provisions and the current inverted block two-part rate with a low monthly basic customer charge. Essentially, the recovery of almost all of the fixed cost of service in volumetric charges results in undue discrimination when the customers in a class are no longer homogeneous. The ACC Staff correctly recognizes the nature of this problem when Staff witness Broderick states "DG customers avoid paying a significant portion of the utility's fixed costs even though DG customers continue to use the grid."[5] Staff witness Solganick reached the same conclusion and states "two customers who require the same equipment might use very different amounts of energy and again would result in one customer being undercharged and the other overcharged."[6] Witness Solganick also notes that "Residential customers are increasingly becoming non-homogenous as they adopt various forms of heat and distributed generation and as their lifestyles, demographics, and work patterns become increasingly more diverse."[7] When the difference in charges is as large as 106% of a customer's base delivery bill the subsidy is no longer just and reasonable and constitutes undue discrimination. The only practical solution is to eliminate the net metering provision and recover costs under a separate rate schedule for partial requirements customers as proposed by UNSE. Further, it is imperative to flatten the three tiered energy rate to two tiers as proposed by the Company to send a better price signal to other potential DG customers. This is a necessary step as UNSE moves over time to TOU based fuel charges and demand based charges for fixed costs.

Q. IS THE STAFF AND UNS ELECTRIC PROPOSAL OF A THREE PART RATE CONSISTENT WITH CURRENT VIEWS ON BEST PRACTICES?

A. The Staff proposal moves toward the adoption of a three-part rate and I will discuss that concept in detail below. It is actually consistent with the best practices approach to

[5] Direct Rate Design Testimony of Thomas Broderick ('Broderick"), page 4, lines 7-9.

[6] Direct Rate Design Testimony of Howard Solganick ("Solganick Rate"), page 7

[7] Ibid. page 9

designing rates for DG as noted by a number of organizations such as e-Labs of the Rocky Mountain Institute who states "These technologies can provide to or require from the grid energy, capacity, and ancillary services based on individual capabilities. But these characteristics vary along many dimensions that are not reflected in block, volumetric rates. For example, when a customer is exposed to a high marginal price tier in an inclining block rate structure, rates can both reinforce and skew the message that price signals should send. Rooftop PV can look more competitive with retail rates based on the higher credit received for energy production."[8] This is the exact conclusion reached above relative to the inefficient orientation of solar panels relative to actual avoided costs because of the energy only price signal.

A report from the MIT Center for Energy and Environmental Policy Research states the following:

> Allocating network costs primarily on the basis of volumetric energy consumption presents inefficiencies in distribution systems evolving to incorporate a growing number of DER and a growing list of new stakeholders. These inefficiencies include: few price signals to incentivize optimal network utilization; cross-subsidization among network users; and business model arbitrage of rate structures.[9]

That same report supports the use of a customer component of the distribution system and demand charges for customers based on the capacity component of the system.[10]

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[8] "RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE", e-Lab Rocky Mountain Institute, August 2014, p.15 http://www.rmi.org/elab_rate_design

[9] "A Framework for Redesigning Distribution Network Use of System Charges Under High Penetration of Distributed Energy Resources: New Principles for New Problems" Ignacio Pérez-Arriaga and Ashwini Bharatkumar, October 2014, p.6 https://mitei.mit.edu/system/files/20141028_UOF_DNUoS-FrameworkPaper.pdf

[10] Ibid. p. 16-20

In a report prepared for EEI titled "Retail Cost Recovery and Rate Design" Kenneth Gordon (the former Chairman of both the Massachusetts Department of Public Utilities and the Maine Public Utilities Commission) and Wayne P. Olson make the following statement:

> To the greatest extent possible, customer- or demand-related fixed costs should not be rolled into energy charges. The end-use customer often sees too high a price for energy and too low a price for demand and customer charges. Hence, the customer never receives the economically efficient price signal for either one.[11]

Each of these references correctly recognizes the role of multi-part rates in addressing the issues of efficient pricing and reflecting cost causation. Current rate designs as recognized by UNSE, the Staff and even RUCO recognize to some extent that the current two-part rate for residential customers is inefficient and includes subsidies. The important point is that subsidies resulting from averaging costs in class rates are far different than artificial subsidies that reach the level of undue discrimination as they do in the case of net metering with largely volumetric rates. Average cost subsidies are found in items such as using the average service line costs knowing full well that the customer on the same side of the street as the transformer has a shorter service line than the neighbor across the street. Short of designing rates for each customer, a utility and its regulators must accept some level of intra class subsidy; however, it is incumbent up them to address undue subsidies and discrimination. The subsidies under net metering with two part rates create undue discrimination that needs to be addressed in the current

[11] "Retail Cost Recovery and Rate Design" Kenneth Gordon and Wayne P. Olson, Prepared for the Edison Electric Institute, December 2004, p. viii. See also p. 26.
http://www.ksg.harvard.edu/hepg/Papers/Gordon.Olson.Retail.Cost.Recovery.pdf

case, not postponed and not to wait on implementation of a phased approach to multi-part rates that does little or nothing to address the problem for years to come.

Q. PLEASE DISCUSS THE CLAIM THAT SEPARATE RATE TREATMENT FOR DG IS DISCRIMINATORY.

A. This is a common claim made by solar advocates who want to maintain the extremely favorable treatment (and profitable marketing opportunity created by the current combination of net metering and largely kWh recovery of fixed costs) accorded to solar DG. The best way address this claim is to analyze the meaning of discrimination in the context of regulation. The Merriam-Webster Dictionary defines discrimination as *the practice of unfairly treating a person or group of people differently from other people or groups of people and the ability to understand that one thing is different from another thing.* As applied to solar DG and discussed above customers who become partial requirements customers are clearly different from full requirements customers and in that sense the discrimination is not inconsistent with the basis for designing rates for homogeneous classes of service. While it may be inconvenient for the solar advocates to recognize that solar DG customers differ from full requirements customers the evidence shows that this is precisely the case. The customers are different based on load characteristics and in terms of cost causation. The question becomes: Does singling out these customers for different rate treatment result in those customers being treated unfairly? The simple answer is no. This answer is supported by a review of the evidence as it relates to cost causation and the contribution of these customers to that cost compared to other full requirements customers. This is an empirical question that requires nothing more than the basic analysis of whether the solar DG customers contribute the same revenues toward the costs they cause as other customers who have the same cost causation. As an example of the necessity for empirical investigation the Vote Solar witness Kobor states in response to UNS Electric Data Request 1.28 that "UNSE has not provided evidence that the Company's NEM and non-NEM customers have significantly different consumption patterns greater than the inevitable diversity in consumption within the residential and small commercial classes." This statement is incorrect because UNS Electric provided bill frequency data for residential customers broken out by full requirements customers and by net metering customers. Exhibit HEO- 4 compares both the bill frequency and the cumulative kWh frequency for these two customer groups. Those frequencies demonstrate conclusively that solar DG customers contribute far less revenue for the exact same delivery costs as other customers if for no other reason than 57.16% of net energy billed customers have zero kWh use meaning those customers contribute nothing to cover any distribution related costs and do not even cover the full customer costs. Exhibit HEO-4 shows that about 89% of DG customers' bills are for usage that does not include charges in the third tier of the rate. In contrast about 69% of residential full requirements customers' bills are for usage that does not include the third tier. Exhibit HEO- 4 also shows that the pattern of cumulative kWhs for both full and partial requirement DG customers is nearly identical after net metering. This means that these DG customers are uniformly large users of electricity than full requirements customers.[12] Given that these customers are larger on average, it also means that the customers demand are larger as well. Thus the

[12] This is consistent with economic price signals that provide a third tier incentive for larger customers to invest in DG and experience a higher implied return on investment.

subsidy assuming equal size for DG customers actually underestimates the subsidy for DG.

Since, the only true avoided costs are related to the marginal energy cost and some potential avoided generation capacity costs at less than one cent per kWh based on the coincident peak demand of less than 24% of the rated capacity depending on the peak load hour. (For this conclusion, the concept of the "Duck Curve" has not been considered because it may well eliminate this avoided cost also.) It is the existence of this undue discrimination that solar advocates seek to maintain to their advantage.

Regulatory policy is not required and in fact is prohibited from picking winners and losers when discrimination becomes undue. The goal of efficient regulatory policy is to develop a system of rates and charges for customers so that as they choose between full requirements service and partial requirements service the utility and its other customers are indifferent between those choices. Such a standard requires that the customers who choose different aspects of utility service pay the full costs of the services they choose to use. It is unreasonable for a customer to use a kilowatt hour of electricity that costs six cents to produce and then pay for that kWh by selling the utility a kWh when the utility value of that kWh is three cents but this is what occurs under the net metering banking provision. It is unreasonable for a customer to use the same distribution services as another customer and pay over almost $500 less per year for that delivery service. This later point is also impacted by the fact that the solar DG customer may actually cost more to serve for the same delivery service based on increased day ahead planning reserve requirements and regulation reserve requirements related to generation operation. DG customers also impact the distribution system relative to VAR requirements and reduced life for voltage regulation devices as examples of cost increases. It is reasonable to conclude that the differences between full and partial requirements customers using solar DG are real, empirically verified and thus not discriminatory. It is also reasonable to conclude that separate treatment is a reasonable step to eliminate discrimination between solar DG customers and full requirements customers.

IV. THE ECONOMIC RATIONALE FOR MULTI-PART RATES

Q. PLEASE EXPLAIN THE ECONOMIC RATIONALE FOR MULTI-PART RATES.

A. As noted above, multi-part rates represent the best practices approach to rates that are just and reasonable, equitable and economically efficient. They have been in use successfully since the 1890s for large customers and were not originally used for smaller customers because of the practical metering constraints and the relative homogeneity of smaller customers at the outset of the electric utility business. This is despite the fact that for over 100 years electric utilities have recognized that there are other services provided to customers other than the energy commodity. This is simply because a kWh provided in one hour may not cause the same cost as in another hour hence the need to have time differentiated (TOU) based energy charges. The utility also provides a variety of capacity services for generation, transmission and distribution. The capacity related services have no costs that vary with energy usage hence charging larger users more has no basis in cost causation and directly contributes to the magnitude of the subsidies under net metering without any economic efficiency benefits and based on the economic literature real dead weight losses.[13] It is important to note that customers using the same amount of energy may have very different capacity related requirements. As an example, a large home with central air-conditioning and gas heating and water heating may use the same amount of electricity in a year as a smaller all-electric home. If we assume that the utility is a summer peaking utility like UNSE, we would expect that the larger home would have a higher coincident peak demand than the smaller home and thus higher generation capacity related costs but would have a lower delivery capacity requirement and thus lower distribution related capacity costs. Incidentally, this is why the tiered rate concept is fatally flawed as a price signal because it punishes customers based solely on the usage level despite the fact that total usage is not correlated with each component of capacity cost causation nor is it necessarily correlated with higher energy costs. The smaller heating customer has lower capacity costs for generation and transmission, lower energy costs and only higher delivery demand costs that are lower than the capacity costs for generation and transmission. Thus the Company is correct to eliminate the third tier and the RUCO rationale for keeping the tier is fatally flawed.

Q. HOW DOES A MULTI-PART RATE PROVIDE EFFICIENT PRICE SIGNALS FOR CUSTOMERS?

A. Since energy charges are not adequate for reflecting cost causation (virtually all economists agree that this is the correct objective for rates) it is necessary to understand all of the components that cause costs to be different. It is a fundamental proposition that costs are caused by customers, demand and energy. In fact all cost studies use

[13] See for example "Rationalizing California's Residential Electricity Rates", Posted on September 29, 2014 by Severin Borenstein, https://energyathaas.wordpress.com/2014/09/29/rationalizing-californias-residential-electricity-rates/

these three elements to classify costs. To match pricing with cost causation would require at least three parts- a customer charge, a demand charge and an energy charge. The Commission Staff correctly recognizes that the rate must at least have these three components and this is a valuable starting point for developing cost based rates. However, the Staff proposal does not recognize that the single demand component of a three part rate cannot reflect cost causation for the different components of the functionalized costs that include production, transmission, substations, primary distribution and secondary distribution unless of course the class CP and NCP and the customer NCP are highly correlated. Since we know that will not be true for DG customers and that demographics will cause it not to be true even for full requirements customers there will be a need for at least two measures of demand. For example the Staff recommends an on-peak demand charge to recover the costs of distribution fixed charges. As I have shown the example above and as may be observed by even a casual review of both load research data and the elements of the distribution system compared to the system peak load, customers cause distribution demand costs not based on the coincident peak demand but on non-coincident peak demands. It is common for utilities to have a greater investment in substation capacity than in generation capacity and more transformer capacity then in substation capacity. The reason is simple. There is more load diversity at the system peak load then there is as the loads move closer to customers. In fact, it is not at all uncommon that substation peaks occur at different times and in some cases even different seasons from the system peak. It is even unusual for more than a few substations to peak coincident with the system peak. As with substations, feeder circuits also peak at different times than the substation that serves the feeder. For example, the load research data underlying the UNS Electric 2014 cost of service study and provided to the parties in response to data requests in this case shows that the residential class CP occurs on July 23 at hour ending 4 PM while the class NCP for the same day occurs at hour 6 PM. That hour is not the residential class NCP used to allocate substation capacity for example since that hour occurs at 5 PM on July 24 one day later. The same data shows that the largest residential customer peaked on August 30th at 9 PM; the largest 1% of customers peaked at 5 PM on July 30th; and the largest 25% of customers peaked at 5PM on July 24th coincident with the class NCP. The class NCP values are also smaller than the customer NCP values that impact the design of transformers and feeders. One other observation worth noting is the differences in feeder loading in the summer late afternoon between 4 PM and 6 PM are relatively inconsequential when considered in the context of system planning. That is the hourly loads over the period from mid- afternoon until 8 PM on a peak day are typically within one to two-tenths of a kW difference from high to low. Thus under the Staff proposal of an on-peak demand charge to recover distribution costs the solar DG customers would still avoid paying for some of the capacity costs they cause. The simple solution is to use maximum customer demand whenever it occurs to recover distribution costs. This will solve the subsidy problem for delivery service and do so without any prolonged delay. It will also be easily implemented and result in a lower per unit charge that will be easier to phase in with a lower impact on bills. As rates evolve over time the Staff proposal of an on-peak demand charge based on marginal peak capacity costs may be added as an additional rate component.

Q. HOW WOULD A DISTRIBUTION DEMAND CHARGE BE DETERMINED?

A. First, it will be necessary to set the time interval over which demand is measured. Staff and the Company propose using one hour initially. One hour is the least commonly used interval with both 15 and 30 minute intervals used more often. Ultimately there are a number of reasons for using the 15 minute interval. First, 15 minute intervals are more stable over time so customers do not see large swings in their demand measurements. The 15 minute intervals are also more reflective of cost causation since transformers and circuits have longer life if they do not experience overload conditions with any frequency. Third the shorter interval results in a lower per unit demand charge to recover the distribution related costs. While the same dollars are recovered regardless of the demand interval, the shorter interval benefits both customers and the utility through stable more predictable charges on a monthly basis. Customers also benefit because a one-time peak does not significantly change the bill. Ideally this demand charge would be based on a contract demand rather than a measured demand in the future since this would reflect the sizing of the local facilities installed to serve the customer and would actually be a separate facilities charge. Some utilities have used this approach for demand billed customers. This charge should be properly based on a 100% ratchet to further minimize the charge and reflect cost causation because these costs are a function of the customer's maximum demand whenever it occurs. That is for distribution demand there is no time dimension. In fact, the Staff proposal to collect these costs in a peak period is not cost based and results in both shifting peaks and uneconomic investment in storage to avoid the peak period charge. Once the interval is determined and the charge is based on maximum demand whenever it occurs subject to a 100% ratchet, the kW charge would send the appropriate price signal and would be economically efficient. Under the Staff proposal, a partial requirements customer would still be able to bypass a portion of the delivery system costs that are necessary for serving the customers load since the distribution system still needs to be large enough to serve the load of the premise plus provide in-rush current, frequency regulation, var requirements and standby and supplemental services.

Q. ARE THERE DEMAND CHARGES THAT ARE APPROPRIATELY INCLUDED IN THE PEAK PERIOD?

A. Yes. It is appropriate to include a demand charge for generation capacity in a peak period. That charge should be based on the marginal capacity cost of the utility. In this way, the capacity value of DG and EE are signaled to the customer. This would result in efficient investment in both DG capacity and storage. If the charge exceeds marginal cost as it would if it was designed to recover the embedded costs of generation capacity, it would create subsidies and promote investments in utility resources inconsistent with the least cost of total utility supply service.

The marginal cost of capacity is determined by the least capital intensive addition to the system. That is nominally a combustion turbine and sets the upper bound for avoided costs as it may be lower if another unit is built to satisfy energy constraints. When capacity is not required in the near term, the demand charge will be based on the net present value of the stream of future capacity payments. In determining the on-peak period for this charge consideration must be given to shifting peaks over time and the probability that peak demands that cause the addition of capacity are properly identified because they may not necessarily be in the highest load hours.

It is important to understand that generation demand charges may also be required outside the peak period to recover other embedded costs. In that case, the charge would be based on monthly maximum demand to the extent that it is greater than peak demand.

Q. HOW ARE TRANSMISSION DEMAND COST RECOVERED?

A. Transmission costs are recovered in a variety of charges including congestion charges where marginal energy costs are based on locational marginal price, on-peak demand charges that may be different from the capacity charges and even some costs in the distribution demand charges for load laterals. For UNSE it is likely that the generation laterals and the bulk system will be recovered in the same on-peak period as the generation capacity marginal costs.

Q. THIS SOUNDS MORE COMPLICATED THAN A THREE-PART RATE PROPOSAL. HOW ARE CUSTOMERS TO UNDERSTAND THE BILL?

A. As in the Staff proposal, there is no need to get to the ultimate rate design in the first step. It will be a gradual process done in steps. In fact, I suggest that the first and most important step in this case would be to phase out the tiered rates as proposed by UNSE by eliminating the third tier. In addition, I would remove all of the energy related costs from base rates and recover those costs through a seasonal and time differentiated energy charge. This will partially mitigate the energy subsidy for DG customers since the energy savings from kWhs in the winter and in the low cost periods for the summer will be somewhat reduced. Coupled with a modified net metering tariff that prohibits banking and purchases solar power at a market based rate as proposed by UNSE will also mitigate the inefficient price signals for rooftop solar. I might note here that the proposed market price for excess generation still contains a subsidy for roof top solar simply because the purchase of capacity under the market rate is year round while the purchase of excess generation is likely to be in low marginal cost periods and the net metering provision provides a capacity payment in the base rates. The UNSE proposal has several advantages that should be noted with respect to introducing the demand charge to the limited group of DG customers. First, customers who install DG are likely to be more sophisticated and more knowledgeable about energy decisions than the typical customer and thus will likely require far less customer education. Second, the move toward more equitable rates begins with addressing the cost recovery for partial requirements customers to eliminate the undue discrimination inherent in the volumetric rates. Third, the UNSE proposal provides a basis for assessing the potential demand response of both DG customers as it relates to solar PV and capacity value and price response to demand based rates.

V. <u>CUSTOMER RESPONSE TO MORE COMPLEX PRICE SIGNALS</u>

Q. IS IT REASONABLE THAT CUSTOMERS CAN AND WILL RESPOND TO MORE COMPLEX PRICE SIGNALS.

A. Yes. In terms of complex price signals the proposals in this case are comparable to rates in other parts of the world. For many years electric utilities have had more complex rate schedules for customers. The first marginal cost based TOU rates were introduced for large customers in the 1950s. It is common to see separate supply and delivery charges with supply charges consisting of multiple blocks or TOU periods. Some rates have a customer charge that is tied to the maximum capacity that can be served by the utility. Under this arrangement the maximum delivery capacity is limited. This is a rate equivalent to a customer charge and a demand rate. In Italy, residential demand rates have been used for many years. Italy is an example of a demand charge that is based on maximum delivery capacity.

Australia is addressing the issue of residential demand charges to address both the issue of cost recovery for solar DG and added loads from air-conditioning in the residential class. The important point is that there is broad recognition of demand charges as a means to fairly recover distribution related costs based on maximum customer demand whenever it occurs. Production and transmission demand charges are partially related to system peak hours as discussed above.

Q. IS THERE EVIDENCE THAT RESIDENTIAL CUSTOMERS CAN RESPOND TO MANDATORY DEMAND CHARGES?

A. Yes. In 2009 a rural electric cooperative in Kansas introduced a mandatory demand charge for recovery of fixed power supply costs based on the peak demand period used by the supplier. The customers of Butler REC have responded as evidenced by the two documents provided in Exhibit HEO- 5. Those documents demonstrate both the educational material and the savings that have resulted from the mandatory rate for residential customers. This shows that the concern of various parties related to the use of demand charges is actually misplaced.

Q. IS THERE EMPIRICAL EVIDENCE THAT CUSTOMERS DO NOT RESPOND TO MARGINAL PRICE SIGNALS AS MUCH AS TO THE TOTAL BILL?

A. Yes. In a 2012 paper by Koichiro Ito of Stanford University[14] found that customers respond to the total bill rather than marginal energy prices. This means that the non-linear energy prices under the inverted block rates are **not** useful as a tool to promote energy conservation. This is further evidence that the insistence of RUCO and others related to the third tier of the inverted rates does not promote conservation and the introduction of more efficient demand rates will not only promote just and reasonable rates, eliminate undue discrimination but will also be consistent with conservation. The findings in this article are not new and have been replicated over the years in various studies. This is further evidence that there is no requirement that residential customers fully understand the components of the rates to promote sound decisions related to a more complex rate design.

