ORIGINAL

0000168732

RECEIVED
2016 FEB 29 P 3:46
AZ CORP COMMISSION
DOCKET CONTROL

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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 REJOINDER TESTIMONY**

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

RESPECTFULLY SUBMITTED this 29th day of February, 2016.

UNS ELECTRIC, INC.

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

and

Arizona Corporation Commission
DOCKETED
FEB 29 2016
DOCKETED BY

Michael W. Patten
Jason D. Gellman
Snell & Wilmer L.L.P.
One Arizona Center
400 East Van Buren Street
Phoenix, Arizona 85004

Attorneys for UNS Electric, Inc.

Original and 13 copies of the foregoing filed this 29th day of February 2016, with:

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

Copies of the foregoing hand-delivered this 29th day of February 2016, to:

Jane Rodda, Administrative Law Judge
Hearing Division
Arizona Corporation Commission
400 West Congress
Tucson, Arizona 85701

Brian E. Smith
Bridget A. Humphrey
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Thomas Broderick, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copy of the foregoing mailed and/or emailed this 29th day of February 2016, to:

Daniel Pozefsky
Residential Utility Consumer Office
1110 West Washington Street, Ste. 220
Phoenix, Arizona 85007
dpozefsky@azruco.com
Consented To Service By Email

Nucor Steel Kingman LLC
c/o Doug Adams
3000 W. Old Hwy 66
Kingman, Arizona 86413

Eric J. Lacey
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson Street, NW
8th Floor, West Tower
Washington DC 20007-5201
EJL@smxblaw.com
Consented To Service By Email

Robert J. Metli
Munger Chadwick PLC
2398 East Camelback Road, Suite 240
Phoenix, Arizona 85016
rjmetli@mungerchadwick.com
Consented To Service By Email

Lawrence V. Robertson, Jr.
P.O. Box 1448
Tubac, Arizona 85646
tubaclawyer@aol.com

Court S. Rich
Rose Law Group pc
7144 E. Stetson Drive, Suite 300
Scottsdale, Arizona 85251
crich@roselawgroup.com
Consented To Service By Email

Thomas A. Loquvam
Melissa M. Krueger
Pinnacle West Capital Corporation
P.O. Box 53999, MS 8695
Phoenix, Arizona 85072-3999
Thomas.loquvam@pinnaclewest.com
Melissa.Krueger@pinnaclewest.com
Consented To Service By Email

Gregory Bernosky
Arizona Public Service Company
P.O. Box 53999. MS 9712
Phoenix, Arizona 85072-3999
gregory.bernosky@aps.com

Rick Gilliam
Director of Research and Analysis
The Vote Solar Initiative
1120 Pearl Street, Suite 200
Boulder, Colorado 80302
rick@votesolar.com
Consented To Service By Email

Briana Kobor, Program Director
Vote Solar
360 22nd Street, Suite 730
Oakland, CA 94612
briana@votesolar.com
Consented To Service By Email

Jill Tauber
Chinyere A. Osula
Earthjustice Washington, DC Office
1625 Massachusetts Avenue, NW, Suite 702
Washington, DC 20036-2212
jtauber@earthjustice.org
Consented To Service By Email

Ken Wilson
Western Resource Advocates
2260 Baseline Road, Suite 200
Boulder, Colorado 80302
ken.wilson@westernresources.org
Consented To Service By Email

Scott Wakefield
Hienton & Curry, P.L.L.C.
5045 N. 12th Street, Suite 110
Phoenix, Arizona 85014-3302

Steve W. Chriss
Senior Manager, Energy Regulatory Analysis
Wal-Mart Stores, Inc.
2011 S.E. 10th Street
Bentonville, AR 72716-0550
Stephen.Chriss@wal-mart.com

Timothy M. Hogan
Arizona Center for Law in the Public Interest
514 W. Roosevelt Street
Phoenix, Arizona 85003
thogan@aclpi.org
Consented To Service By Email

Michael Alan Hiatt
Katie Dittelberger
Earthjustice
633 17th Street, Suite 1600
Denver, Colorado 80202
mhiatt@earthjustice.com
kdittelberger@earthjustice.com
Consented To Service By Email

Jeff Schlegel
SWEEP Arizona Representative
1167 W. Samalayuca Dr.
Tucson, Arizona 85704
schlegelj@aol.com

Ellen Zuckerman
SWEEP Senior Associate
4231 E. Catalina Dr.
Phoenix, Arizona 85018
ezuckerman@swenergy.org

C. Webb Crockett
Patrick Black
Fennemore Craig, PC
2394 East Camelback Road, Suite 600
Phoenix, Arizona 85016
wcrockett@fclaw.com
pblack@fclaw.com
Consented To Service By Email

Kevin Higgins
Energy Strategies, LLC
215 South State Street, Suite 200
Salt Lake City, Utah 84111
khiggins@energystrat.com

Meghan H. Grabel
Osborn Maladon, PA
2929 North Central Avenue
Phoenix, Arizona 85012
mgrabel@omlaw.com
Consented To Service By Email

Gary Yaquinto, President & CEO
Arizona Investment Council
2100 North Central Avenue, Suite 210
Phoenix, Arizona 85004
gyaquinto@arizonaaic.org
Consented To Service By Email

Cynthia Zwick
Arizona Community Action Association
2700 North 3rd Street, Suite 3040
Phoenix, Arizona 85004
czwick@azcaa.org
Consented To Service By Email

Craig A. Marks
Craig A. Marks, PLC
10645 N. Tatum Blvd., Suite 200-676
Phoenix, Arizona 85028
craig.marks@azbar.org
Consented To Service By Email

Pat Quinn
President and Managing Partner
Arizona Utility Ratepayer Alliance
5521 E. Cholla Street
Scottsdale, Arizona 85254
patt.quinn47474@gmail.com

Jeffrey W. Crockett
Crockett Law Group PLLC
2198 East Camelback Road, Suite 305
Phoenix, Arizona 85016
jeff@jeffcrockettlaw.com
Consented To Service By Email

Kirby Chapman, CPA
Chief Financial and Administrative Officer
Sulphur Springs Valley Electric Cooperative, Inc.
311 E. Wilcox
Sierra Vista, Arizona 85650
kchapman@ssvec.com
Consented To Service By Email

Mark Holohan, Chairman
Arizona Solar Energy Industries Association
2122 W. Lone Cactus Dr., Suite 2
Phoenix, Arizona 85027

Garry D. Hays
Law Offices of Garry D. Hays, PC
2198 East Camelback Road, Suite 305
Phoenix, Arizona 85016
ghays@lawgdh.com

Vincent Nitido
Trico Electric Cooperative, Inc.
8600 West Tangerine Road
Marana, Arizona 85653
vnitido@trico.coop

Jason Y. Moyes
Jay I. Moyes
Moyes Sellers & Hendricks
1850 N. Central Ave., Suite 1100
Phoenix, Arizona 85004
jasonmoyes@law-msh.com
kes@drsaline.com
jimoyes@law-msh.com
Consented To Service By Email

By Jaclyn Howard

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Rejoinder Testimony of

David G. Hutchens

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

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 Blvd., Tucson, Arizona, 85701.

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes. I filed both.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my testimony is to generally comment on the Surrebuttal Testimonies filed in this proceeding. A number of the parties put forth positions that do not take into consideration the overall public interest that the Commission must consider in deciding the issues in this case.

Q. How do you believe that the Commission can best ensure that the public interest is served in this proceeding?

A. The public interest can best be served through rates that support the availability of safe, reliable and affordable electric service. To achieve these objectives, UNS Electric has focused on efficient operations while seeking to secure only the most cost-effective energy resources to serve customers' energy needs. The Company also must effectively manage the growth of demand during peak usage periods to limit the costs that must be passed along to customers. The rates proposed in this proceeding, including the three-part rates developed for residential customers, are designed from the ground up to support these efforts. For this reason and many others, the approval of the Company's proposal would serve the public interest.

Q. How would the public interest be served by the use of three-part rates for residential customers?

A. Utility rate design should serve the public interest. Customers rightly expect, that their utilities and the regulators who oversee them have provided them with a fair price – one that reflects their appropriate share of the costs that underlie their service.

In other words, our customers are trusting us to get rate design right. And as testimony in this case has made clear, the continued use of two-part rates with a low fixed charge would not reflect the best interest of customers or the utility's ability to recover the costs of providing safe, reliable service.

Residential customers' total consumption is no longer a fair proxy for the cost that utilities like UNS Electric must incur to serve them. There was a time when it was close enough, but that was before rooftop solar arrays, robust energy efficiency measures, and other new technologies reshaped the landscape for residential electric service.

We have always known that utility service costs are driven in large part by demand. This is particularly true in Arizona, where our infrastructure must have the capacity to provide reliable service on the hottest days of the year (even if those days happen to be cloudy).

Customers should be billed based on rates that reflect the cost of service. They should be told what really affects their bills, even if some parties to this case claim they won't be able to understand it. The overall public interest should be put ahead of special interests that seek to bend rate design to their own purposes.

Q. Would customers have difficulty understanding three-part rates?

A. Three-part rates are no more confusing for customers than our current rates, which include multiple tiers, charges that change with the seasons and an alphabet soup of acronyms. I'm also confident that customers will find them less confusing once parties in this matter stop spreading misleading statements about them. I've seen our proposed demand charge described as a fine or extra charge designed to penalize our customers. Such misleading statements cloud the understanding of a concept – electric demand – that clearly plays a critical role in determining the costs of providing electric service.

Energy demand is not overly difficult to understand, particularly in the context of other charges on customers' bills. The Company is committed to a comprehensive communications campaign that will educate customers about our new rates and provide information for managing their electric demand. It will be far easier to manage peak hourly energy use under our proposed rates than it has been for customers to determine when their monthly consumption reaches a level subject to higher per-kWh charges under a traditional tiered rate structure.

Customers who choose to do so will find it easy enough to understand our proposed rates. Our focus, though, should be on approving fair and accurate rates that recover costs appropriately from all customers.

Q. Would three-part rates increase costs for UNS Electric customers?

A. No. In the short term, the proposed rates are designed to be revenue neutral for UNS Electric. Over the long term, though, three-part rates would likely lead to *lower* costs for our customers. By providing more accurate price signals regarding the true cost of demand, three-part rates would give residential customers a good reason to reduce their peak hourly energy use during high usage periods. This, in turn, would reduce UNS Electric's need for system investments far more effectively than reductions in kWh consumption, which are the only savings incentivized under current two-part rates. Reducing the Company's need for system investments ultimately would lead to lower rates for our customers, a clear benefit to the public interest.

Q. How would three-part rates affect UNS Electric's service reliability?

A. Residential rates with a demand component would provide customers with a clear incentive to use less energy during periods of peak electric demand. If they respond to these accurate price signals, their reduced usage would relieve pressure on transformers, conductors and other key system components that can be subject to failure during peak load or overload conditions. In this way, three-part rates would contribute positively to the reliability of the Company's service, providing another reason why their approval would serve the public interest.

Q. Some providers of distributed generation (DG) solar power systems claim three-part rates would discourage the use of renewable energy resources in UNS Electric's service territory. Is that true?

A. Not at all. By reducing embedded subsidies for DG systems, our proposed rates and net metering revisions would redirect investment to more cost-effective community-scale systems that provide greater benefits shared by all customers. Rooftop systems would remain an affordable option for customers committed to providing a portion of their own energy from the sun. In fact, our proposed rates would give customers a chance to reduce their impact on both the environment *and* their neighbors' utility bills. While this might not serve the business interests of some Intervenors in this matter, it most definitely would serve the public interest.

Q. How might the Company's proposed rates affect the local economy in UNS Electric's service territory?

A. Keeping our rates as affordable as possible is the best contribution we can make to our local economy. Our proposal would accomplish that objective in part by reducing the subsidies embedded in our current rates that lead to higher costs for customers. Traditional two-part rates with a low fixed-cost component charge too high a price for energy while ignoring the cost of demand – the factor that more directly drives the need for system improvements and higher rates. This, in turn, has created unduly generous incentives for DG solar systems and other strategies that reduce kWh consumption without meaningful, reliable reductions in peak usage. Sending more accurate price signals will result in more effective energy management strategies that reduce, rather than increase, costs for customers.

Some Intervenors in this proceeding have adopted a more self-interested economic development strategy that calls for the preservation of current subsidies for solar DG systems. While their singular focus is understandable, given their business model, the economic development efforts of entire communities should not be compromised by electric rates held artificially high to promote a single industry. Like any regulated utility, UNS Electric's success is determined by the economic well-being of the communities it serves. That's why our proposal – including our proposed economic development rate – are designed to provide broad benefits to all customers and, as such, would serve the public interest.

Q. Why has your Rejoinder Testimony focused so intently on the public interest?

A. I want to make sure we don't lose sight of our obligations to customers in this increasingly crowded and contentious docket. Many of the parties who have intervened in this matter have no real interest in the bills our customers pay. Rather, they hope to use this proceeding as a proxy for an industry debate that has filled the pages of trade journals, driven up consulting fees and influenced stock prices. We must remain focused on the true purpose of this proceeding: approving rates that fairly reflect our prudently incurred costs and provide solid support for our continued efforts to provide safe, reliable and affordable service to customers. That remains our first and only priority and the best way to ensure that the public interest is served.

Q. Do you have any additional comments?

A. No.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Rejoinder Testimony of

Kentton C. Grant

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

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 and Rebuttal Testimony in this proceeding?

A. Yes.

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

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

Q. Which Intervenors' testimony do you address in your Rejoinder Testimony?

A. My Rejoinder Testimony addresses the testimonies of Robert B. Mease and Jeffrey Michlik filed on behalf of the Residential Utility Consumer Office ("RUCO"). Specifically, I discuss the Company's position with respect to Mr. Mease's revised estimates for the cost of equity and the rate of return on fair value rate base, which is commonly referred to as the fair value rate of return ("FVROR"). Additionally, I address his offer to consider recommending a 9.50% cost of equity and the adoption of Staff's FVROR, subject to UNS Electric limiting its rate increase no more than $15.1 million. With respect to Mr. Michlik's testimony, I reiterate the Company's earlier response to his rejection of UNS Electric's proposed property tax deferral, as well as his treatment of the costs that will be incurred by UNS Electric in its appeal of property tax values for Gila River Unit 3.

II. RESPONSE TO SURREBUTTAL TESTIMONY OF RUCO WITNESS ROBERT B. MEASE.

Q. Did Mr. Mease revise his recommended cost of equity and FVROR in his Surrebuttal Testimony?

A. Yes. Mr. Mease revised his original cost of equity estimate of 8.35% to an updated value of 9.13%. Consequently, the weighted average cost of capital (WACC) recommended by Mr. Mease increased from 6.61% to 7.02%. He then subtracted an inflation rate of 1.54%, revised upward from the previous rate of 1.35%, to arrive at a FVROR 5.48%. The following table summarizes the changes made to the WACC and FVROR in Mr. Mease's Surrebuttal Testimony:

	Direct Testimony	Surrebuttal Testimony
WACC	6.61%	7.02%
Inflation Adjustment	-1.35%	-1.54%
FVROR	5.26%	5.48%

Q. What is the Company's position with respect to Mr. Mease's revised cost of equity and FVROR?

A. As described in the Rejoinder Testimony of UNS Electric witness Ann Bulkley, the revised estimate of 9.13% for the Company's cost of equity is still too low. Additionally, UNS Electric still takes issue with the methodology used by Mr. Mease in calculating his recommended FVROR. Although this methodology was adopted several years ago in a prior rate order for UNS Electric, the use of an explicit inflation adjustment to derive the FVROR is seriously flawed from both a theoretical and practical perspective.

Q. Did Mr. Mease express a willingness to recommend a higher cost of equity and the adoption of Staff's FVROR?

A. Yes. On page 21 of his Surrebuttal Testimony, lines 4-6, Mr. Mease states that RUCO would consider recommending Staff's cost of common equity of 9.50% provided "the overall revenue requirement is not greater than $15.1 million." Additionally, on page 22, lines 15-20, Mr. Mease references RUCO's potential acceptance "of the cost of equity and fair value adjustment." Although he does not explicitly reference the 5.63% FVROR recommended in Staff's Surrebuttal Testimony, he implies that RUCO would be willing to recommend that value if the Company's revenue increase is capped at $15.1 million.

Q. How was the value of $15.1 million derived by RUCO?

A. While it was not explicitly laid out in RUCO's Surrebuttal Testimony, it is my understanding that RUCO subtracted an additional $260,000 of operating expenses from the $15,360,000 non-fuel revenue increase recommended in Staff's Surrebuttal Testimony. Staff's revised non-fuel revenue increase is discussed in the Surrebuttal Testimony of Staff witness Donna H. Mullinax (see page 5, lines 5-9, and Attachment DHM-1, line 6). As discussed by Ms. Mullinax, Staff's revised rate increase of $15.4 million resulted from a number of relatively minor adjustments that increased the overall non-fuel revenue deficiency to $18.5 million from Staff's original value of $18.1 million. Based on the recommendation of Staff witness Barbara Keane, the $18.5 million revenue deficiency was then reduced by $3.1 million due to the revised treatment of the deferred costs associated with Gila River Unit 3.

Q. What is the Company's position with respect to the $15.1 million rate increase referenced by Mr. Mease?

A. While UNS Electric does not agree in principle with the additional operating expense adjustments recommended by RUCO, the Company would be willing to stipulate to a

$15.1 million non-fuel revenue increase, and the related treatment of deferred Gila River Unit 3 costs, as long as the Company is provided with a reasonable opportunity to actually earn a 9.50% return on equity. This means that the rate design approved for UNSE must actually be capable of generating the targeted level of non-fuel revenues, setting aside normal variations due to weather conditions and sales mix. From the Company's perspective, continued reliance on an outdated rate design, coupled with a continuation of the current net metering rules, would not give UNS Electric a reasonable opportunity to earn its allowed return on equity.

III. <u>RESPONSE TO SURREBUTTAL TESTIMONY OF RUCO WITNESS JEFFREY MICHLIK.</u>

Q. Does Mr. Michlik still reject the Company's proposed property tax deferral described in the Direct Testimony of UNS Electric witness Jason Rademacher?

A. Yes.

Q. Does Mr. Michlik also continue to propose that UNS Electric forego future rate recovery of 50% of the costs that will be incurred to appeal property tax values for Gila River Unit 3?

A. Yes.

Q. Has the Company's position changed with respect to the proposed property tax deferral and future rate recovery of 100% of the costs of appealing property tax values for Gila River Unit 3?

A. No. UNS Electric still supports these proposals for full cost recovery. The rationale for the Company's position is described in the Rebuttal Testimony of UNS Electric witness Jason Rademacher. Additionally, it should be noted that from a financial perspective, a rejection of UNS Electric's proposals for property tax recovery would add yet another obstacle in the Company's effort to actually earn its allowed return on equity. Although the Company is accustomed to managing its costs carefully in order to earn its cost of capital, future changes in property tax rates are clearly beyond the control of UNS Electric, and the costs required to appeal the property tax valuation for a power plant can be quite large and often fall outside of an historical test year used in the rate setting process.

Q. Does this conclude your Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Rejoinder Testimony of

Ann E. Bulkley

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

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 and Rebuttal 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 Surrebuttal Testimonies of Mr. Robert B. Mease on behalf of the Residential Utility Consumer Office ("RUCO") and Dr. J. Randall Woolridge on behalf of The Alliance for Solar Choice ("TASC"), 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-1 through AEB-2, which have been prepared by me or under my direction.

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

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

- In Section II, I provide a summary and overview of my Rejoinder Testimony.
- In Section III, I respond to Mr. Mease's analyses and recommendations.
- In Section IV, I respond to Dr. Woolridge's analyses and recommendations.

II. RESPONSE TO THE REBUTTAL TESTIMONY OF RUCO WITNESS MEASE

Q. Please summarize the Surrebuttal Testimony of RUCO witness Mease.

A. Mr. Mease's Surrebuttal Testimony included updated DCF and CAPM analyses and a Comparable Earnings analysis. Based on the results of those analyses, Mr. Mease increased his recommended ROE from 8.35 percent to 9.13 percent. Mr. Mease accepts the Company's proposed capital structure which consists of 52.83 percent equity and 47.17 percent debt and the Company's 4.66 percent cost of debt. Separate from his updated analytical results, Mr. Mease states that RUCO would accept a 9.50 percent ROE assuming adoption of a certain revenue requirement..[1]

[1] Surrebuttal Testimony of Mr. Robert Mease, at 21-22.

Q. What is your response to Mr. Mease's recommended ROE?

A. Based on the results of the other analyses presented in my rebuttal testimony, I believe that a 9.50 percent ROE would represent the low end of the range of reasonable ROEs for UNS.

Q. Do you agree with the methodology used by Mr. Mease in the development of his updated Constant Growth DCF analysis?

A. Yes. Mr. Mease relies on 90-day average prices as of the end of January 2016 for a proxy group of twelve companies that is similar to the proxy group used in my rebuttal analysis. Mr. Mease relies on projected earnings per share growth rates from Value Line and Yahoo! Finance that are based on the analytical period that he relies on for historical prices. The range of results produced in this analysis is 8.33 percent to 10.12 percent, which overlaps the range of results presented in my Rebuttal Testimony using the Constant Growth DCF approach.

Q. Please summarize Mr. Mease's updated CAPM analysis.

A. Mr. Mease updated his CAPM analysis to reflect the proxy group change discussed previously. Mr. Mease presents two calculations of the historical Market Risk Premium ("MRP") in his CAPM analysis, the first is intended to be based on the geometric mean (Schedule RBM-6, page 1) and the section (Schedule RBM-6, page 2) based on the arithmetic mean. Mr. Mease relies on a risk free rate of 2.50 percent in his updated analysis. The beta used in his analysis is as published by Value Line. The results of these analyses are 7.07 percent and 6.84 percent respectively.

Q. Do you agree with Mr. Mease's updated CAPM analysis?

A. No, I do not. I believe that the use of a forward-looking estimate of the MRP is preferable to a historically calculated MRP for the reasons discussed in my Rebuttal Testimony. I also do not agree with the use of the geometric mean in the analysis. This issue has also been addressed in my Rebuttal Testimony.

In addition to the differences in opinion on the methodologies, discussed previously, I also disagree with the specific calculations of the CAPM that are presented in Schedule 6 pages 1 and 2 of Mr. Mease's Surrebuttal Testimony Specifically, I disagree with the calculation of the historical MRP using the arithmetic and geometric means, and the current risk-free rate.

Mr. Mease calculates the MRP as the difference between the total return on large company stocks and the total return on long-term corporate bonds. There are two errors in this calculation. First, Mr. Mease has relied on the total bond return, not the income only portion of that return. As discussed in my rebuttal testimony, Morningstar, the publisher of the data relied on by Mr. Mease in his calculation of the MRP, states that to calculate the equity risk premium, it is necessary to deduct the income only return on bonds from the total stock return not the total return on the bond. Morningstar notes that the total return includes the capital appreciation, the income and the capital.

The second error is that Mr. Mease's calculation relies on the total return on corporate bonds, not on government bonds. Mr. Mease provides the CAPM formula in his Schedule RDM-6. In that formula he notes that the MRP is calculated as the market return (r_m) less the risk-free rate (r_f). Corporate bonds are not risk free assets. Traditionally, the income only return on government bonds have been used as a proxy for a risk-free asset.

Q. Are there other errors in the calculation of the MRP as presented in Schedule RDM-6?

A. I believe so. Schedule RDM-6, page 1 indicates that it is the CAPM using the geometric mean in the calculation of the MRP. Assuming that Mr. Mease has relied on Morningstar as the source of his data for this analysis, which is the common source for the calculation of the historical MRP, the geometric mean return on large company stocks is reported to be 10.1 percent. Mr. Mease's analysis relies on a return of 12.0 percent.

Q. Is the current risk free rate relied on by Mr. Mease consistent with the rate used in his Direct Testimony?

A. No. In his Direct Testimony, Mr. Mease uses the yield on the 30-year Treasury bonds, noting that the long-term bonds were specifically used since this matches the long-term perspective of the cost of equity analyses.[2] In his rebuttal testimony, Mr. Mease relies on the three-month average yield on the 20-year Treasury bonds, of 2.50 percent.[3] As of January 29, 2016, which is the time period relied on for his DCF analysis, the three-month average yield on 30-year Treasury bonds was approximately 2.95 percent.

Q. Have you adjusted Mr. Mease's analysis for these recommended changes?

A. Yes, I have. As shown in Exhibit AEB-1, updating Mr. Mease's analysis to correct the calculation of the historical MRP and using the current risk-free rate results in a range of returns of 6.90 percent to 8.38 percent.

---

[2] Direct Testimony of Robert B. Mease, at 12.

[3] Yield curve provided by Robert B. Mease.

Q. Have you reviewed Mr. Mease's comparable earnings analysis?

A. Yes, I have.

Q. Do you typically rely on a comparable earnings analysis similar to what Mr. Mease has prepared?

A. No, I do not. The comparable earnings analysis prepared by Mr. Mease looks at the achieved return for the proxy companies over the period from 2002 through 2015 and estimates the return that will be achieved by those companies for three forward-looking time periods, 2016 and 2018 through 2020. Mr. Mease also calculates a return over the historical and projected time period.

The determination of the cost of equity in this proceeding is intended to be the return that is reasonable for UNS on a forward-looking basis. Therefore the historical actual returns over the last 14 years are not as significant as what investors are expecting for returns based on current and projected market conditions. However, as shown in Mr. Mease's schedule, the average return projected by AUS and Value Line for 2018-2020 is 9.50 percent.

Q. Do you agree with Mr. Mease's view on how the Commission should consider all analytical results presented in this case?

A. Mr. Mease states that no individual method provides an "exclusive foolproof formula for determining a fair return. In evaluating the cost of equity all relevant evidence should be used and weighted equally in order to minimize judgmental and measurement infirmities."[4]

---

[4] Surrebuttal Testimony of Robert B. Mease, at 11.

While I agree that there is no foolproof formula, I believe it is the analyst's responsibility to consider the results of the individual methodologies to determine if each result is reasonable and would meet the standards established by *Hope* and *Bluefield.* Certain analyses presented to this Commission result in returns that are well below any authorized ROE for a vertically integrated utility over the past 35 years. I do not believe it is appropriate to rely on the mathematical average of the results of all methodologies especially if the results are outside of a range of reasonableness.

With respect to the analysis presented by Mr. Mease in his Surrebuttal Testimony, his CAPM results that range from 6.84 percent to 7.07 percent are 218-241 basis points below any authorized return for a vertically integrated utility in the last 35 years. Furthermore, this range is 206-229 basis points below Mr. Mease's recommended ROE of 9.13 percent and 243-266 basis points lower than the 9.50 percent ROE that Mr. Mease suggests RUCO would agree to along with other factors.[5] Based on these comparisons, I do not believe it would be appropriate to provide equal weight to these particular CAPM results or results that fall into a similar range that are produced using other methodologies, inputs and assumptions.

Q. Have other regulatory commissions rationalized ROE results as you suggest should be done?

A. Yes. The FERC has routinely identified a range of reasonableness for the ROE and has excluded results that are either above or below that range as being outliers. I would exclude these CAPM results on the same basis.

---

[5] Surrebuttal Testimony of Robert B. Mease, at 21-22.

Q. Please summarize your conclusions with respect to Mr. Mease's analytical results.

A. Mr. Mease's Constant Growth DCF results produce a range of results between 8.33 percent and 10.12 percent, which is within the range established in my Rebuttal Testimony. The projected return estimates included in Mr. Mease's Comparable Earnings analysis estimates a range of earned returns for the individual proxy companies of between 7.50 percent and 12.5 percent for 2018 through 2020. The mean and median returns are 9.50 percent. While I do not necessarily agree with all of the methodologies relied on for the reasons discussed in my rebuttal and rejoinder testimony, the results of Mr. Mease's analysis support at least an ROE of 9.50 percent.

III. RESPONSE TO TASC WITNESS WOOLRIDGE

Q. Please summarize Dr. Woolridge's Surrebuttal Testimony.

A. Dr. Woolridge continues to support an ROE of 8.75 percent, which is 75 basis points below the ROE that has been agreed to by the Staff, RUCO and the Company.[6] As support for this position, Dr. Woolridge cites the current low interest rate environment and suggests that since analysts have not accurately predicted interest rate increase in recent years, forecasts should not be considered in setting the forward-looking ROE in this case. Dr. Woolridge acknowledges, however, that the average ROEs authorized by state regulatory commissions for electric utilities since 2012 have all been significantly higher than his recommendation.[7]

---

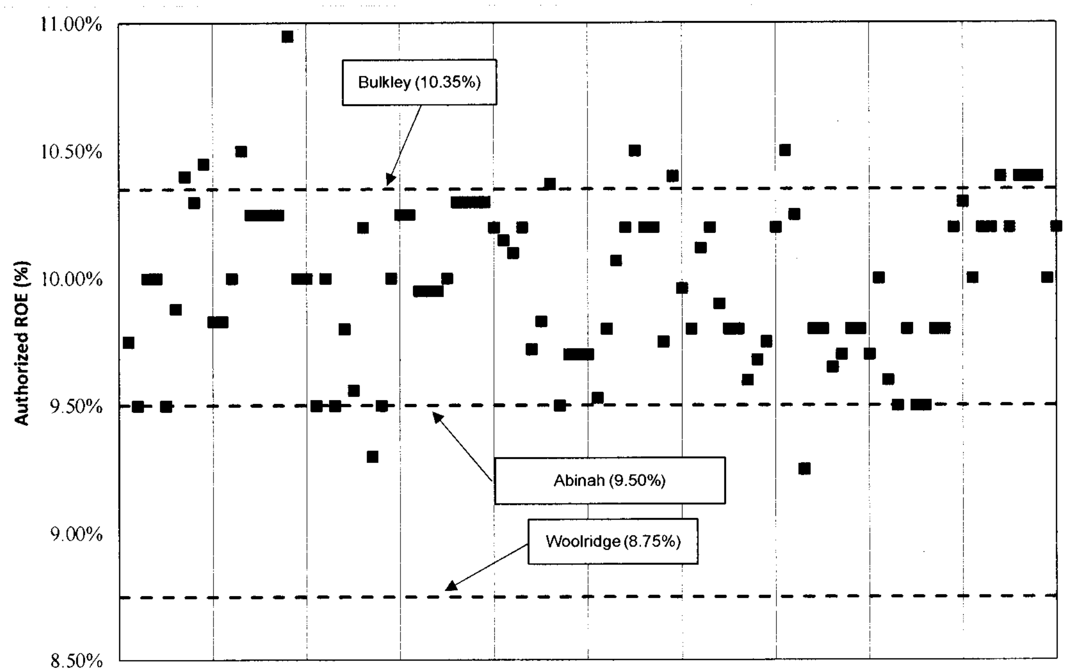
6 Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 9.
7 Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 4.

Q. What is your overall response to Dr. Woolridge's recommendation?

A. Dr. Woolridge presents unsubstantiated theories that allowed ROEs are lagging behind the decline in interest rates that has occurred in recent years, and that state Commissions have been reluctant to go below the 10.00 percent level. On this basis, Dr. Woolridge supports his ROE recommendation, even though it is 100 basis points lower than the average authorized ROE for integrated electric utilities in 2015 of 9.75 percent. While Dr. Woolridge argues that allowed ROEs have lagged behind capital market cost rates, meaning that they have been slow to reflect the lower interest rate environment, the average authorized ROE for electric utilities in 2015 actually increased since the filing of Dr. Woolridge's direct testimony. The average authorized ROE for vertically integrated electric utilities in the fourth quarter of 2015 was 9.86 percent. Woolridge offers no analysis or supporting documentation to demonstrate that UNS Electric has significantly lower risk than those electric utilities to justify a recommendation that is substantially lower than the average authorized ROE.

Chart 1 shows that authorized ROEs span a wide range over the period from 2012 through 2016. Dr. Woolridge's ROE recommendation of 8.75 percent is below that entire range. By comparison, my ROE recommendation of 10.35 percent is at the upper end of the range of ROE awards for vertically integrated electric utilities and the 9.50 percent ROE agreed upon by Staff, RUCO and the Company is below the average authorized ROE in 2015-2016.

Chart 1: ROE Decisions for Integrated Electric Utilities – 2012-2016



Contrary to Dr. Woolridge's position, capital market conditions do not suggest that allowed ROEs should be declining. Interest rates are expected to increase, credit spreads between government bonds and utility bonds have been widening, and volatility in equity markets has increased substantially since the Federal Reserve's decision in December 2015 to raise short-term interest rates, suggesting increased risk to equity holders.

Regarding Dr. Woolridge's critique of the ROE estimation methodologies relied on in developing my recommendation, Dr. Woolridge's Surrebuttal Testimony does not raise any issues that are materially different than those raised in his direct testimony. None of these points suggest that an ROE of 8.75 percent is warranted for UNS Electric.

IV. CAPITAL MARKET CONDITIONS

Q. What is Dr. Woolridge's view on current capital market conditions, interest rates and the effect of these factors on the return requirements of utility investors?

A. Dr. Woolridge testifies that interest rates have continued to decline despite continual forecasts of higher interest rates. As support for this position, Dr. Woolridge provides Figure 1, which charts the yield on 30-year Treasury bonds from 2009-2016. Dr. Woolridge's primary assertion with respect to interest rates is that forecasts of increasing interest rates have been wrong in the past; therefore, he argues that rather than rely on interest rate forecasts, it is more reasonable to rely on the current low interest rate environment as being representative of future conditions. In support of his position, Dr. Woolridge presents several studies that have reviewed economists' forecasts of Treasury bond yields over the period from 2010 through 2015.[8]

Q. Do you agree with Dr. Woolridge's view on capital market conditions and their effect on the return requirements of utility investors?

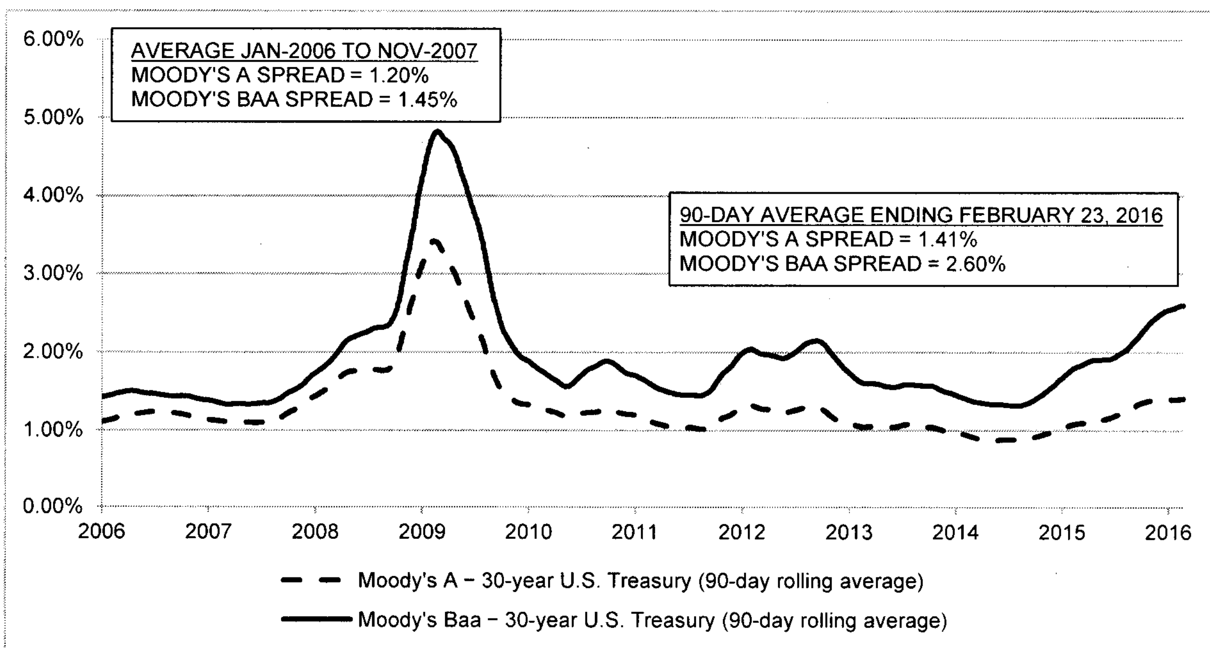
A. No, I do not. I will readily acknowledge that economists and others have struggled to accurately predict the path of interest rates over the past several years. However, this period has included the most severe recessionary period experienced in recent times followed by a slow and uncertain economic recovery. The combination of Federal Reserve market intervention (e.g., quantitative easing) and the uncertain path of post-Great Recession economic recovery have made such predictions challenging. In my view, however, this does not render interest rate forecasts meaningless to investors. I am not aware of any market expert or investor that would assume, as Dr. Woolridge does, that it is reasonable that current interest rates on government bonds, which remain near

[8] Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 11.

25 year lows, will be the rates experienced in the marketplace in the future.[9] This logic belies the basic upward sloping shape of the Treasury yield curve, as well as the recent policy statements of the Federal Reserve.

In addition, Dr. Woolridge entirely ignores the fact that yields on corporate and utility bonds have been steadily increasing, and that credit spreads between government bonds and corporate bonds are higher than they were immediately prior to the 2007-2009 financial crisis. As discussed in my rebuttal testimony, these elevated credit spreads are an indication of investor risk aversion that should not be dismissed. I have updated Chart 2 from my rebuttal testimony through February 23, 2016. As shown on the chart, average spreads between A-rated and Baa-rated utility bonds and government bonds have continued to increase since the filing of my rebuttal testimony. This evidence contradicts Dr. Woolridge's view that capital costs for utilities are declining.

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

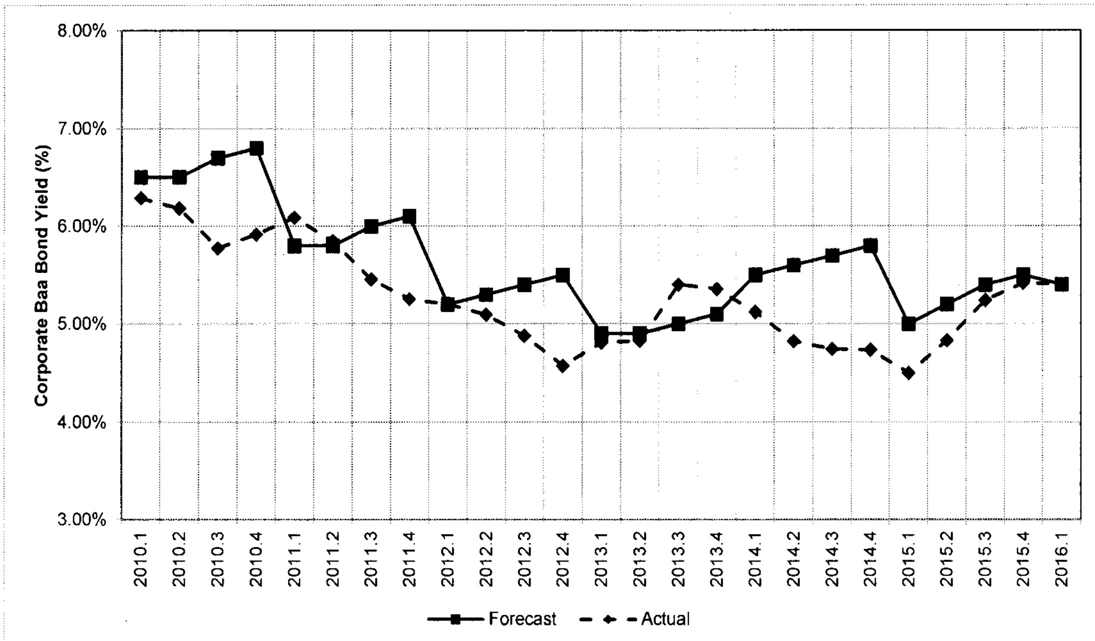


[9] Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 15.

Q. What is your response to Dr. Woolridge's concern about the ability of forecasters to accurately predict interest rates?

A. Dr. Woolridge has focused entirely on government bond yields, which are heavily influenced by the monetary policy of the Federal Reserve. As shown in Figure 1, however, projections of Baa-rated corporate bond yields (which are controlled by market forces) from Blue Chip Financial Forecasts for the period 2010 through 2016 have been more accurate than projections of government bond yields (which are subject to Federal intervention).

Chart 3: Corporate Bond Yield Projections and Actual Yields – 2010 - 2016



Corporate bond yields are more closely tied to equity cost rates. The increase in yields on corporate and utility bonds suggests that equity costs are also higher because there is a direct connection between equity costs and yields on corporate and utility bonds. It is for this reason that, in developing an ROE adjustment formula, the California Public Utilities Commission ("PUC") relies on the change in the Moody's utility bond yield, because it is more closely tied to changes in equity costs than are government bonds. The California PUC explains its rationale as follows:

> The purpose of an interest rate benchmark is to gauge changes in interest rates that also indicate changes in equity costs of utilities. U.S. Treasuries are more sensitive to economic changes and risks in the international capital markets than utility bonds because they are bought and sold globally. However, U.S. utility bonds are generally affected less than Treasuries as a result of major shifts of international capital because a majority of U.S. utility bonds are traded within the U.S.
>
> Consistent with our use of utility bond interest rates in ROE, PBR, and MICAM proceedings and desire to use an index that more likely correlates and moves with utility industry risk, utility bonds should be adopted for the CCM [cost of capital mechanism] index.[10]

Q. What is your conclusion regarding Dr. Woolridge's recommendation to rely on current interest rates rather than forward-looking estimates of interest rates?

A. The estimation of the ROE is a forward-looking concept. Therefore, it is reasonable and appropriate to consider what investors believe market conditions will be in the future. Investors, not just economists and market forecasters, are expecting that interest rates will rise. This factor must be accounted for in estimating the ROE for UNS Electric.

Q. Please summarize Dr. Woolridge's testimony with respect to the market reaction to the Federal Reserve's announcement of a 25 basis point increase in the Fed Funds rate in December 2015.

A. On page 13 of his Surrebuttal Testimony, Dr. Woolridge presents a chart of yields on U.S. Treasury bonds on December 16, 2015, which is the day when the Federal Reserve announced its decision to raise short-term interest rates by 25 basis points. On pages 14-

---

[10] Public Utilities Commission of the State of California, Decision 08-05-035, May 29, 2008 at 12-13.

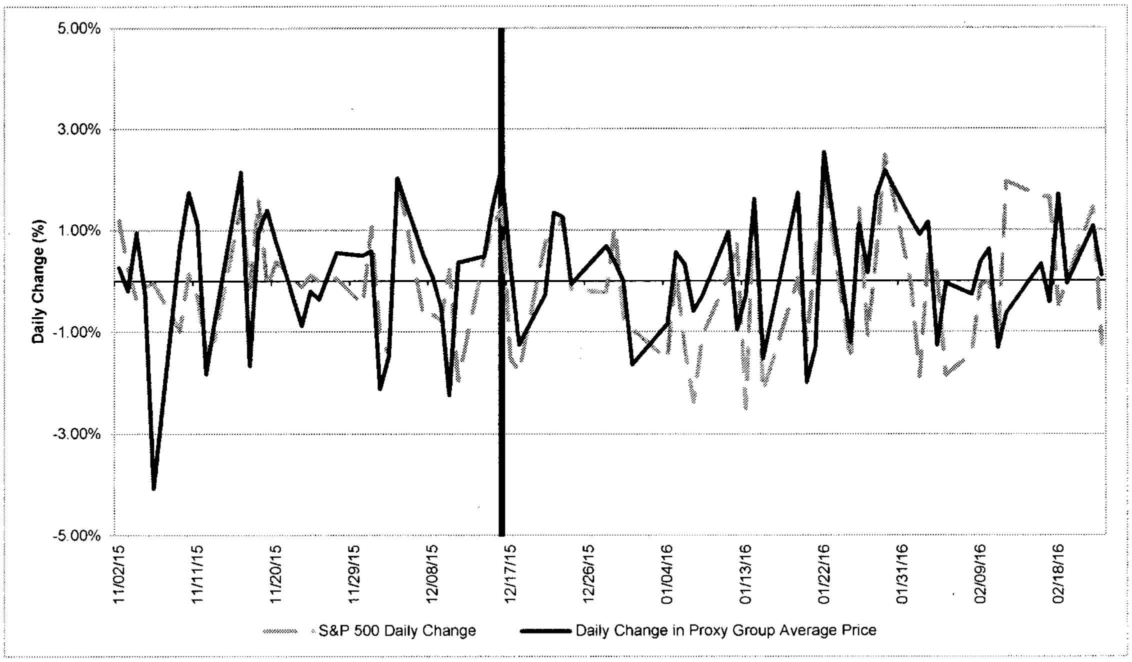
15, Dr. Woolridge testifies that the Dow Jones Utility Index has risen by 8.0 percent since the FOMC announcement, while the S&P 500 has declined by 4.0 percent.

Q. Has Dr. Woolridge considered the recent volatility in financial markets, and the implications for the cost of capital?

A. No, he has not. Based on Figure 8 in Dr. Woolridge's Surrebuttal Testimony, he appears to believe that the two hour time span following the FOMC's announcement of its decision to increase the Fed Funds rate by 25 basis points is somehow indicative of investor's long-term sentiment. However, Dr. Woolridge has ignored the fact that market volatility has been significant in the last several months. Volatility is another sign of investor risk aversion.

I have conducted an analysis of the volatility in the share prices of the companies in my proxy group for the period from November 2, 2015 through February 23, 2016. As shown in Chart 4, the share price volatility of my proxy group companies has been similar to the volatility of the S&P 500 during this period.