VI. <u>CUSTOMER COST ANALYSIS</u>

Q. DO YOU HAVE COMMENTS ON THE VARIOUS WITNESSES WHO RECOMMEND THE BASIC CUSTOMER METHOD FOR CALCULATING CUSTOMER COSTS?

A. Yes. Witnesses for WRA and SWEEP both support the concept of the Basic Customer Method for determining the customer charge. The basic customer method is not a method for calculating the customer component of costs that is based on cost causation because it fails to reflect any costs more than meter, service and direct customer

[14] Do Consumers Respond to Marginal or Average Price? Evidence from Nonlinear Electricity Pricing, October 2012 http://www.nber.org/papers/w18533.pdf

accounting costs such as meter reading and billing in the customer costs and hence the customer charge. It is simply a result driven methodology (lower costs for the residential class and for smaller customers in the class) that does not meet the criteria of theoretically sound cost causation. As a result of this method, all of the remaining distribution system costs must be classified as demand. This includes USOA accounts 364-368. By failing to classify accounts 364-368 as both customer and demand, the resulting cost analysis suffers from significant defects related to cost causation. First, residential customers are allocated a disproportionate share of scale economies in the distribution system. Residential transformers in account 368 have substantially higher costs per kVa of installed capacity than larger demand customers, typically more than twice the cost per kVa. Demand allocation alone assumes the same cost per kVa for all classes. Second, the use of demand to allocate costs for investments in accounts 364 through 367 over allocates the quantity of these inputs to larger customers and assumes that miles of conductor is proportional to demand and not to number of customers. This is empirically an incorrect assumption. Third, public utility regulatory accounting including the NARUC Electric Utility Cost Allocation Manual supports the classification of distribution plant between customer and demand. Based on these factors the Basic Customer Method should never be considered as a viable alternative for calculating the customer charge.

This recommendation appears designed less to follow accepted principles of cost of service analysis and more tailored to advance the interest in artificially depressing fixed charges in rates in order to support higher kWh charges. The economics of solar DG and energy efficiency are both significantly related to the total kWh charge for customers. Increasing the kWh charge provides a larger subsidy for solar customers and is used as a marketing point by the solar industry. It results in a mismatch of customer savings and utility savings when EE investments are made. This is essentially a subsidy for energy efficiency.

Q. IS IT CORRECT THAT THE ONLY COSTS A UTILITY INCURS TO SERVE A NEW CUSTOMER ARE THE METER, SERVICE AND BILLING COSTS?

A. For this statement to be correct, the service line would need to be directly connected to the generator. In the early days of electric service that was the case and generators operated at the same DC voltage as the loads they served. Essentially, the electric utilities served customers in the immediate vicinity and service was unmetered. It was typical to speak of the transmission of electricity from the plant to the customer over a copper conductor and the service area was effectively about 1.5 miles from the generator. If we return to that description of the industry, the statement would be correct except for of course no meter was used. Since none of these circumstances still exist, the statement is incorrect because even to be able to access service requires a transformer and conductor for underground service and poles, conductor and transformer for overhead service.

To see how biased this recommendation is relative to actual costs it is worth noting that the advocates of the Basic Customer Method do not even include all of the labor costs associated with meter reading, billing and customer service. This is true in spite of the accounting requirement to count pensions and benefits applicable to payroll costs in the current period. Further, the method does not account for any office space or equipment necessary to perform the functions deemed to be customer related. As a practical matter, the Basic Customer Method has no support from cost accounting theory for public utilities, the NARUC Electric Cost Allocation Manual or economic theory. Importantly, efficient rates require a customer charge that recovers most if not all of the fully loaded customer costs. Recognition that the costs of the facilities in accounts 364-368 is a necessary condition to have rates reflect cost causation. The minimum system classification properly recognizes cost causation and appropriately shares the benefits of economies of scale among the rate classes. The basic customer charge method requires that all distribution plant accounts be allocated on NCP demand. The result is an under allocation of costs to residential and small commercial customers and excess allocation to larger customers.

Q. WHY IS IT IMPORTANT TO INCREASE THE CUSTOMER CHARGE AS PROPOSED IN THIS CASE?

A. By coupling the higher customer charge with elimination of the third tier as proposed, the intraclass subsidy will be reduced. That is important for moving to rates that meet the cost causation and matching principles. In a market where customers have competitive choices hidden subsidies in even monopoly rates are not sustainable. By improving the rate design gradually, the transition to economically efficient, state of the art, multi-part rates will ultimately be accomplished with fewer and smaller customer impacts.

VII. THE CONCEPTS OF FAIRNESS, EFFICIENCY AND GRADUALISM

Q. ARE THERE GENERALLY ACCEPTED PRINCIPLES OF RATE DESIGN THAT PLAY A ROLE IN THE RATE PROPOSALS OF THE PARTIES?

A. There are always important principles that should be reflected in rate design. The three principles of fairness, efficiency and gradualism have been recognized by a number of the witnesses in their testimony either directly or indirectly. These principles are consistent with rate principles developed by Bonbright and discussed widely by others. The following is a summary of the witnesses' views:

TASC witness Fulmer concludes that "As I discuss throughout this testimony, UNSE's proposal to double the monthly customer charge and require new DG customers to be on a three-part rates violates the principles of understandability, public acceptability, avoidance of undue discrimination, and wastefulness." I will discuss this concept below.

APS witness Faruqui cites Bonbright a number of times in his testimony. He summarizes the principles and discusses their applicability in detail. While I agree with much of that discussion there are issues that make his recommendation inconsistent with cost causation.

SWEEP witness Schlegel uses Bonbright as support for his basic customer charge argument and states "The definition and composition of a customer fixed charge should be consistent with the definition contained in Bonbright's Principals of Utility Rates. Bonbright defines basic customer costs as those operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption." I will show below that the UNSE proposal is completely consistent with Bonbright and that witness Schlegel has reached an erroneous economic conclusion.

Q. PLEASE DEFINE THESE THREE PRINCIPLES.

A. In defining gradualism as a measure of rate change for individual rate components such as customer charges, the witnesses for the other parties seem to focus solely on a percentage increase as the measure of gradualism. Looking solely at percentage increases as the basis of determining gradualism can often give very misleading results. Thus the TASC concern for a 100% increase in the customer charge as violating gradualism is misplaced. Both Staff witnesses recommend gradualism but provide no precise definition of the concept. They use it to temper class increases and rate design and one can only infer from their recommendations what their view may be. Similarly the AECC endorses gradualism in both cost allocation and rate design. To properly define gradualism it is necessary to recognize that gradualism is not based solely on a percentage increase basis. For example, if one were to make a rate proposal introducing a new billing determinant, such as a demand charge, with a charge of one cent, the percentage increase would be infinite but would hardly violate the principle of gradualism. The same is true in this case where the percentage increase of 100 percent in the customer charge translates to an approximately \$0.33 per day increase in the customer charge. The current charge is relatively low compared to both the cost of service and the level required for economically efficient two-part rates. A \$0.33 per day increase is fully consistent with the principle of gradualism. Fundamentally, there is an increase in fixed costs occurring; some increase in fixed charges is justified. Another example applicable in this case is assessing the actual bill differences for customers from the prior period including the impact of the reduced Base Power value. This provides addition head room for adjusting rates without violating the gradualism principle.

In this case, there is no adverse impact on the kWh price signal from the increased customer charge as that increase does not recover all of the increase in residential revenue requirement. Failure to increase the customer charge violates principles of fairness by increasing undue discrimination. Every witness in this case agrees that changes in distribution costs are driven by changes in the number of customers and NCP demand or NCP alone, not by kWh consumption. Simply, it is insufficient to define the principle of gradualism solely along a percentage increase as even a de minimis actual increase may be a significant percentage increase for a low dollar rate impact. Actual increases must also be assessed in real (as opposed to nominal) bill increases.

Q. PLEASE DEFINE THE CONCEPT OF FAIRNESS.

A. This is the most difficult of the three concepts to define since fairness is often in the eye of the beholder. As a case in point, solar DG advocates see nothing unfair about DG customers paying hundreds of dollars less for delivery service than full requirements customers pay for exactly the same service. They also see nothing wrong with using a high cost kWh in the summer and swapping it out with a low cost kWh in the spring or fall even though other customers must make up that shortfall in fuel costs. Finally, they see nothing wrong with net metering that allows them to save the full Base Power plus PPFAC even though the avoided energy costs (the solar actual savings) is always less than the Base Power plus PPFAC and other customers must pay the difference. From their view this is fair. When Bonbright defined fairness (or equity as used by APS witness Faruqui) it is explicitly defined in terms of cost allocation based on cost causation. As a general rule both customers and the courts have a view that fairness results when rates reflect the principles of cost causation and the matching provision that the charges for customers match the costs incurred as the service is provided. It is certainly not correct that differences in rates that reach the level of undue discrimination are fair as defined by Bonbright himself who specifically notes that rates must not be unduly discriminatory.

Q. PLEASE DEFINE THE CONCEPT OF EFFICIENCY.

A. The concept of efficiency has both a demand and supply dimension. In either event efficiency requires that prices be set on marginal cost. The key point is that when a customer purchases an additional kWh or requires more delivery capacity (kW) the charge should reflect the cost of that additional service. KWh charges cannot be efficient for purchases of capacity and the current Base Power plus PPFAC charge cannot be efficient when costs vary both seasonally and diurnally. The recovery of costs in demand charges cannot be efficient with a single demand charge because a single charge cannot simultaneously reflect coincident peak load characteristics and non-coincident peak load characteristics. If the signals do not match cost causation the incorrect incentives will result in even more costs for customers and larger potential subsidies from inefficient investments. As a case in point, charging too much for peak demand will promote investment in storage to reduce peak demand but will not save the utility costs beyond the generation capacity component. Other customers will be forced to pay more as the result of excess storage investment. Further, the customers hardest hit by these types of cross subsidy are those who cannot afford solar DG, do not have an economic location for storage, do not own their premise and those who cannot afford storage investments.

Q. WHY ARE THESE THREE PRINCIPLES IMPORTANT IN RATE DESIGN IN PARTICULAR?

A. While all of the Bonbright principles are important and in fact some are even mandated by the courts, these three principles apply specifically to rate design and support principles that are also related to other aspects of regulation such as revenue requirements or environmental efficiency by internalizing externalities that have been included in utility costs. These three principles are most important for rates because they provide significant guidance in the design of particular rate elements. For example the witness for SWEEP says that the Bonbright principles support the use of the basic customer charge. He notes that "Bonbright defines basic customer costs as those operating and capital costs found to vary with the number of customers regardless, or almost regardless, of power consumption." If we turn to utility cost accounting, the NARUC Electric Cost Allocation Manual (NARUC Manual) or economic analysis, we find that Bonbright's definition means far more than basic customer costs defined by the SWEEP witness.

As Dr. James Suelflow writes in his treatise Public Utility Accounting: Theory and Practice published by the Institute of Public Utilities at Michigan State University: "… distribution transformers and primary and secondary lines including conductors and devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs." Dr. Suelflow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer. In other words, assets that are in closer proximity to the load served reflect less diversity and the classification of the costs associated with those assets should recognize this point and those costs do not vary with power consumption.

The correlation between customers and a portion of distribution costs has been confirmed by academic and regulatory research work related to estimating Total Factor Productivity (TFP) for use in price cap regulation where customers or connections has been an output measure for calculating the X-Factor in the formula P = I – X. The formula P= I – X is essentially a formula that relates either price or the functional equivalent revenue requirements to inflation and changes in productivity as measures by the relationship of physical outputs like customers and demand to measures of physical inputs such as meters or transformers. For example, the following statement from an Australian electric distribution TFP study says "The connection component recognises that some distribution outputs are related to the very existence of customers rather than either throughput or system line capacity. This will include customer service functions such as call centres and, more importantly, **connection related capacity (eg having more residential customers requires more small transformers and poles**)." (Emphasis added.) This information is developed specifically for a network electric utility providing delivery services. I would note that the emphasis on connections as related to connection related capacity is the result of the correlation of distribution costs to the number of customers. In a more recent study related to the electric distribution utilities in Ontario, Canada, The Pacific Economics Group (PEG) found that customer numbers was an empirically significant output measure for determining productivity. In each case the productivity measure is used to determine the expected changes in costs over time. As an aside, the customer component of TFP has the largest cost elasticity weight meaning the customer component is more significant than the other output measures. In addition to Australia and Ontario, other jurisdictions such as Great Britain and the Netherlands also use customer numbers to develop TFP.

Based on this research, it is fair to conclude that the weight of modern empirical evidence is fully supportive of the minimum system use to classify a portion of the distribution system costs in accounts 364-368 as both customer and demand. The customer component of these costs is wholly consistent with the Bonbright definition of costs measured as those that do not vary with power consumption.

Finally, there is no question that the NARUC Manual states that the distribution plant costs in Accounts 364-368 have both a demand and a customer component. The NARUC Manual states "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer- related costs." (Emphasis added.) NARUC's position is unequivocal in this regard. It specifically provides only two alternatives for the classification and allocation of more than basic costs to the customer component. Thus SWEEP witness Schlegel's own definition of customer costs supports, consistent with the Bonbright authority he relies on, results in a much larger customer charge including a fully loaded portion of the distribution system as part of an efficient and fair customer charge. The concept of a basic customer charge is not supported by Bonbright, cost accounting, empirical evidence from economic theory or even NARUC.

Q. YOU NOTED ABOVE THAT YOU WERE IN GENERAL AGREEMENT WITH APS WITNESS FARUQUI ON APPLICATION OF THESE PRINCIPLES. WHERE DO YOU DISAGREE?

A. My disagreement is not theoretical but rather based on the principles of cost causation noted above and a fundamental difference related to distribution demand costs. As I have shown above the proper customer charge is more than basic customer costs thus Dr. Faruqui has not recommended a customer charge consistent with cost causation. He has also recommended a demand charge concept as follows: "It is typically applied to the individual customer's maximum demand, either during a defined on-peak period, or regardless of time of occurrence, or based on a combination of the two." At a minimum there must be two separate demand charges, one would be the distribution costs in a facilities charge based on maximum demand whenever it occurs and another demand charge for production and transmission costs based on a demand measured in a peak period. If by a combination of the two, Dr. Faruqui means a separate facilities demand charge such as used by Empire District Electric in their general service demand rates than there is no disagreement. This point should be clarified.

VIII. <u>SERVING ALL CUSTOMERS IN A CLASS UNDER THE SAME RATE SCHEDULE</u>

Q. WHY IS IT IMPORTANT TO SERVE ALL CUSTOMERS IN A HOMOGENEOUS RATE CLASS UNDER THE SAME RATES?

A. All customers with like service characteristics have the same cost causing factors and should be subject to the same price signals regardless of other circumstances that may warrant different treatment from a societal perspective. Using the same rate sends the same price signals so that even customers who may require special consideration see the same incentives for efficiency as all other customers. The question becomes how to provide utility bill assistance to customers whose circumstances warrant special consideration.

Q. HOW HAVE UTILITIES ADDRESSED THE ISSUES OF SPECIAL NEEDS CUSTOMERS?

A. Utilities have used a variety of options to address low income consumers and others with special needs. In fact, the inverted block rates used in California and adopted elsewhere including Arizona were instituted as lifeline rates in the 1980s based on the idea that low income customers were low users and that low customer charges coupled with a suitable low tier would provide assistance to low income customers. As a practical matter the assumption of correlation between use and income is weak at best and actually non-existent in many cases.

Beyond tiered rates utilities have used several basic methods to address low income issues: discounted charges; fixed dollar discount; fixed percentage discount; means tested discounts; age tested discounts; percent of income plans and so forth. Each of these general concepts has variations as well. For example, means tested discounts may be a percentage of the bill, a percentage of the bill excluding fuel costs, a dollar amount and so forth. The one element that all have in common is they provide assistance to some subset of residential customers deemed to require bill assistance.

From an economic perspective these tools are typically not designed to maximize the benefits of assistance. Rather they are a crude method for providing assistance unrelated to the actual need of the customer. The need for assistance is a function of income, family size, household age distribution and a variety of variables that impact the customer's bill. For example, the increased customer charge benefits all low income customers whose use exceeds the system average on an annual basis. Thus the argument against increasing the fixed charge and reducing the intraclass subsidy works against those who have the largest bills. Decreasing the intraclass subsidy provides more relief for those who have the highest impact whether the relief is fixed dollar amount or a percent of the bill. It is not uncommon for this to benefit more than half the low income customers. Even under a means tested discount it is possible that the higher customer charge would result in a more favorable outcome for larger customers. Under a percentage of income plans the rate design has no impact on a qualifying customer. Finally, the ACAA paints a picture that increasing the customer charge will have dire consequences for low income customers without providing any empirical evidence of any such impacts. Given the saturation of electric appliances from the Residential Energy Consumption Survey for 2009 (the latest year available) it is unlikely that any significant number of low income customers who pay their own bills and are not poor (college students for example) have annual consumption that is as low as 300 kWh per month. These low uses tend to result from other impacts such as partial month bills or use during months with no heating or air-conditioning load.

This conclusion is supported by the bill frequency data provided in response to a data request to UNSE. I have summarized that frequency data in Exhibit HEO- 6. The exhibit shows that only 17.5% of CARES customers have monthly bills below 300 kWh as compared to 22.5% for non-CARES customers. That same exhibit shows that the kWh frequency for CARES customers is virtually the same as for the class as a whole at all cumulative consumption levels. This is not surprising when one considers that the average bill for CARES customers is 769 kWhs per month and for all customers is 830 kWhs or only 61 kWhs per month more than CARES. As a practical matter it is also important to understand the data in the bill frequency includes bills for less than thirty days as the result of turn-offs and turn-ons. The frequency of low income moves is typically higher than for the population as a whole with some exceptions such as college communities.

ACAA also claims that the "most frequent bill" for CARES customers shows usage in the 400 kWh range, their own data (Figure 2) contradicts this finding; in that figure, the largest number of bills issued to CARES customers is in the 1,500 kWh range – the same range that is shown in Figure 1 for RES-01 customers as having the highest number of bills.

Q. WILL THE THREE PART RATE ADVERSELY IMPACT LOW INCOME CUSTOMERS?

A. As with most questions about impacts the response is it depends. If the customers have a high peak demand and low annual use bills will increase. On the other hand if these customers use mostly baseload service with low coincident peak and non-coincident peak demands the three part rate will also provide a benefit for these customers as a result of lower energy charges and higher load factors. Further, the three part rate will help low income energy programs focus on efficiency measures that will not just save kWhs but will also reduce demand.

IX. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. I conclude that the size and nature of the solar subsidy is significant and that the net metering banking provision contributes directly to this subsidy based on avoided energy costs and avoided fixed costs. As proposed by UNSE that provision should be eliminated at least going forward and I would suggest that it be eliminated for all customers as soon as practical. Second, I agree with Staff that a multi-part, unbundled rate is the solution to addressing cost recovery for all customers. Until such time as that rate is fully implemented for all customers, solar DG customers should be served under a separate rate schedule that fully embodies the principles I have discussed above as a multi-part rate that includes customer charges, demand charges and TOU energy charges all based on cost causation. Third, I conclude that serving all full requirements residential customers including CARES customers under the same rate is appropriate as both UNSE and the Staff have noted. I agree that increasing the customer charge substantially is required for more efficient rates. Finally, I agree that the third tier of the inverted rate should be eliminated and that no tiers are required under multi-part rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Appendix A

DR. H. EDWIN OVERCAST

Educational Background and Professional Experience

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke

Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc., the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Arkansas Public Service Commission, the Corporation Commission of Oklahoma, the Ohio Public Utilities Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, the Michigan Public Service Commission, the Public Service Commission of Maryland and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. In Canada, he has testified before the Ontario Energy Board, the British Columbia Utilities Commission, the New Brunswick Energy and Utilities Board and the Alberta Energy and Utilities Board. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General

Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black and Veatch in January of 2005. At that time he became a Principal of the EMS Division, he is currently a Director in the Management Consulting of Black and Veatch.

Appendix B

SMART RATES FOR SMART UTILITIES

Creating a New Customer Paradigm with Enhanced Pricing of Utility Services

H. Edwin Overcast

BLACK & VEATCH
Building a world of difference.

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Introduction

The U.S. electric utility industry is in the midst of rapid technological change and a transformation of the customer service paradigm. Much of the debate surrounding the changing industry centers on the implementation of more sustainable practices, such as energy efficiency and distributed energy resources, and compliance with more stringent environmental regulations. Notably, the debates continue to focus on technological and operational solutions. However, developing a 21st century rate design, or Smart Rates, can help facilitate solutions to today's industry challenges and provide customers with better price signals to assess competitive service offerings.

Smart Rates recognize that utilities provide a variety of services to customers and that the costs of these services are not always caused by the amount of energy the customer consumes. From a rate design perspective, Smart Rates fully unbundle[1] each component of utility costs and bill those components on the appropriate customer billing determinants consistent with the concept of cost causation. The unbundling of costs changes virtually all of the current rate traditions because it no longer rolls all utility costs into a single kilowatt-hour (kWh) charge or single kilowatt (kW) charge as if those costs are caused only by the single measure of customer energy consumption. Cost unbundling is critical for accommodating competition from on-site generation and allowing customers to choose which services they need from the utility.