Chart 4: S&P 500 and Proxy Group Average Price Volatility



It is not surprising that increased volatility (i.e., risk) in equity markets, including utility stocks, would drive investors toward lower-risk alternatives such as Treasury bonds in the short-term. Increased volatility in equity markets demonstrates an increase in the risk for shareholders, which results in a higher cost of equity, not a lower cost of equity as suggested by Dr. Woolridge.

Q. **Dr. Woolridge states that the purpose of your comparison of forecasted economic indicators on pages 23-24 of your rebuttal testimony was to support Mr. Abinah's claim that the 9.50 percent ROE provided in the 2013 settlement is reflective of the current economic environment. What is your response?**

A. Dr. Woolridge apparently misunderstood the analysis in my rebuttal testimony. The intention of that analysis was to demonstrate the difference in forecasted economic conditions between the 2009 and 2012 cases and 2015, in order to support my ROE recommendation. As stated in my rebuttal testimony, based on that analysis, my conclusions were that 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.

Q. Do you agree with Dr. Woolridge that historical trends in GDP growth, unemployment, and inflation suggest that capital costs have declined?

A. No, I do not. On pages 8 and 9 of his Surrebuttal Testimony, Dr. Woolridge presents three charts showing historical GDP growth, the unemployment rate, and the annual inflation rate from 2006 through 2015. As discussed previously with regard to interest rates, the use of historical economic data from this time period was characterized by one of the most severe recessions in U.S. history, followed by an uncommonly slow and uncertain economic recovery, which makes a review of historical data from this period difficult to interpret as the expectations of future market conditions. The highly accommodative monetary policy of the Federal Reserve during much of this period has distorted the level of government bond yields, even as the economy has slowly recovered and unemployment has dropped below 5.0 percent. The FOMC's decision to increase short-term interest rates in December 2015 suggests that they do not agree with Dr. Woolridge that capital costs should remain at historic lows, given the outlook for economic growth and stronger employment trends.

Q. Please summarize your position regarding how the Commission should consider market conditions in establishing a reasonable ROE for UNS Electric.

A. The ROE that is set in this case is intended to be a forward-looking ROE. Dr. Woolridge suggests ignoring projected interest rates because he argues that forecasters cannot predict the future with certainty. Instead, Dr. Woolridge suggests that the Commission should assume that interest rates on government bonds will not change from current levels, even though those interest rates are near 25 year lows and are heavily influenced by the highly accommodative monetary policy of the Federal Reserve. In my view, given current market conditions and analysts' expectations that interest rates will not remain at the currently low levels as the economy continues to recover from the severe recession, it is reasonable to consider the effect of rising interest rates in developing a forward-looking estimate of the cost of equity.

V. RESPONSE TO WOOLRIDGE'S CRITIQUE OF BULKLEY ROE ESTIMATION METHODOLOGIES

Q. Please summarize the issues that are discussed in this section.

A. In this section of my rejoinder testimony, I respond to Dr. Woolridge's critique of (1) the growth rates used in my constant growth DCF model, (2) the long-term GDP growth rate in my multi-stage DCF model, (3) various inputs and assumptions in my CAPM analysis, and (4) the validity of my Bond Yield plus Risk Premium analysis.

Q. What is Dr. Woolridge's position with respect to the earnings growth forecasts that you relied on in your constant growth DCF analysis?

A. Dr. Woolridge criticizes my constant growth DCF analysis for relying on projected EPS growth rates, stating that these growth rates are biased upward. Dr. Woolridge cites a

2010 McKinsey study to support his view that analyst bias still exists. Despite his belief that EPS growth rates are biased, Dr. Woolridge acknowledges that in choosing the growth rate used in his DCF model, he relied primarily on the EPS growth rates for his proxy group.[11]

Q. What is your response to Dr. Woolridge's use of growth rates other than forecasted EPS growth rates in his constant growth DCF analysis?

A. Dr. Woolridge also presented other growth rates, such as 5-year and 10-year historical growth rates in EPS and DPS as reported by Value Line, although he has either not relied on these growth rates or given them less weight in his DCF analysis. Since the ROE that is to be established in this proceeding is forward-looking, I believe it is more appropriate to rely on the projected growth rates. Furthermore, as discussed previously with respect to interest rates, my concern with the use of this data is that the time period covered by these historical growth rates represents the severe recessionary period of 2007-2009 and the post-recessionary period, which has been viewed by analysts as an unusually slow recovery. I do not believe it is reasonable to expect that future growth rates will reflect this particular historical period.

Q. What is your response to Dr. Woolridge's opinion that analyst growth rates are overly optimistic?

A. With regard to the 2010 McKinsey study, my response is that the McKinsey study does not break out the reported results by industry, so it is not possible to conclude whether the observed analyst bias pertains specifically to regulated electric and gas utilities. However, Exhibit JRW-4, page 2, of Dr. Woolridge's Direct Testimony shows that earnings predictability and stock price stability are high for the companies in both the

[11] Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 18.

Woolridge and Bulkley proxy groups. On the one hand, Dr. Woolridge is arguing that regulated utilities are low risk compared to other industry groups because they have low Beta coefficients and high earnings predictability and stock price stability. On the other hand, Dr. Woolridge is concerned that utilities' earnings growth rates are not predictable and that analyst growth rates are overly optimistic. It is difficult to reconcile these two positions.

The McKinsey study also states that the size of the forecast error tends to decline when economic growth accelerates and increase as economic growth slows. This suggests that, as the U.S. economy has recovered from the Great Recession, the size of any forecast error should be declining. Finally, Wall Street analysts are required to certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation.[12] In light of restrictions imposed by the October 2003 Global Settlement, it is unclear how or why utility analysts' estimates would continue to be biased. That 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.[13]

Q. In addition to the information provided in your rebuttal testimony, are you aware of any additional articles on analyst bias?

A. Yes, I am. According to Zacks Investment Research, a reputable source of consensus growth rate forecasts, brokerage analysts are "expected to be to objective experts for the

---

12 See, http://www.sec.gov/rules/final/33-8193. {Regulation AC]

13 The 2002 Global Financial Settlement resolved an investigation by the U.S. Securities and Exchange Commission and the New York Attorney General's Office of a number of investment banks related to concerns about conflicts of interest that might influence the independence of investment research provided by equity analysts.

industries they cover."[14] With regard to guidance provided by companies to brokerage analysts, Zacks writes:

> It is not in the best interest of corporate executives to share the most optimistic projections with brokerage analysts, however. A large percentage of executive compensation comes from company stock and stock option plans. Executives realize that if their company reports earnings that are below analysts' forecasts, almost without exception, the stock price will tumble. This in turn costs them money. Therefore, it is more advantageous for executives to provide brokerage analysts with conservative earnings estimates.[15]

With respect to analyst's incentive to provide overly optimistic earnings forecasts, Zacks observes:

> Clients will only act on a brokerage analyst's recommendation if they think the recommendation will help them make money. The more money a firm's clients make from a particular analyst's recommendations, the more valuable the analyst is to the firm. Since the analysts issue far more "buy" recommendations than "sell" recommendations, they want to avoid making earnings forecasts that are overly optimistic. The incentive for issuing conservative earnings estimates is that the company has a better chance of reporting earnings that exceed forecasts. In turns, clients will be happy to see the stock's price rise. Conversely, there is no incentive to issue an earnings forecast that is overly optimistic.[16]

Finally, in terms of the issue of reported earnings vs. forecasted earnings, Zacks observes:

> Over 10 years ago, only about 50% of companies met or exceeded earnings estimates every quarter. Now that number has moved to 80% as corporate executives and brokerage analysts have wised up to the importance of creating conservative earnings estimates.[17]

---

14 Source: http://www.zacks.com/help/zrank-guide.php?p=3
15 Ibid.
16 Ibid.
17 Ibid.

Q. What is the long-term GDP growth rate that you relied on in your Multi-Stage DCF analysis?

A. As discussed in my rebuttal testimony, I relied on a long-term GDP growth rate of 5.4 percent.[18] This long-term growth rate is applied beginning in year 11 and continuing through year 200 of the multi-stage DCF analysis.

Q. Please summarize Dr. Woolridge's response to the GDP growth rate you relied on in your Multi-Stage DCF analysis.

A. Dr. Woolridge again refers to historical five and ten-year measures of growth in earnings and dividends for utility companies, the majority of which include the Great Recession and post-recessionary period, and concludes that these growth rates are substantially lower than the GDP growth rate I have relied on as a measure of the long-term projected growth. Dr. Woolridge states that I have not provided any theoretical or empirical support for this growth rate.[19] Finally, Dr. Woolridge states that I have ignored projected long-term GDP growth rates from government agencies in favor of historical data.

Q. What is your response to Dr. Woolridge on the development of the long-term GDP growth rate used in your analysis?

A. Dr. Woolridge tries to reconcile the forward-looking long-term growth rate provided by government agencies with the 5-10 year historical growth in earnings and dividends for utilities. However, as discussed previously, the 5-10 year historical growth is reflective of a very severe recessionary period, followed by a very slow recovery from that recession. As such, it is not reasonable to suggest that the long-term GDP growth rate in

---

18 The Surrebuttal Testimony of J. Randall Woolridge, Ph.D., incorrectly references this growth rate as being 540% (p. 21).

19 Surrebuttal Testimony of J. Randall Woolridge, Ph.D., at 21.

the multi-stage DCF model, which will be applied more than ten years after that severe recession, should be in line with growth rates during that historical period. In summary, while Dr. Woolridge criticizes the long-term nominal GDP growth rate used in my multi-stage DCF analysis for not being consistent with the most recent economic downturn, my approach takes into consideration the real GDP growth rate during all the economic cycles since 1929 and the projected long-term inflation rate, consistent with the approach discussed by market analysts such as Morningstar.[20]

Q. Dr. Woolridge states that your long-term GDP growth rate is not supported by any empirical studies. What is your response?

A. The use of GDP growth either for the final stage of a multi-stage DCF analysis or for determining a "blended growth rate" is common practice among practitioners and accepted by regulators. The logic for this practice is that over the long run, a utility's revenues and earnings will grow at about the same pace as the general economy. Dr. Morin cites this logic in his book on regulatory finance:

> One way to account for the two stages of growth is to modify the single-stage DCF model by specifying the growth rate as a weighted average of short-term and long-term growth rates. The blended growth rate is calculated as a weighted average giving two-thirds weight to the analyst's five-year growth projections (Zacks, IBES, etc.) and one-third to historical long-term growth of the economy as a whole and/or the long-range projections of growth in Gross Domestic Product (GDP) projected for the very long term. FERC has adopted such a method in the past for determining the return on equity for gas and oil utilities.[21]

---

[20] Rebuttal Testimony of Ms. Bulkley, at 57.

[21] Roger A. Morin, Ph.D., *New Regulatory Finance*, Public Utility Reports, Inc., 2006, p. 309.

Q. Has the FERC recently revised its DCF methodology for electric utilities?

A. Yes In its recent Order No. 531, the FERC gave considerable attention to this matter as it relates to long term growth rates for electric utilities. It ultimately concluded:

> Therefore, in this proceeding, and in future public utility cases, the Commission will adopt the same two-step DCF methodology used in natural gas and oil pipeline cases. In other words, there will be a single, six-month average dividend yield for each company in the proxy group. More importantly, the estimate of the dividend growth rate for each company in the proxy group will now include a short-term projection of dividend growth (with a two-thirds weight) and a long-term projection of dividend growth (with a one-third weight). The short-term growth estimate will be based on the five-year projections reported by IBES (or a comparable source). *Given the absence of an electric industry-specific long-term growth projection that reasonably reflects investor expectations, the long-term growth estimate will be based on an average of the GDP growth rates that have been relied on in gas and oil pipeline cases*. [footnotes excluded, FERC Order 531 at 39.]

This reinforces both the logic and precedent for utilizing GDP as a proxy for long-term growth rates in the multi-stage DCF model.

Q. Dr. Woolridge continues to criticize the market risk premium used in your CAPM analysis because it is derived from analysts' EPS growth rates for the companies in the S&P 500, which he believes are overly-optimistic and upwardly-biased. What is your response?

A. Dr. Woolridge does not offer any new arguments in his Surrebuttal Testimony that I have not already responded to in my rebuttal testimony. As stated in my rebuttal testimony, 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."[22] Dr. Woolridge states that the expected total return for the market is often measured by reference to the S&P 500.[23] This is consistent with the approach I have used to estimate the forward-looking MRP in my CAPM analysis. Therefore, I continue to believe that the results of my CAPM analysis are a reliable indicator of equity cost rates for electric utility companies such as UNS Electric.

Q. Please comment on Dr. Woolridge's concern that your Bond Yield Plus Risk Premium analysis uses the historical risk premium and applies it to forecasted Treasury bond yields.

A. My Bond Yield Plus Risk Premium analysis is based on a regression analysis that establishes the relationship between authorized ROEs for electric utilities and corresponding Treasury bond yields at the time of the ROE award. Based on the regression model, it is possible to determine what a reasonable ROE would be at a given interest rate. My analysis presents the results based on both current Treasury bond yields and near-term and long-term forecasts. The 9.87 percent that Dr. Woolridge references from the updated analysis presented in my rebuttal testimony is based on a 30-day average of the actual yield on 30-year Treasury bonds as of November 30, 2015. Even that result, which is based on currently low Treasury bond yields, is 112 basis points higher than Dr. Woolridge's ROE recommendation of 8.75 percent.

Q. Dr. Woolridge states that the trend and norm for authorized ROEs nationally is below 10.0 percent. Do you agree?

A. I do not. As shown in Chart 1, there have been 108 rate cases involving integrated electric utilities from January 2012 through February 2016 where the allowed ROE has

---

22 Direct Testimony of J. Randall Woolridge, Ph.D., at D-20.
23 Ibid.

been specified in the decision. Slightly more than half (i.e., 51 percent) of those 108 decisions has resulted in an allowed ROE of 10.0 percent or higher. Consequently, I conclude that the majority of ROE awards for integrated electric utilities since 2012 have been above 10.0 percent.

I also researched the current authorized ROE for the companies in Dr. Woolridge's proxy group. As shown in Attachment AEB-2, the average ROE award for these companies (including both electric and natural gas) has been 10.00 percent. In computing this average, I eliminated any decisions that did not specify the authorized ROE and any decisions that were issued prior to 2010.

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

Exhibit AEB-1

Robert Mease CAPM Analysis
Corrections

Schedule RDM-6, page 1- As filed
Geometric Mean

Ticker	Rf rate	Beta	Rm	Rf	Expected Return
ALE	2.50%	0.80	12.00%	6.10%	7.22%
AEP	2.50%	0.70	12.00%	6.10%	6.63%
EE	2.50%	0.75	12.00%	6.10%	6.93%
EDE	2.50%	0.70	12.00%	6.10%	6.63%
ES	2.50%	0.75	12.00%	6.10%	6.93%
GXP	2.50%	0.85	12.00%	6.10%	7.52%
IDA	2.50%	0.80	12.00%	6.10%	7.22%
OTTR	2.50%	0.85	12.00%	6.10%	7.52%
PNW	2.50%	0.75	12.00%	6.10%	6.93%
PNM	2.50%	0.80	12.00%	6.10%	7.22%
POR	2.50%	0.80	12.00%	6.10%	7.22%
WR	2.50%	0.75	12.00%	6.10%	6.93%
			Mean		7.07%

Schedule RDM-6, page 1 -Corrected
Geometric Mean

Ticker	Rf rate	Beta	Rm	Rf	Expected Return
ALE	2.95%	0.80	10.1%	5.00%	7.03%
AEP	2.95%	0.70	10.1%	5.00%	6.52%
EE	2.95%	0.75	10.1%	5.00%	6.78%
EDE	2.95%	0.70	10.1%	5.00%	6.52%
ES	2.95%	0.75	10.1%	5.00%	6.78%
GXP	2.95%	0.85	10.1%	5.00%	7.29%
IDA	2.95%	0.80	10.1%	5.00%	7.03%
OTTR	2.95%	0.85	10.1%	5.00%	7.29%
PNW	2.95%	0.75	10.1%	5.00%	6.78%
PNM	2.95%	0.80	10.1%	5.00%	7.03%
POR	2.95%	0.80	10.1%	5.00%	7.03%
WR	2.95%	0.75	10.1%	5.00%	6.78%
				Mean	6.90%

Schedule RDM-6, page 2- As filed
Arithmetic Mean

Ticker	Rf rate	Beta	Rm	Rf	Expected Return
ALE	2.50%	0.80	12.00%	6.40%	6.98%
AEP	2.50%	0.70	12.00%	6.40%	6.42%
EE	2.50%	0.75	12.00%	6.40%	6.70%
EDE	2.50%	0.70	12.00%	6.40%	6.42%
ES	2.50%	0.75	12.00%	6.40%	6.70%
GXP	2.50%	0.85	12.00%	6.40%	7.26%
IDA	2.50%	0.80	12.00%	6.40%	6.98%
OTTR	2.50%	0.85	12.00%	6.40%	7.26%
PNW	2.50%	0.75	12.00%	6.40%	6.70%
PNM	2.50%	0.80	12.00%	6.40%	6.98%
POR	2.50%	0.80	12.00%	6.40%	6.98%
WR	2.50%	0.75	12.00%	6.40%	6.70%
			Mean		6.84%

Schedule RDM-6, page 2- Corrected
Arithmetic Mean

Ticker	Rf rate	Beta	Rm	Rf	Expected Return
ALE	2.95%	0.80	12.10%	5.10%	8.55%
AEP	2.95%	0.70	12.10%	5.10%	7.85%
EE	2.95%	0.75	12.10%	5.10%	8.20%
EDE	2.95%	0.70	12.10%	5.10%	7.85%
ES	2.95%	0.75	12.10%	5.10%	8.20%
GXP	2.95%	0.85	12.10%	5.10%	8.90%
IDA	2.95%	0.80	12.10%	5.10%	8.55%
OTTR	2.95%	0.85	12.10%	5.10%	8.90%
PNW	2.95%	0.75	12.10%	5.10%	8.20%
PNM	2.95%	0.80	12.10%	5.10%	8.55%
POR	2.95%	0.80	12.10%	5.10%	8.55%
WR	2.95%	0.75	12.10%	5.10%	8.20%
				Mean	8.38%

Exhibit AEB-2

AUTHORIZED RETURN ON EQUITY ANALYSIS - WOOLRIDGE PROXY GROUP
AUTHORIZED RETURN ON EQUITY

Woolridge Electric Proxy Group Company	Ticker	Authorized Return on Equity
ALLETE, Inc.	ALE	10.38%
Alliant Energy Corporation	LNT	10.31%
Ameren Corporation	AEE	9.42%
American Electric Power Company, Inc.	AEP	9.97%
Avista Corporation	AVA	10.06%
Black Hills Corporation	BKH	9.93%
CMS Energy Corporation	CMS	10.30%
Consolidated Edison, Inc.	ED	9.21%
Dominion Resources, Inc.	D	10.20%
Duke Energy Corporation	DUK	10.06%
Edison International	EIX	10.45%
El Paso Electric Company	EE	
Empire District Electric Company	EDE	
Entergy Corporation	ETR	9.93%
Eversource Energy	ES	9.41%
FirstEnergy Corporation	FE	9.75%
Great Plains Energy Inc.	GXP	9.50%
IDACORP, Inc.	IDA	9.90%
MGE Energy, Inc.	MGEE	10.20%
NorthWestern Corporation	NWE	10.03%
OGE Energy Corporation	OGE	10.08%
Otter Tail Corporation	OTTR	10.74%
PG&E Corporation	PCG	10.40%
Pinnacle West Capital Corporation	PNW	10.00%
PNM Resources, Inc.	PNM	10.07%
Portland General Electric Company	POR	9.60%
SCANA Corporation	SCG	10.25%
Westar Energy, Inc.	WR	
Xcel Energy Inc.	XEL	9.86%
MEAN		10.00%
LOW		9.21%
HIGH		10.74%

AUTHORIZED RETURN ON EQUITY - UTILITY OPERATING COMPANIES

Company Name	Ticker	Type	States of Operation	Year Completed	Docket No.	Authorized Return on Equity
ALLETE (Minnesota Power)	ALE	Electric	Minnesota	2010	D-E-015/GR-09-1151	10.38%
Interstate Power & Light Co.	LNT	Electric	Iowa	2010	D-RPU-2010-0001	10.44%
Interstate Power & Light Co.	LNT	Natural Gas	Iowa	2012	D-RPU-2012-0002	10.00%
Wisconsin Power and Light Co	LNT	Electric	Wisconsin	2014	D-6680-UR-119 (Elec)	10.40%
Wisconsin Power and Light Co	LNT	Natural Gas	Wisconsin	2014	D-6680-UR-119 (Gas)	10.40%
Ameren Illinois	AEE	Electric	Illinois	2015	D-15-0305	9.14%
Ameren Illinois	AEE	Natural Gas	Illinois	2015	D-15-0142	9.60%
Union Electric Co.	AEE	Electric	Missouri	2015	C-ER-2014-0258	9.53%
Appalachian Power Co.	AEP	Electric	Virginia	2014	C-PUE-2014-00026	9.70%
Appalachian Power Co.	AEP	Electric	West Virginia	2015	C-14-1152-E-42T	9.75%
Indiana Michigan Power Co.	AEP	Electric	Indiana	2013	Ca-44075	10.20%
Indiana Michigan Power Co.	AEP	Electric	Michigan	2012	C-U-16801	10.20%
Ohio Power Co.	AEP	Electric	Ohio	2011	C-11-0352-EL-AIR	10.30%
Southwestern Electric Power Co	AEP	Electric	Louisiana	2013	D-U-32220	10.00%
Southwestern Electric Power Co	AEP	Electric	Texas	2013	D-40443	9.65%
Avista Corp.	AVA	Electric	Idaho	2015	C-AVU-E-15-05	9.50%
Avista Corp.	AVA	Natural Gas	Idaho	2015	C-AVU-G-15-01	9.50%
Avista Corp.	AVA	Natural Gas	Oregon	2015	D-UG-284	9.50%
Avista Corp.	AVA	Electric	Washington	2016	D-UE-150204	9.50%
Avista Corp.	AVA	Natural Gas	Washington	2016	D-UG-150205	9.50%
Alaska Electric Light Power	AVA	Electric	Alaska	2011	D-U-10-029	12.88%
Black Hills Colorado Electric	BKH	Electric	Colorado	2014	D-14AL-0393E	9.83%
Black Hills Nebraska Gas	BKH	Natural Gas	Nebraska	2010	D-NG-0061	10.10%
Cheyenne Light Fuel Power Co.	BKH	Electric	Wyoming	2014	D-20003-132-ER-13	9.90%
Cheyenne Light Fuel Power Co.	BKH	Natural Gas	Wyoming	2014	D-30005-182-GR-13	9.90%
Consumers Energy Co.	CMS	Electric	Michigan	2015	C-U-17735	10.30%
Consumers Energy Co.	CMS	Natural Gas	Michigan	2015	C-U-17643	10.30%
Consolidated Edison Co. of NY	ED	Electric	New York	2015	C-15-E-0050/C-13-E-0030 (Ext)	9.00%
Consolidated Edison Co. of NY	ED	Natural Gas	New York	2014	C-13-G-0031	9.30%
Orange & Rockland Utlts Inc.	ED	Electric	New York	2015	C-14-E-0493	9.00%
Orange & Rockland Utlts Inc.	ED	Natural Gas	New York	2015	C-14-G-0494	9.00%
Rockland Electric Company	ED	Electric	New Jersey	2014	D-ER-13111135	9.75%
Virginia Electric & Power Co.	D	Electric	North Carolina	2012	D-E-22, Sub 479	10.20%
Duke Energy Carolinas LLC	DUK	Electric	North Carolina	2013	D-E-7, Sub 1026	10.20%
Duke Energy Carolinas LLC	DUK	Electric	South Carolina	2013	D-2013-59-E	10.20%
Duke Energy Ohio Inc.	DUK	Electric	Ohio	2013	C-12-1682-EL-AIR	9.84%
Duke Energy Ohio Inc.	DUK	Natural Gas	Ohio	2013	C-12-1685-GA-AIR	9.84%
Duke Energy Progress LLC	DUK	Electric	North Carolina	2013	D-E-2, Sub 1023	10.20%
Southern California Edison Co.	EIX	Electric	California	2012	Ap-12-04-015	10.45%
Entergy Arkansas Inc.	ETR	Electric	Arkansas	2016	D-15-015-U	9.75%
Entergy Gulf States LA LLC	ETR	Electric	Louisiana	2013	D-U-32707	9.95%
Entergy Louisiana LLC	ETR	Electric	Louisiana	2014	D-UD-13-01	9.95%
Entergy Mississippi Inc.	ETR	Electric	Mississippi	2014	D-2014-UN-0132	10.07%
Connecticut Light & Power Co.	ES	Electric	Connecticut	2014	D-14-05-06	9.17%
NSTAR Gas Co.	ES	Natural Gas	Massachusetts	2015	DPU 14-150	9.80%
Public Service Co. of NH	ES	Electric	New Hampshire	2010	D-DE-09-035	9.67%
Western Massachusetts Electric	ES	Electric	Massachusetts	2011	DPU 10-70	9.60%
Yankee Gas Services Co.	ES	Natural Gas	Connecticut	2011	D-10-12-02	8.83%
Jersey Cntrl Power & Light Co.	FE	Electric	New Jersey	2015	D-ER-12111052	9.75%
Kansas City Power & Light	GXP	Electric	Kansas	2015	D-15-KCPE-116-RTS	9.30%
Kansas City Power & Light	GXP	Electric	Missouri	2015	C-ER-2014-0370	9.50%
KCP&L Greater Missouri Op Co	GXP	Electric	Missouri	2013	C-ER-2012-0175 (MPS)	9.70%
Idaho Power Co.	IDA	Electric	Oregon	2012	D-UE-233	9.90%
Madison Gas and Electric Co.	MGEE	Electric	Wisconsin	2014	D-3270-UR-120 (Elec)	10.20%
Madison Gas and Electric Co.	MGEE	Natural Gas	Wisconsin	2014	D-3270-UR-120 (Gas)	10.20%
NorthWestern Corp.	NWE	Electric	Montana	2010	D-D2009.9.129 (elec)	10.25%
NorthWestern Corp.	NWE	Natural Gas	Montana	2013	D-D2012.9.94	9.80%
Oklahoma Gas and Electric Co.	OGE	Electric	Arkansas	2011	D-10-067-U	9.95%
Oklahoma Gas and Electric Co.	OGE	Electric	Oklahoma	2012	Ca-PUD201100087	10.20%
Otter Tail Power Co.	OTTR	Electric	Minnesota	2011	D-E-017/GR-10-239	10.74%
Pacific Gas and Electric Co.	PCG	Electric	California	2012	Ap-12-04-018 (Elec)	10.40%
Pacific Gas and Electric Co.	PCG	Natural Gas	California	2012	Ap-12-04-018 (Gas)	10.40%
Arizona Public Service Co.	PNW	Electric	Arizona	2012	D-E-01345A-11-0224	10.00%
Public Service Co. of NM	PNM	Electric	New Mexico	2011	C-10-00086-UT	10.00%
Texas-New Mexico Power Co.	PNM	Electric	Texas	2011	D-38480	10.13%
Portland General Electric Co.	POR	Electric	Oregon	2015	D-UE-294	9.60%
South Carolina Electric & Gas	SCG	Electric	South Carolina	2012	D-2012-218-E	10.25%
South Carolina Electric & Gas	SCG	Natural Gas	South Carolina	2014	D-2014-6-G	10.25%
Northern States Power Co. - MN	XEL	Electric	Minnesota	2015	D-E-002/GR-13-868	9.72%
Northern States Power Co. - MN	XEL	Natural Gas	Minnesota	2010	D-G-002/GR-09-1153	10.09%
Northern States Power Co. - MN	XEL	Electric	North Dakota	2014	C-PU-12-813	9.75%
Northern States Power Co - WI	XEL	Electric	Wisconsin	2015	D-4220-UR-121 (Elec)	10.00%
Northern States Power Co - WI	XEL	Natural Gas	Wisconsin	2015	D-4220-UR-121 (Gas)	10.00%
Public Service Co. of CO	XEL	Electric	Colorado	2015	D-14AL-0660E	9.83%
Public Service Co. of CO	XEL	Natural Gas	Colorado	2013	D-12AL-1268G	9.72%
Southwestern Public Service Co	XEL	Electric	New Mexico	2014	C-12-00350-UT	9.96%
Southwestern Public Service Co	XEL	Electric	Texas	2015	D-43695	9.70%

Notes:
[1] Operating Subsidiaries with rate cases not covered by SNL Financial were excluded from the analysis.
[2] Operating Subsidiaries with rate cases that were silent with respect to traditional rate case parameters were excluded from the analysis.
[3] Excludes Operating Subsidiaries with most recent rate case prior to 2010.
[4] Kansas Gas and Electric Co. was labeled as Westar Energy Inc. since the two companies file rate cases jointly.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Rejoinder Testimony of

David J. Lewis

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

Exhibit

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 or Rebuttal Testimony in this proceeding?

A. Yes.

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

A. My Rejoinder Testimony addresses the testimonies of Robert B Mease and Jeffery Michlik filed on behalf of the Residential Utility Consumer Office ("RUCO"). Specifically, I discuss the non-fuel revenue requirement presented by Mr. Michlik and the revenue increase of $15.1 million that Mr. Mease references in his Surrebuttal Testimony.

II. RESPONSE TO SURREBUTTAL REVENUE REQUIREMENT ADJUSTMENT.

Q. Did RUCO accept the revenue requirement adjustments you described in your Rebuttal Testimony?

A. Yes, RUCO accepted all of the revised adjustments except the proposed base cost of fuel.

Q. Do you agree with RUCO's base cost of fuel amount?

A. No. In calculating the base cost of fuel amount, RUCO applied $0.053689 per kWh to retail sales of 1,626,067,036 kWh. Although I agree that $0.053689 represents the actual cost per kWh that the Company incurred from January through December 2015, I do not agree with the sales volumes used. RUCO should have used the adjusted sales volumes filed in this case of 1,600,809,167 kWh. Had the correct retail sales volumes been used the base cost of fuel would have been $85,945,843.

Q. Are there any other adjustments in RUCO's rebuttal position you would like to address?

A. Yes, RUCO decreased test year medical expense by $316,694, and increased dental expenses by $10,846. Upon further review, RUCO's adjustments did not take into account the portion that should have been allocated to capital investments. Had the adjustment been calculated to reflect the portion that would have been allocated to capital, medical expense would have decreased by $187,737, and dental expense increased by $6,430.

Q. Does the Company agree with RUCO's revised Revenue Requirement presented by Mr. Michlik?

A. No. Mr. Michlik Surrebuttal Testimony is recommending a gross revenue requirement of $17,206. This is largely due to the Rate of Return on common equity of 9.13%. However, in Mr. Mease's Surrebuttal Testimony, page 21 lines 4-6, Mr. Mease states that RUCO would consider recommending Staff's cost of common equity of 9.50% provided "the overall revenue requirement" is not greater than $15.1 million.

Q. Do you believe Mr. Mease meant to refer to the "overall revenue *requirement*", or was he instead referring to the "overall revenue *increase*"?

A. I believe he meant to refer to the overall revenue increase. That is because the overall revenue requirement is much higher, and Mr. Mease refers to a "$7.5 million overall reduction in total revenue increase" on page 22 of his Surrebuttal Testimony. The referenced amount of $15.1 million is indeed $7.5 million lower than the non-fuel revenue increase of $22.6 million requested by UNS Electric in its rate application.

Q. Is the Company willing to accept a non-fuel revenue increase of $15.1 million?

A. As discussed in the Rejoinder Testimony of Company witness Kentton Grant, the Company would be willing to accept a $15.1 million non-fuel revenue increase, and the related treatment of deferred Gila River Unit 3 costs, as long as the Company is provided with a reasonable opportunity to actually earn a 9.50% return on equity. However, this does not mean that UNS Electric agrees with the rationale underlying RUCO's additional operating expense adjustments and reserves the right to oppose them in future rate cases.

Q. Do you have any other comments?

A. Yes. As part of my Rejoinder Testimony I am submitting revised **Exhibit DJL-RJ-1** that explains in more detail the Surrebuttal positions of Staff and RUCO and the revised revenue requirement deficiency for RUCO with the above corrections to their filed testimony.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit DJL-RJ-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 Rebuttal Pos.	RUCO Rebuttal Pos.	UNSE Rejoinder 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)	(1,773,667)	($1,773,667)	**No Adjustment**	**No Adjustment**
Fortis Rate Base Adjustment	(10,249)	(10,249)	(10,249)	($10,249)	**No Adjustment**	**No Adjustment**
Gila River Adjustment	(11,389)	(2,011,389)	(2,011,389)	($2,011,389)	To Reduce RB by $2M related to depreciation expense as deferred by the accounting order for Gila River.	Accepted Staff's Adjustment
ARO	(1,101,971)	(1,101,971)	(1,101,971)	($1,101,971)	**No Adjustment**	**No Adjustment**
Working Capital	(6,294,187)	(6,014,606)	(6,014,542)	($6,014,542)	CWC adjustment- Increase $279,581. D&O prepaid reduction by 50% ($16,778). Staff also used 50% reduction based on total expense not average balance.	Accepted Staff's Adjustment
Total Adjustments to Rate Base	(547,193)	(2,267,612)	(2,267,548)	(2,267,548)		
Rate Base	$ 272,013,127	$ 270,292,716	$ 270,292,780	$ 270,292,780		
Requested Rate of Return	**7.67%**	**7.22%**	**7.22%**	**7.22%**	Capital Structure: 47.17 % debt @ 4.66% , 52.83% Equity @ 9.5%. FVI .50%. ROR on OCRB 7.22%	Accepted Staff's Adjustment
Required Operating Income OCRB	$20,852,600	$19,508,890	$19,508,892	$19,508,892		
Fair Value Increment of Rate Base	$83,704,602	$83,706,670	$83,706,669	$83,706,669		
Fair Value Rate Base (FVRB)	$355,717,730	$353,999,386	$353,999,449	$353,999,449	**Modified from original Position:** To correct formula error FVROR changed from 5.60% to 5.63%	Accepted Staff's Adjustment
Proposed FVROR	1.50%	**0.50%**	**0.50%**	**0.50%**		
Required Operating Income on FVRB	1,255,569	$418,533	$418,533	$418,533		
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**	**No Adjustment**
Non-Retail Rev, Fuel & Purchase Power	-	7,781,534	9,779,021	9,779,021	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. This rate is subject to change prior to new base cost of fuel rates going into effect.	RUCO recommends a Base Cost of Fuel rate of $0.053689 per kWh. This is based on 2015 actual fuel and purchase power costs and equates to $87.3M using retail sales of 1,626,067,036 kWh.
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.	**No Adjustment**
REST & DSM	(1,537,369)	(1,537,369)	(1,537,369)	(1,537,369)	**No Adjustment**	**No Adjustment**
Service Fees	95,034	95,034	95,034	95,034	**No Adjustment**	**No Adjustment**
Other Revenues	(45,506)	(45,506)	(45,506)	(45,506)	**No Adjustment**	**No Adjustment**
Total Adjustments to Operating Revenues	(8,887,400)	($1,105,866)	$891,621	$891,621		

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

	As Filed UNSE	STAFF	RUCO	UNSE	STAFF	RUCO
	12/31/14	Rebuttal Pos.	Rebuttal Pos.	Rejoinder Pos.	Summary of Position	Summary of Position
Operating Expense Adjustments						
Payroll Expense	(172,011)	(172,011)	(172,011)	(172,011)	**Staff adjustment was Withdrawn.**	**No Adjustment**
Payroll Tax Expense	(13,397)	(13,397)	(13,397)	(13,397)	**Staff adjustment was Withdrawn.**	**No Adjustment**
Pension & Benefits	(123,376)	(123,376)	57,932	57,932	**No Adjustment**	RUCO used a 3 year average for Medical and Dental - did not account for the amount that is O&M only.
Retiree Medical	(37,384)	(37,384)	(37,384)	(37,384)	**No Adjustment**	**No Adjustment**
Rate Case Expense	(53,349)	(53,349)	(37,344)	(37,344)	**No Adjustment**	Allowed $350K over 3yrs
Bad Debt Expense	358,151	489,791	489,791	489,791	Staff excluded Mercator write off from their normalization ($450K). Staff used a Three Year retail revenues total divided by 3 year retail expense.	Accepted Staff's Adjustment
Depr. & Amort. Expense	6,624,227	6,624,227	6,624,227	6,624,227	**No Adjustment**	**No Adjustment**
Property Tax	(873,950)	(873,950)	(873,950)	(873,950)	**No Adjustment**	**No Adjustment**
Incentive Compensation	(169,378)	(14,023)	32,529	32,529	Staff adjusts for a 2yr average. And 50-50 sharing between ratepayers and Stakeholders.	Accepted Staff's adjustments. Plus a reduction to Operating income for Wellness programs and Spot awards.
Injuries and Damages	(355,542)	(35,442)	(35,442)	(35,442)	To remove the $1M insurance deductible we booked in 2013 but reversed in July 2015 due to a favorable outcome.	Accepted Staff's Adjustment
Membership Dues	10,590	10,590	26,106	26,106	**No Adjustment**	Ruco excluded all of UARG and 29.55% of EEI; leaving only their estimate of legislative advocacy
Gila River Deferred Cost	(3,100,000)	-	-	-	**No Adjustment**	**No Adjustment**
Fortis Acquisition Costs	5,522,093	5,522,093	5,522,093	5,522,093	**No Adjustment**	**No Adjustment**
Gila O&M and Outages	(3,370,536)	(3,370,536)	(3,370,536)	(3,370,536)	**No Adjustment**	**No Adjustment**
Income Taxes	5,174,155	3,750,327	3,652,767	3,652,767	To adjust for STAFF changes (bad debt, Inj&dam,Payroll,Incentive Comp, D&O, Interest Sync, Purchased Power)	Ruco interest Sync
OATT	(14,531,456)	(14,511,531)	(14,511,531)	(14,511,531)	Staff is recommending the OATT Revenue Requirement amount that is currently used for the TCA rate in effect during the test year (2013 Plant data) should be used.	**No Adjustment**
D&O Insurance	-	20,028	20,028	20,028	Removal of 50% of the D&O related expense.	Accepted Staff's Adjustment
Purchased Power	-	(7,781,534)	(9,779,021)	(9,779,021)	Corresponding adjustment to revenue.	Corresponding adjustment to revenue.
Total Adjustments to Operating Expense	(5,111,163)	(10,569,477)	(12,405,143)	(12,405,143)		
Total Net Adjustments	(13,998,563)	(11,675,343)	(11,513,522)	(11,513,522)		
Adjusted Operating Income	$8,043,875	$10,369,097	$10,530,917	$10,530,917		
Operating Income Deficiency	$14,064,294	$9,558,327	$9,396,509	$9,396,509		
Gross Revenue Conversion Factor	1.6084	1.6070	1.6070	1.6070	This is due to the removal of $450,000 bad debt expense reserve for mining company bankruptcy filing.	Accepted Staff's Adjustment
Increase in Gross Revenue Requirement	$22,621,010	$15,360,039	$15,099,716	$15,099,716		

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Rejoinder Testimony of

Michael E. Sheehan

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

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 or Rebuttal Testimony in this proceeding?

A. Yes.

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

A. My testimony responds to Staff's surrebuttal witness Barbara Keene in regard to the base cost of fuel and purchased power and the proposed modifications to the Purchased Power and Fuel Adjustment Clause ("PPFAC").

II. BASE COST OF FUEL AND PURCHASED POWER

Q. What did Staff recommend in surrebuttal testimony regarding the base cost of fuel and purchased power for UNSE?

A. Staff recommended that UNSE update the base cost of fuel and purchased power prior to establishing new rates in this case based on Staff's methodology as proposed in Staff's direct testimony.

Q. Does the Company accept Staff's surrebuttal proposal in regard to the base cost of fuel and purchased power.

A. Yes. The Company believes that updating the base cost of fuel and purchased power just prior to establishing new rates in this case will provide UNSE customers with the most up to date estimate.

III. PROPOSED MODIFICATIONS TO THE PPFAC

Q. Did Staff recommend approving the Company's proposed Base Rate Annual Adjustment?

A. No, but Staff proposed an alternative.

Q. What was Staff's alternative proposal?

A. Staff recommends that the formula used for calculating the monthly PPFAC rate be modified to include consideration of the bank balance.

Q. Does the Company agree with Staff's alternative proposal?

A. Yes. The Company believes that the inclusion of the bank balance in the monthly PPFAC rate calculation provides for a more timely and equitable recovery[1] of the bank balance for both customers and the Company.

Q. Did Staff's surrebuttal address the Company's proposed modification of a PPFAC percentage rate adjustment?

A. No.

[1] Recovery means that in a scenario where the bank balance is over collected, UNSE customers would receive refunds on a more timely basis. Whereas, in the scenario where the bank balance is under collected, the Company would realize cost recovery on a more timely basis.

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.

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. An example of UNSE's proposed PPFAC rate percentage methodology is provided in Exhibit MES-J-1.

Q. Why is the Company's proposed PPFAC percentage rate an improvement over the current PPFAC rate calculation?

A. 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. In addition, 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 equitable by rate class?

A. If we compared the incremental cost of serving similarly sized Residential Service customers to that of Large Power Service customers[2], we would 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 that results in Residential Service customers utilizing a higher percentage of on-peak energy during the year and consuming a higher percentage of energy during the summer months relative to the usage of Large Power Service customers. In addition to these seasonal and time of use differences, Residential Service customers would also incur higher costs on a $/kWh basis associated with any fixed costs being spread over few kilowatt hours. Further, Large Power Service customers take delivery at a higher voltage level thus avoiding additional costs associated with distribution losses. The Company believes that the proposed PPFAC percentage rate will provide more accurate and equitable price signals resulting in an improved rate design for customers.

Q. Does this conclude your Testimony?

A. Yes, it does.

---

[2] As shown on Page 4 of Exhibit MES-J-1, a comparison is made between 25 MW of new Residential Service customers and 25 MW of new Large Power Service customers. Page 5 highlights that Residential Service customers were estimated to cost 8.34% higher than Large Power Service customers on a marginal cost basis (energy only) based on 2015 estimates of UNSE system costs.

Exhibit MES-RJ-1

PPFAC % Rate Overview

- UNS Electric is proposing to modify the PPFAC to better allocate price increases/deceases by customer rate classes

- This change would utilize a PPFAC percentage rate rather than a straight $/kWh rate that is currently used today

- The PPFAC % rate provides for a more equitable treatment of price changes by rate class by allocating costs that mirror the cost of service rate design principles

- The following example details how this methodology would be applied comparing the impacts to a Residential Service customer with a low load factor to a Large Power Service customer with a high load factor.