This paper sets forth the theory and practice of 21st century rate designs through full rate unbundling of utility services and provides a framework for "Smart Rates" that enable customers to purchase – and pay an equitable and supportable price for – the services they want and need, regardless of their energy consumption levels. Through the use of Smart Rates, a utility can send customers a proper price signal associated with each service and improve the efficiency of all its services to customers.

Many aspects of the electric utility industry have changed dramatically since its founding, yet rate structures have significantly lagged these advancements. In order to best represent today's electric services and meet the needs of today's electric consumers, modern rate designs are essential. Smart Rates enable customers to use electricity and electric services more efficiently and provide utilities with revenue stability that enable the offering of more responsive services to accommodate customers' specific demands.

[1] Rate unbundling in this context is simply pricing each utility provided service separately so that customers pay only for the services they use, rather than paying a single charge that includes all services and assumes that all customers within a class have homogenous service requirements.

The Challenge with Current Utility Rate Designs

Current utility rate designs have their foundation in rates developed in the 19th century. The most common rates in use today are based on the watt-hour meter and consist of a fixed customer charge and some form of volumetric charge per kWh. As a practical matter, the choice of rate designs for various customer classes has depended specifically on the cost of metering relative to the total cost of service to the customer. For larger customers, most utilities use one of the following rate forms, both developed in the 19th century, or a combination of the two forms:

- **Hopkinson Demand Rate:** The most common method of pricing electricity for customers served with demand meters, such as large industrial customers. The Hopkinson Demand Rate consists of an energy charge for total kWh consumption in addition to a demand charge based on the facility's maximum energy use during any short time period (quarter-hour, half-hour or one-hour) in the month.
- **Wright Hours Use of Demand:** This rate form is also used for demand metered customers and bills those customers using kWh charges for different levels of hours use of demand. The Wright Hours Use of Demand consists of a customer charge and kWh charge blocks based on the number of hours that the customer's maximum monthly demand is used. Hours use is calculated by dividing the monthly kWhs by the measured maximum demand. The price of energy declines as the hours use increases recognizing both the customer's increased load factor and the increasing use of off-peak energy.

Even today, not all electric service applications are metered and the rate design used for such services are the same flat rate service used by the industry when it first started delivering electric power to customers in the 1880s.

Unless the rate design reflects cost causation for the services provided, customers who elect to buy particular service components will not pay for all the services they consume. This creates market instabilities as the result of cross-subsidies embedded in the utility's rates. Such cross-subsidies cannot withstand today's market pressures and will result in skewed prices and service levels for all market participants.

UNDERSTANDING COST DRIVERS

As noted, modern regulatory requirements for demand-side management (DSM) and energy efficiency, as well as customer demands for distributed generation (DG), do not align with current utility rate structures. The reason for this is that current rate structures incorrectly assume that energy, or measured kWh use, causes the utility to incur nearly all costs except for the costs that are reflected in a modest customer charge. For larger customers, the use of both a demand component and an energy component assume that a single measure of kW demand coupled with a unit kWh charge cause all of the fixed costs of utility service. In reality, utility services and the costs associated with each are caused by fixed and variable cost drivers. Both the fixed and variable cost drivers differ for different cost components and for different seasonal and diurnal periods.

Fixed costs do not change with energy use but can vary as a result of other cost drivers, such as customers or demand. Because these costs are fixed, they do not change with any hourly pattern of energy use, even though some time interval is used to measure demand (e.g., highest 15, 30 or 60 minutes). *Appendix A* provides a brief description of the determination of demand for billing capacity-related costs to customers. Examples of utility fixed costs include:

- The investment in the fleet of plants generating electric power.
- The integrated transmission network investment that moves power from generators to the distribution system.
- The distribution system that provides power to homes and businesses.

Variable costs, on the other hand, can vary by season of the year, time of use, and/or environmental conditions such as forced outages or partial unit deratings that change the marginal source of energy for a particular time period. Examples of variable costs include:

- Fuel and fuel handling costs.
- Purchased power.
- Volumetric charges from regional transmission organizations (RTOs) or independent system operators (ISOs).
- Chemical costs.
- Energy-related operations and maintenance costs.
- Other environmental costs.

A Utility's Cost Causative Factors

Whether fixed or variable, costs are generally caused by one or a combination of three general factors:

- **Customer:** In general, if a cost varies as a result of customer count, then this is a customer-caused cost and can include customer service expenses (e.g., billing and meter reading), and facilities or assets located on the customer premise, such as the meter and service line, and even portions of the distribution system that serve to connect customers to the grid.
- **Energy:** These are the costs that vary directly with the number of kWhs produced, with the cost of fuel being the largest component.
- **Demand**: Demand related costs are those costs caused by the largest load in kW imposed on various parts of the utility's transmission or distribution systems.

  NOTE: *The demand factor that causes costs differs for different types of cost elements. For example, some form of coincident demand is the cause of both utility production and transmission costs. This peak hour or other measure of demand drives the required capacity along with a level of reserves and it is this measure of demand that should be the basis for the charges to recover that unbundled cost.*

Understanding the nature of different utility costs, the types of costs, and what causes costs to be incurred enables utilities to use specific pricing mechanisms that align with cost factors (Table 1).

Table 1 - Unbundled Costs by Type and Causal Factors

COST FUNCTION	COST TYPE	CAUSAL FACTOR(S)	PRICING
Generation Plant	Fixed	Demand	kW Charge
Transmission Plant	Fixed	Demand	kW Charge
Distribution Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
General Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
Generation O&M	Fixed, Variable	Demand, Energy	kW Charge and kWh Charge
Transmission O&M	Fixed	Demand	kW Charge
Distribution O&M	Fixed	Demand, Customers	kW Charge and Customer Charge
Administrative & General costs	Fixed	Demand, Customers	kW Charge and Customer Charge

This table shows the appropriate type of charge to recover the categorized costs in order to match cost causation with pricing without a detailed specification of the particular charge.

UNDERSTANDING UTILITY SERVICES

Unbundling of rates requires an understanding of all services a utility provides, and the cost drivers for each service. Most stakeholders generally understand that a utility provides safe and reliable electric service to its customers. However, most characterize this service as simply providing the energy product, which is one reason why the kWh-based rate structure continues to prevail today. In reality, utilities provide numerous services, including:

- Generation service
- Transmission and distribution services
- Customer service
- A variety of services that provide safe and reliable operation of the electric system as well as the facilities that use the electricity behind the meter, such as voltage regulation, in-rush current for starting electric motors and other ancillary services.

Each of the listed major functions of the utility can provide multiple specific services for a variety of customers. Furthermore, each service also includes a quality of service component, generally defined as firm or non-firm. Firm quality means that the utility provides service continuously without interruption except those related to unavoidable system outages (e.g. outages caused by severe weather). Non-firm quality means that the customer has agreed with the utility to permit its service to be interrupted at times the utility chooses. Table 2 demonstrates the multiple services provided under the generation functional umbrella, and how those services have different patterns of cost based on the quality of service.

Table 2. Potential generation services

SERVICE	QUALITY
Full Requirements	Firm
Full Requirements	Non-Firm
Partial Requirements- Supplemental	Firm/ Non-Firm
Partial Requirements- Supplemental Baseload	Firm/ Non-Firm
Partial Requirements- Supplemental Peaking	Firm/ Non-Firm
Partial Requirements- Standby/Backup	Firm/ Non-Firm
Partial Requirements- Maintenance Service	Firm/ Non-Firm
Partial Requirements- Scheduled Maintenance Service	Firm/ Non-Firm
Partial Requirements- Unscheduled Maintenance Service	Firm/ Non-Firm
System Related Services- Black Start, Area Protection, Frequency, Transmission Support	Firm

As Table 2 illustrates, there are many potential services (the list is not intended to be comprehensive) provided by the generation assets. Each service has different cost characteristics as well as quality differences. The result is that rates for unbundled generation may differ based on the type of service required. A similar set of requirements relate to transmission and even to some distribution services, although the closer the service is to the customer the less costs and quality of service provided vary. For example, if the provision of energy is non-firm, that service does not change the cost of the distribution facilities for serving the customer because the utility must still be able to meet the customer's maximum requirements when there is no interruption of service.

MODERN CHALLENGES TO TRADITIONAL RATES

Net Metering Policies

The fallacy of applying 19th century rate structures to the types of 21st century electric utility services required by customers is made clear by the economic effects of DSM programs, and the growing adoption of DG assets (e.g., rooftop solar) among customers who seek the economic benefit net metering policies provide. While these customers are using less energy, and some may even be net-producers of energy, they are still using utility services. However, because current rate structures assume that the level of kWh consumed by the customer causes the utility's costs; discontinuities in billing and cost recovery among customers are created. According to the Edison Electric Institute (EEI):

While net metering policies vary by state, customers with rooftop solar or other distributed generation systems usually are credited at the full retail electricity rate for any electricity they sell to electric companies via the grid. The full retail electricity rate includes, not only the cost of power but also all of the fixed costs ... that makes the electric grid safe, reliable, and able to accommodate solar panels or other distributed generation systems. Through the credit, net-metered customers effectively are avoiding paying these costs for the grid.[2]

Net metering is the practice of allowing on-site generation to reduce the kWh portion of the residential customer's bill (netting generation against load) on a unit kWh generated basis. Recognizing that under a utility's traditional rate design the kWh charge for these customers recovers most of the fixed costs and the variable costs of energy on an average basis, the compensation for the customer's level of self-generation essentially assumes that all of the costs not recovered under net metering can be saved by the utility. That is simply not the case.

Consider, for example, the utility that peaks after sunset in every month of the year. Solar PV makes zero contribution to reducing the fixed costs for that utility. Importantly, the only cost savings are the avoided energy costs - and that would not even be valued at the utility's highest energy cost hours. In this case, net metering forces all non-solar PV customers to bear the costs of production, transmission and distribution capacity costs that are caused by the solar PV customer. While this is an extreme case to illustrate this deficiency in net metering, there are many utilities where the peak loads occur when solar PV is not generating its maximum output. This means that the avoided costs of the utility will not be as large as the credit provided under net metering, and that a cross subsidy will be created which allows solar PV customers to avoid paying for the fixed costs they cause the utility to incur.

Demand-Side Management Issues

With respect to DSM, issues similar to those under net metering arise when DSM programs save energy, but not capacity. A simple example illustrates this point:

A recreational facility owner invests in skylights to save energy during the day. The skylight salesman calculated his expected savings by dividing the total utility bill by the monthly kWh and providing a unit kWh savings. However, the facility was billed on a commercial rate that included a demand charge. Needless to say, the savings did not materialize because the facility's peak demand occurred at night due to its heavy lighting load. The skylights created no demand savings - only daytime energy savings. Based on the actual savings, the skylights were not economic and the owner made a poor decision to invest his limited capital on an inefficient solution to reduce energy-related costs.

By unbundling rates, the utility recovers all of its costs from each customer regardless of the amount of energy (kWh) used by the customer, or when the energy was used. Such a pricing structure will create rates that fairly portray the value of the service in the market and will eliminate the inherent

[2] "Straight Talk About Net Metering." Edison Electric Institute (http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Straight%20Talk%20About%20Net%20Metering.pdf). September 2013.

intra-class cost subsidies in current utility rates, creating benefits for all segments of the energy industry.

21st Century Rate Design

A 21st century rate design fully unbundles each component of cost and bills those components to customers based on the appropriate billing determinants (customer, kW, kWh) consistent with cost causation. The unbundling of costs and the implementation of modern rate designs appropriately change virtually all of the current rate traditions perpetuated over the years. Different rate components are billed separately and each customer will only pay for the services they use. This section focuses on the components of an unbundled rate design.

Unbundled rates consist of the basic customer, demand and energy charges. Under full unbundling, these basic rate components are translated into:

- Customer charge
- Production demand charge
- Transmission demand charge
- Distribution demand charge
  - Distribution substation service
  - Distribution primary service
  - Secondary distribution demand
- Energy charge
  - Energy service at transmission voltage
  - Energy service at substation delivery
  - Energy service at primary delivery with and without transformation
  - Energy service at secondary voltage.

Obviously, not every utility will require all of these distinct charges based on their existing service arrangements and the customers' available service options. Further, there may well be subcomponents of various costs associated with services such as back-up, standby, maintenance and supplemental power as each relate to generation, transmission, distribution and energy services. In some markets, unbundled services, such as meter reading and billing, may not be provided by the utility. In that case, the customer charge component needs to reflect the exclusion of the costs of these services.

A customer's rates may also differ based on geographic segments of the utility's system because costs may differ at different load nodes (this consideration is particularly important for systems with wide geographic reach that include different load nodes and/or climatic considerations.)

UNBUNDLED RATE COMPONENTS

Derivation of the Customer Charge

The derivation of a fully unbundled rate design begins with the customer cost component. While customer costs will always be a subject of debate among a utility's stakeholders, the logic supporting this concept is quite simple: If a cost varies based on customer count, then the cost is customer-related. This includes a utility's customer service functions and its assets located on the customer premise.

Another element of customer costs are those portions of the utility's minimum distribution system required to serve even the smallest customer. Minimum distribution system requirements include transformers, secondary conductors, poles and/or underground facilities.

To derive its fixed customer charge, a utility uses a detailed cost of service study that unbundles costs into various components. These unbundled costs form the basis for setting the rates for each component of service. For example, if the cost of service study calculates the customer component to be $300 per year, that amount would be the basis for a $25 per month customer charge. The annual cost derived from the utility's cost of service study would include the annualized cost to support the investment in a meter, service line, transformers, secondary conductors and poles, Operation & Maintenance (O&M) expenses related to the customer's plant, general plant, and any other assets required to provide the service, and customer service expenses (e.g., billing, meter reading, customer accounts and collections).

Derivation of the Production Demand Charge

Not all electric utilities will have production demand charges. This discussion focuses on the need for such charges for a vertically integrated utility. In that case, the production demand charge includes the fixed costs of generation and the transmission lines and related facilities that interconnect the utility's generation to its bulk transmission system. Ideally, these costs would be collected through two separate demand charges. This is the preferred rate structure because the typical electric utility experiences distinct differences between the marginal costs of production for serving peak loads compared to the costs for serving loads occurring other than during the peak period (i.e., base load production). At the same time, with the expected increase in the penetration of distributed energy resources (DER) on utility systems, this rate structure will properly value the benefits of DER to the customer based on the times when such self-generation actually is operating.

In general terms, the first demand charge (known as the Production Peak Demand Charge) recognizes the capacity costs associated with the utility's peak demand period, while the second demand charge recognizes the higher capacity costs of base load units that provide substantially lower energy costs. These costs are recovered based on the maximum demand in the peak demand period subject to a one hundred percent ratchet.

The carrying cost of the utility's least-cost production resource (nominally a gas turbine) and the associated transmission costs would be collected as a demand charge based on a demand measure during the highest load hours, where load is defined as: *The sum of customer load, forced outage load, scheduled outage load and generator deratings.*

This demand charge reflects the unbundled costs of required capacity with a level of reserves. The result is that certain charges may be incurred by the customer based on specific time periods that may differ from on-peak hours for energy, in general, and may differ for generation and transmission. For example, if the reserve requirements are calculated by an RTO or ISO based on a specific set of critical hours, those critical hours may be appropriate for determining the billable production demand associated with peaking facilities. If these hours are very short periods, such as the maximum demand hour in the summer months of June, July and August, it is not feasible to know in advance when those peak hours may occur and the peak hours used to measure the hours when the demand charge is applied may change from year-to-year and month-to-month.

It is important to note that deriving the Production Peak Demand Charge based on a short demand period runs the risk of shifting load out of that period. In addition, this also creates risk for increasing load after the peak demand period, causing the peak to occur in different hours because shifting load out of a short period may reduce natural diversity. It is critical that the shifting peak concept be fully assessed because there is a possibility that the loss of natural diversity in loads may cause other capacity-related costs to increase - such as for the utility's distribution and transmission facilities.

By establishing a longer fixed period for deriving the Production Peak Demand Charge, the shifting demand peak creates no issue for creating a new production demand peak outside of the demand hours. This is done by taking advantage of the natural diversity that occurs between loads.

It is also critical to understand that the need for capacity is based on more than just the customer load on the utility's system. Simply, the total maximum load on the system is the sum of customer loads, scheduled outage loads, unscheduled outage loads and unit derating loads. The latter two components change for every time interval just like customer loads. In some cases, the seasonal derating is known in advance based on the generation technology or a condition such as lower water flows that occur naturally.

Other factors may also derate the capacity of a unit without forcing the unit out of service (e.g., tube leaks). Since these types of occurrences reduce available capacity, they must be treated as load for purposes of determining the peak hours that matter for cost causation purposes. It has been said that if load factor on the generation system increases beyond a certain point, it will be necessary to build reserves just to schedule maintenance activities. Thus, it is important to understand the full demand on generation resources for purposes of establishing the demand period for production. Shifting load to off-peak periods does not always result in the full expected savings and could with some technologies create a new peak period in the former off-peak hours.

The second demand charge (known as the Production Base Load Demand Charge) is designed to recover that portion of the utility's revenue requirement associated with production not recovered through the Production Peak Demand Charge. The value of this charge may be zero in some circumstances. Where there are additional costs, the Production Base Load Demand Charge will be based on the highest monthly demand outside the peak demand period, without any ratchet provision. Thus, customers who benefit from lower cost energy will contribute to the additional capacity costs that produce those savings.

In the alternative, where utilities operate in restructured markets, the Production Peak Demand Charge of RTO or ISO participants could be based on the capacity responsibility determined by the operational control entity. This charge would be subject to a 100 percent ratchet on an annual basis. The remainder of the capacity costs not covered by the Production Peak Demand Charge would be recovered in a second demand charge applicable to the highest monthly load occurring in the month, without a ratchet.

Derivation of the Transmission Demand Charge

For transmission, the analysis of peak loads need not be the same as for generation. On integrated utility systems, native load may be only one component of the peak load. Understanding how the system is loaded on an hourly basis is a necessary element for the determination of transmission system peak periods. It is possible that the demand allocation for the generation function will differ from the allocation that is appropriate for the transmission function. This is particularly true where transmission for others across the utility system results in higher loading at times other than the native load system peak.

Transmission system loading on integrated utility systems is not solely a function of customer load on the system because of congestion management and centralized dispatch. For example, if load flows across the individual utility system because of lower cost generation, a transmission system may be fully loaded many more hours than retail customers' own load alone would indicate. Determination of the expected loading may also change because of events unrelated to the transmission facility owner, such as unit forced outages, changes in relative fuel costs, must-run generation and other factors that alter grid dispatch. The result of these factors is to change the allocation and cost responsibility for transmission in a way that impacts the appropriate demand period determination. To do this, it is important to understand the components of the transmission system and the cost drivers for each:

- **Generation laterals**: costs driven by connecting generation to the system and should be included in the generation/production demand costs.
- **Load laterals:** Costs driven by the loads on the lateral and may differ from the system or the transmission peak. Costs for load laterals are recovered through the distribution facilities demand charge.
- **Bulk transmission system**: Costs driven by loading of the bulk system and are recovered based on the load characteristics of the system. Options include:
  - Maximum load occurs in each month of the year: The demand charge is based on the peak period demand within every month and is the basis for the transmission demand charge.
  - Maximum load occurs in summer: If system is loaded only during four summer months, then the costs would be based on demand that occurs during the peak demand time period, even though the charges are billed over all 12 months. In essence, the non-seasonal demand would be equal to the average of the four critical peak demand periods.

Derivation of the Distribution Demand Charge

Distribution demand costs are driven by the customer peak load whenever it occurs. These costs are not identifiable on a time-of-use basis and the individual customer's maximum demand or contract demand (the maximum obligation of the utility to provide the local distribution service) is the appropriate demand measure to use to recover such costs. Any distribution costs not recovered in the customer cost category and the portion of transmission costs for load laterals are recovered in the distribution demand charge. The distribution demand charge would include a 100 percent demand ratchet based on either the customer's contract or actual demand.

As a general rule, the distribution system components peak at times that may not be coincident with the generation or transmission peak load. In planning and designing the distribution system, an important design element is natural load diversity that occurs based on the electricity use of the premise (businesses and residences have differing time patterns of load).

Certain activities, such as storage may alter the natural diversity of loads. For example, controlling electric water heaters by shutting them off for extended peak periods results in much higher coincident peak demands on delivery facilities because the natural load diversity is disrupted by the added control. The result is both higher distribution costs and higher peak demands for customers subject to control. Based on experience with time-of-use rates, there is potential for a similar impact on the distribution peaks and the cost of delivery service.

The recovery of distribution-related costs based on maximum demand whenever it occurs is fundamental to cost-based rates.

The three components of the distribution demand charge are recognized in the cost allocation process and relate to substation costs, primary facilities and secondary facilities not recovered in the customer charge. Conceptually, in a modern electric system all secondary costs should be customer-related. The allocation process recognizes that diversity increases as the load is measured further from the customer's individual load. To the extent that loads are homogeneous, a single distribution demand charge would be adequate. If there is little homogeneity, then the costs may need to be broken out separately but billed under the same 100 percent ratchet provision.

The customer and ratcheted demand charges would be based on an annual cost payable in 12 equal amounts. These annual charges would be premise-based so that a new customer occupying the premise would have his bills initially based on the premise's measures of demand. In addition, if a customer has service turned off at the premise and subsequently turns service back on, the customer would be responsible for the payment of fixed charges for the period where service was not taken as part of the cost of establishing service. Non-ratcheted demand charges would be based on the actual monthly use of demand.