PPFAC Rate (Current)

Test Year	KWh	Fuel Costs	$/kWh
Residential	826,362,520	45,732,487	$0.055342
Small Commercial	118,623,805	6,473,935	$0.054575
Commercial	562,295,292	30,492,916	$0.054229
Industrial/Mining	92,718,383	4,300,663	$0.046384
	1,600,000,000	87,000,000	$0.054375

Rate Change Assumptions	
Existing Base Power Supply, $/kWh	$0.054375
New Average Fuel Rate, $/kWh	$0.049531

PPFAC Rate, $/KWh	-$0.004844

PPFAC Rate $/kWh = Existing Base Power Supply, $/kWh / New Average Fuel Rate, $/kWh

PPFAC Rate $/kWh applied equally across all Rate Classes

Base Cost of Fuel and Purchase Power	Base Power Supply $/kWh	PPFAC Rate $/kWh	Net Power Supply $/kWh	Rate Impact %
Residental	$0.055342	-$0.004844	$0.050498	-8.75%
Small Commercial	$0.054575	-$0.004844	$0.049732	-8.88%
Commercial	$0.054229	-$0.004844	$0.049386	-8.93%
Industrial/Mining	$0.046384	-$0.004844	$0.041540	-10.44%
Aggregated Base Rate	$0.054375	-$0.004844	$0.049531	-8.91%

PPFAC Percentage Rate (Proposed)

Rate Change Assumptions	
Base Power Supply , $/kWh	$0.054375
New Average Power Supply, $/kWh	$0.049531

PPFAC, %	-8.908%

PPFAC % Rate = New Average Fuel Rate, $/kWh / (Existing Base Power Supply, $/kWh – 1)

PPFAC % applied equally
across all
Rate Classes

Base Cost of Fuel and Purchase Power	Base Power Suppy $/kWh	PPFAC % %	Net Power Supply $/kWh	Rate Impact $/kWh
Residental	$0.055342	-8.908%	$0.050412	-$0.004930
Small Commercial	$0.054575	-8.908%	$0.049714	-$0.004862
Commercial	$0.054229	-8.908%	$0.049399	-$0.004831
Industrial/Mining	$0.046384	-8.908%	$0.042252	-$0.004132
Aggregated Base Rate	$0.054375	-8.908%	$0.049531	-$0.004844

PPFAC % Rate Results

- PPFAC % Rate provides more equitable treatment of price changes by rate class
- PPFAC % Rate mirrors rate case cost of service rate design principles
- PPFAC % Rate allocates cost to reflect seasonal and hourly usage patterns
- Based on this example, the decrease in the PPFAC rate results in a bigger savings to residential customers

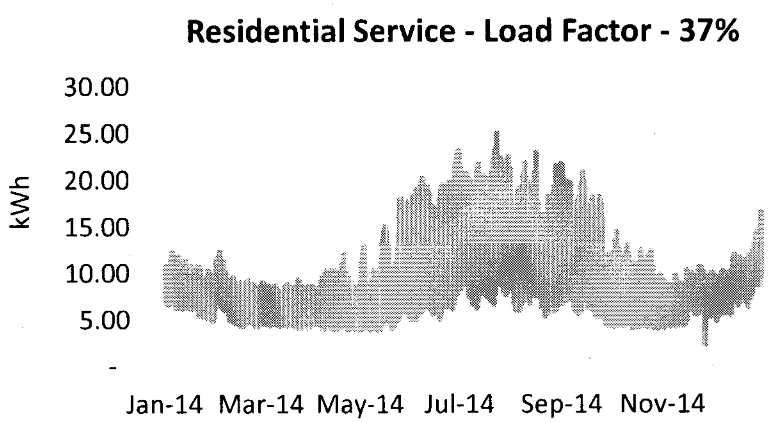
UNSE Customer Rate Class	Existing Base Power Supply Rate $/kWh	New Power Supply Rate $/kWh Current PPFAC Rate	New Power Supply Rate $/kWh Proposed PPFAC % Rate
Residential Service	$0.055342	$0.050498	$0.050412
Large Power Service	$0.046384	$0.041540	$0.042252

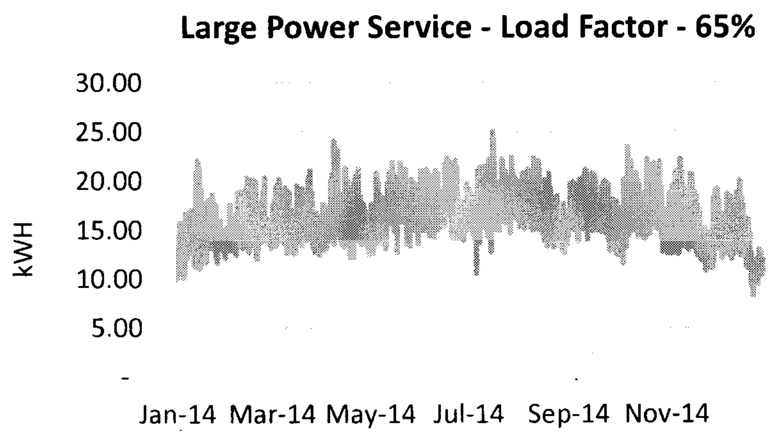
Residential Service vs. Large Power Service

Residential Service customers consume a higher percentage of on-peak and summer energy versus Large Power Service customers

	Residential		Large Power Service	
TOU	Annual Usage, kWh	% of Annual	Annual Usage, kWh	% of Annual
On-Peak	568,517	75%	166,486	67%
Off-Peak	189,311	25%	83,485	33%
Total	757,828	100%	249,971	100%

Summer Usage	344,713	45%	89,279	36%





Residential Service vs. Large Power Service

Low Load Factor Customers Incur

- Higher marginal costs (seasonal usage)
- Higher fixed system costs (spread over fewer kWh)
- Higher distribution losses

The PPFAC % Rate better allocates PPFAC changes based on the cost to serve a particular rate class

Marginal Cost by Rate Class

Months	UNSE 2015 Marginal Costs $/kWh	Residental 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

Note: *The marginal costs represented in the table above only reflect the cost of energy and exclude any fixed costs such as firm capacity or transmission.*

Customer Bill Samples

- The following exhibits details how the customer bill would be modified under the PPFAC % rate methodology.

- The following customer rate classes are show below:
  - RES-01 Residential Service
  - LPS – Large Power Service

UniSourceEnergy SERVICES

#BWNMMYZ

Bill Due: 02-01-2016
Due Date: 02-15-2016

John Doe
2222 S 5th Street
Prescott AZ 86304-8073

RES-01 Residential Service

DELIVERY SERVICES	
Customer Charge	10.00
Customer Charge Acquisition Credit	1.15 CR
Delivery Charge 1st 400kWhs 400.00 @ $0.0193	7.72
Delivery Charge 401-1000 kWhs 600 @ $0.03435	20.62
Delivery Charge - Above 1,000 kWhs 288.00 @ $0.038499	11.09
Transmission Cost Adjustor-kWh 1,288.00 @ $0.00114	1.47
POWER SUPPLY CHARGES	
Base Power Supply Charge kWh 1,288.00 @ $0.055342	71.28
PPFAC - kWh 1,288.00 @ $-0.004844	**6.26 CR**
PPFAC Acquisition CR - kWh 1288.00 @ $-0.00098	1.26 CR
TOTAL DELIVERY & POWER SUPPLY CHARGES	113.52
GREEN ENERGY CHARGES	
Renewable Energy Standard Tariff	3.40
DSM Surcharge - kWh 1,288.00 @ $0.0015	1.93
LFCR EE 0.3058% of $113.52	0.35
LFCR DG 0.2746% of $113.52	0.31
TAXES AND ASSESSMENTS	
State Sales Tax	7.63
County Sales Tax	0.34
City Franchise Fee	2.66
RUCO Assessment	0.04
ACC Assessment	0.29
TOTAL CURRENT CHARGES - Electric Service	130.18

PPFAC Rate

UniSourceEnergy SERVICES

#BWNMMYZ

Bill Due: 02-01-2016
Due Date: 02-15-2016

John Doe
2222 S 5th Street
Prescott AZ 86304-8073

RES-01 Residential Service

DELIVERY SERVICES	
Customer Charge	10.00
Customer Charge Acquisition Credit	1.15 CR
Delivery Charge 1st 400kWhs 400.00 @ $0.0193	7.72
Delivery Charge 401-1000 kWhs 600 @ $0.03435	20.62
Delivery Charge - Above 1,000 kWhs 288.00 @ $0.038499	11.09
Transmission Cost Adjustor-kWh 1,288.00 @ $0.00114	1.47
POWER SUPPLY CHARGES	
Base Power Supply Charge kWh 1,288.00 @ $0.055342	71.28
PPFAC % @ - 8.91% of $71.28	**6.35 CR**
PPFAC Acquisition CR - kWh 1288.00 @ $-0.00098	1.26 CR
TOTAL DELIVERY & POWER SUPPLY CHARGES	113.41
GREEN ENERGY CHARGES	
Renewable Energy Standard Tariff	3.40
DSM Surcharge - kWh 1,288.00 @ $0.0015	1.93
LFCR EE 0.3058% of $113.41	0.35
LFCR DG 0.2746% of $113.41	0.31
TAXES AND ASSESSMENTS	
State Sales Tax	7.63
County Sales Tax	0.34
City Franchise Fee	2.66
RUCO Assessment	0.04
ACC Assessment	0.29
TOTAL CURRENT CHARGES - Electric Service	130.07

PPFAC % Rate

UniSource Energy SERVICES

#BWNMMYZ

Bill Due: 02-01-2016
Due Date: 02-15-2016

ABC Company
444 N Main Ave
Prescott AZ 86304-8073

LPS – Large Power Service

DELIVERY SERVICES	
Customer Charge	1,200.00
Customer Charge Acquisition Credit	143.78 CR
Demand Charge per kW 1,384 @22.00	30,448.00
Transmission Cost Adjustor per kW 1,384 @ $0.4329	599.13
Power Factor Adjustment	1,210.00
Delivery Charge 622,000.00 @ $0.000462	287.36
POWER SUPPLY CHARGES	
Base Power Supply Charge kWh 622,000.00 @ $0.046384	28,850.85
PPFAC - kWh 622,000.00.00 @ $-0.004844	**3012.97 CR**
PPFAC Acquisition CR - kWh 622,000.00 @ $-0.00098	609.56 CR
TOTAL DELIVERY & POWER SUPPLY CHARGES	58,829.03
GREEN ENERGY CHARGES	
Renewable Energy Standard Tariff	90.00
DSM Surcharge - kWh 622,000.00 @ $0.0015	933.00
LFCR EE 0.3058% of $58,829.03	179.89
LFCR DG 0.2746% of $58,829.03	161.54
TAXES AND ASSESSMENTS	
ACC Assessment	119.59
TOTAL CURRENT CHARGES - Electric Service	60,313.06

PPFAC Rate

UniSource Energy SERVICES

#BWNMMYZ

Bill Due: 02-01-2016
Due Date: 02-15-2016

ABC Company
444 N Main Ave
Prescott AZ 86304-8073

LPS – Large Power Service

DELIVERY SERVICES	
Customer Charge	1,200.00
Customer Charge Acquisition Credit	143.78 CR
Demand Charge per kW 1,384 @22.00	30,448.00
Transmission Cost Adjustor per kW 1,384 @ $0.4329	599.13
Power Factor Adjustment	1,210.00
Delivery Charge 622,000.00 @ $0.000462	287.36
POWER SUPPLY CHARGES	
Base Power Supply Charge kWh 622,000.00 @ $0.046384	28,850.85
PPFAC % @ - 8.91% of $28,850.85	**2570.61 CR**
PPFAC Acquisition CR - kWh 622,000.00 @ $-0.00098	609.56 CR
TOTAL DELIVERY & POWER SUPPLY CHARGES	59,271.39
GREEN ENERGY CHARGES	
Renewable Energy Standard Tariff	90.00
DSM Surcharge – kWh 622,000.00 @ $0.0015	933.00
LFCR EE 0.3058% of $59,271.39	181.25
LFCR DG 0.2746% of $59,271.39	162.76
TAXES AND ASSESSMENTS	
ACC Assessment	119.59
TOTAL CURRENT CHARGES - Electric Service	60,757.99

PPFAC % Rate

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF 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

Rejoinder Testimony of

Carmine A. Tilghman

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

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, 85701.

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes, I filed both Direct and Rebuttal testimony in this proceeding.

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

A. I will be addressing portions of Staff Witness Broderick's testimony; Staff Witness Liu's testimony; TASC Witness Fulmer's testimony; and APS Witness Brown's testimony.

Q. Staff recommended that net metering be continued without changes, contingent upon the Commission accepting their recommendation to migrate from two-part to three-part rates, and requested a confirmation that UNSE would be willing to accept this recommendation until at least its next rate case. Does the Company accept these positions?

A. Not entirely. In my Rebuttal Testimony (page 3, lines 17-18), I stipulated Staff's proposed three-part rate structure would eliminate the need to specifically address the current NEM policy *if properly designed and implemented in a timely manner* (emphasis added.) As Mr. Broderick noted in his Surrebuttal Testimony, compensation to DG solar customers will be higher under the most recent rate design proposal due to the higher kWh rates being offered and the ability to over-generate energy during the winter months for use in the summer months. The current three-part design structure currently proposed is a transitional structure specifically designed to minimize the impacts to customers transitioning to a new rate structure, and continues to send the incorrect price signal for the design and installation of DG solar. The Company still believes the elimination of monthly rollover (banked kWh for use in later months) and the application of a market-based proxy rate (renewable credit rate) is still the most appropriate method for excess energy delivered to the grid from a solar DG system. To be clear, the Company has only proposed this NEM policy change be effective for those customers who submitted an application after June 1, 2015, and that customers who submitted an application by June 1, 2015 remain on the current NEM rate structure.

The Company does, however, appreciate Staff's willingness to find common ground during this transitional period, and the Company would like to be supportive of this position. The Company does not, however, agree with the idea that NEM policy changes must wait until the Company's next general rate case. The Company disagreed with Staff and the intervening parties' position that NEM changes should be made through a general rate case, and continues to disagree with that position. If Staff is going to maintain its position that the results of the pending Value and Cost of Solar docket (No. E-00000J-14-0023) cannot be applied until the Company's next general rate case, then the Company strongly asserts that the issue be addressed in this rate case, as originally contemplated.

The Company has previously presented arguments in support of changing the current NEM policy, with additional supporting Surrebuttal Testimony by APS Witness Brown. At this time, the Company would like to reserve the right to continue the discussion of NEM changes during the hearing, while the idea of a properly designed and implemented three-part rate design structure is being contemplated.

Q. TASC Witness Fulmer again asserts that geographically dispersed DG provides a "smoother" more reliable solar power source than a central station. Do you agree with this statement?

A. No. Mr. Fulmer supports his diversity claim by relying on several studies that compare multiple DG sites to a single utility scale facility. If the Company were only discussing the proliferation of DG relative to a single utility scale facility, I would concur with the conclusion. However, what Mr. Fulmer fails to acknowledge is that the utility is developing multiple utility scale facilities, located in multiple regions, spread across the entire UNSE service territory.

As I previously noted in my Rebuttal Testimony, the dispersion of DG is predicated on the solar installer's ability find suitable customers to purchase or lease their systems without any regard to the system impact or reduction or overall variability. This process, which has historically been targeted to customers with either the financial means or necessary credit scores to procure a system, does not result in a well-planned, organized distribution of solar DG.

On the contrary, the Company's ability to procure and install multiple large scale solar facilities, consistent with integrated resource planning principles, provides similar geographic dispersion benefits without relying on the random nature of solar DG sales.

In addition, there are multiple forms of intermittency associated with solar DG. Mr. Fulmer only addresses solar "intermittency" as the overall impact to the grid, he fails to even acknowledge the intermittency impacts on the individual distribution transformer and feeder circuits, and the associated wear and tear, regardless of the supposed smoothing benefits of dispersed DG. Intermittency associated with utility scale solar does not impact these distribution components.

Finally, as previously noted, there are numerous benefits associated with utility scale solar not associated with DG, such as secure communications, downward ancillary services, and interoperability with the Company's system control and data acquisition system (SCADA).

Q. TASC Witness Mr. Fulmer provided a Value of Solar analysis in his Surrebuttal Testimony. Does the Company agree with Mr. Fulmer's assertions?

A. No, the Company does not agree with Mr. Fulmer's value of solar assertion. As the Commission currently has a Value and Cost of DG Solar docket in which TASC may attempt to validate their position, it is unnecessary to do so in this proceeding. However, the Company would like to note one very significant point regarding TASC's position: While Mr. Fulmer and TASC believe the benefits of DG solar to be on the order of \$0.10-\$0.14 per kWh, *at no time does Mr. Fulmer or TASC ever attempt to provide a justification why the ratepayers should pay twice the amount for solar than what the Company can procure for an equivalent amount of solar on its distribution system.*

Q. Both Staff Witness Liu and TASC Witness Fulmer provided calculations of the impacts of proposed rates on customers. Did you review the assumptions contained within their respective models?

A. Yes, but only as the assumptions related to the solar systems' production, installation costs, and other solar related data.

Q. Do you agree with the assumptions used by Staff and TASC? In not, please explain.

A. The data used by Staff witness Liu is reasonable; however, there were several discrepancies in the TASC model used by Mr. Fulmer. Several of these discrepancies were noted by Staff Witness Liu, particularly as it relates to the specified location, production, and installation costs. Specifically, the two major differences noted are:

1. Staff used Company provided data of 1,800 kWh/kw, while TASC provided Staff an annual production value of 1,698 kWh/kW (Liu Surrebuttal, page 5, line 4). While TASC Witness Fulmer did not provide a direct reference to the production value used in his calculation, footnote 57 contained in Mr. Fulmer's Surrebuttal Testimony (page 27) indicates the use of a customer whose average annual consumption of 18,000 kWh is 80% offset by an 8.5 kW solar system, implying an average annual production of 1,694 kWh/kw.
2. Staff selected a cost of installation of $2,750 per kW, which was the average of the $2,500 per kW provided by the Company and the $3,000 per kW provided by TASC (Liu Surrebuttal, page 7, line 9). Surprisingly, TASC Witness Fulmer did not use the same installed cost value that TASC provided to Staff, but rather used a much higher installed system cost of $3.60/watt, or $3,600 per kW (Fulmer surrebuttal, page 28, line 5).

Q. Have you reviewed the testimony provided by APS Witness Brown?

A. Yes, I have.

Q. Do you agree with Mr. Brown's conclusions regarding the use of large scale solar as a proxy for DG?

A. Yes. As the Company has previously stated, which is consistent with the conclusion by Mr. Brown, the use of large scale solar procured in a competitive market is the most appropriate method for pricing DG.

Q. A number of interveners have submitted Surrebuttal Testimony that is ideologically opposed to the positions you have previously stated in your testimony. Does your lack of acknowledgement of these statements in your rejoinder testimony mean your position, or the Company's position, has changed?

A. No. In the limited amounted of time available to provide Rejoinder Testimony, I have limited my testimony to addressing only a few of the Intervenors' comments. A lack of acknowledgement in my Rejoinder testimony regarding a specific interveners' Surrebuttal Testimony should not be construed as a change in the Company's previously stated position.

Q. Did Staff request the company to submit a draft Plan of Administration for its REST surcharge?

A. Yes. Attached as **Exhibit CAT-RJ-1** is an initial draft of the Plan of Administration that we will work with Staff to finalize. We would anticipate filing a final Plan of Administration for commission approval as part of our compliance filing following the issuance of a final commission decision in this case.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit CAT-RJ-1

UNS Electric, Inc.
Renewable Energy Standard and Tariff
Plan of Administration

Table of Contents

1. GENERAL DESCRIPTION

This document describes the plan for administering the Renewable Energy Standard and Tariff rules ("REST") and associated Implementation Plan ("IP" or "Plan"), as approved by the Arizona Corporation Commission ("Commission") in Decision No. 69127 (Nov 14, 2006), applicable to UNS Electric, Inc. ("UNS Electric"), and codified in the Arizona Administrative Code ("A.A.C.") R14-2-1801 through R14-2-1815. The REST provides the requirements and governance to affected utilities required to meet the Arizona Renewable Portfolio Standard ("RPS").

2. DEFINITIONS

Implementation Plan – The annual Company Plan that describes how it intends to comply with the Renewable Energy and Standard Tariff rules for the next calendar year.

REST Surcharge - An amount generally expressed as a rate per kWh, which reflects the per kWh charge applied to an individual customers billed usage, by customer class, designed to cover the cost of the Company's approved annual Implementation Plan budget.

REST Plan - The Company's Renewable Energy and Standard Tariff Implementation Plan approved by the Commission on an annual basis.

REST Year - A calendar year beginning January 1 and lasting through December 31.

REST Costs - The costs associated with the design, implementation, management, contracts, training, education, labor, and other services contained in the Company's Implementation Plan and incurred by the Company, which otherwise would not be incurred without the Commission's RPS mandate and which are not recovered through the Company's general retail rate structure.

All other terms and definitions associated with the REST are contained in the Arizona Administrative Code ("A.A.C.") Section R14-2-1801.

3. REST PLAN COMPONENTS

The REST Plan will consist of, at a minimum, the following components designed to meet the Company's annual requirements of the Arizona Renewable Portfolio Standard. Those components are:

1. Executive Summary: Designed to provide an overview of the Company's annual Implementation Plan.
2. Utility Scale Renewable Generation: A description of the Company's existing and proposed utility scale (grid tied) renewable generation; including but not limited to: facility location, size, expected production, and operational dates.

3. Distributed Renewable Generation: A description of the Company's existing and expected distributed renewable generation; including but not limited to: total residential and non-residential capacity, and expected annual production for both residential and non-residential. These values shall be reported regardless of system ownership or Renewable Energy Credit ("REC") ownership.

4. Market Cost of Comparable Conventional Generation ("MCCCG"): The equivalent market cost of energy and capacity associated with a particular renewable technology, typically shown as a weighted average annual value. The Plan shall include a description and associated exhibit showing the annual MCCCG rates stated as a single dollar per MWh value by technology type. At a minimum, the MCCCG will be calculated for the following technology types: wind, photovoltaic ("PV"), concentrated solar thermal, and biomass. The MCCCG for multiple regions may be included, as appropriate (i.e. – Arizona wind versus New Mexico wind).

5. Above Market Cost of Comparable Conventional Generation ("AMCCCG"): The difference between the Company's contractual obligation under a Power Purchase Agreement ("PPA") and the associated technology's MCCCG. The Plan shall contain an exhibit showing the annual AMCCCG values by contract and total required annual revenue based on expected production.

6. Line Item Budget: The line item budget shall contain, at a minimum, specific estimated budgeted amounts for the following categories. At a minimum, the budget shall contain the following:

   a. Utility Scale Energy Costs - AMCCCG costs associated with current or expected Power Purchase Agreements (PPA) for the associated implementation year. Additionally, any Commission authorized recovery of estimated carrying costs associated with Company owned investments shall be listed.

   b. Customer Sited DG Energy Costs – All costs associated with customer up front, performance based, or other Commission approved incentives shall be listed. Additional costs associated with customer based programs may be included, such as meter reading costs, consumer education and outreach programs, and other customer based program costs.

   c. Program Labor and Administration Costs –Internal labor costs that are not currently collected through the Company's base rates, as identified in the Company's previous general rate case, shall be listed. External labor costs, including temporary administrative support, student interns, and legal costs associated with the administration, preparation, and representation of the Company with regards to renewable energy shall be included. Administrative costs associated with materials, fees, supplies and other costs shall be listed.

d. Research and Development (R&D) Costs – All costs associated with Commission approved R&D programs shall be listed separately.

e. Carryover Funds – Carryover funds is the imbalance amount on the Company's annual compliance report that shows the difference between the amount collected by the Company for a specific year through its renewable energy surcharge and the actual amount spent on implementing the Commission approved implementation plan. This value will represent either an over-collection or under-collection funds by the Company relative to the actual cost of the previous year's implementation plan. This value shall be applied to the subsequent annual implementation plan budget (i.e. – an over-collected amount for the year 2015, as shown in Company's annual report filing on April 1, 2016, shall be applied to the budget for the 2017 implementation plan).

7. REST Tariff: The Company shall provide a proposed REST tariff and Statement of Charges, which shall include proposed per kWh charge and customer surcharge caps.

8. Associated Exhibits: The Company shall provide associated exhibits as required for the following:

   a. Budget
   b. MCCCG
   c. AMCCCG
   d. New resources plan and costs
   e. REST Tariff and Statement of Charges
   f. Renewable Energy Credit Purchase Program (as applicable)

4. CALCULATION OF THE REST RATE

The REST Tariff rate and associated customer caps shall be calculated annually, and while subject to variation, with the following principles in mind:

a. The annual per kWh rate and customer caps shall be designed to generate revenues to be approximately equal to the requested budget.
b. The percentage of revenues associated with each customer class should, within reason, attempt to approximate the percentage of sales from each class. Exceptions may be made for disproportionate economic impacts to a specific customer class if the Commission believes it is in the public interest.

Subject to Commission approval, the REST tariff rate shall be reset on January 1 of each year, and shall be effective with the first January billing cycle unless otherwise ordered by the

Commission. A REST tariff approved after January shall not be retroactive, and the any imbalance shall be collected subject to the provision of Carryover Funds described herein.

5. FILING AND PROCEDURAL DEADLINES

A. July 1Filing

UNS Electric shall file their proposed implementation plan no later than July 1 each year.

B. April 1 Filing

UNS Electric shall file their annual report no later than April 1 each year.

C. Additional Filings

UNS Electric will also file with the Commission any additional information that the Commission Staff determines pertinent to the Company's implementation or annual report filings.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Rejoinder Testimony of

Dallas J Dukes

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

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 or Rebuttal Testimony in this proceeding?