Derivation of the Energy Charge

The final component of the unbundled rate design is the energy charge. The energy charge recovers all of the variable costs associated with the production or purchase of power. Further, the energy charge is not part of the utility's base rate. Rather, it is reflected in a full tracking fuel clause that recovers not only fuel and purchased power, but also variable production costs, environmental costs (e.g., scrubber chemicals), variable charges from the RTO or ISO, and any other costs that change with the consumption of energy.

The energy charge is subject to regular adjustments, like a fuel clause, and includes a deferral account that matches these costs dollar for dollar. The energy charges under this charge are differentiated based on cost causation by season, by time of use, by voltage level of service and, where applicable, by critical periods above and beyond the time of use periods. The adjustments to this charge are always seasonal-based adjustments in the sense that over or under recoveries of cost in a season are subsequently recovered in that season.

Energy charges may not require the inclusion of all of the cost components described above. For example, some utilities may not have distinct seasons. Others may have diurnal cost differences that are so small that there is no reason to separately bill for those differences. Some utilities with little diurnal difference may instead have critical peak periods when, for a few hours per month or for a few hours per season, they may experience costs far in excess of typical average or marginal cost levels. For example, the average cost might be approximate $35 per MWh for 97 percent of the time, but could easily exceed $100 per MWh in the remaining hours. In this case, the ability to provide proper price signals to customers would be important as would rate provisions designed to match costs and revenues under the critical peak period.

ILLUSTRATIVE RATE STRUCTURES

Using the concept of fully unbundled rates means that a utility's traditional rate class definitions are no longer as important. Cost-based rates enable the use of a less homogeneous class of customers, (e.g., there is no need to have one or more residential classes of service). There will no longer be a need for separate rate classes for certain end-uses, such as churches or schools, to reflect their different load characteristics compared to those of other general service customers. The ability to recover costs based on individual load characteristics then allows for rates based on other relevant conditions of service that have specific cost implications, such as voltage level of service or transformer or substation ownership.

Thinking about the factors that impact cost must begin with the customer component of costs including meter and service investment. This classification should also recognize that voltage level of service is of particular importance. In that context, it is possible to define a Small General Service Secondary Voltage Class. This class would consist of all customers who have essentially the same types of meter installations and service lines (e.g., residential, residential space heating, small commercial, small commercial all electric, etc.). Differences in other characteristics of utility service, such as demand coincidence factors and individual maximum demands, would not matter since the costs that are caused by these demand measures are already unbundled. The important point is to derive each component of the rate structure to reflect the actual cost of service.

Other classes would include General Service Primary Voltage, General Service Primary Voltage Transformer Ownership, Large General Service Substation, Large General Service Transmission, Non-Firm Service Rates and Back-Up and Standby Service Rates. These rates would reflect the different costs associated with each service and, as appropriate, seasonal, time of use and critical peak pricing-type considerations based on service level requirements and associated costs.

Customers who require unique service arrangements would have those costs recovered in a separate monthly fixed charge for directly-assigned facilities. For example, an industrial customer may take service at the substation, but require one or more dedicated lines to connect the substation to its facility. In that instance, the dedicated lines would be a directly-assigned cost and recovered under a separate charge unrelated to the customer's actual load.

To illustrate these concepts, the following tables outline the rate forms for General Service Secondary Voltage Class and General Service Primary Voltage Class customers.

Rates for the General Service Secondary Voltage Class assume the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the secondary level.
- All primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 3 - Rate structure for General Service Secondary Voltage Class customers (i.e., residential)

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Customer Charge $300.00/year or $25.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Distribution Demand Charge $3.00/kilowatt of billed demand	Fixed	Charges resulting from the demand-related portions of the distribution system. This charge can be based on the greater of the current month's maximum demand, or the maximum demand occurring in any of the preceding 11 months.
Transmission Demand Charge $12.00/kilowatt year or $1.00/month	Fixed	This charge is for services provided by the bulk transmission system. It should be based on the rolling average of the maximum on-peak demand for the system
Production Demand Charge $96.00/kilowatt year or $8.00/month	Fixed	Includes the fixed costs of generation and the infrastructure that connects generation to the bulk transmission system.
Energy Charge Charges would vary based on time of use, such as $0.058/kWh for summer on-peak and $0.038/kWh for winter off-peak	Variable	Recovers all of the variable costs associated with the production or purchase of power, most notably fuel and environmental costs.

Charges based on a hypothetical vertically integrated electric utility providing a bundled service.

The rate components of a General Service Primary Voltage Class are outlined below assuming the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the primary level.

- Remaining primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 4 - Rate structure for General Service Primary Voltage Class

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Annual Customer Charge $600.00/year or $50.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Primary Distribution Facilities Demand Charge $24.00/year or $2.00/kilowatt of billed demand	Fixed	Charge based on the greater of the current month's maximum demand or the maximum demand occurring in any of the preceding 11 months payable in monthly installments.
Transmission System Demand Charge $11.75/kW-year or $0.98/month	Fixed	Charge based on the rolling average of the maximum on-peak demand occurring in the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments
Production Peak Demand Charge $94.00/kW-year or $7.84/month	Fixed	Charge based on the rolling average of the maximum peak demand occurring during the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments.
Production Base Load Demand Charge $6.86/kW per month	Fixed	Charge based on the actual maximum demand occurring monthly regardless of the time the demand occurred.
Energy Charges Variable	Variable	The energy charges hereunder shall be determined from time to time to recover the total variable costs associated with the production, purchase and delivery of energy to the Company's transmission system including any volumetric charges imposed under an RTO/ISO Tariff. The summer season is defined as the months of June through September. The charges effective for the twelve months commencing June 1, 2014 are as follows: • Summer On-Peak (Hours 10 AM to 11 PM weekdays excluding holidays) $0.568 per kWh • Summer Off-Peak (All other hours in the season) $0.0441 per kWh • Winter On-Peak (Hours 6 AM to 10 AM and 5 PM to 9 PM weekdays excluding holidays) $0.0451 per kWh • Winter Off-Peak (All other hours in the season) $0.0372 per kWh

As these two rate structures illustrate, many of the unit charges for primary customers are lower because generation and transmission capacity related costs reflect lower primary voltage losses. For primary distribution costs, the lower charge represents the exclusion of secondary facilities from the cost of service at the distribution level. The lower energy-related charges are also the result of lower losses. The higher customer charge reflects higher metering and service costs, including using primary minimum system costs for service at this level. This general pattern will be repeated for each additional rate schedule with charges declining as the result of fewer facilities and lower losses. In addition, charges such as the residual generation costs or transmission costs will differ based on class load characteristics.

ROLE OF ADVANCED TECHNOLOGIES

Perhaps the primary reason rate structures have not changed significantly during the past century was due to a lack of technology to measure and appropriately charge for a variety of utility services. Until recently, utilities did not possess the technology and capability for measuring and recording data for each of its individual cost drivers.

Today's smart meters and advanced metering infrastructure (AMI) enable utilities to measure more than monthly kWh consumption. The technologies and back office software programs enable utilities to produce dynamic pricing information for customers and measure, record, bill and credit based on the usage levels of each service. Examples of additional services advanced technologies can track include:

- Time differentiated energy costs including critical peak prices;
- Demands by time of use and by maximum demand regardless of time; and
- Power factor measurement.

Smart meters permit a wider variety and type of price signals that can remove rate subsidies and send better, more cost-effective price signals to customers. With smart meters, each different rate component may be billed separately, enabling customers to pay for only the services they use.

OTHER CONSIDERATIONS

In addition to the various unbundled charges described above, it will be important to overlay seasonal and diurnal cost characteristics, critical peak pricing and time-of-use pricing, load control credits and other yet to be developed programs that reduce loads and create cost savings that would not be reflected in rates. Thus, we would expect to see energy prices that vary by season and by time of day based on time periods defined by cost differences, where appropriate. It will be important to develop seasonal and diurnal periods based on the underlying marginal costs recognizing that for some utilities those periods may vary in different parts of their systems. This would be the case where a portion of the utility delivery system is served off an electrically isolated load node of the transmission system. Where the system receives service from isolated facilities, the cost of these facilities and service should be borne only by the customers using these services. If the system is fully integrated, the costs of different nodes should be averaged across those nodes.

It is also important to remember that because unbundled rates eliminate intra-class subsidies that are included in many of today's traditional rate structures, certain policy goals could no longer be viably reflected as part of the rate. As such, programs such as low income bill assistance would need to be addressed indirectly through fixed bill credits funded by a separate rate component.

Ultimately these unbundled rates will be designed to recover the utility's class-related revenue requirements. The resulting price signals will be significantly more efficient from an economic perspective resulting in less resource waste and more economically efficient power systems. A key element of the successful implementation of unbundled rates will be to educate customers on how the rates reflect the underlying costs of particular utility services and how the customer can manage electricity use to reduce those costs. Overall, such rates are expected to generate efficiency gains for both customers and the utility.

The benefits of unbundled Smart Rates will accrue to every stakeholder group even though some members will pay more for the services they buy and others will pay less. Customers who pay more benefit from receiving the correct price signal and understand the benefits of alternative choices related to DSM and DG investments. For the utility, unbundled rates will not change the utility's revenue requirement in total, but will impact the stability of revenues favorably and will cause the utility to be more proactive in its marketing of unbundled services to customers. It will likely take substantial effort on the part of the utility to educate stakeholders of these benefits in a rising cost environment. It is the Smart Rates that will allow customers to use electricity more efficiently and allow the utility to recover its costs from customers who cause those costs to be incurred. While the utility will be economically indifferent as rate designs change, it will also benefit from better price signals as consumers adapt to the cost causative factors that form the basis for unbundled rates. Changing rate design will also impact customers who have made investments based on the economic signals of the 19th Century rates and some of those investments will no longer be cost effective. The issue of customer stranded costs will be a difficult element of the transition, but is inevitable because of technological advances in metering and in utility operations.

The end result of unbundled rates will be a more cost effective and better integrated utility system to the benefit of economic growth and new investments that enhance the efficiency of the utility grid. This new customer paradigm is a prerequisite for improving the safety and reliability of the utility system.

Appendix A

As electric rates become unbundled, it is important to understand the concept of demand billing. The concept of demand billing is one of measuring the maximum capacity of the electric utility's system used in any particular period of measurement. Load varies from moment to moment based on the actual use of electric appliances including motor loads such as compressors in HVAC systems or refrigerators and freezers. Lighting load varies even from minute to minute as lights are turned on and off. Some loads run continuously while other loads operate infrequently. The net result is that any particular customer can have a different load shape on a daily basis.

Figure A-1 Daily Residential Hourly Load Shape

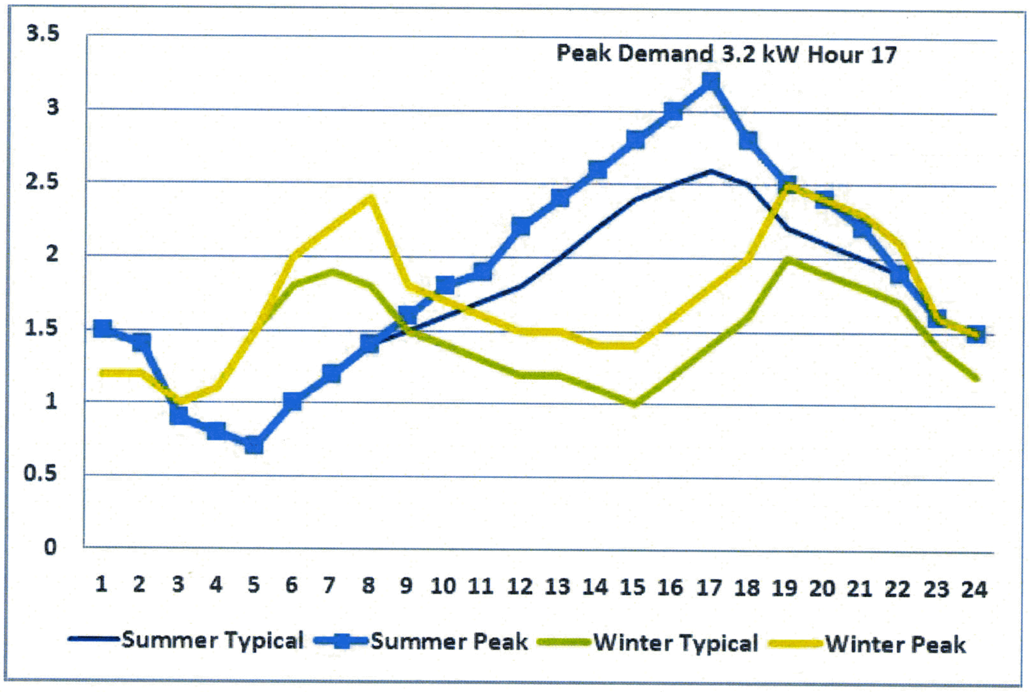


Figure A-1 shows a typical day summer and winter load shape and the peak day for both seasons. The peak hour demand for this customer occurs in the summer and is 3.2 kW. This is the customer's non-coincident peak demand based on an hourly measure. Hourly demand averages the kWh usage over the underlying measurement interval. For example, this demand may be average over four-15 minute intervals as illustrated in Figure A-2.

Figure A-2 Summer Peak Hour kW per Interval

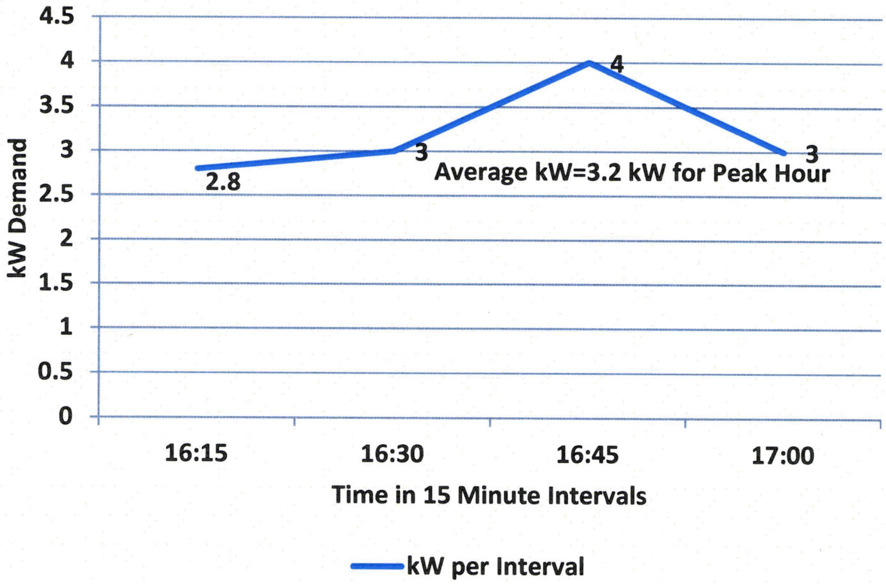


Figure A-2 illustrates the averaging of four-15 minute intervals to derive the customer's maximum demand. Maximum demand is also measured using shorter intervals. Table A-1 provides the demand in kW for each of the three possible measurement intervals.

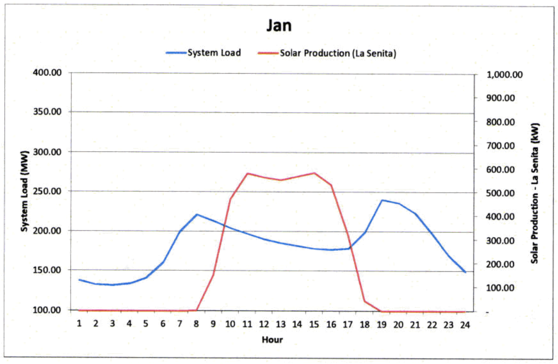
INTERVAL	kW DEMAND
15 Minutes	4 kW
30 Minutes	3.5 kW
60 Minutes	3.2 kW

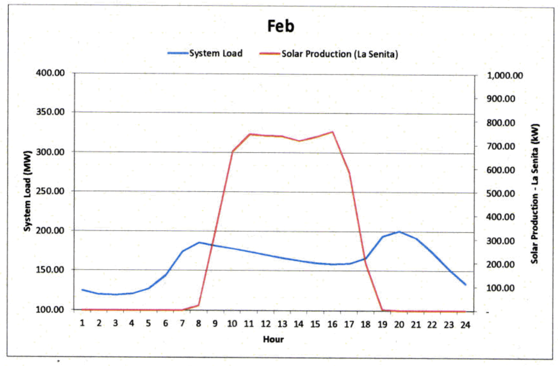
Since the kW measure of capacity required to meet the customer's load is the maximum demand on the utility system, the 15-minute interval is more representative of the required capacity for the utility's local distribution facilities. In any event, the choice of the measurement interval has little impact on customers' bills except for customers with highly variable loads. The reason for this is the costs are fixed and the higher measure of demand results in a lower unit charge for the customer.

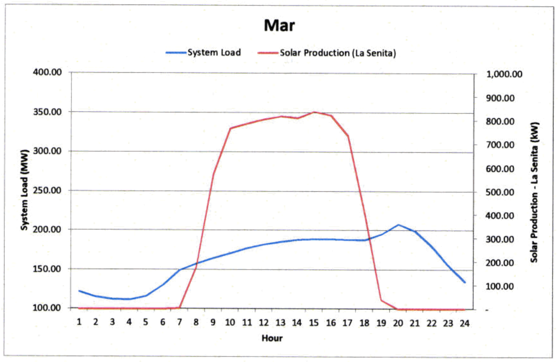
As discussed earlier, there are many different billing demands that are relevant for cost recovery purposes. The same method of calculation is used in each instance although the hour or hours of measurement may differ. That is, some measures of demand might be defined as occurring within a specific range of hours. For example, the demand may be defined as occurring between the hours of 1 p.m. and -4 p.m. Since our data is reported on an hour-ended basis, the peak demand would be measured as the maximum demand occurring during the hours of 14 through 16 above. In that case, the demand would be 3 kW occurring at hour 16.

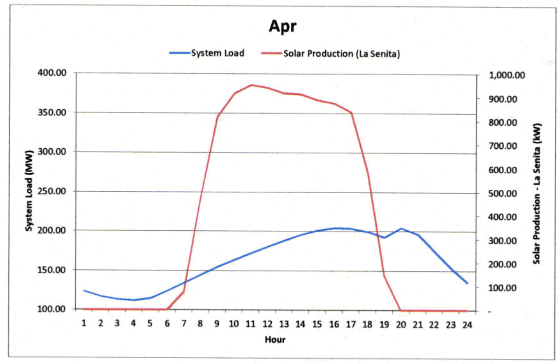
Exhibit HEO-1

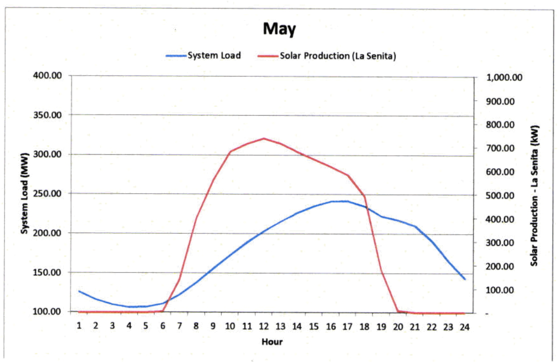
LA SENITA

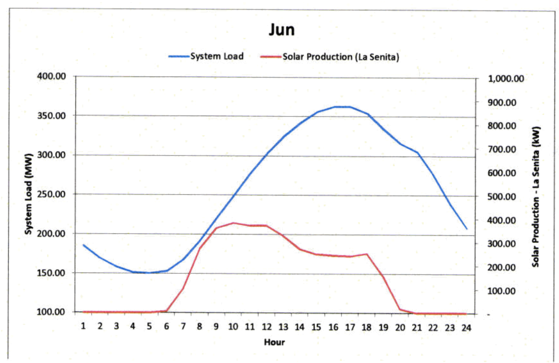

Jan
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour


Feb
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour


Mar
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour


Apr
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour


May
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour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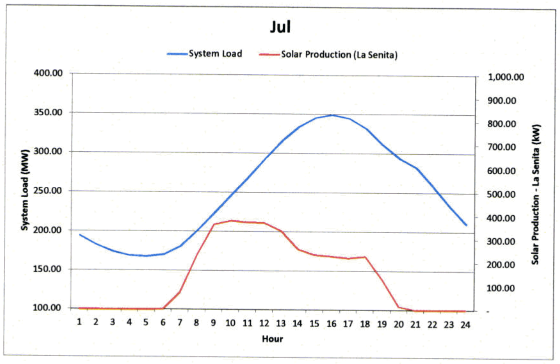
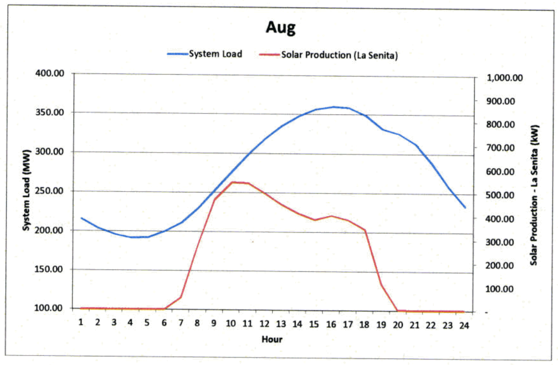
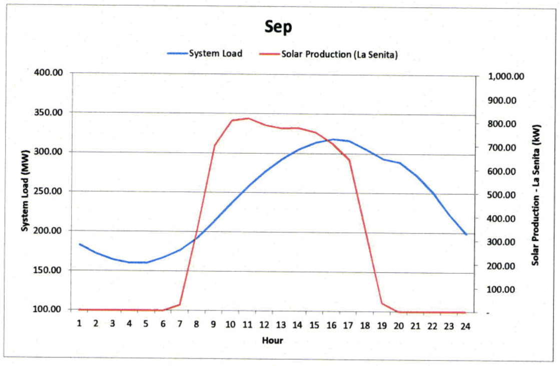
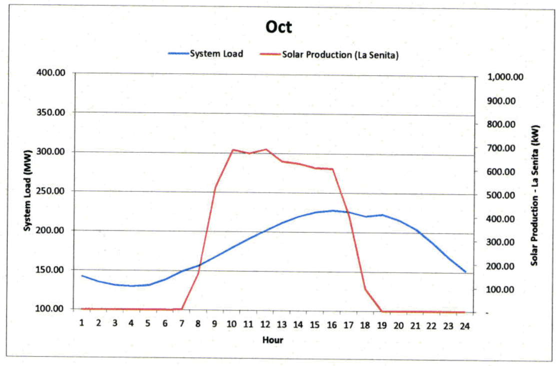
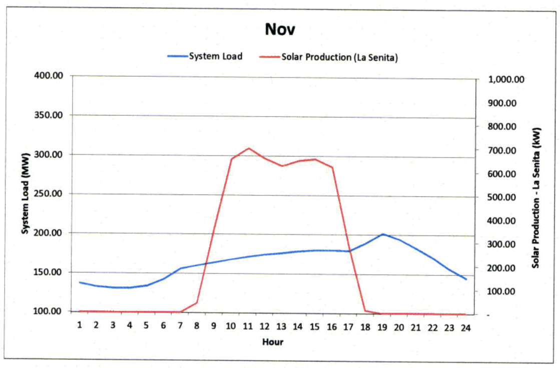
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour

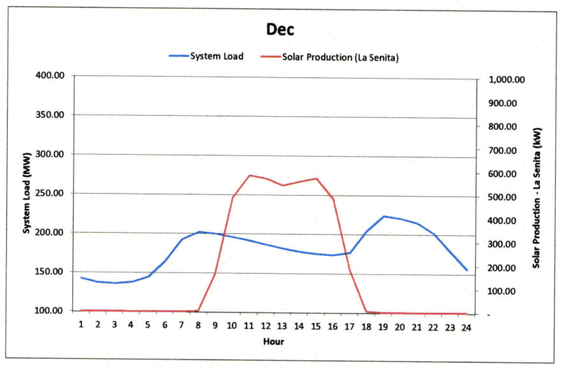

Jul
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour


Aug
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour

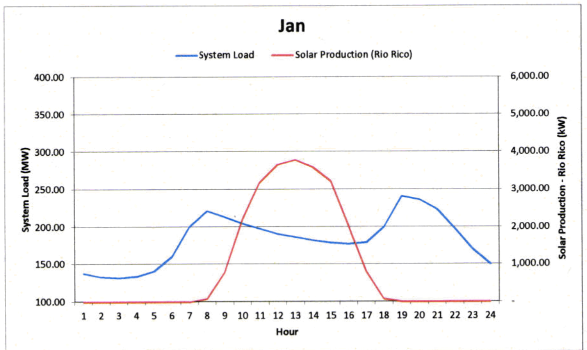

Sep
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour

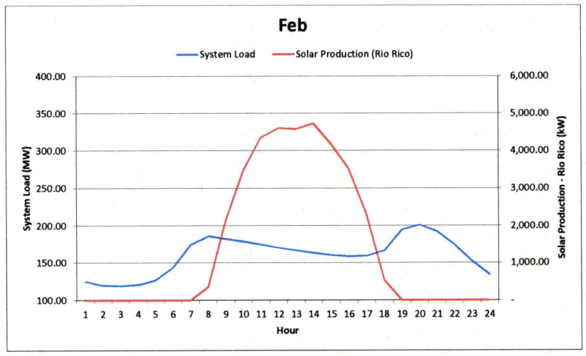

Oct
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour

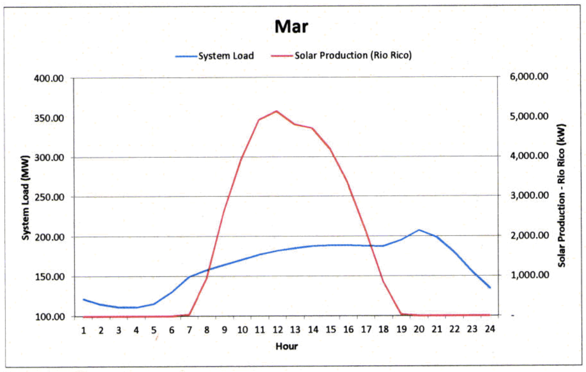

Nov
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour

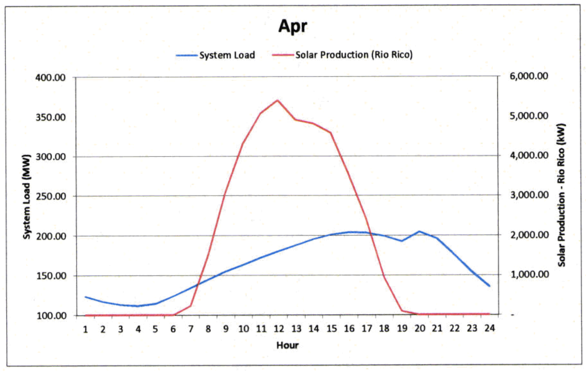

Dec
System Load
Solar Production (La Senita)
System Load (MW)
Solar Production - La Senita (kW)
Hour

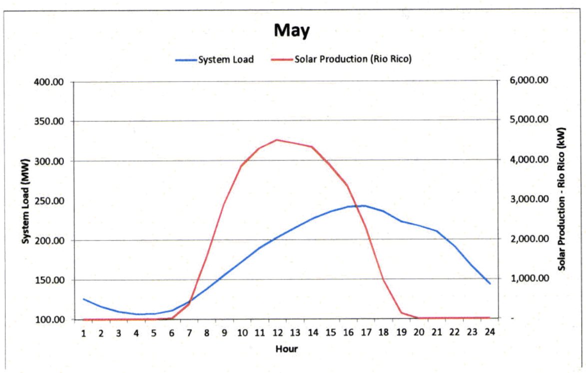
RIO RICO

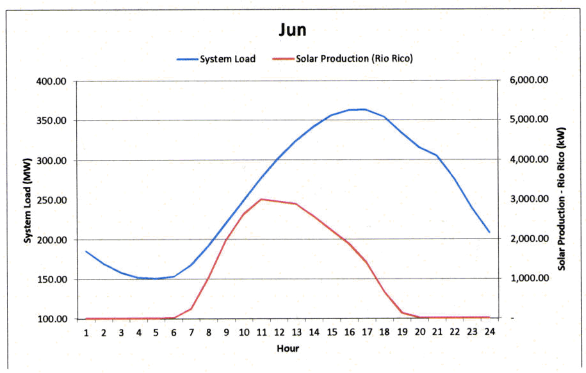

Jan
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

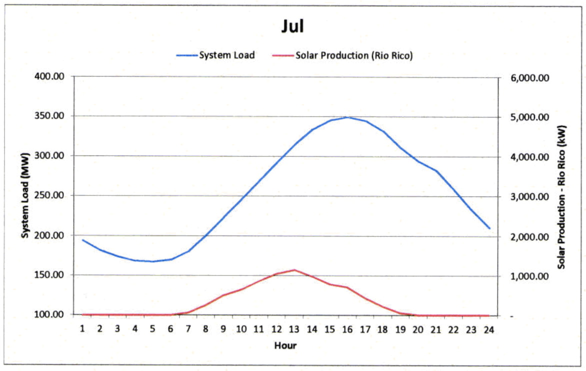

Feb
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

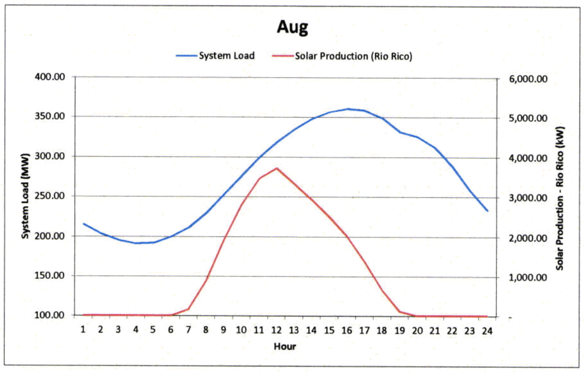

Mar
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

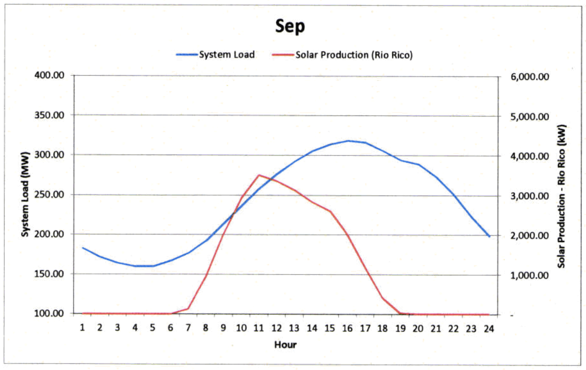

Apr
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

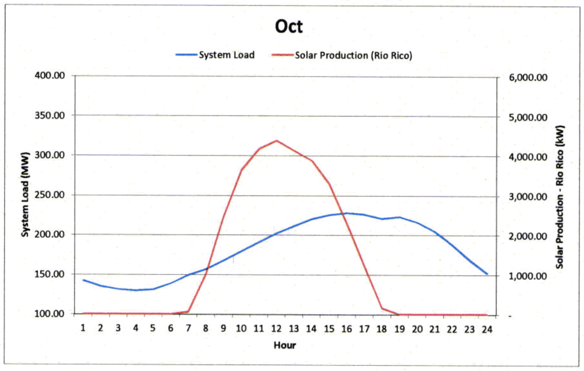

May
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

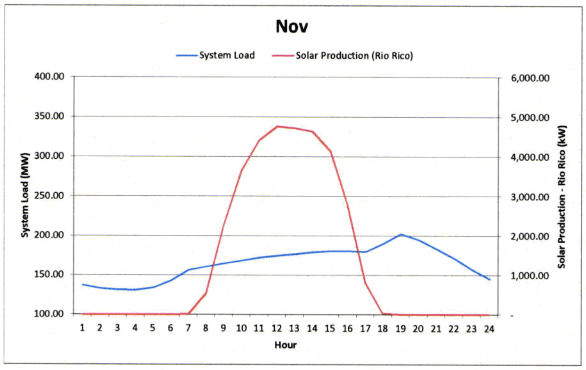

Jun
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Jul
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Aug
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Sep
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Oct
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour


Nov
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

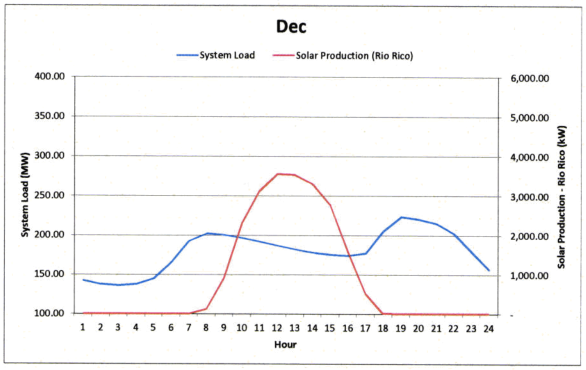
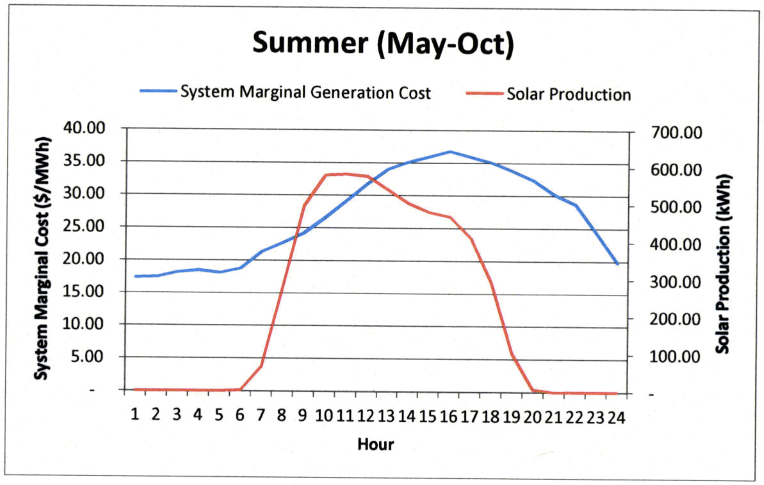
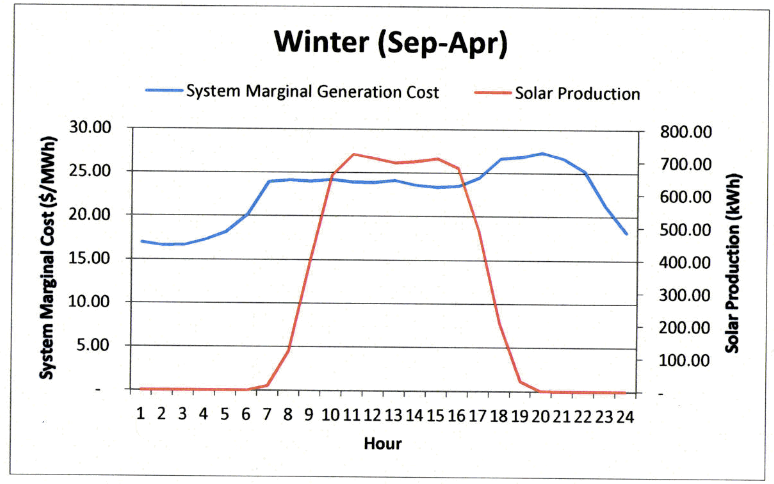

Dec
System Load
Solar Production (Rio Rico)
System Load (MW)
Solar Production - Rio Rico (kW)
Hour

Exhibit HEO-2

LA SENITA

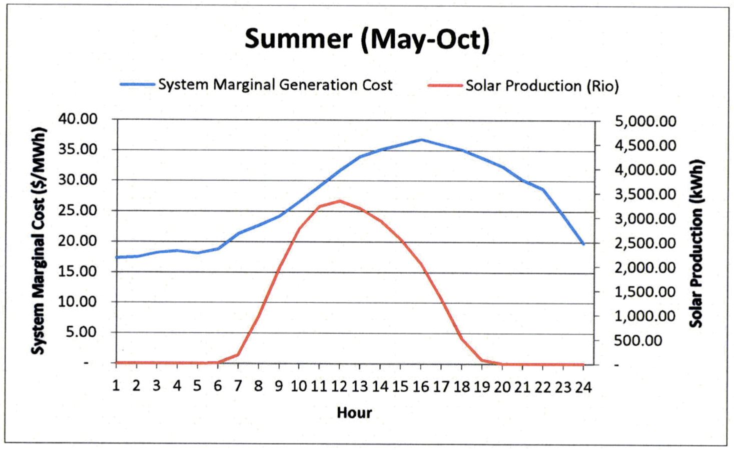


Summary (May-Oct)
System Marginal Generation Cost
Solar Production
System Marginal Cost ($/MWh)
Solar Production (kWh)
Hour



Winter (Sep-Apr)
System Marginal Generation Cost
Solar Production
System Marginal Cost ($/MWh)
Solar Production (kWh)
Hour

RIO RICO


Summer (May-Oct)
System Marginal Generation Cost
Solar Production (Rio)
System Marginal Cost ($/MWh)
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
-
Solar Production (kWh)
5,000.00
4,500.00
4,000.00
3,500.00
3,000.00
2,500.00
2,000.00
1,500.00
1,000.00
500.00
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

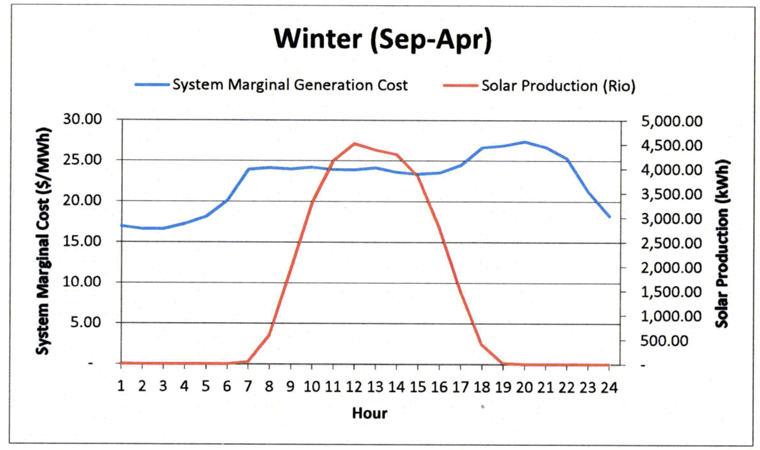
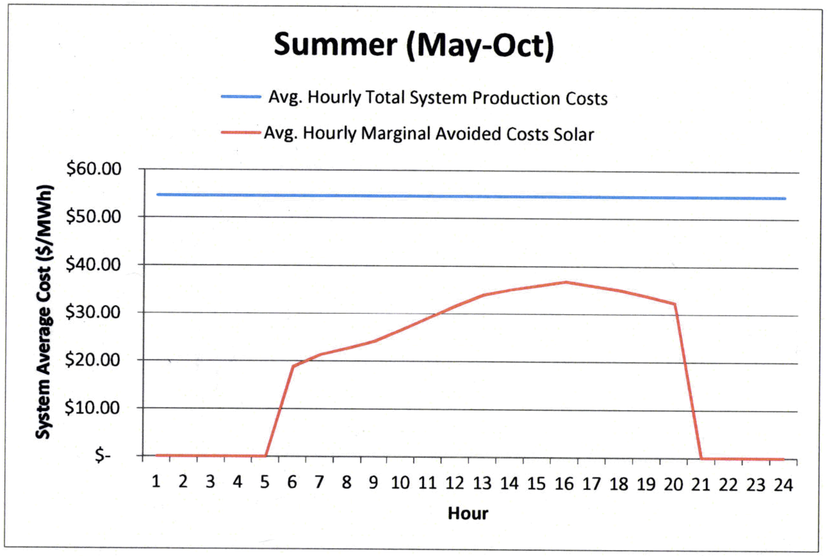
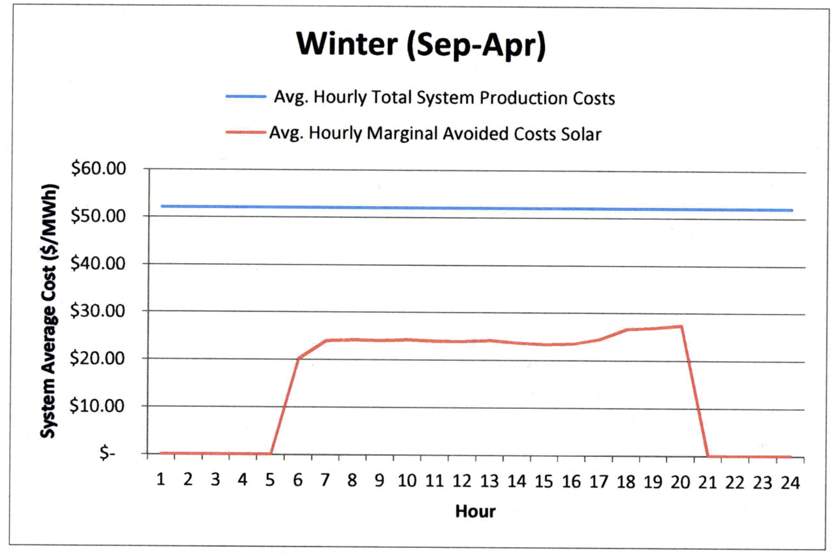

Winter (Sep-Apr)
System Marginal Generation Cost
Solar Production (Rio)
System Marginal Cost ($/MWh)
30.00
25.00
20.00
15.00
10.00
5.00
-
Solar Production (kWh)
5,000.00
4,500.00
4,000.00
3,500.00
3,000.00
2,500.00
2,000.00
1,500.00
1,000.00
500.00
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

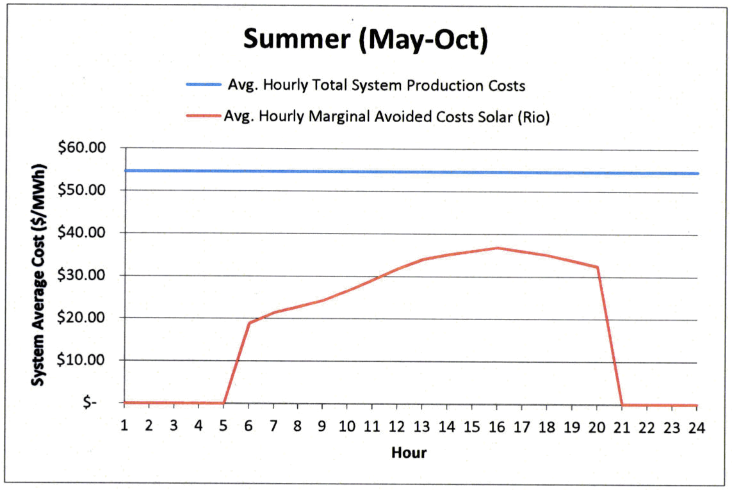
Exhibit HEO-3

LA SENITA


Summer (May-Oct)
Avg. Hourly Total System Production Costs
Avg. Hourly Marginal Avoided Costs Solar
System Average Cost ($/MWh)
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour


Winter (Sep-Apr)
Avg. Hourly Total System Production Costs
Avg. Hourly Marginal Avoided Costs Solar
System Average Cost ($/MWh)
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

RIO RICO


Summer (May-Oct)
Avg. Hourly Total System Production Costs
Avg. Hourly Marginal Avoided Costs Solar (Rio)
System Average Cost ($/MWh)
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

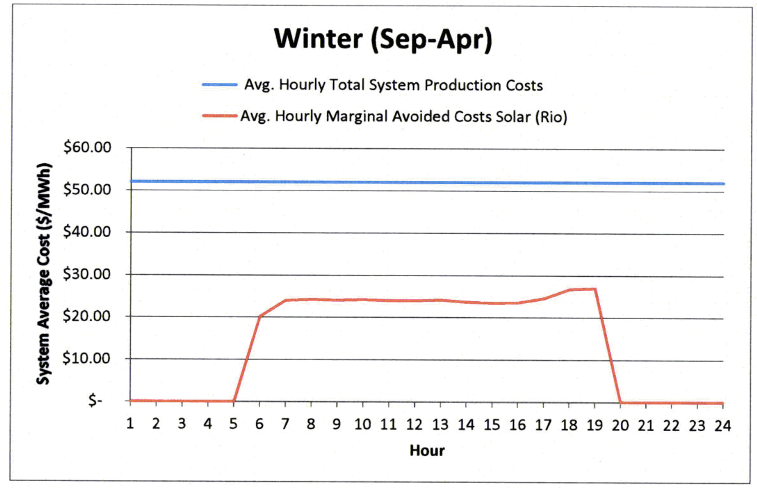
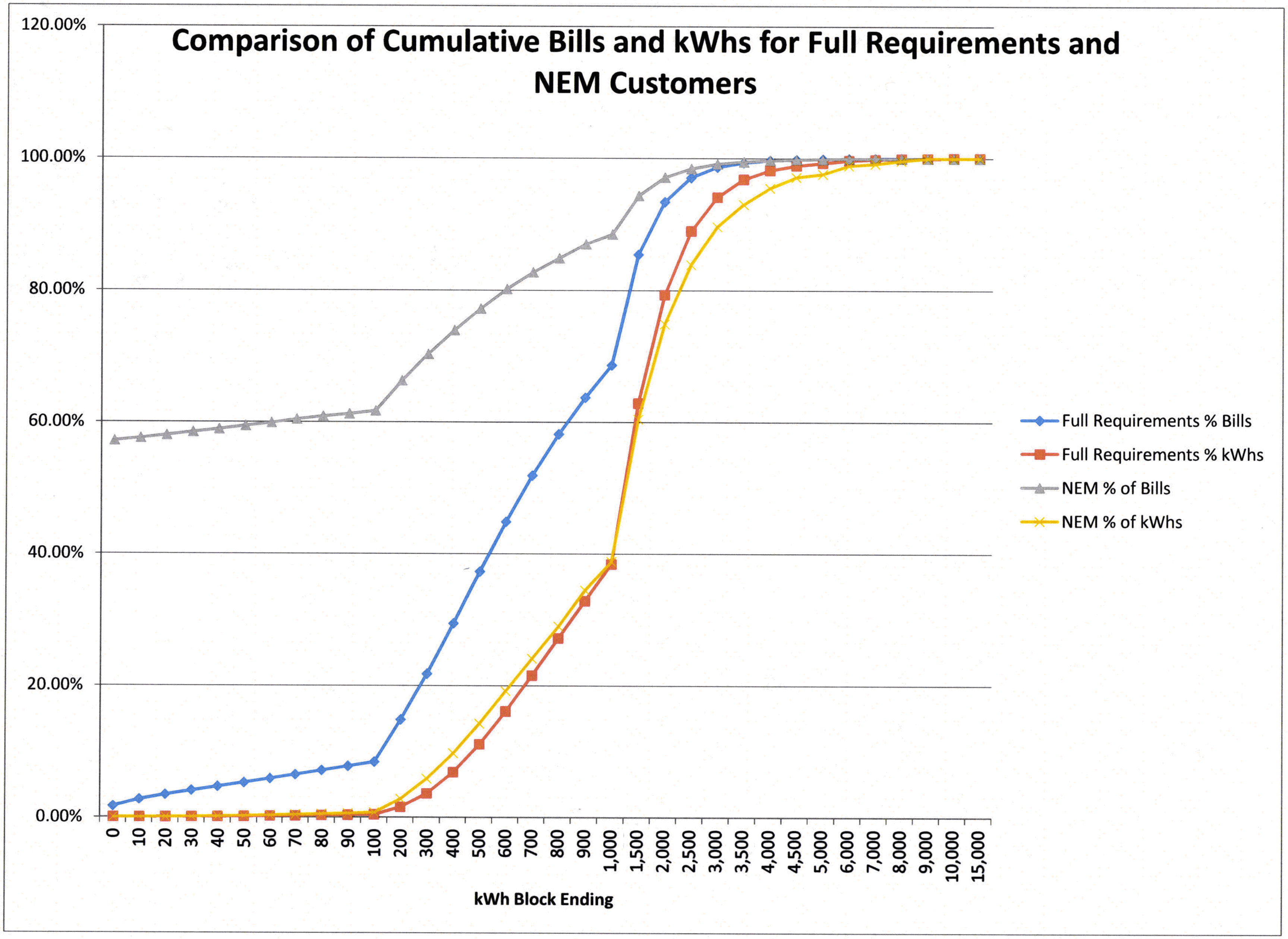

Winter (Sep-Apr)
Avg. Hourly Total System Production Costs
Avg. Hourly Marginal Avoided Costs Solar (Rio)
System Average Cost ($/MWh)
$60.00
$50.00
$40.00
$30.00
$20.00
$10.00
$-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Hour

Exhibit HEO-4



Comparison of Cumulative Bills and kWhs for Full Requirements and NEM Customers
120.00%
100.00%
80.00%
60.00%
40.00%
20.00%
0.00%
0
10
20
30
40
50
60
70
80
90
100
200
300
400
500
600
700
800
900
1,000
1,500
2,000
2,500
3,000
3,500
4,000
4,500
5,000
6,000
7,000
8,000
9,000
10,000
15,000
kWh Block Ending
Full Requirements % Bills
Full Requirements % kWhs
NEM % of Bills
NEM % of kWhs

Exhibit HEO-5

Make Free Demand Work For You

For the past five years, Butler REC has had a demand based rate. We thought it would be good to have a review on how you can take advantage of the rate to help save on your electric bill. The rate includes both a demand and an energy rate, thereby sending a price signal to the customer about these costs.

Back in 2009 we took the energy charge and divided it into energy and demand. We lowered the energy part of the bill by approximately 20 percent and moved that amount to a $5 per kW demand that is billed based on maximum hourly usage between 5 and 8 p.m. on weekdays. This design was based on feedback from our customer surveys, which showed a desire to have more control of your electric costs. Here is a quick review of the basics.

What is demand?

Electric demand refers to the maximum amount of electrical power that is being consumed at a given time, as opposed to energy which is the amount of power used over a period of time. For example, a typical clothes iron requires, or demands, 1,000 watts of power. If that iron is used for one hour it consumes 1,000 watt-hours or one kilowatt-hour of energy.

Using multiple appliances at the same time increases your demand. A typical dishwasher has a demand of 1,200 watts. If you used the dishwasher at the same time as the clothes iron, the total demand for these two appliances would be 1,000 watts plus 1,200 watts or 2,200 watts. If, instead, you choose to operate these at separate times, the maximum demand for these two appliances would only be 1,200 watts.

We have always had a demand charge. Historically, demand-related costs were included in the energy rate charged per kWh to residential and small commercial members. This was partially due to the higher cost of metering equipment required to measure demand. Members had no reason to reduce their demand as there was no immediate financial incentive.

With Butler's automated metering system, demand readings are readily available for residential and small commercial members. So historically you've always paid for the demand incurred by the cooperative, but now it will appear as a separate line item on your bill.

How is Demand Determined for residential and small commercial service?

As you are aware, you currently have a demand component on your bill, but how is demand determined?

Demand is FREE on weekdays any time prior to 5 p.m. and after 8 p.m. In addition to that, demand is FREE on weekends and most major holidays. This FREE demand has no effect on the minimum or billing demands mentioned later in this article. The demand you are billed for is determined by your highest hourly usage on weekdays between the hours of 5 p.m. and 8 p.m.

How is the Minimum Demand Determined?

The minimum demand is determined by taking 70 percent of the highest monthly demand of either July or August. The minimum demand is in effect for the months of September through June.

How is Demand Determined Throughout the Year?

- In July and August, the billing demand will be the highest hourly demand during the weekday peak hours (5 p.m. to 8 p.m.).
- For the months of September through June the billing demand will be the greater of:
  - The minimum demand, which is 70 percent of the highest monthly demand from the prior July and August billing demand, or
  - The highest hourly demand during the weekday peak hours (5 p.m. to 8 p.m.) of the current month.

	Monthly Demand, kW	70 percent of Prior July/Aug Monthly Demand, kW	Billing Demand, kW
January	**6.2**	4.6	6.2
February	**6.3**	4.6	6.3
March	4.5	**4.6**	4.6
April	3.9	**4.6**	4.6
May	3.2	**4.6**	4.6
June	**6.1**	4.6	6.1
July	**6.6**		6.6
August	**6.2**		6.2
September	4.4	**4.6**	4.6
October	4.1	**4.6**	4.6
November	**5.6**	4.6	5.6
December	**6.5**	4.6	6.5

How is Billing Demand Determined?

Now that we know how your monthly demand and minimum demand are calculated we can determine the billing demand. For the months of July and August you are billed for your actual monthly demand. For the months of September through June we compare the actual monthly demand to your minimum demand. Whichever one is higher will be your billing demand.

Why July and August are important and how can I lower my bill?

From our example above we know that July and August will set our minimum demand for the rest of the year. So our goal is to manage our demand and take advantage of the FREE demand.

Your home's heating and cooling make up the majority of your bill. We are not asking you to do without cooling or heating your home, we just want you to be aware of the time frame and manage your home's energy consumption during that time.

Remember, you get FREE demand until 5 p.m. and after 8 p.m. on weekdays and all day on weekends and most major holidays. Operating appliances such as your dishwasher, oven, washer, and dryer outside of the time frame of 5 p.m. to 8 p.m. will help to lower your demand charge. If we can reduce this demand, we can reduce our annual cost of purchased power. This reduction in demand will help to keep future costs and rates down, as well as delay the need to build new generating plants.

How do I know what my household demand is?

The demand for a typical residential service ranges from five to 10 kW. **You can monitor your demand by clicking the Hourly Usage icon on the home page.** If you do not have internet access, the cooperative staff can provide you with your own historical demand. This will give you an idea on how you use electricity during the month.

What can I do to reduce my demand?

During times of peak demand, here are simple steps you can take to reduce electricity demand:

- Run large appliances such as washing machines, clothes dryers, and dishwashers outside the time frame of 5 p.m. to 8 p.m. on weekdays.
- Use the microwave or convection oven instead of the oven or range whenever possible.
- Run your electrically heated aboveground pool pump for just 12 hours per day (between the hours of 10 p.m. and 10 a.m.) instead of around the clock.
- Turn off all of the unnecessary lights around your home.
- Set the thermostat on the water heater to a lower temperature during the summer, such as 120 degrees.
- Use compact fluorescent light bulbs–they use 75 percent less electricity and last 10 times longer.
- When properly set, your programmable thermostat can help reduce your heating and cooling cost by up to 10 percent.
- Use ceiling fans to help circulate the cool air and make you feel cooler when you are in a room. In the summer the blades should rotate to move the air down to help produce a cooling breeze. In the winter, air should be moved upwards towards the ceiling to disperse the warm air that tends to accumulate there and distribute more evenly in the room.
- If you replace your refrigerator with an energy efficient one, properly dispose of the old one instead of continuing to use it as a secondary refrigerator. If you do use the old one, avoid keeping it on in the garage or other locations that get hot and humid. The refrigerator has to work harder in these areas to keep cool.
- Use and outdoor clothesline to dry items instead of your dryer. It will save you money and make your clothes smell great.

These are just some examples of ways to manage your demand. If you have more questions, call the office at 316-321-9600.

Manager's Report - December 2014

Your Holiday Refund is on its Way!

I hope you and your family had a great Thanksgiving and are looking forward to the Christmas season. It can be a wonderful time for families, but it can also be a time of sadness for those who have lost loved ones this past year. I hope you will join me in trying to be an encouragement for those individuals.

Great News–Holiday Refund is on it's Way!

We have some great news for you as a member of Butler REC. As a cooperative our objective is to run as efficiently as possible and only charge enough to operate and keep our mortgage obligations. So I am happy to tell you that you will be seeing a holiday refund on the bill you receive later this month. It should be one of the largest holiday refunds that we have given in Butler REC's history.

Several factors have made this refund possible. First, many of you conserved during the 5 to 8 p.m. peak times and that helped lower the cooperative's power cost. Those of you who participated saw immediate bill reductions, but it also helped our power cost overall. Those savings combined with Kansas Electric Power Cooperative (KEPCo), our power supplier, refinancing some of their debt at better terms, created more margins than we needed this year.

We also had a very good year with our propane division even though we executed several changes during the year to help propane customers save during what was one of the most volatile propane pricing years in history. When propane prices reached close to $5 per gallon, we waved the standard minimum gallon requirements in an attempt to help our customers get by until prices came down to a more reasonable level.

This fall we came out with prepay contracts well below what most of the competitors offered. We had an overwhelming number of you switch to our prepaid contracts for this winter.

So Merry Christmas and happy New Year from Butler REC, Regional Energy and Regional Media. We hope this holiday refund will help make your families holidays a little brighter.

Cost of Service Study

As you heard last month, it has been almost five years since our last rate adjustment and we are looking at a cost of service study. We are not planning on a rate increase for residential and most commercial members, but we are looking at a small increase in the customer and demand charge with a corresponding decrease in the kWh charge. In other words, this won't change the power costs of the average member in these classes. This will help make your electric bill less susceptible to extremely hot summers or cold winters.

2015 Budget & Work Plans

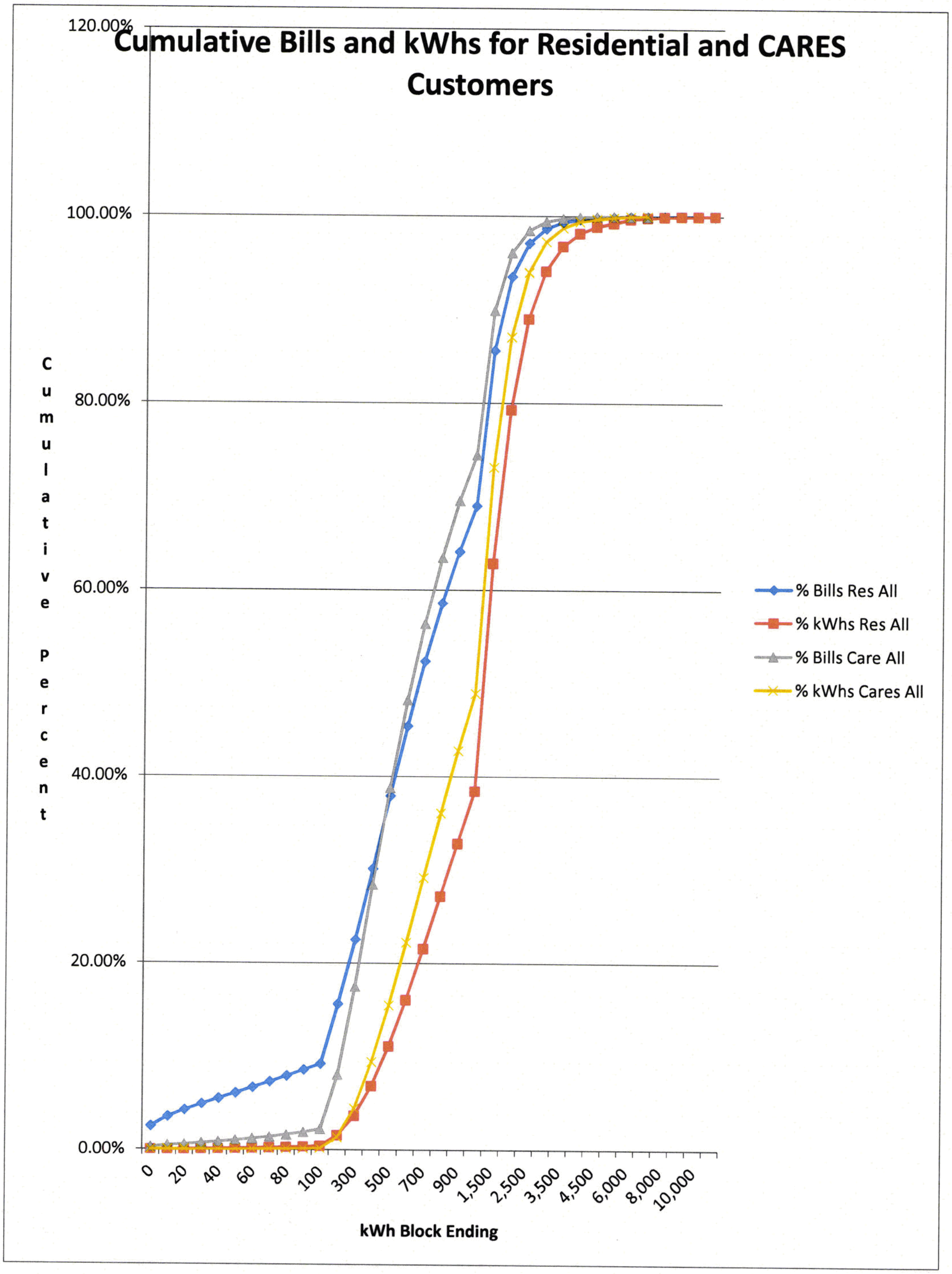
The co-op staff and Board of Trustees are currently working on the 2015 Budget and Work Plans. Items of importance that we are discussing include peaking generators, which could help our wholesale power cost and renewable generation including community solar and roof top projects. In addition, we are considering a residential insulation program that may help lower your power bill more than the cost of financing the insulation over time and, of course, the possibility of expanded right-of-way maintenance to help with reliability and blinking problems.

In closing, from all of us here at Butler REC have a great holiday season and a wonderful new year.

Robert "Dale" Short

Submitted by Butler REC on Fri, 2014/12/05 - 10:57am

Exhibit HEO-6


Cumulative Bills and kWhs for Residential and CARES Customers
Cumulative percent
120.00%
100.00%
80.00%
60.00%
40.00%
20.00%
0.00%
0
20
40
60
80
100
300
500
700
900
1,500
2,500
3,500
4,500
6,000
8,000
10,000
kWh Block Ending
% Bills Res All
% kWhs Res All
% Bills Care All
% kWhs Cares All

Rebuttal Testimony of
Denise A. Smith

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE – INTERIM CHAIRMAN
BOB STUMP
BOB BURNS
TOM FORESE
VACANT

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

Rebuttal Testimony of

Denise A. Smith

on Behalf of

UNS Electric, Inc.

January 19, 2016

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V. Additional Minor Modifications to Rules and Regulations....................8

Exhibits:

DAS-R-1 Clean version of additional modifications of Rules and Regulations

DAS-R-2 Redlined version of addition modifications of Rules and Regulations

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Denise A. Smith. My business address is 88 E. Broadway Blvd., Tucson, Arizona 85702.

Q. Did you submit Direct Testimony on behalf of UNS Electric, Inc. ("UNS Electric" or "Company") in this Docket?

A. Yes.

Q. Have you reviewed the Direct Testimonies filed by the Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission"), the Arizona Community Action Association ("ACAA") and Southwest Energy Efficiency Project ("SWEEP")?

A. Yes, I have.

Q. What subject matter do you cover in your Rebuttal Testimony?

A. I address: (i.) the positions of Staff and the ACAA regarding the proposed changes to the Rules and Regulations ("Rules"); (ii.) the concerns raised by the ACAA regarding deposits, CARES and Warms Spirits; (iii.) the concerns raised by SWEEP regarding Energy Efficiency ("EE"); and (iv.) the need for additional proposed modifications to the Rules.

II. <u>RESPONSE TO STAFF.</u>

Q. Do you agree with Staff's recommendations regarding the Rules?

A. The Company agrees to the following Staff recommendations without modification:

- At the end of Subsection 10.H. add "For Customers who choose to not have an automated meter installed or wish to replace an automated meter with a non-transmitting meter, the Special Meter Reading Fee will be a monthly recurring charge. The Automated Meter Opt-Out Set-Up Fee will only apply to those Customers who request the removal of an automated meter." The charge will also be reflected in the Statement of Charges.
- At the end of Subsection 11.I.6. add "listed in the Statement of Charges."

The Company agrees to the following Staff recommendations with minor modifications:

- Staff recommends adding "by the Company" to the end of Subsection 11.L.2. The Company recommends modifying this statement to "by the Company or its Agent" because the Company employs an outside credit and collections agency.
- Staff recommends adding language to the end of Subsection 4.A.6. that states, "This charge will only apply to customers who request this information more than once in a 12-month period". The Company recommends modifying this statement to "This charge will apply for each interval history request made or when Customers request their consumption history more than once in a 12-month period." This change is needed to clarify each additional request after the first annual request is assessed an administrative fee. The fee would not apply to future customer data available through the web or mobile devices.

The Company does not agree to the following Staff recommendation:

- Staff recommends that UNS Electric's proposed Subsection 12.H. not be approved for inclusion in its Rules. Subsection 12.H. provides that for customers who provide documentation certifying that they depend on electricity to power a life-sustaining medical device or if their medical condition warrants continuous electrical service and they accumulate a three (3) month bill, the customer will have the load limited to their premise in lieu of a disconnection of service. Load limiting would not necessarily be used only for customers with medical device alerts. It is a technology which could also be used at times of the year when extreme weather conditions might preclude service from being completely shut off. With respect to customers having a medical device or condition requiring continuous electricity, they are not exempt from disconnection for non-payment. Furthermore, no customer is guaranteed continuous electric service (e.g. storm-caused outage). For that reason, in the pamphlet provided to a customer to have a medical device alert placed on their account includes a signed statement by the physician indicating they have discussed contingency plans with their patient/our customer should the power go out. Another sentence in the pamphlet clearly states a medical device alert is not a discount program or a guarantee of uninterrupted service. In lieu of disconnecting service, limiting the amount of electricity into a home to provide ample power to operate a medical device and basic appliances - such as refrigeration, water supply, lighting, and small motors in the heating and cooling systems - should cause customers relief knowing regardless of the financial status of the utility account, service will not be interrupted by the utility.

Q. Are there any other issues that you would like to address from Staff's testimony?

A. Yes. The Direct Rate Design Testimony of Eric Van Epps recommends that the Company provide a draft Plan of Administration ("POA") for the DSM adjuster in the Company's rebuttal testimony. Following discussions to clarify Staff's request for a POA and what additional data is to be included, the Company will draft a POA that is consistent with A.A.C. R14-2-2401 *et seq.*, Electric Energy Efficiency Standards. Due to the nature of the request and timing associated with the development of the POA, the Company will provide a draft POA prior to the hearing in this matter.

III. RESPONSE TO ACAA.

Q. Do you agree with the ACAA's recommendations regarding holding harmless CARES customers from the modifications in UNS Electric's Rules regarding deposits?

A. No, and the Company further wishes to clarify that UNS Electric is not proposing to assess "additional" deposit amounts. Establishment or re-establishment of deposits occurs when customers demonstrate a repeated failure to pay their bill, or evidence is produced suggesting the probability a customer will not pay. If/when certain factors make it challenging for a customer to pay a bill and/or deposit, it is brought to UNS Electric's attention and every attempt will be made to provide a workable solution. These solutions may include referrals to assistance agencies, payment arrangements, or simply granting of extra time. UNS Electric has a long-standing history of working directly with individual customers to successfully meet their payment obligations. In 2015, UNS Electric granted 14,066 payment extensions to customers based on stated need.

Q. Do you agree with the ACAA's recommendations regarding not requiring a deposit when a customer files bankruptcy?

A. No, the United States Bankruptcy Code (Title 11, Chapter 3, Section 366) requires utilities to assess a deposit on post-petition accounts in order to furnish necessary assurance of payment. Furthermore, the language added to Subsection 3.B.3. of the Rules is consistent with ACC-approved Arizona Public Service Company ("APS") Schedule 2.7.6.1. Moreover, the assessment of deposits reduces instances of bad debt which all customers then must pay, regardless of bankruptcy.

Q. Do you agree with the ACAA's recommendations to add bill assistance and other related information to the disconnect notice?

A. Yes, the Company supports Ms. Zwick's request to add information to our Disconnect Notices notifying customers of agencies providing bill assistance opportunities in their area and information about weatherization agencies and information about the CARES discount. These changes will be incorporated as part of an upcoming bill redesign project.

Q. Does the Company support reallocating 10% of the Warm Spirits funding to agencies for program delivery?

A. The Company would be willing to allocate 10% of its matching funds for program delivery. All funding from customer donations, however, must be passed along to customers in need according to the information customers receive regarding their contributions to the Warm Spirits program ("100% of your contribution is passed along to customers in need").

Q. Ms. Zwick is concerned with the CARES program outreach. Please explain UNS Electric's current outreach methods to increase participation in the CARES program?

A. UNS Electric Customer Service Representatives distribute information on local assistance agencies when customers express an inability to pay their bill. The Company runs CARES informational campaigns for UNS Electric throughout the service areas that include bill inserts, advertising in newspapers and radio, social media posts and stories in the Company's quarterly e-newsletter "PluggedIn". In 2015, the Company implemented additional outreach efforts in Nogales, the most financially burdened area in UNS Electric's service territory. The outreach included transit shelter ads, posters and flyers distributed at community centers and community events.

IV. RESPONSE TO SWEEP.

Q. Should the addition of new Demand Side Management (DSM) programs be considered in the current UNS Electric rate case as requested by SWEEP?

A. No, it is not necessary or appropriate to consider additional DSM programs in this rate proceeding. A new UNS Electric EE Implementation Plan was approved by the Commission in Docket No. E-04204A-14-0178, Decision No. 75297 (October 27, 2015). The Company recognizes that rate design changes considered in this proceeding may require the development of new DSM programs. Following established protocol, the Company will file such programs under a new EE Implementation Plan or on a stand-alone basis through a DSM docket.

Q. Are additional DSM programs necessary in order to enable UNS Electric to meet the Energy Efficiency Standard and Rule ("EEES")?

A. No, not at this time. This issue was also evaluated recently in Docket No. E-04204A-14-0178. UNS Electric, through the 2015/2016 EE Implementation Plan, applied for funding for those new programs and measures it deemed cost-effective, prudent and implementation ready. UNS Electric currently projects cumulative 2015 savings are within a percentage point of the 2015 cumulative EEES mark of 9.5% of the prior year's retail sales. Current progress toward the standard was made despite numerous regulatory challenges at the beginning of the EEES.

Q. Do you agree with SWEEP's proposal to recover funding of DSM programs through base rates?

A. No, the funding of DSM programs should continue to be recovered through the DSM surcharge and not through increasing the base rates. Recovering DSM related expenses through the DSM surcharge provides ratepayers with important transparency of the investment being made in energy efficiency programming. As the regulatory environment for EE continues to evolve with the Clean Power Plan the recovery of expenses should be made through a resource-based decision model and transparent.

Q. Does UNS Electric plan to provide customer education or programming for customers on three part rates?

A. Yes, UNS Electric will support customers on three-part rates with a combination of education, technology, and EE programs. Education and outreach activities would include printed/on-line materials and direct customer engagement. An outline of a customer communication plan is included in the rebuttal testimony of Dallas Dukes.

An example of a technology solution, would be demand control equipment to reduce peak demand and improve energy efficiency. The demand would be controlled at a level that the customer chooses. The equipment would stabilize electric use by managing equipment with thermal storage such as water heaters, air conditioners, hot tubs, etc. Electric loads like these can be turned off for small periods of time without effecting overall comfort or convenience.

The implementation of three-part rates provides more accurate price signals and gives the utility and customers expanded opportunities to implement EE measures. The vast majority if not all EE programs reduce demand. Demand reduction on the utility system has significant benefits to customers through reduced system costs

New demand-related DSM programs will be filed as part of a new EE Implementation Plan or on a stand-alone basis.

V. ADDITIONAL MINOR MODIFICATIONS TO RULES AND REGULATIONS.

Q. Why is the Company proposing additional minor modifications to the Rules?

A. Tucson Electric Power Company ("TEP") filed a rate case after UNS Electric filed this rate case. TEP proposed a few additional minor modifications to its Rules that were not included in the UNS Electric rate case. The Company would like to make a few minor modifications to the UNS Electric Rules to be consistent with TEP's Rules.

Q. What additional minor modifications to the Rules is the Company proposing?

A. There are four (4) minor modifications to the Rules the Company would like to make: (i.) Minor changes to Subsection 3.B.1.a. This is a non-substantive change; (ii.) Minor changes to Subsection 3.B.3. This is a non-substantive change; (iii.) Subsection 3.H. was deleted because it is not a current practice of the Company, and (iv.) Modifications to

Subsection 8.F.3. regarding the Company's liability. The current liability limitation language in Subsection 8.F.3. is focused on limitations on the Company's liability to customers for damages arising from the Company's provision of electric service. The language does not clearly address liability limitations related to third parties. The Arizona Court of Appeals recently addressed the appropriate scope of utility liability limitations and upheld limitations on utility liability to non-customers. Such a limitation acts to protect utility customers against undue expenses that may result in higher rates. Therefore, we are clarifying our liability limitation language in Section 8.F.3 to meet the ruling of the Court of Appeals and further protect our customers from potential liability to third-parties. The clean version of the additional modifications to the Rules is attached as **Exhibit DAS-R-1**. The redlined changes are attached as **Exhibit DAS-R-2**.

Q. Are there any other modifications to be made to the Rules?

A. Yes, there was an error made in Subsection 3.B.3. of the proposed UNS Electric redlined Rules. Due to an oversight, the language, "or more" was not deleted and should have been redlined in this Subsection. This is the same rule that was proposed in 3.B.1.a.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

Exhibit DAS-R-1

SECTION 3
ESTABLISHMENT OF SERVICE

A. Information from New Applicants

1. The Company may obtain the following minimum information from each application for service:

   a. Name or names of Applicant(s);

   b. Service address or location and telephone number;

   c. Billing address/telephone number, if different than service address;

   d. Social Security Number or Driver's License number and date of birth to be consistent with verifiable information on legal identification;

   e. Address where service was provided previously;

   f. Date Applicant will be ready for service;

   g. Statement of whether premises have been supplied with electric service previously;

   h. Purpose for which service is to be used;

   i. Statement of whether Applicant is owner or tenant of or agent for the premises;

   j. Information concerning the energy and demand requirements of the Customer; and

   k. Type and kind of life-support equipment, if any, used by the Customer or at the service address.

2. Where service is requested by two (2) or more individuals, the Company will have the right to collect the full amount owed to the Company from any one of the Applicants.

3. The supplying of electric service by the Company and the Customer's acceptance of that electric service will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's applicable Rates, and Rules and Regulations.

4. The term of any agreement not otherwise specified will become operative on the day the Customer's installation is connected to the Company's facilities for the purpose of taking electric energy.

5. The Company may require a written contract with special guarantees from Applicants whose unusual characteristics of load or location would require excessive investment in facilities or whose requirements for service are of a special nature.

6. Signed contracts may be required for service to commercial and industrial establishments. No contract or any modification of the contract will be binding upon the Company until executed by a duly authorized representative of the Company.

7. Where an occupant of the premises who owes a debt to the Company, but is not the Applicant or the Customer, the occupant shall also be jointly and severally liable for the bills rendered to the premises.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

B. Deposits

1. The Company may require from any present or prospective Customer a deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.3. below. Upon proper application by the Customer, the Company will then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company will be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for electric service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's electric service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest will accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company will not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service with the Company within the past two (2) years and was not delinquent in payment twice during the last twelve (12) consecutive months of service and was never disconnected for nonpayment; or

   b. The Applicant can produce a letter of credit or verification from an electric utility where service of a comparable nature was last received by Applicant, which states Applicant had a timely payment history at time of service discontinuation; or

   c. Instead of a deposit, the Company receives deposit guarantee notification from a social or governmental agency acceptable to the Company. A surety bond may be provided as security for the Company in an amount equal to the required deposit.

2. Cash deposits held by the Company twelve (12) months or longer will earn interest at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published in the Federal Reserve website.

3. Residential Customers – The Company may require a residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) bills or has been disconnected from service during the last twelve (12) months.

   Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account after twelve (12) consecutive months of service following full payment of deposit during which time the Customer has not been delinquent two (2) times or has not been disconnected for non-payment, unless the Customer has filed bankruptcy in the last twelve (12) months.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

4. Non-Residential Customers – The Company may require a non-residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) bills or if the Customer has been disconnected for non-payment during the last twelve (12) months, or when the Customer's financial condition may jeopardize the payment of their bill.

   Deposits and non-cash deposits on file with the Company will be reviewed after twenty-four (24) consecutive months of service and will be returned provided the Customer has not been delinquent two (2) times or disconnected for non-payment in the most recent twelve (12) month period, unless the Customer's financial condition warrants extension of the deposit.

5. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

6. A separate deposit may be required for each meter installed.

7. Residential Customer deposits will not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits will not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

8. The posting of a deposit will not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

C. Conditions for Supplying Service

The Company reserves the right to determine the conditions under which service will be provided. Conditions for service and extending service to the Customer will be based upon the following:

1. Customer has wired his premises in accordance with the National Electric Code, City, County and/or State codes, whichever are applicable.

2. If the Company determines that there is a reasonable basis to believe that the Customer's premises poses a safety risk to Company employees, then the Company may, at its option, install a meter or facilities with remote connect and/or disconnect capabilities.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Customer has installed the meter loop in a suitable location approved by the Company.

4. In the case of a mobile home, the meter loop must be attached to a meter pole or to an approved support.

5. In case of temporary construction service, the meter loop must be attached to an approved support.

6. All meter loop installations must be in accordance with the Company's specifications and located at an outdoor location accessible to the Company.

7. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper right-of-way locations.

8. Developers must have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

9. Where the installation requires more than one meter for service to the premises, each meter panel must be permanently marked (not painted) by the contractor or Customer to properly identify the portion of the premises being served.

10. The identification will be the same as the apartment, office, etc., served by that meter socket. The identifying marking placed on each meter panel will be impressed into or raised from a tab of aluminum, brass or other approved non-ferrous metal with minimum one-fourth (1/4) inch-high letters. This tag must be riveted to the meter panel. The impression must be deep enough to prevent the identification(s) from being obscured by subsequent painting of the building and attached service equipment.

11. The Company may require the assistance of the Customer and/or the Customer's contractor to open the apartments or offices at the time the meters are set, in order to verify that each meter socket actually serves the apartment or office indicated by the marking tag. In the case of multiple buildings the building or unit number and street address will be identified on the pull section in the manner described above.

D. Grounds for Refusal of Service

The Company may refuse to establish service if any of the following conditions exist:

1. When the Applicant or affiliate of the Applicant with common ownership has an outstanding amount due for the same class of electric service with the Company and the Applicant is unwilling to make arrangements with the Company for payment, in such cases, the Company shall be entitled to transfer the balance due or credit owed on the terminated service to any other active account of the Customer for the same class of service. The failure of the Customer to pay the active account shall result in the suspension or termination of service.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities;

3. The Applicant refuses to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements;

4. Customer is known to be in violation of the Company's Rates or Rules and Regulations;

5. Customer fails to furnish the funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service;

6. Customer fails to provide safe access to the meter that would be serving the Customer;

7. Applicant falsifies his or her identity for the purpose of obtaining service;

8. Service is requested by an Applicant and a prior Customer, who is either living with the Applicant, or who is an occupant of the premises who owes a debt to the Company from the same class of service from the same or a prior service address;

9. The Applicant is acting as an agent for a prior Customer who is deriving benefits from the energy supplied and who owes a delinquent bill from the same class of service from the same or a prior service address;

10. There is evidence of tampering or energy diversion.

11. Where the Company has a reasonable belief that the Applicant has common ownership with an affiliate that owes a delinquent bill for the same class of service.

E. Service Establishment, Reestablishment or Reconnection Charge

1. The Company will make a charge, as approved by the ACC, for service transfer for meter reads only set forth as Fee No. 1 in the UNS Electric Statement of Charges.

2. The Company may make a charge, as approved by the ACC, for the establishment, reestablishment, or reconnection of service. The charge for establishment, reestablishment or reconnection of service during regular business hours is set forth as Fee No. 4 in the UNS Electric Statement of Charges.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Should service be established, reestablished or reconnected during a period other than the Company's regular business hours, at the Customer's request, the Customer may be required to pay an after-hour charge for the service connection set forth as Fee No. 5 in the UNS Electric Statement of Charges. Where the Company's scheduling will not permit service establishment, reestablishment or reconnection of service on the same day as requested, the Customer can elect to pay the after-hour charge for establishment that day, or service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment, reestablishment or reconnection of service outside of regular business hours.

4. For the purpose of this Rule, the definition of service establishment is where the Customer's facilities are ready and acceptable to the Company, the Applicant has obtained all required permits and/or inspections indicating that the Applicant's facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

5. Service Reconnection Charge

   Whenever the Company has discontinued service under its usual operating procedures because of any default by the Customer as provided herein, a reconnection charge, not to exceed the charge for the reestablishment of service as set forth as Fee Nos. 4-5 in the UNS Electric Statement of Charges, shall be made and may be collected by the Company before service is restored. When, due to the behavior of the Customer, it has been necessary to discontinue service utilizing other than usual operating procedures, the Company shall be entitled to charge Fee No. 6 to restore service, as set forth in the UNS Electric Statement of Charges.

F. Temporary Service

1. Applicants for temporary service may be required to pay Line Extension charges in accordance with Section 7.C.9.d.

2. Where the duration of service is to be less than one (1) month, the Applicant will also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1. above.

4. If at any time during the term of the agreement for service the character of a temporary Customer's operations changes so that, in the opinion of the Company, the Customer is classified as permanent, the terms of the Company's Line Extension rules will apply.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

G. **Identification of Load and Premises**

Upon request of the Company, the electric load and premises to be served by the Company must be clearly identified by the Customer at the time of application. If the service address is not recognized in terms of commonly used identification system, the Customer may be required to provide specific written directions and/or legal descriptions before the Company will be required to act upon a request for electric service.

H. Tampering With or Damaging Company Equipment

1. The Customer agrees, when accepting service, that no one except authorized Company employees or agents of the Company will be allowed to remove or replace any Company owned equipment installed on Customer's property.

2. No person, except an employee or agent acting on behalf of the Company shall alter, remove or make any connection to the Company's meter or service equipment.

3. No meter seal may be broken or removed by anyone other than an employee or agent acting on behalf of the Company; however, the Company may give its prior consent to break the seal by an approved electrician employed by a Customer when deemed necessary by the Company.

4. The Customer will be held responsible for any broken seals, tampering, or interfering with the Company's meter(s) or any other Company owned equipment installed on the Customer's premises. In cases of tampering with meter installations, interfering with the proper working thereof, or any tampering, interfering, theft, or service diversion, including the falsification of Customer read-meter readings, Customer will be subject to immediate discontinuance of service. The Company will be entitled to collect from the Customer or other person benefitting from the service, under the appropriate Rate, for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also additional security deposits as well as all expenses incurred by the Company for property damages, investigation of the illegal act, and all legal expenses and court costs incurred by the Company.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

5. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or wrongful act or omission on the part of any Customer's agents, employees, licensees or contractors.

I. Access

1. The Customer is responsible for providing safe access to Company facilities. The Company's authorized agents shall have satisfactory unassisted twenty-four (24) hour a day, seven (7) days a week access to the Company's equipment located on Customer's premise for the purpose of service connection, service disconnection, operation, maintenance, repair and service restoration work that the Company may need to perform.

2. If additional resources are required to gain safe access to perform service establishment, disconnection, meter reading, or routine maintenance, due to an affirmative, wrongful, and/or criminal act by the Customer, the Company will be entitled to collect from the Customer all expenses incurred by the Company for additional resources including: investigation of access, all legal expenses, and court costs.

J. Customer-Specific Information

Customer-specific information shall not be released without specific prior Customer authorization unless the information is requested by law enforcement or other public agency, or is requested by the Commission or its staff, or is reasonably required for legitimate account collection activities, or is necessary to provide safe and reliable service to the Customer. Such Customer authorization may be obtained electronically, in writing, or orally, as long as the oral authorization is recorded.

SECTION 8
PROVISION OF SERVICE

A. Company Responsibility

1. The Company will be responsible for the safe transmission and distribution of electricity until it passes the point of delivery to the Customer.

2. The Company will be responsible for maintaining in safe operating condition all meters, equipment and fixtures installed on the Customer's premises by the Company for the purpose of delivering electric service to the Customer. However, the Company will not be responsible for the condition of meters, equipment, and fixtures damaged or altered by the Customer.

3. The Company may, at its option, refuse service until the Customer has obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction and safety standards, including any applicable Company specifications.

4. The Company will determine, in its sole discretion, the type of service (including voltage and Point of Delivery) to be furnished for utilization by the Customer. This includes determinations involving: 1) requirements to take Primary Service and Metering; and 2) service voltage (including for any new on-site generation installations or generation retrofits at the Customer's premises).

B. Customer Responsibility

1. Each Customer will be responsible for maintaining in safe operating condition all Customer facilities on the Customer's side of the point of delivery.

2. Each Customer will be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying electric service to that Customer.

3. Each Customer will exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer will be responsible for loss of or damage to Company property on the Customer's premises arising from neglect, carelessness, misuse, diversion, or tampering and will reimburse the Company for the cost of necessary repairs or replacements.

4. Each Customer will be responsible for payment for any equipment damage and/or estimated unmetered usage and all reasonable costs resulting from unauthorized breaking of seals, interfering, tampering or bypassing the Company meter.

5. Each Customer will be responsible for notifying the Company of any equipment failure identified in the Company's equipment.

SECTION 8
PROVISION OF SERVICE
(continued)

6. Each Customer will be responsible for informing the Company of, and meeting the Company's requirements regarding on-site or distributed generation (including distributed renewable resources and combined heat and power facilities) that the Customer or the Customer's agent intends to interconnect to the Company's transmission or distribution system. This includes compliance with all requirements contained within the Company's most current Interconnection Requirements for Distributed Generation, and the terms and conditions of the Company's Agreement for the Interconnection of Customer's Facility. Customer must also agree to enter into the Interconnection Agreement with the Company. Further, any interconnection must be in accordance with any applicable Commission regulation and order governing interconnection, as well as applicable laws.