A. Yes.

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

A. I will respond to the testimony of witness Broderick of Staff, Fulmer of TASC, witness Quinn of AURA, witness Alston of AURA, witness Rubin of AURA, witness Kobor of Vote Solar, witness Huber of RUCO, witness Zwick of ACCA, witness Wilson of Western Resource Advocates, and witness Schlegel of Sweep.

Q. How is your rejoinder testimony organized?

A. In addition to this Introduction, Section 2 provides a summary of the benefits associated with three-part rates and how transitioning to them is in the public interest, Section 3 addresses the bill impacts associated with the proposed three-part rates, as presented its Company's Rejoinder Testimonies, Section 4 address a couple specific positions stated by an Intervenor in Surrebuttal Testimony.

II. PUBLIC INTEREST

Q. Have you reviewed Staff witness Broderick's proposal to provide bill credits or system incentives to DG customers[1]?

A. Yes, I have. Mr. Broderick proposes a 15% bill credit for DG customers before June 1, 2015 and a 15% cost per kW incentive for DG solar installations for the first six months following the completion of the full transition from two-part rates to three-part rates. The Company is proposing some modifications to these proposals as described in the Rejoinder Testimony of Company witness Craig Jones.

Q. Does the Company believe that Mr. Broderick's bill credit proposal for pre June 1, 2015 DG customers is in the public interest?

A. Yes, we believe it would be in the public interest if the Commission approves either (i) a bill credit for pre June 1, 2015 DG customers or (ii) to grandfather these customers under two-part rates in a manner as proposed by the Company in its Direct Testimony.

Q. Several intervening witnesses have asserted that three-part rate design is not in the public's interest or more specifically not in the interest of Residential Customers. Can you please summarize some of the key benefits of three-part rates and how this rate structure is in the public interest?

A. Yes, the Company and many of the Intervenors' witnesses addressing rate design have testified with regards to the many benefits associated with three-part rate design or demand based rates. I will attempt to summarize some of the key points testified to so far in this proceeding.

1. Three-part rates will be beneficial to our customers

---

[1] Staff Witness Broderick at 6:2-29, 14:2-4

"multi-part rates represent the best practices approach to rates that are just and reasonable, equitable and economically efficient"[2]

"three-part rates, which include a demand charge as well as a fixed charge and an energy charge, do a much better job of reflecting the cost structure of generating and delivering electricity than two-part rates"[3]

"Including a demand charge (in addition to a basic service charge and energy charges) in a retail rate provides customers with rates that better reflect the way utility costs are incurred."[4]

"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 recover 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."[5]

"Staff considered other solutions to the problem caused by shifting fixed costs from vacant, seasonal and distributed generation ("DG") customers. While other solutions would require carving out subclasses and applying measurements to define inclusion or exclusion, Staff's long-term rate design proposal sets the foundation to deal with these concerns without arguing over whether one or more subclasses exist and which customers should be selected for different rates."[6]

---

[2] Dr. Overcast Rebuttal at p. 27.
[3] Ahmad Faruqui Surrebuttal at p. 2.
[4] Daniel G. Hansen Direct at p. 4.
[5] Thomas M. Broderick Direct at p. 2.
[6] Howard Solganick Surrebuttal p. 12.

"In fact, demand charges correct the misalignment between a customer's cost of service and their bill inherent in two-part energy rates that rely on a monthly service charge and kWh energy charges to recover the utility's infrastructure investment necessary to serve the home."[7]

"The demand charges proposed by UNSE provide price signals that will inevitably enhance the productivity and efficiency of solar DG. What the fixed charge proposal of UNSE does do is to promote overall system efficiency by tying rates and cost causality more closely together so that marginal rates better reflect actual marginal costs while the fixed rates recover unavoidable fixed costs. This improves the price signals to customers, reduces the degree to which cross subsidies are built into rates (including those that flow from non-solar to solar customers), and makes the actual market value of solar DG and energy efficiency more transparent. In short, the result of both the change in fixed costs and the adoption of demand charges for solar DG customers is to insert the disciplines of market and cost that have been lacking in the past."[8]

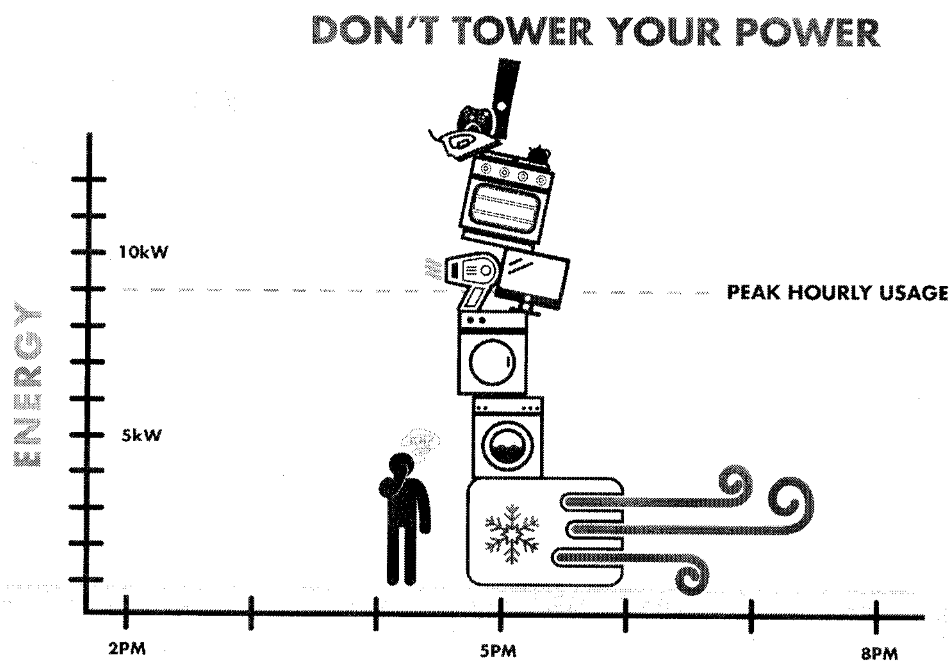
The citations above represent the opinions of nine experts that collectively have over 250 years of professional experience in rate design, cost of service rate-making, utility operations and rate case proceedings. Together, these witnesses testify for the advancement of rate design and support that three-part rates are (i) the best practice approach to rates, (ii) in the public interest and (iii) beneficial to all retail customers.

2. <u>Three-part rates will empower customers to save</u>

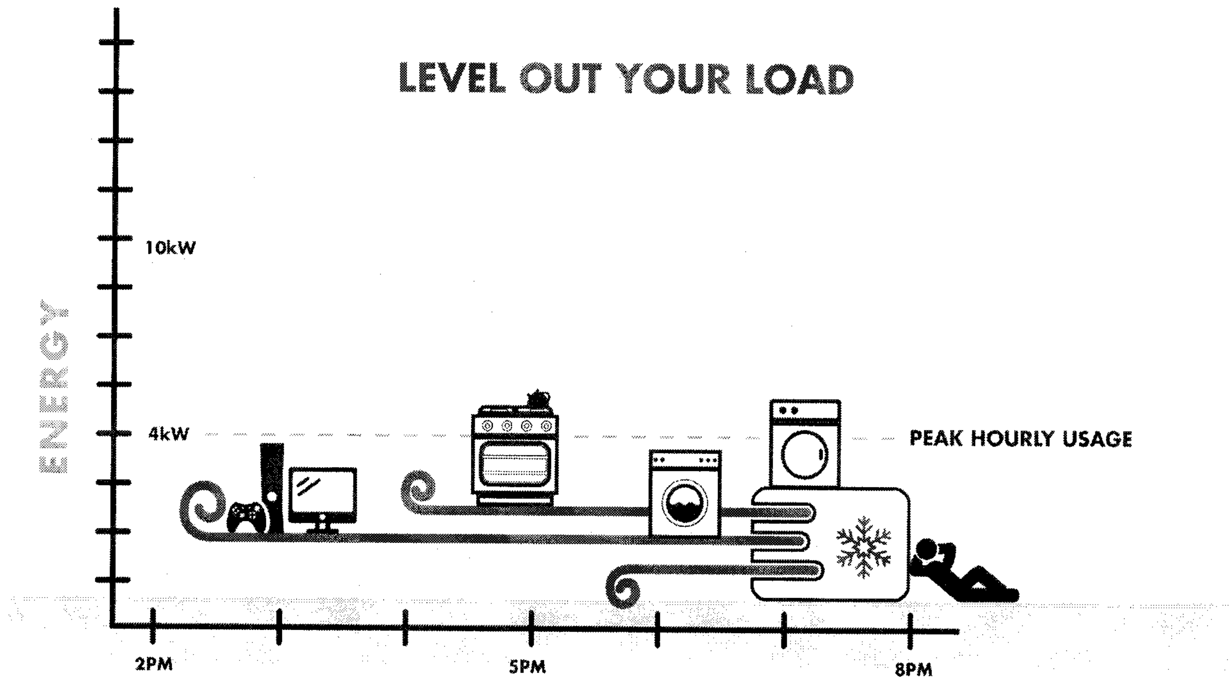
Three-part rates provide price signals to customers that are more closely aligned with how costs are actually incurred in providing safe and reliable electric service. Demand-based rates will provide a real financial incentive to reduce customer peak usage and to

[7] Charles A. Miessner Surrebuttal p. 4.
[8] Ashley C. Brown Surrebuttal p. 23.

use the utility system more efficiently – thus reducing overall system costs, which is clearly in the public interest and beneficial to all customers. And by recovering system costs partially through demand charges and not only through energy charges, the customer then has more options available to them to reduce their monthly bills. They can purchase higher efficiency appliances or household electrical devices, and reduce their energy consumption and thus reduce the cost associated with the energy and demand portions of their bill. They can still adjust their thermostat during peak hours and cycle their air conditioner and furnace less and thus save energy and reduce demand. And/or they can spread out the usage of their higher load appliances – not run their electric clothes dryer during peak hours or at the same time as using their electric stove (even if during peak hours); reducing their highest hourly consumption in those peak hours and the cost associated with that portion of their bill. Below are just a couple of potential illustrations that can be used to assist Customers in this concept.



Using multiple electric appliances at the same time will increase the peak hourly usage charge on your monthly bill.

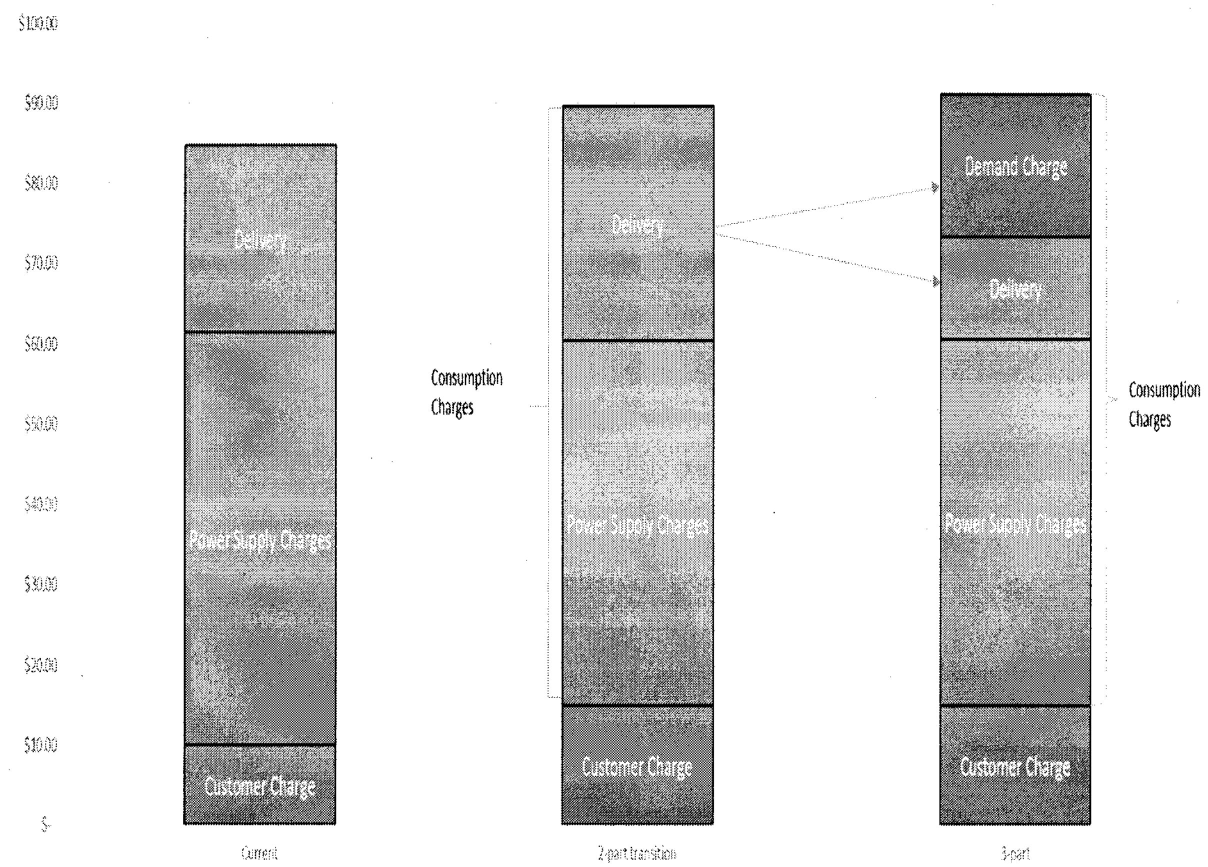


Spreading out your use of appliances during peak usage periods and throughout the day will reduce your peak hourly usage – and lower your bills.

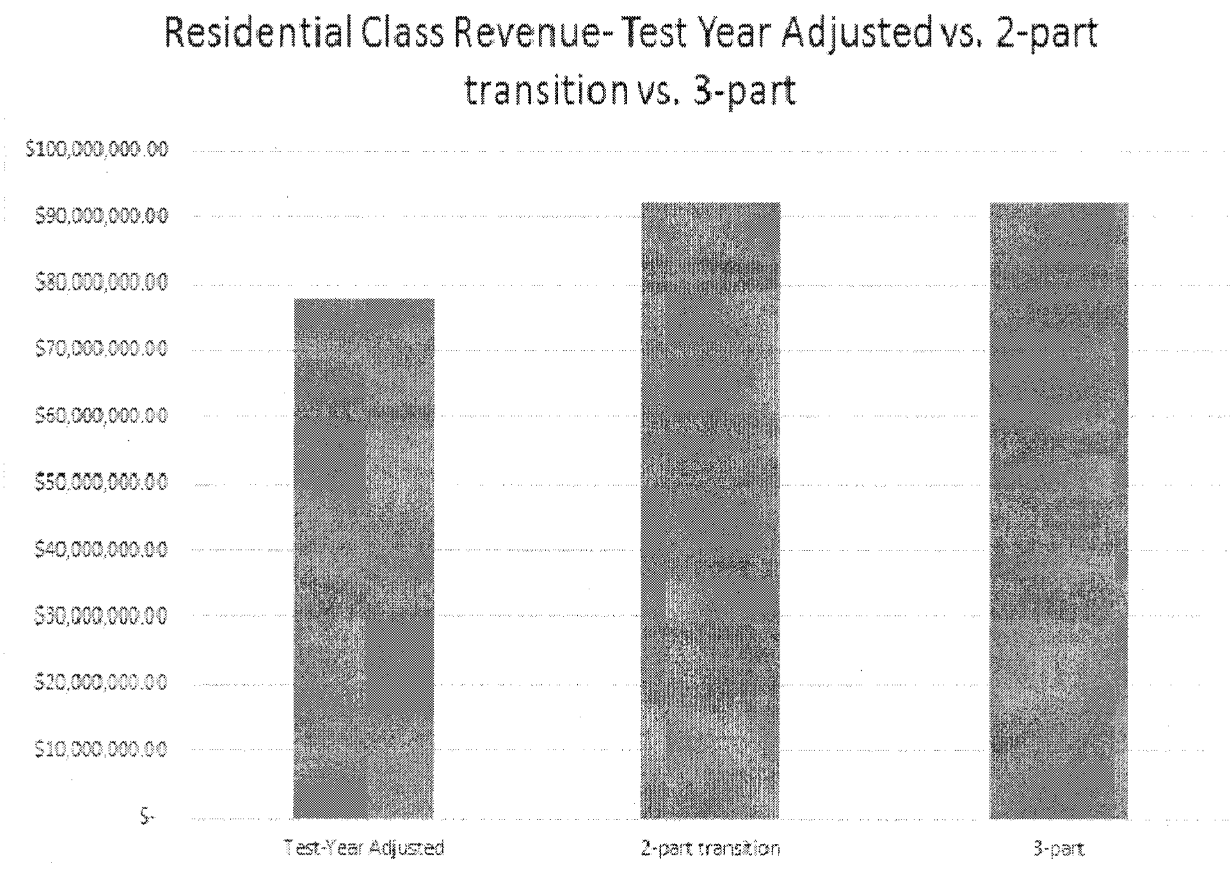
Understand, we are not adding a cost to the customers' bills in the class, we are proposing to split the same cost into two <u>controllable</u> charges. One based upon the accumulated energy used by a customer in a billing period and one based upon the highest energy usage in one hour during peak demand periods. As APS witness Brown stated, "demand charges do not increase rates. They are revenue neutral since the demand costs are already embedded in tariffs. What demand charges do is make those costs transparent, and by doing so, enable all customers, low income included, to shape their demand in ways that can reduce their bill."[9]

[9] Ashley Brown Surrebuttal at p. 8.

Average Monthly Bill Impacts Current to 2-part transition to 3-part



What this means, is that the proposed three-part rate structure is designed to recover the same amount of revenue as a two-part structure, just in a different way.



And under three-part rates, customers will now have an additional way to reduce their bill. In the Direct Testimony of APS witness Miessner, he stated that 60% of a sample of APS' customers on a three-part rate reduced their demand after switching to the three-part rate, with those who actively manage their demand achieving demand savings of 10% to 20% or more.[10] This makes economic sense as customers are given a financial incentive to use electrical equipment differently or at varying times, rather than all at once. It also provide solar DG customers the signal that increasing late afternoon production reduces peak utility demand.

[10] Charles Miessner Direct at p. 7.

3. <u>The proposed three-part rate, as proposed by UNS Electric, is designed specifically to minimize unexpected bill impacts.</u>

The intention of the three-part rate, as proposed by the Company and Staff, is as a transitional structure and has many features specifically included to assure gradualism in rate impacts, rate stability and any unexpected changes. Essentially, the three-part rate proposal is designed very conservatively to the customers' favor by mitigating the chances of adverse impacts (versus our transitional 2-part rate) for our full requirement customers.

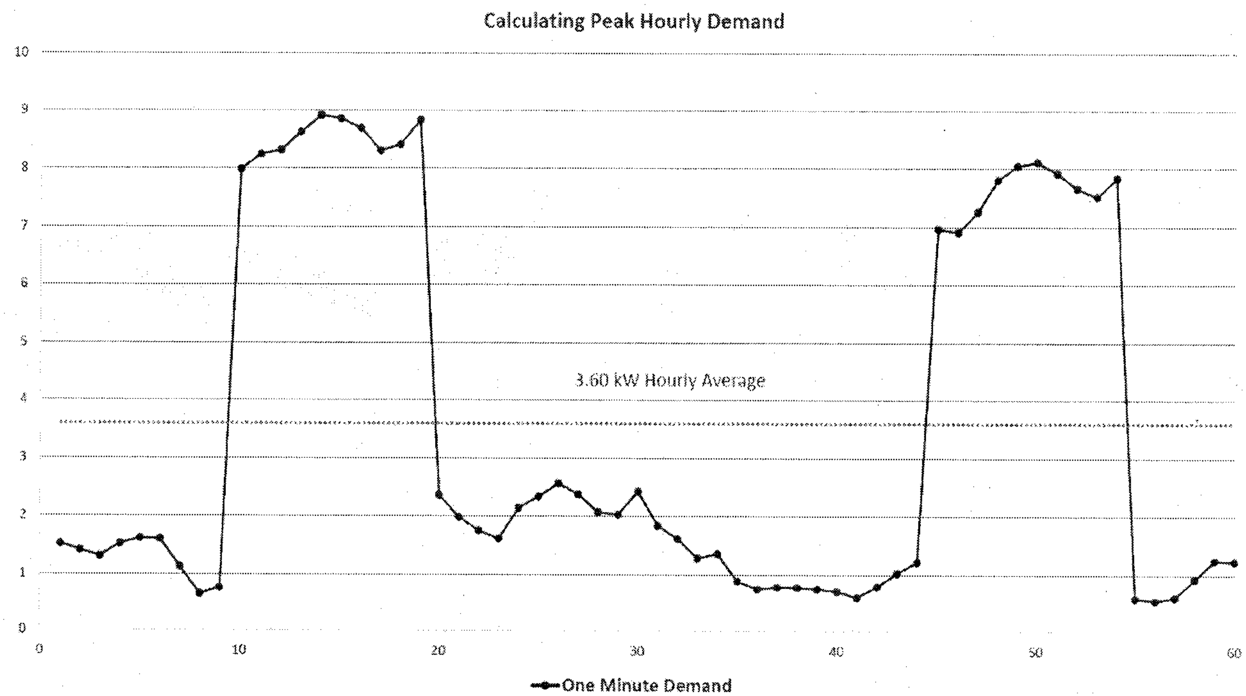
Only customers will atypical usage patterns will see increases on a three-part rate related to how they use the electric grid and the cost to serve them. An incomplete list of these customers includes: partial requirement service, someone using an arc welder during peak hours, or unusually high levels of purely Ohmic heating[11]. These customers will have the opportunity to save by changing their behavior or deploying their dollars into cost effective measures to reduce their demand levels, because they are currently using the system significantly less efficiently than the vast majority of the class. The minimum load factor will help to protect these customers to avoid unexpectedly high bills while it is in effect. But their bills will still show measured demand, showing the demand that could've been used for billing, if not for the minimum load factor. This will give these customers valuable information along with the price signal associated with the billed demand charges, so these customers can modify their usage patterns, if they choose too.