7. The Customer, at his expense, may install, maintain and operate check-measuring equipment as desired and of a type approved by the Company, provided that this equipment will be installed so as not to interfere with operation of the Company's equipment. This is also provided that no electric energy will be remetered or submetered for resale to another or to others, except where such remetering will be done in accordance with the applicable orders of the Commission.

C. Continuity of Service

The Company will make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company will not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:

1. Any cause against which the Company could not have reasonably foreseen, or made provision for (*i.e* force majeure, see Subsection 8.E.);

2. Intentional service interruptions to make repairs or perform routine maintenance; or

3. Curtailment, including brownouts or blackouts.

D. Service Interruptions

1. The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

SECTION 8
PROVISION OF SERVICE
(continued)

3. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company will attempt to inform affected Customers at least twenty-four (24) hours in advance of the scheduled date and these repairs will be completed in the shortest possible time to minimize the inconvenience to the Customers of the Company.

4. The Commission will be notified of interruption in service affecting the entire system or any significant portion thereof. The interruption of service and cause will be reported by telephone to the Commission within four (4) hours after the responsible Company representative becomes aware of said interruption. A written report to the Commission will follow.

E. Interruption of Service and Force Majeure

1. The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 8.E.4. and 8.E.5. or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission, or distribution equipment, or to eliminate the possibility of damage to the Company's property or to the person or property of others.

2. Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this limitation or interruption will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

3. The use of electric energy upon the Customer's premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

4. Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

   a. flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

   b. accident or explosion;

   c. war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

   d. acts of God;

   e. interference of civil and/or military authorities;

SECTION 8
PROVISION OF SERVICE
(continued)

f. strikes, lockouts, or other labor difficulties;

g. vandalism, sabotage, or malicious mischief;

h. usurpation of power, or the laws, rules, regulations, or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

i. breakage or accidents to equipment or facilities;

j. lack, limitation or loss of electrical or fuel supply; or

k. any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

5. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

6. Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

F. General Liability

1. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

2. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

3. Except in the case of the Company's willful misconduct or gross negligence, the Company will not be liable to Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) for the period of service interruption.

SECTION 8
PROVISION OF SERVICE
(continued)

4. In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

5. The Company will not be responsible in an occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

G. Construction Standards and Safety

The Company will construct all facilities in accordance with the provisions of the ANSI C2 Standards (National Electric Safety Code, 2007 edition, and other amended editions as are adopted by the ACC), the 2007 ANSI B31.1 Standards, the ASME Boiler and Pressure Vessel Code, and other applicable American National Standards Institute Codes and Standards, except for those changes the ACC makes or permits from time to time. In the case of conflict between codes and standards, the more rigid code or standard will apply.

Exhibit DAS-R-2

SECTION 3
ESTABLISHMENT OF SERVICE

A. Information from New Applicants

1. The Company may obtain the following minimum information from each application for service:

   a. Name or names of Applicant(s);

   b. Service address or location and telephone number;

   c. Billing address/telephone number, if different than service address;

   d. Social Security Number or Driver's License number and date of birth to be consistent with verifiable information on legal identification;

   e. Address where service was provided previously;

   f. Date Applicant will be ready for service;

   g. Statement of whether premises have been supplied with electric service previously;

   h. Purpose for which service is to be used;

   i. Statement of whether Applicant is owner or tenant of or agent for the premises;

   j. Information concerning the energy and demand requirements of the Customer; and

   k. Type and kind of life-support equipment, if any, used by the Customer or at the service address.

2. Where service is requested by two (2) or more individuals, the Company will have the right to collect the full amount owed to the Company from any one of the Applicants.

3. The supplying of electric service by the Company and the Customer's acceptance of that electric service will be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for electric service under the Company's applicable Rates, and Rules and Regulations.

4. The term of any agreement not otherwise specified will become operative on the day the Customer's installation is connected to the Company's facilities for the purpose of taking electric energy.

5. The Company may require a written contract with special guarantees from Applicants whose unusual characteristics of load or location would require excessive investment in facilities or whose requirements for service are of a special nature.

6. Signed contracts may be required for service to commercial and industrial establishments. No contract or any modification of the contract will be binding upon the Company until executed by a duly authorized representative of the Company.

7. Where an occupant of the premises who owes a debt to the Company, but is not the Applicant or the Customer, the occupant shall also be jointly and severally liable for the bills rendered to the premises.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

B. Deposits

1. The Company may require from any present or prospective Customer a deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.3. below. Upon proper application by the Customer, the Company will then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company will be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for electric service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's electric service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest will accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company will not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service~~ of a comparable nature~~ with the Company within the past two (2) years and was not delinquent in payment twice during the last twelve (12) consecutive months of service and~~or~~ was never~~not~~ disconnected for nonpayment; or

   b. The Applicant can produce a letter of credit or verification from an electric utility where service of a comparable nature was last received by Applicant, which states Applicant had a timely payment history at time of service discontinuation; or

   c. Instead of a deposit, the Company receives deposit guarantee notification from a social or governmental agency acceptable to the Company. A surety bond may be provided as security for the Company in an amount equal to the required deposit.

2. Cash deposits held by the Company twelve (12) months or longer will earn interest at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published in the Federal Reserve website.

3. Residential Customers – The Company may require a residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) ~~or more~~ bills or has been disconnected from service during the last twelve (12) months.

   Deposits or other instruments of credit will automatically expire or be refunded or credited to the Customer's account after twelve (12) consecutive months of service following full payment of deposit during which time the Customer has not been delinquent two (2) times or has not been disconnected for non-payment, unless the Customer has filed bankruptcy in the last twelve (12) months.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

4. Non-Residential Customers – The Company may require a non-residential Customer to establish or reestablish a deposit if the Customer becomes delinquent in the payment of two (2) bills or if the Customer has been disconnected for non-payment during the last twelve (12) months, or when the Customer's financial condition may jeopardize the payment of their bill.

   Deposits and non-cash deposits on file with the Company will be reviewed after twenty-four (24) consecutive months of service and will be returned provided the Customer has not been delinquent two (2) times or disconnected for non-payment in the most recent twelve (12) month period, unless the Customer's financial condition warrants extension of the deposit.

5. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

6. A separate deposit may be required for each meter installed.

7. Residential Customer deposits will not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits will not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

8. The posting of a deposit will not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.

C. Conditions for Supplying Service

The Company reserves the right to determine the conditions under which service will be provided. Conditions for service and extending service to the Customer will be based upon the following:

1. Customer has wired his premises in accordance with the National Electric Code, City, County and/or State codes, whichever are applicable.

2. If the Company determines that there is a reasonable basis to believe that the Customer's premises poses a safety risk to Company employees, then the Company may, at its option, install a meter or facilities with remote connect and/or disconnect capabilities.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Customer has installed the meter loop in a suitable location approved by the Company.

4. In the case of a mobile home, the meter loop must be attached to a meter pole or to an approved support.

5. In case of temporary construction service, the meter loop must be attached to an approved support.

6. All meter loop installations must be in accordance with the Company's specifications and located at an outdoor location accessible to the Company.

7. Individual Customers may be required to have their property corner pins and/or markers installed to establish proper right-of-way locations.

8. Developers must have all property corner pins and/or markers installed necessary to establish proper locations to supply electric service to individual lots within subdivisions.

9. Where the installation requires more than one meter for service to the premises, each meter panel must be permanently marked (not painted) by the contractor or Customer to properly identify the portion of the premises being served.

10. The identification will be the same as the apartment, office, etc., served by that meter socket. The identifying marking placed on each meter panel will be impressed into or raised from a tab of aluminum, brass or other approved non-ferrous metal with minimum one-fourth (1/4) inch-high letters. This tag must be riveted to the meter panel. The impression must be deep enough to prevent the identification(s) from being obscured by subsequent painting of the building and attached service equipment.

11. The Company may require the assistance of the Customer and/or the Customer's contractor to open the apartments or offices at the time the meters are set, in order to verify that each meter socket actually serves the apartment or office indicated by the marking tag. In the case of multiple buildings the building or unit number and street address will be identified on the pull section in the manner described above.

D. Grounds for Refusal of Service

The Company may refuse to establish service if any of the following conditions exist:

1. When the Applicant or affiliate of the Applicant with common ownership has an outstanding amount due for the same class of electric service with the Company and the Applicant is unwilling to make arrangements with the Company for payment, in such cases, the Company shall be entitled to transfer the balance due or credit owed on the terminated service to any other active account of the Customer for the same class of service. The failure of the Customer to pay the active account shall result in the suspension or termination of service.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities;

3. The Applicant refuses to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements;

4. Customer is known to be in violation of the Company's Rates or Rules and Regulations;

5. Customer fails to furnish the funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service;

6. Customer fails to provide safe access to the meter that would be serving the Customer;

7. Applicant falsifies his or her identity for the purpose of obtaining service;

8. Service is requested by an Applicant and a prior Customer, who is either living with the Applicant, or who is an occupant of the premises who owes a debt to the Company from the same class of service from the same or a prior service address;

9. The Applicant is acting as an agent for a prior Customer who is deriving benefits from the energy supplied and who owes a delinquent bill from the same class of service from the same or a prior service address;

10. There is evidence of tampering or energy diversion.

11. Where the Company has a reasonable belief that the Applicant has common ownership with an affiliate that owes a delinquent bill for the same class of service.

E. Service Establishment, Reestablishment or Reconnection Charge

1. The Company will make a charge, as approved by the ACC, for service transfer for meter reads only set forth as Fee No. 1 in the UNS Electric Statement of Charges.

2. The Company may make a charge, as approved by the ACC, for the establishment, reestablishment, or reconnection of service. The charge for establishment, reestablishment or reconnection of service during regular business hours is set forth as Fee No. 4 in the UNS Electric Statement of Charges.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

3. Should service be established, reestablished or reconnected during a period other than the Company's regular business hours, at the Customer's request, the Customer may be required to pay an after-hour charge for the service connection set forth as Fee No. 5 in the UNS Electric Statement of Charges. Where the Company's scheduling will not permit service establishment, reestablishment or reconnection of service on the same day as requested, the Customer can elect to pay the after-hour charge for establishment that day, or service will be established on the next available business day. Even so, a Customer's request to have the Company establish service after-hours is subject to the Company having Staff available; there is no guarantee that the Company will have the staffing available for service establishment, reestablishment or reconnection of service outside of regular business hours.

4. For the purpose of this Rule, the definition of service establishment is where the Customer's facilities are ready and acceptable to the Company, the Applicant has obtained all required permits and/or inspections indicating that the Applicant's facilities comply with local construction safety and governmental standards and regulations, and the Company needs only to install a meter, read a meter, or turn the service on.

5. Service Reconnection Charge

   Whenever the Company has discontinued service under its usual operating procedures because of any default by the Customer as provided herein, a reconnection charge, not to exceed the charge for the reestablishment of service as set forth as Fee Nos. 4-5 in the UNS Electric Statement of Charges, shall be made and may be collected by the Company before service is restored. When, due to the behavior of the Customer, it has been necessary to discontinue service utilizing other than usual operating procedures, the Company shall be entitled to charge Fee No. 6 to restore service, as set forth in the UNS Electric Statement of Charges.

F. Temporary Service

1. Applicants for temporary service may be required to pay Line Extension charges in accordance with Section 7.C.9.d.

2. Where the duration of service is to be less than one (1) month, the Applicant will also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1. above.

4. If at any time during the term of the agreement for service the character of a temporary Customer's operations changes so that, in the opinion of the Company, the Customer is classified as permanent, the terms of the Company's Line Extension rules will apply.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

G. Identification of Load and Premises

Upon request of the Company, the electric load and premises to be served by the Company must be clearly identified by the Customer at the time of application. If the service address is not recognized in terms of commonly used identification system, the Customer may be required to provide specific written directions and/or legal descriptions before the Company will be required to act upon a request for electric service.

~~H. Identification of Responsible Party~~

~~Any person applying on behalf of another Customer for service to be connected in the name of or in care of another Customer must furnish to the Company written approval from that Customer guaranteeing payment of all bills under the account. The Customer is responsible in all cases for service supplied to the premises until the Company has received proper notice of the effective date of any change. The Customer shall also promptly notify the Company of any change in physical or electronic billing address.~~

H~~I~~. Tampering With or Damaging Company Equipment

1. The Customer agrees, when accepting service, that no one except authorized Company employees or agents of the Company will be allowed to remove or replace any Company owned equipment installed on Customer's property.

2. No person, except an employee or agent acting on behalf of the Company shall alter, remove or make any connection to the Company's meter or service equipment.

3. No meter seal may be broken or removed by anyone other than an employee or agent acting on behalf of the Company; however, the Company may give its prior consent to break the seal by an approved electrician employed by a Customer when deemed necessary by the Company.

4. The Customer will be held responsible for any broken seals, tampering, or interfering with the Company's meter(s) or any other Company owned equipment installed on the Customer's premises. In cases of tampering with meter installations, interfering with the proper working thereof, or any tampering, interfering, theft, or service diversion, including the falsification of Customer read-meter readings, Customer will be subject to immediate discontinuance of service. The Company will be entitled to collect from the Customer or other person benefitting from the service, under the appropriate Rate, for all power and energy not recorded on the meter as the result of such tampering, or other theft of service, and also additional security deposits as well as all expenses incurred by the Company for property damages, investigation of the illegal act, and all legal expenses and court costs incurred by the Company.

SECTION 3
ESTABLISHMENT OF SERVICE
(continued)

5. The Customer will be held liable for any loss or damage occasioned or caused by the Customer's negligence, want of proper care or wrongful act or omission on the part of any Customer's agents, employees, licensees or contractors.

I~~J~~. Access

1. The Customer is responsible for providing safe access to Company facilities. The Company's authorized agents shall have satisfactory unassisted twenty-four (24) hour a day, seven (7) days a week access to the Company's equipment located on Customer's premise for the purpose of service connection, service disconnection, operation, maintenance, repair and service restoration work that the Company may need to perform.

2. If additional resources are required to gain safe access to perform service establishment, disconnection, meter reading, or routine maintenance, due to an affirmative, wrongful, and/or criminal act by the Customer, the Company will be entitled to collect from the Customer all expenses incurred by the Company for additional resources including: investigation of access, all legal expenses, and court costs.

J~~K~~. Customer-Specific Information

Customer-specific information shall not be released without specific prior Customer authorization unless the information is requested by law enforcement or other public agency, or is requested by the Commission or its staff, or is reasonably required for legitimate account collection activities, or is necessary to provide safe and reliable service to the Customer. Such Customer authorization may be obtained electronically, in writing, or orally, as long as the oral authorization is recorded.

SECTION 8
PROVISION OF SERVICE

A. Company Responsibility

1. The Company will be responsible for the safe transmission and distribution of electricity until it passes the point of delivery to the Customer.

2. The Company will be responsible for maintaining in safe operating condition all meters, equipment and fixtures installed on the Customer's premises by the Company for the purpose of delivering electric service to the Customer. However, the Company will not be responsible for the condition of meters, equipment, and fixtures damaged or altered by the Customer.

3. The Company may, at its option, refuse service until the Customer has obtained all required permits and/or inspections indicating that the Customer's facilities comply with local construction and safety standards, including any applicable Company specifications.

4. The Company will determine, in its sole discretion, the type of service (including voltage and Point of Delivery) to be furnished for utilization by the Customer. This includes determinations involving: 1) requirements to take Primary Service and Metering; and 2) service voltage (including for any new on-site generation installations or generation retrofits at the Customer's premises).

B. Customer Responsibility

1. Each Customer will be responsible for maintaining in safe operating condition all Customer facilities on the Customer's side of the point of delivery.

2. Each Customer will be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying electric service to that Customer.

3. Each Customer will exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer will be responsible for loss of or damage to Company property on the Customer's premises arising from neglect, carelessness, misuse, diversion, or tampering and will reimburse the Company for the cost of necessary repairs or replacements.

4. Each Customer will be responsible for payment for any equipment damage and/or estimated unmetered usage and all reasonable costs resulting from unauthorized breaking of seals, interfering, tampering or bypassing the Company meter.

5. Each Customer will be responsible for notifying the Company of any equipment failure identified in the Company's equipment.

SECTION 8
PROVISION OF SERVICE
(continued)

6. Each Customer will be responsible for informing the Company of, and meeting the Company's requirements regarding on-site or distributed generation (including distributed renewable resources and combined heat and power facilities) that the Customer or the Customer's agent intends to interconnect to the Company's transmission or distribution system. This includes compliance with all requirements contained within the Company's most current Interconnection Requirements for Distributed Generation, and the terms and conditions of the Company's Agreement for the Interconnection of Customer's Facility. Customer must also agree to enter into the Interconnection Agreement with the Company. Further, any interconnection must be in accordance with any applicable Commission regulation and order governing interconnection, as well as applicable laws.

7. The Customer, at his expense, may install, maintain and operate check-measuring equipment as desired and of a type approved by the Company, provided that this equipment will be installed so as not to interfere with operation of the Company's equipment. This is also provided that no electric energy will be remetered or submetered for resale to another or to others, except where such remetering will be done in accordance with the applicable orders of the Commission.

C. Continuity of Service

The Company will make reasonable efforts to supply a satisfactory and continuous level of service. However, the Company will not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from:

1. Any cause against which the Company could not have reasonably foreseen, or made provision for (*i.e* force majeure, see Subsection 8.E.);

2. Intentional service interruptions to make repairs or perform routine maintenance; or

3. Curtailment, including brownouts or blackouts.

D. Service Interruptions

1. The Company will make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

SECTION 8
PROVISION OF SERVICE
(continued)

3. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company will attempt to inform affected Customers at least twenty-four (24) hours in advance of the scheduled date and these repairs will be completed in the shortest possible time to minimize the inconvenience to the Customers of the Company.

4. The Commission will be notified of interruption in service affecting the entire system or any significant portion thereof. The interruption of service and cause will be reported by telephone to the Commission within four (4) hours after the responsible Company representative becomes aware of said interruption. A written report to the Commission will follow.

E. Interruption of Service and Force Majeure

1. The Company will make reasonable provision to supply a satisfactory and continuous electric service, but does not guarantee a constant or uninterrupted supply of electricity. The Company will not be liable for any damage or claim of damage attributable to any temporary, partial or complete interruption or discontinuance of electric service attributable to a force majeure condition as set forth in Subsections 8.E.4. and 8.E.5. or to any other cause which the Company could not have reasonably foreseen and made provision against, or which, in the Company's judgment, is necessary to permit repairs or changes to be made in the Company's electric generating, transmission, or distribution equipment, or to eliminate the possibility of damage to the Company's property or to the person or property of others.

2. Whenever the Company deems a condition exists that warrants interruption or limitation in the service being rendered, this limitation or interruption will not constitute a breach of contract and will not render the Company liable for damages suffered thereby or excuse the Customer from further fulfillment of the contract.

3. The use of electric energy upon the Customer's premises is at the risk of the Customer. The Company's liability will cease at the point where its facilities are connected to the Customer's wiring.

4. Neither the Company nor the Customer will be liable to the other for any act, omission, or circumstances (including, but not limited to, the Company's inability to provide electric service) occasioned by or in consequence of the following:

   a. flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements;

   b. accident or explosion;

   c. war, rebellion, civil disturbance, mobs, riot, blockade or other act of the public enemy;

   d. acts of God;

   e. interference of civil and/or military authorities;

SECTION 8
PROVISION OF SERVICE
(continued)

f. strikes, lockouts, or other labor difficulties;

g. vandalism, sabotage, or malicious mischief;

h. usurpation of power, or the laws, rules, regulations, or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect;

i. breakage or accidents to equipment or facilities;

j. lack, limitation or loss of electrical or fuel supply; or

k. any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by exercise of due diligence the Company or the Customer is unable to overcome.

5. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees will not be considered to be a matter within the control of the Company.

6. Nothing contained in this Section will excuse the Customer from the obligation of paying for electricity delivered or services rendered.

F. General Liability

1. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's electric services, unless such claims are caused by the Company's willful misconduct or gross negligence.

2. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any wrongful or negligent acts or omissions of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

3. Except in the case of the Company's willful misconduct or gross negligence, ~~The liability of~~ the Company will not be liable to Customer or any other party for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of, or related to, establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment, except that for an interruption of service to a Customer, to the extent resulting from error, mistake, omission, interruption or delay by the Company, the Company's liability, if any, to the Customer -shall not exceed an amount equal to the charges for service applicable under the Company's Rates (calculated on a proportionate basis where appropriate) ~~to~~for the period of service interruption. ~~during which the error, mistake, omission, interruption or delay occurs, except if such damages are caused by the Company's willful misconduct or gross negligence.~~

SECTION 8
PROVISION OF SERVICE
(continued)

4. In no event will the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

5. The Company will not be responsible in an occasion for any loss or damage caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any electric facilities.

G. Construction Standards and Safety

The Company will construct all facilities in accordance with the provisions of the ANSI C2 Standards (National Electric Safety Code, 2007 edition, and other amended editions as are adopted by the ACC), the 2007 ANSI B31.1 Standards, the ASME Boiler and Pressure Vessel Code, and other applicable American National Standards Institute Codes and Standards, except for those changes the ACC makes or permits from time to time. In the case of conflict between codes and standards, the more rigid code or standard will apply.