Our typical residential and small general service customers primarily will not see their annual cost of electricity increase simply as a result of migrating to three-part rates, what they will see is greater opportunity to reduce their bill. This is consistent with the foundational principles of proper rate design and is in the public interest and beneficial to

[11] Heating resulting from the passage of an electric current through a resistive material.

our customers. The features put in place to assure this are: measuring the "demand" as the customer's highest hourly usage, limiting this measurement to peak hours only, including just a portion of demand related cost in the demand rate and a load factor floor.[12]

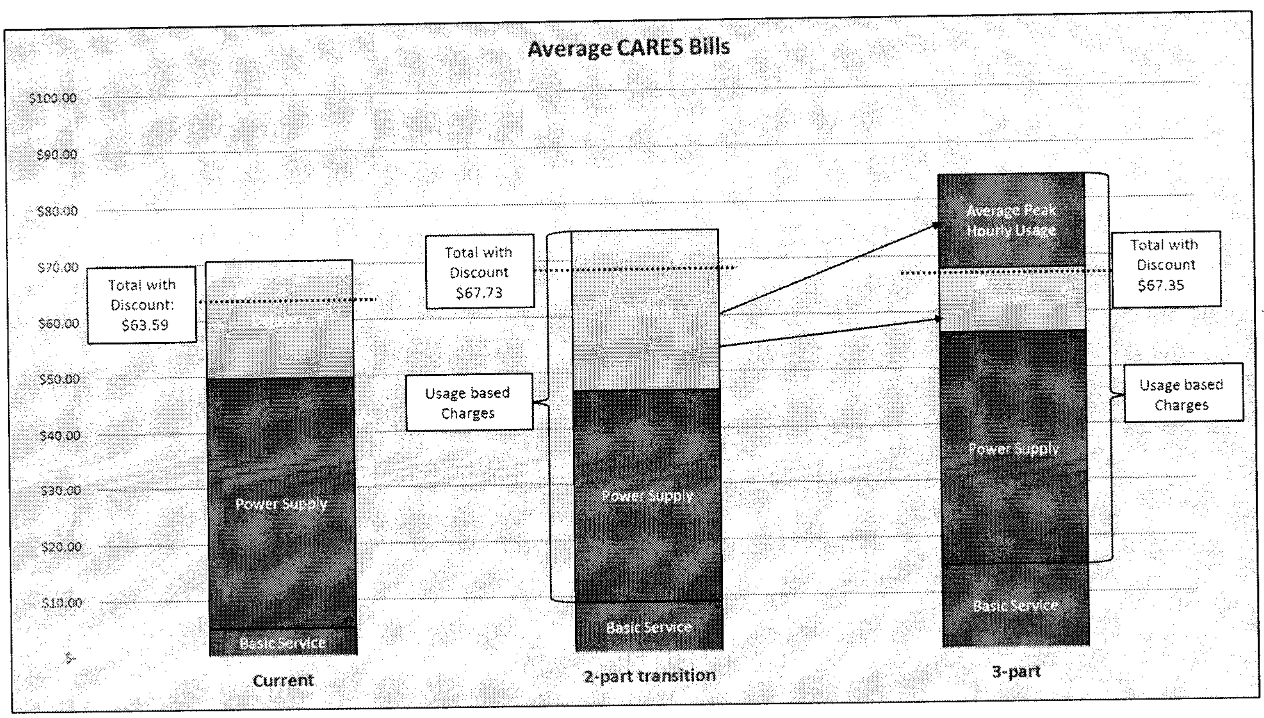
Using an hourly measure for demand alone is a significant mitigating measure, as appliances are rarely used for an entire hour and even when they are, the current draw associated with their usage is cyclical. Below is a chart based on a typical UNS Electric customer, showing their typical peak hour and peak day. You can see if we were using a one minute interval, their demand determinant would be 8.91 kW, using a 15 minute it would be 4.95 kW, but by using a one hour interval the measured demand is 3.60 kW.



[12] Craig Jones Rebuttal at p. 13-15.

4. <u>Three-part rates (as proposed by UNS Electric) will be beneficial to low income customers</u>

Low income customers (CARES customers at UNS Electric) are not by default low usage customers, in fact their usage levels are essentially equivalent to standard residential customers. But more importantly when transitioning to three-part rates, they do have load factors[13] that are equivalent too or even slightly higher than standard residential customers. As such, three-part rates will benefit the CARES customers of UNS Electric. And as discussed above, will give these customers increased options to reduce their bill. As designed by the Company and explained in more detail in the Rejoinder testimony of Craig Jones – CARES customers will receive a $17 flat discount off each month's bill. To the extent they are low usage customers, this specific change to our initially proposed CARES rates will greatly mitigate any impacts associated with the elimination of the artificially low first rate tier included in present rates.



[13] Load factor is defined as the average usage over a period of time divided by the customer's maximum demand (as measured for billing) over the same period of time.

However, and just as importantly, as pointed out be APS witness Ashley Brown, recovering fixed cost more equitably through three-part rates as opposed to two-part will reduce the subsidy presently being provided to customers that can afford to invest in distributed generation ("DG"). In UNS Electric's service territory, less than 0.4% of CARES customers are DG customers, however 2.3% of standard residential customers are – and that number and differential is increasing rapidly. As discussed in Mr. Brown's Surrebuttal Testimony, "Higher income customers are more likely to install rooftop solar, and all other customers, including low income customers, pay the subsidies in question in the form of higher rates. This is, in effect, a wealth transfer from lower income customers to higher income customers. All available analysis indicates that the cross-subsidies inherent in the current suite of net metering and volumetric rate design subsidies transfer wealth from low income customers to high income customers."[14] It is therefore in the public interest, and specifically beneficial to low income customers, to reduce and ultimately eliminate these types of subsidies.

5. Its beneficial to make the transition now and not to delay

Now is the time to move to transitional three-part rates to begin the process of empowering customers with improved price signals and additional bill reduction options. At this time of low market fuel and power cost, resulting in base power and PPFAC rates combined being almost 15% less than they were about two years ago. Customers are in a better position to deal with any learning curve associated with a transition to three-part rates with a moderate demand charge. But, like gasoline prices, natural gas and thus power costs will likely increase over time, so getting the price signals closer to correct will promote the reduction of market purchases during peak times and is clearly in the public interest and beneficial to our customers.

[14] Ashley C. Brown Surrebuttal at p. 5.

In addition, APS witness Ashley Brown addressed the issue of making the transition now and not delaying with his statement: "Moreover, as can already be seen in this state and others, the politics of getting the tariffs right becomes increasingly difficult when more and more people are invested in a severely flawed tariff that skews the prices in costly and economically perverse ways. It is best to get the prices right from the beginning so that when customers make their decision about whether or not to go solar, the price signals are correct and the costs and benefits to society are correctly aligned in the tariff formulation."[15] This statement is true not only for solar, but for any energy technology investment made by customers as a result of skewed price signals.

6. <u>Three-part rates will promote faster advancement of load control technologies, load management programs and customer usage monitoring</u>

By matching cost recovery to cost causation – demand driven cost to demand charges; it is simply logical that monetary price signals rewarding the reduction of peak consumption will provide greater incentive for the advancement of cost effective technologies, additional energy management programs (including behavioral programs) and greater demand for customer access to closer to real time usage information. This is the same conclusion supported by Staff, as testified to by Mr. Solganick. "Customers would have greater information available to make their own energy decisions, and rates would more accurately price those decisions and lessen the consequential impact on other customers."[16] As well as by APS witness Brown, "solar DG providers oppose demand charges and other types of pricing that would enable new energy service providers and vendors to offer consumers products to reduce their energy bills. They are committed to maintaining barriers to new entrants who might offer valuable products and services that provide customers with more options"[17] and "RMI coins a phrase, "flexiwatts," to

[15] Ashley C. Brown Surrebuttal at p. 31.
[16] Howard Solganick Direct p. 12.
[17] Ashley Brown Surrebuttal at p. 10.

describe the services and technology that exist to fill the business space demand charges will offer. A recent RMI blog post hails demand charges as an opportunity for new technologies, customer options, and reduced grid costs"[18] All of which is in the public interest and beneficial to customers.

III. BILL IMPACTS

Q. Do you have revised estimates of how the Company's proposed three-part rate structure and net metering tariff will impact customers?

A. Yes. The table below demonstrates that DG customers will continue to see significant savings under the Company's proposed three-part rate structure and the respective metering proposals by Staff and the Company. 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.

[18] Ashley Brown Surrebuttal at p. 24.

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)	$ 63.66	66.68	$ 31.30	$ 34.79
Bill Savings from 2-part Rate	NA	$ (3.02)	$ 32.36	$ 28.87
Bill Savings from 3-part Rate	NA	NA	$ 35.37	$ 31.89
900 kWh per Month				
Average Monthly Bill (pre-tax)	$ 103.01	$ 103.50	$ 38.88	$ 45.08
Bill Savings from 2-part Rate	NA	$ (0.49)	$ 64.13	$ 57.92
Bill Savings from 3-part Rate	NA	NA	$ 64.62	$ 58.42
1,200 kWh per Month				
Average Monthly Bill (pre-tax)	$ 136.15	$ 130.70	$ 44.45	$ 49.10
Bill Savings from 2-part Rate	NA	$ 5.44	$ 91.69	$ 87.04
Bill Savings from 3-part Rate	NA	NA	$ 86.25	$ 81.60
1,500 kWh per Month				
Average Monthly Bill (pre-tax)	$ 171.09	$ 157.77	$ 49.60	$ 55.99
Bill Savings from 2-part Rate	NA	$ 13.33	$ 121.49	$ 115.11
Bill Savings from 3-part Rate	NA	NA	$ 108.17	$ 101.78

It is evident from the comparisons presented in this table that customers across the usage spectrum with typical load factors will see minimal bill changes from the transitional rate. In actuality, the primary reason a typical low usage customer is seeing a small increase in their monthly bill is as a result of eliminating the artificially low 400 kWh tier present in the two-part volumetric transition rates. For 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 $58.42 monthly compared to the Company's proposed full requirements transitional two-part rate and $57.92 compared to the Company's proposed three-part rate. This represents respective monthly bill savings of approximately 56% from full requirements service in both cases.

IV. <u>GENERAL ISSUES</u>

Q. Are there any positions stated in the Surrebuttal Testimonies of Intervenors you would like to specifically address?

A. Yes. There are a couple areas I would like to specifically respond to.

Q. On page 42 of Ms. Kobor's Surrebuttal Testimony, she argues that the proper bill comparisons for residential and small commercial customers should be the movement from the Company's current two-part rates to the Company's proposed three-part rates. Do you have any observations with respect to her position?

A. Yes. I will concentrate on Ms. Kobor's comments with respect to residential customers but my observations can also be applied to her comments on small commercial customers as well. First, I disagree with Ms. Kobor that the proper bill impact comparison should be the movement from the Company's current rates to the proposed three-part rates. When it is used by her in the context of rate impacts being <u>driven</u> by the migration to three-part rate design and ignoring that we are requesting a revenue increase. Because the reality is that when a utility must recover more cost from fewer units of sale – even maintaining two-part rates will result in bill increases. On a purely percentage basis, those customers presently enjoying very low bills will see higher percentage increases as fixed cost recovery is better aligned with cost causation – even in two-part rate design.

Nevertheless, the Company is presenting its bill impact schedules with Rejoinder Testimony (see CAJ-RJ-1) showing the movement from current two-part rates to proposed three-part rates. However, these schedules will show bill impacts that incorporate adjustments the Company has made since Rebuttal and the numbers will differ slightly from those submitted with Rebuttal. Therefore, the remainder of my observations will use the rates submitted in the Company's Rebuttal case, so as to be apples-to-apples with Ms. Kober's analysis.

Q. On page 42 of her Surrebuttal Testimony, Ms. Kobor identifies the residential bill impact of moving from current rates to the Company's proposed three-part rate as 16%.[19] Do you agree?

A. No. Ms. Kobor misstates the impact by using a simple mean of monthly average bill changes from the Company's sample of 2,306 residential customers. Ms. Kobor's use of a simple mean here does not represent an "average bill impact," but represents a simple mean of customer average monthly bill impacts. A customer with an average monthly bill of $20 who experiences a $5 monthly bill increase sees an increase of 25%. Conversely, a customer with a $200 monthly bill who experiences a $10 monthly bill increase sees an increase of 5%. However, taking a simple mean of these two customer bill impacts yields an average monthly bill increase of 15%.[20] Obviously, using a simple mean of average impacts will bias the result toward the observations with the smaller base bills, in this case the customer with the original bill of $20, and observations with smaller kWh usage. The proper way to look at bill impacts is to calculate bills with different rate structures at different usage levels and then compare the results for equivalent usage levels. I have calculated the residential bill impacts in moving from current rates to the Company's proposed rebuttal three-part rates, including the proposed non-fuel revenue increase, for monthly usage levels of 200 kWh, 500 kWh, 795 kWh, 900 kWh, 1,200 kWh, and 1,500 kWh and they are presented in the table below. The results for 795 kWh are presented in bold because that is the mean monthly kWh usage level for the sample.

---

[19] Kobor Surrebuttal at 42:7.

[20] The simple mean is obtained by adding 25% to 5% and dividing by 2.

Monthly Bill Impacts of <u>Rebuttal</u> 3-part Rates to Current Rates

Average Monthly Usage	Average Monthly Load Factor	Billing kW	Monthly Bill with Current Rates	Monthly Bill with Proposed 3-Part Rates	Change ($)	Change (%)
200 kWh	19.9%	1.37	$ 26.56	$ 33.39	$ 6.83	25.7%
500 kWh	23.6%	2.90	$ 52.92	$ 62.41	$ 9.49	17.9%
795 kWh	**25.7%**	**4.24**	**$ 81.79**	**$ 90.08**	**$ 8.29**	**10.1%**
900 kWh	26.3%	4.69	$ 92.05	$ 99.79	$ 7.74	8.4%
1,200 kWh	27.7%	5.93	$ 122.25	$ 127.31	$ 5.06	4.1%
1,500 kWh	28.9%	7.11	$ 152.85	$ 154.52	$ 1.67	1.1%

It is obvious from table that the average customer bill impact will be nowhere near 16%. For the sample mean of 795 kWh per month, the bill impact of moving from current rates to the proposed three-part rates is estimated to be $8.29, or 10.1%, for the Company's Rebuttal case. Also, keep in mind that $5.00 of the $8.29 increase is due solely to the proposed $5.00 increase in the Basic Service Charge. Therefore, only the remaining $3.29, is because of the movement to a three-part demand rate, without the artificially low 400 kWh block rate and of course with the remaining rate increase (at the Rebuttal level).

Q. On page 43 of her Surrebuttal Testimony, Ms. Kobor presents two figures that purport to give the story of the bill impacts of moving from current rates to proposed three-part rates. Do you have any comments on these figures?

A. Yes. Ms. Kobor concentrates only on the percentage change in monthly customer bills for the intervals presented. This approach suffers from the same bias that I noted in my example earlier. If the sample contains customers with low usage levels and low load factors, these customers will show bill impacts with large percentage increases even though the changes in dollar terms may be deemed reasonable to begin the transition to a more cost based rate structure.

Q. On page 44 of her Surrebuttal Testimony, Ms. Kobor states that "nearly 88% of residential customers are expected to see bill increases under the UNSE proposal, with nearly one in five customers expected to have their monthly bills increase by more than 30%."[21] How do you respond?

A. Ms. Kobor laments the fact that nearly 88% of residential customers are expected to see a bill increase in the move from current rates to the proposed three-part rates, but the fact of the matter is that 100% of the customers sampled will see an increase in the movement from current two-part rates to transitional two-part rates because of the requested increase in the Company's non-fuel revenues. To identify three-part rates as the culprit for bill increases is very misleading.

With respect to nearly one in five customers in the sample seeing a monthly bill increase of more than 30%, my previous discussion stands. While some customers may see monthly increases in the range of 30%, the dollar impacts associated with them are typical of increases some customers will see in a rate case using an historical test year, with declining billing determinants (fewer energy sales) and the inclusion of a major new asset into rate base. Some customers incurring more significant percentage increases than others is unavoidable within a class of customers having varying system usage patterns. I calculated the number of customers in the sample that would see monthly bill increases above 30% and arrived at 358, or 15.5%, of the 2,309 sampled. The average monthly bill increase for these customers would be $10.11 (from current rates and based on our **Rejoinder** position), which is due to (1) the $5 increase in the Basic Service Charge, (2) the non-fuel revenue increase, and (3) as a result of eliminating the artificially low 400 kWh rate block. This increase is not a result of the movement to three-part rates.

[21] Kobor Surrebuttal at 44:1-2.

I should note that a minimum bill approach, as suggested by a number of Intervenors, including Ms. Kober, if designed to recover anything approaching an appropriate level of fixed cost recovery, would have similar if not greater percentage impacts for a significant proportion of customers bills. Recall from my direct testimony that one of four residential bills issued was for 300 kWh or less. Any meaningful minimum bill would produce very large percentage increases as it relates to these bills versus present rates. For example, if you assumed a minimum bill were to be set at only $20 (which I would not view as meaningful), a zero consumption customer would see a 100% bill increase from UNS Electric's present standard residential rate.

Q. On page 44 of her Surrebuttal Testimony, Ms. Kobor has a discussion of the Company's proposed minimum load factor adjustment. Do you have any comments?

A. Ms. Kobor states that because the minimum load factor adjustment is proposed to be a temporary measure, bill impacts will only increase when it is removed.[22] Once again, this argument is consistent with those of many interveners in this case who oppose three-part demand rates for residential and small commercial rate classes, namely that utility customers are unsophisticated and cannot learn. The heretofore absence of three-part rates in the residential and small commercial rate classes has been because of the lack of sophistication in metering technology, not a lack of customer understanding. Three-part demand rates have been a staple of utility ratemaking for years and there is no reason to suspect that residential and small commercial customers cannot become educated and adept at managing their bills under three-part rate design. The minimum load factor adjustment should be considered as analogous to training wheels on a bicycle. Just because you take them off after a period of practicing doesn't mean you automatically fall over, never to get up again. I would also add that the minimum load factor will provide information that will allow the Company to target customer communications and programs

[22] Kobor Surrebuttal at 44:21-25.

such as: educational materials, load management programs, assistance programs and other customer outreach to directly assist these customers during this transition period to empower them to improve their load factors and to use the system more efficiently and thus lower their bills.

Q. Does this conclude your Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF 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

Rejoinder Testimony of

Craig A. Jones

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

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 or Rebuttal Testimony in this proceeding?

A. Yes.

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

A. I will respond to the testimony of witnesses Quinn and Alston of Arizona Utility Ratepayer Alliance ("AURA"), witnesses Van Epps and Solganick of Staff, witness Higgins of Arizonans for Electric Choice and Competition and Noble Americas Energy Solution LLC ("AECC"), witness Yaquinto of Arizona Investment Council ("AIC"), witnesses Hendrix and Tillman of Wal-Mart, witness Zarnikau of Nucor Steel Corporation ("NUCOR"), witness Huber of Residential Utility Consumer Office ("RUCO"), witness Zwick of Arizona Community Action Association ("ACAA"), witness Wilson of Western Resource Advocates ("WRA"), and witness Schlegel of Southwest Energy Efficiency Project ("SWEEP"). Since many of these witnesses cover the same issues, in most cases I will refer to them collectively for ease of discussion.

Q. How is your Rejoinder Testimony organized?

A. In addition to this Introduction, Section II discusses the currently proposed allocation of revenues between the rate classes and the resulting rates as well as the related bill impacts. Section II will be based on the revised revenue requirement discussed by other Company witnesses in their Rejoinder Testimony. I also include revised Schedule H pages to reflect these revisions. Section III provides some comments related to the Company's CARES proposals and a modification to help address some parties' concerns about the impact on the lower use customers. In Section IV I will explain why the Company not only wishes to maintain its originally filed Buy-Through rate with all of its provisions, but that also, after reviewing all of the testimony, the Company now believes it should recover all of the generation costs in the last 3 years of its 4 year pilot offering by removing the 75% reduction to generation rates in years 2 through 4 of our original proposal. Section V will discuss Staff's proposal in its Surrebuttal Testimony to credit DG solar customers a mix of a 15% credit and a 15% incentive. Section VI will discuss a few miscellaneous issues from certain witnesses including requested revisions to the Lost Fixed Cost Recovery ('LFCR") Plan of Administration ("POA") and Transmission Cost Adjustment ("TCA") POA.

My Rejoinder Testimony addresses various witnesses and specifically a few items the Company does not agree with as presented in the various parties' Surrebuttal Testimony. My omission of any issue, either intentionally or unintentionally, in no way indicates the Company acquiesces to the other Party's position. Time constraints only allow a limited group of issues to be addressed in this Rejoinder Testimony. The Company reserves the right to address any other issues it deems unacceptable if it so chooses at a later time if necessary.

II. REVENUE ALLOCATION AND BILL IMPACTS

Q. Many of the parties have suggested the level of revenues recovered from the various classes should be more reflective of the proportions filed in the Company's original proposal instead of what was proposed in the Company's Rebuttal position. Would you like to speak to these requests?

A. Yes. The Company's original proposal, while certainly reasonable and acceptable, did allocate substantially more to the Residential class in an attempt to move cost recovery to a proportionally more equitable level between the rate classes based on the results of the Class Cost of Service Study ("CCOSS"). In a rate case, rate design and cost allocation are dynamic numbers. You start out with what you believe are reasonable numbers and blend in "gradualism" and "subsidy reduction" as well as other concepts as appropriate. This means that as the proceeding progresses and other parties' opinions are considered, sometimes your proposal evolves. In this case our proposal has evolved. After reviewing Staff's Direct position, blending in a reduction to the requested revenue requirement deficiency and adjustments to the base power costs, the Company modified its original position. The Company did not move fully to Staff's recommendation but did move toward their proposal. After considering the necessary facts, the Company reviewed how its changes impacted various customer's bills. Since the current CCOSS indicates the Residential classes should have a higher proportion of cost allocated to them, the Company allocated the revenue to the classes to produce either a decrease or a near neutral change to the Large Power Service ("LPS") rate classes, the Large General Service ("LGS") rate classes and the Medium General Service ("MGS") rate classes with larger increases going to Small General Service ("SGS"), Residential, Lighting and Interruptible rate classes. Please refer to **Exhibit CAJ-RJ-2** to see the H-1 through H-4 Schedules that have been updated to reflect the lower overall revenue requirement currently being requested by the Company. Schedule H-1 in this exhibit reflects the level of costs allocated to each general rate class.

The revised CCOSS uses the same allocation methods as the CCOSS originally filed by the Company in this proceeding. It was adjusted to reflect the lower overall revenue requirement being requested. The results still show that the rates being charged to the largest rate classes are producing revenues in excess of what the CCOSS indicates they should be responsible for, but due to gradualism and bill impact, the Company believes the results are reasonable at this time. More movement will be proposed in a subsequent rate case if the results still justify the adjustment.

A summary of the bill impacts resulting from the Company's proposed rates can be found in **Exhibit CAJ-RJ-1**. More detailed analysis of the bill impacts can be found in **Exhibit CAJ-RJ-2**. Schedule H-4 provides detailed bill impacts at various assumed usage levels for all rate classes. For both the Residential and SGS rate classes it also contains comparison of bill impacts resulting in the implementation of the proposed transitional rates the Company agreed to in its Rebuttal position (as adjusted to reflect the reduced revenue requirement) as well as the bill impacts of the three-part rates at those same usage levels. The calculations for the three-part rates assume a revenue neutral adjustment for the class as a whole, but will show varying impacts depending on the customer's volume of usage and load factor.

Exhibit CAJ-RJ-1 summarizes the results of Schedule H-4 for the primary rate classes and provides a bill impact calculation for each class' typical customer. For a typical Residential customer their bill will increase by approximately $4.82 per month on average which is an approximate 5.7% increase. An LPS customer's bill will generally increase by approximately 1%. Under the Company's current proposal the Residential and SGS customers will pay the transitional rates through the first quarter of 2017 at which point they will move to the new three-part rates. As mentioned above, by design the new three-part rates are to be revenue neutral for each primary rate class when compared to the transitional two-part rate. The change in rate design will result in bills changing by some amount, but that will vary by each individual customer's total usage and how they use their energy. For each of the individual classes, as a whole, changing to three-part rates will be revenue neutral. The various levels of bill impacts for residential and SGS customers are also reflected in **Exhibit CAJ-RJ-2** at pages 1 of 34 through page 22a of 43.

III. <u>CARES</u>

Q. A few of the parties have suggested the proposed three-part rates may impact low-income customers in a negative way and should be modified to protect this group of customers. Has the Company considered making any changes to the provisions offered to the CARES customers?

A. Yes. The Company wishes to modify its Rebuttal proposal and offer a flat discount amount to all CARES customers. This new proposal will increase the amount of discount to approximately $1.3 million per year, and will provide additional mitigation of bill impacts for the lower usage CARES customers. The Company continues to propose to recover the cost of the discount from the remaining residential customers.

Q. What is the Company proposing in your Rejoinder Testimony?

A. The Company now proposes a flat discount of $17 per month for CARES customers and a flat discount of $27 per month for the CARES-Medical (limited to prevent a negative bill). This has the added benefit of offsetting the only portion of the bill – the basic service charge – that the customer does not have the opportunity to change. The proposed $15 basic service charge will be more than offset for all CARES customers. In fact, based on test year data and the Company's proposed three-part rate design for nearly 3,000 CARES bills per year will be less than $10 under the proposed three-part rates. The three-part rate design will empower the customer to reduce their bill even more. They have control over how much they consume, how fast they consume it and when they consume it. As they become more educated through the use of a better rate design and the Company's educational programs, CARES customer will be able to reduce their bill even more.

Q. Please summarize the Company's proposal for the CARES customers.

A. The below table sets forth the current CARES discount, the transitional CARES discount, and the CARES discount under 3-part rates.

CARES Rates	Current	Transition	Proposed
Monthly Basic Service Charge	$4.90	$9.00	$15.00
Usage Discounts	30% 0-300 kWh	No change	N/A
	20% 301-600 kWh	No change	N/A
	10% 601-1000 kWh	No change	N/A
	Flat $8 > 1,000 kWh	No change	Flat $17
Average Bill Impact	N/A	$4.14	($0.23)

Q. Does the Company continue to oppose Ms. Zwick's proposal to expand the eligibility of CARES to more customers by increasing the percentage of the Federal poverty level?

A. Yes. The reasons are set forth in my Rebuttal Testimony. The current proposal is already providing approximately $1.3 million of benefits to CARES customers. The proposal to expand the CARES eligibility requirement would result in an additional cost shifts to other customers.

IV. BUY-THROUGH (AGS RIDER)

Q. Which Commission Staff and/or Intervenor parties addressed the Company's proposed Experimental Rider 14 – Alternative Generation Service (AGS) in Surrebuttal Testimony?

A. Staff, AECC, AIC, and Wal-Mart addressed proposed Experimental Rider 14 - AGS in Surrebuttal Testimony.

Q. Have you considered any changes to your original proposal as it relates to the AGS service the Company has proposed?

A. Yes, although the Company continues to oppose the buy-through rate, it is modifying its proposal because all parties appear to oppose shifting any cost recovery to other customers. The only practical way to ensure this is for the buy-through customer to pay the full retail rate with the exception of base power and PPFAC. Therefore the Company proposes to eliminate the discount in years 2-4.

Q. Do you have any comments on the Intervenor's Surrebuttal Testimonies with respect to the Company's proposed AGS Rider?

A. Yes. I am largely in agreement with the Surrebuttal Testimony of AIC witness Gary Yaquinto and will not address that testimony directly unless to rely on it for my comments on the other parties' positions. Staff witness Howard Solganick addresses the Company's proposed AGS Rider only to reiterate Staff's position that the AGS program should not impact any other customers and adds that if the AGS program is approved on a permanent basis, which the Company opposes, Staff recommends that the Company propose a market price for customers returning to utility service so as not to negatively impact other customers on the system.[1] To the recommendation of protecting other customers on the

[1] Staff Solganick Surrebuttal at 13:19-24 and 14:1-3.

system, the Company's position remains, as I stated in Rebuttal Testimony, that the Company does not support the AGS program and if it is approved in a form that results in lost revenues to the Company, those revenues should be eligible for recovery. The Company would consider other proposals, but the LFCR mechanism seems to be the most appropriate.[2] The Company believes that the issue of lost revenues should be addressed before anything like the proposed AGS program is adopted.

With respect to former AGS customers returning to utility service, the Company agrees with Staff. The AGS Rider as proposed states that the Company will provide returning customers with generation service at a market index price plus $20 per MWh until the Company is reasonably able to reintegrate them into the Company's generation planning and provide power at the applicable rate schedule. The length of this transition would be at the Company's determination, but no longer than one year.

Q. Please summarize Wal-Mart's Surrebuttal position regarding the Company's proposed Experimental Rider 14.

A. Wal-Mart witness Chris Hendrix essentially reiterated the same recommendations that he made in his Direct Testimony. Namely that the Company's proposed Experimental Rider 14 should be approved with several modifications related to the proposed management fee, participation requirements, participation limit, generation cost recovery, and program term.

Q. Do you have any comments on Wal-Mart's recommendations?

A. The Company addressed each of these proposed modifications sufficiently in Rebuttal and recommended their rejection. Wal-Mart has offered no further convincing evidence for adopting their recommendations in Surrebuttal Testimony. However, Mr. Hendrix makes

---

[2] Jones Rebuttal at 27:17-27 and 28:1-2.

some additional assertions to which the Company wishes to respond. These assertions relate to the program's eligibility requirements, participation limit, and term.

Q. Please address Wal-Mart's assertions regarding program eligibility.

A. Mr. Hendrix recommends in his Direct and Surrebuttal Testimony that all UNS Electric rate classes should be allowed to participate in the program. However, as I stated in my Rebuttal Testimony the Fortis acquisition settlement order that requires the Company to propose a buy-through tariff specifically designates only the Company's LPS class for inclusion in the program.[3] In his Surrebuttal Testimony, Mr. Hendrix argues that because the Company is proposing to move three Wal-Mart stores in the UNS Electric service area from the LPS rate class to the LGS rate class in this proceeding, Wal-Mart is being excluded from the program because of the proposed reclassification. However, the truth of the matter is that none of the three Wal-Mart facilities in the UNS Electric service area identified by Mr. Hendrix would meet the program's minimum 2,500 kW load threshold requirement for participation regardless of rate classification in the absence of load aggregation, which the Company opposes.[4]

Q. Please address Wal-Mart's claims with respect to the program participation limit.

A. In his Direct and Surrebuttal Testimony Mr. Hendrix has proposed that the total program participation limit be raised from the Company's proposed 10 MW of total customer load to 150 MW. Furthermore, in his Surrebuttal Testimony Mr. Hendrix asserts the following:

> The Company does not seem to understand that my increased cap proposal is to supplant the market power purchases in the future. Since the Company is buying power on the open market, the AGS Program with my increased

[3] UNSE Jones Rebuttal at 47:12-19.
[4] UNSE Jones Rebuttal at 46:22.

cap of 150 MW is replacing the Company's own wholesale market purchases with those of the Customers participating in AGS.[5]

Q. Do you agree that the Company did not understand Wal-Mart's rationale for its recommendation?

A. No. The Company fully understands Wal-Mart's rationale for its recommendation. As I stated in my Rebuttal Testimony, an Integrated Resource Plan (IRP) is a utility process 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. Far from existing in isolation, a utility's supply-side resources, namely utility-owned generation and power market purchases in this case, are highly interdependent. A utility will optimize its planning and use of these supply-side resources to minimize system costs to the benefit of all customers on the system. Utility flexibility in this process is vital and the loss of any optionality is detrimental to the utility's efforts. Wal-Mart is proposing that a small group of customers be allocated approximately 85% of the Company's purchased power market opportunities[6] to their benefit only, not for the benefit of the vast majority of customers on the system.

Finally, the utility obligation to serve is a long-term endeavor. This small group of customers with no utility obligation to serve would reap the benefits of a relatively soft power market while those benefits currently flow through to all UNS Electric customers. How long would AGS participants be willing to take on these responsibilities if the power market were to rebound and market prices approach and exceed utility service? Mr. Hendrix's proposal clearly underestimates the difficulties associated with reintegrating 150

[5] Wal-Mart Hendrix Surrebuttal at 5:14-18.
[6] UNSE Sheehan Direct at 12.

MW of load, approximately 35% of current planning requirements,[7] back into the UNS Electric system.

Q. What are Mr. Hendrix's recommendations for the program term?

A. Mr. Hendrix objects to tagging the program as "Experimental" or "Pilot" and seems to recommend against the proposed 4-year program term. Although Mr. Hendrix does not propose an alternative to 4 years in his Surrebuttal, in Direct Testimony Mr. Hendrix recommended that there should be no limit on the term of the program.[8]

Q. What rationale does Mr. Hendrix give for an unlimited program term?

A. Mr. Hendrix argues that a testing and evaluation period is unnecessary because evidence shows that programs of this type have been effective in Arizona and other jurisdictions. He points to the APS AG-1 program in Arizona as evidence of this. However, in evidence provided in this docket APS has estimated that it has experienced a net loss from its AG-1 program since inception to May 2015 of approximately $16.8 million.[9] This evidence supports the Company's proposal that if ordered to offer AGS in any form, the program term should be limited to 4 years after which a full program evaluation should be performed.

Q. Do you wish to address AECC's Surrebuttal position regarding the Company's proposed Experimental Rider 14?

A. No. My responses to Wal-Mart and AIC's Rebuttal of Mr. Higgins cover the key issues I would have addressed.

---

[7] UNSE Sheehan Direct at 2:16.
[8] Wal-Mart Hendrix Direct at 9:2.
[9] AIC Data Request, AIC 1.1.

V. STAFF'S PROPOSED DG SOLAR BILL CREDIT AND INCENTIVE

Q. In Staff witness Broderick's Surrebuttal Testimony he proposes a 15% bill credit for DG customers before June 1, 2015[10] and a 15% cost per kW incentive for DG solar installations for the first six months following the completion of the full transition from two-part rates to three-part rates[11]. Do you wish to express any thoughts on this proposal?

A. The Company believes this proposal is designed as a transitional option for DG solar customers to address many of the concerns expressed in various parties' testimonies in this proceeding. In his testimony, Mr. Broderick also mentions the cost of the credits and incentives could be recovered through a special surcharge or through REST funds[12]. The Company does not believe the proposed three-part rate is overly burdensome on the partial requirements customers, but understands a desire to create a more gradual transition especially if pre-June 1, 2015 DG solar customer are not allowed to be grandfathered onto a two-part rate. In the event the Commission allows pre-June 1, 2015 DG solar customers to be grandfathered to a two-part rate it is the Company's opinion that the 15% bill credit for those customers would not be necessary. However, if the Commission approves Staff's and the Company's three-part rate design for all DG customers, the Company believes that the cost of any bill credit should be recovered through the REST. The Company is of the opinion that this type of credit is better addressed in the REST in order to evaluate its merits as it relates to REST compliance.

The Company estimates such a discount will result in a total credit amount of approximately $135,000 per year (1,500 pre 6/1/15 DG customers at an average of $50 per month of total bill after moving to a three part rate, multiplied by 15% and multiplied by

[10] Staff Broderick Surrebuttal at 6:2-9.
[11] Staff Broderick Surrebuttal at 14:2-4.
[12] Staff Broderick Surrebuttal at 6:5 and 14:7.

12 months per year) that would be recovered from all customers through the REST. As stated above if Staff's proposal is accepted by the Commission, the Company prefers the REST option as the method of recovery as it gives transparency to the discount.

Q. Does the Company support Staff's proposal for post-June 1, 2015 DG customers??

A. No. The Company does not agree with Staff's proposal relating to the 15% cost per kW incentive for DG solar installations. It is the Company's position that this portion of the proposal is not necessary and should not be approved. However, if the Commission determines that post-June 1, 2015 DG customers receive incentives, the Company proposes using a method that is consistent with the 15% bill credit proposed for the pre-June 1, 2015 DG solar customers.

Q. Why does the Company wish to recommend changes to Staff's proposal as it relates to post-June 1, 2015 if the Commission accepts it?

A. The reasons the Company would like to modify the proposal for the post June 1, 2015 DG solar customer are threefold. The key concerns the Company identified as needing to be changed are:

1) at minimum, a flat $/kW with a cap on the total incentive amount would be necessary to avoid creating an incentive to create artificially high pricing of equipment and proposed oversizing of the system;

2) the number of applications in that six-month window would likely sky rocket because there are no utility incentives currently available and installers would want to maximize installation falling within the window of time an incentive is offered. This could result in installations doubling or even tripling during that window and;

3) the proposal appears to create a "dead-band". Customers installing facilities during the interim period from June 1, 2015 through an estimated three-part rate implementation date proposed to be in the first quarter of March 2017 would get nothing.

Additionally, if the incentive is paid on a percentage of cost per kW of the installed unit, the cost during that 6-month window will be substantial. If a solar unit costs approximately $3 per watt, a 7 kW system would have an installed cost of approximately $21,000, which would produce a one-time incentive payment of approximately $3,150 (15% of $21,000). Currently the pace of installation in the UNS Electric territory is about 25 units a month. During the six month window a total incentive payment of approximately $472,500 would be created that year. That is at the non-incentive pace of installations. If the pace increases substantially, that amount could exceed $1,000,000 very easily.

Again, the Company believes that any incentives for post June 1, 2015 DG customers should be addressed in the Company's REST Plan following the implementation of three-part rates.

VI. MISCELLANEOUS ISSUES

Q. What other items would you like to address?

A. Staff witness Broderick indicated he would like to see a revised POA for the LFCR.[13] The Company does not oppose providing a revised LFCR POA, but believes it would be premature to do so at this time. The current LFCR POA is generally reflective of Staff's overall proposal in this proceeding (may need to be modified to exclude fixed charge option references). It would need to be modified after the final Order of the Commission to

[13] Staff Broderick Surrebuttal at 11:1.

reflect any revisions to rate design, added rate categories and the new rates, but that will not be known until after the final Order. The Company has already submitted as part of its direct case a LFCR POA that adds back to the LFCR rates an amount to reflect lost fixed costs associated with generation and the other 50% of the demand charges, along with other changes including the blending of the rate into one percentage adjustment and increasing the cap. The Company's POA would also need to be updated to reflect the final Order of the Commission if it agrees to allow the Company to recover all of its lost fixed cost, including generation and the demand related costs. All of these revisions would be more appropriately addressed as part of the Company's compliance filing subsequent to the Commission's final Order. The Company has no objection to providing Staff an early version for their review if time allows.

Staff witness Van Epps also requested that the Company add language or a work paper that more precisely define the TCA calculation process.[14] The Company is agreeable to working with Staff to document what the Company believes is a common understanding of what the TCA calculation process is and provide it to Staff before the end of the hearing to assure they agree with the process as documented. Once we have created a final document, the Company proposes that it be submitted as part of the compliance filing subsequent to the final Order in this proceeding.

Q. Does this conclude your Testimony?

A. Yes, it does.

[14] Staff Van Epps Surrebuttal 2:22-24.

Exhibit CAJ-RJ-1

Exhibit CAJ-RJ-1

UNS Electric Inc.
Bill Impacts
Test Period Ending December 31, 2014

Line No.	Class Description	Customer Counts To-date (Dec 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 WITH MARGIN INCREASE, FUEL/PPAFC TRUE-UP AND TCA: Annual Bill Change	Monthly Bill Change	Percent Change to Total Bill With Fuel Increase	COS RETURNS
1	Residential Current to Transition	75,504	$104.60	$4.40	$26.39	$74.72	$5.24	$31.45	$1,075.95	$57.84	$4.82	5.68%	
2	Residential Transition to Demand		$107.84	$3.24	$19.43	$74.39	($0.33)	($2.00)	$1,093.38	$17.43	$1.45	1.62%	
3	Residential Current to Demand		$107.84	$7.64	$45.82	$74.39	$4.91	$29.45	$1,093.38	$75.27	$6.27	7.39%	
4	Residential CARES - Current to Transition	5,904	$77.86	$4.37	$26.22	$57.60	$3.91	$23.46	$812.75	$49.68	$4.14	6.51%	
5	Residential CARES Transition to Demand		$79.85	$2.31	$13.86	$54.84	($2.76)	($16.56)	$808.14	($2.70)	($0.23)	-0.33%	
6	Residential CARES Current to Demand		$79.85	$6.68	$40.08	$54.84	$1.15	$6.90	$808.14	$46.98	$3.92	6.17%	6.55%
7	Residential CARES-M Current to Transition	251	$95.32	$4.48	$26.88	$69.54	$3.90	$23.38	$989.14	$50.26	$4.19	5.35%	
8	Residential CARES-M Transition to Demand		$100.02	$5.09	$30.54	$64.26	($5.28)	($31.68)	$985.68	($1.14)	($0.10)	-0.12%	
9	Residential CARES-M Current to Demand		$100.02	$9.58	$57.48	$64.26	($1.37)	($8.22)	$985.68	$49.26	$4.11	5.26%	
10	Residential TOU	266	$127.07	$8.47	$50.80	$84.34	$5.34	$32.04	$1,268.46	$82.84	$6.90	6.99%	
11	Residential TOU Super Peak	5	$125.50	$8.16	$48.94	$84.26	$9.64	$57.84	$1,258.56	$106.78	$8.90	9.27%	
12	Small General Service Current to Transition	8,839	$145.07	$9.38	$56.30	$117.41	$10.90	$65.39	$1,574.88	$121.69	$10.14	8.37%	
13	Small General Service Transition to Demand		$147.72	$2.65	$15.91	$118.50	$1.09	$6.55	$1,597.32	$22.46	$1.87	1.43%	
14	Small General Service Current to Demand		$147.97	$12.28	$73.69	$118.70	$12.18	$73.11	$1,600.02	$146.80	$12.23	10.10%	6.23%
15	Small General Service TOU	14	$245.40	$13.02	$78.10	$174.56	$14.12	$84.71	$2,519.76	$162.81	$13.57	6.91%	
16	Interruptible Service	25	$9,142.83	$875.25	$5,251.49	$6,938.55	$661.82	$3,970.93	$96,488.28	$9,222.42	$768.54	10.57%	
17	Medium General Service	1279	$3,081.61	$35.27	$211.62	$2,425.66	$38.51	$231.04	$33,043.60	$442.66	$36.89	1.36%	
18	Medium General Service TOU	9	$7,119.98	($120.16)	($720.96)	$6,496.26	$227.41	$1,364.46	$81,697.44	$643.50	$53.63	0.79%	18.30%
19	Large General Service	10	$28,354.74	($445.25)	($2,671.48)	$28,354.74	($445.25)	($2,671.48)	$340,256.88	($5,342.96)	($445.25)	-1.55%	
20	Large General Service (Formally LPS)	7	$40,649.16	($1,721.36)	($10,328.13)	$40,649.16	($1,721.36)	($10,328.13)	$487,789.92	($20,656.26)	($1,721.36)	-4.06%	
21	Large General Service TOU	2	$58,778.38	($332.07)	($1,992.42)	$54,340.61	$1,338.29	$8,029.74	$678,713.94	$6,037.32	$503.11	0.90%	
22	Large Power Service	4	$113,504.35	$1,198.74	$7,192.45	$113,504.35	$1,198.74	$7,192.45	$1,362,052.20	$14,384.90	$1,198.74	1.07%	18.42%
23	Large Power Service TOU	0	$188,146.50	$3,250.24	$19,501.44	$167,697.86	$677.25	$4,063.50	$2,135,066.16	$23,564.94	$1,963.75	1.12%	
24	Lighting Service	1,922	$15.33	$2.04	$12.24	$15.33	$2.04	$12.24	$183.96	$24.48	$2.04	15.35%	8.73%

Exhibit CAJ-RJ-2

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	$8,380,673	10.0%	$78,169,265	$14,136,082	18.08%	$92,305,348
2	Small General Service	12,922,488	1,067,025	8.3%	12,461,200	1,528,313	12.26%	13,989,513
3	Interruptible Power Service	2,920,047	108,956	3.7%	3,111,532	-82,529	-2.65%	3,029,003
4	Medium General Serive	0	43,784,304	0.0%	0	43,784,304	0.0%	43,784,304
5	Large General Service	46,292,475	-36,705,909	-79.3%	43,498,604	-33,905,841	-77.95%	9,592,763
6	Large Power Service	21,454,373	-14,846,030	-69.2%	17,170,623	-10,483,155	-61.05%	6,687,468
7	Lighting	528,359	71,219	13.5%	546,954	52,625	9.62%	599,578
8	Subtotal	$167,886,452	$1,860,238	1.11%	$154,958,178	$15,029,800	9.70%	$169,987,977
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	$1,955,272	1.15%	$156,787,255	$15,029,800	9.59%	$171,817,055

Total Electric Retail Service — Recap Schedules

(a) H-2 (P2) — A-1

(b) Total increase is $69,916 less than Schedule A1, Line 10 due to difference from Test Year billed to booked revenues

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	$14,612	($444,219)	$1,793,740	$2,585,159	$4,378,898	$5,352,853	$544,347	11.32%	$973,954	18.20%
2	Residential Service	RES-01	31,759,612	46,999,721	-289,767	-5,063,987	31,469,845	41,935,733	73,405,578	86,527,437	7,768,105	9.86%	13,121,859	15.16%
3	Residential Service TOU	RES-TOU	116,271	152,725	11,729	16,811	128,000	169,535	297,536	323,404	54,408	20.23%	25,869	8.00%
4	Res Bright Community Solar	RES-BC	34,190	53,651	-588	0	33,602	53,651	87,253	101,654	13,813	15.72%	14,401	14.17%
5	Residential Unbilled		110,955	-266,920	-110,955	266,920	0	0	0	0	0	0.00%	0	0.00%
6	Small General Service	SGS-10	6,255,704	6,650,173	-128,102	-335,235	6,127,602	6,314,938	12,442,540	13,970,043	1,064,166	8.25%	1,527,503	10.93%
7	Small General Service TOU	SGS-TOU	8,527	8,085	465	1,583	8,992	9,668	18,660	19,470	2,859	17.21%	810	4.16%
8	Interruptible Power Service	IPS	1,335,391	1,584,656	-112,156	303,640	1,223,235	1,888,297	3,111,532	3,029,003	108,956	3.73%	(82,529)	-2.72%
9	Medium General Service	MGS	0	0	0	0	0	0	0	43,140,732	43,140,732	n/a	43,140,732	100.00%
10	Medium General Service TOU	MGS-TOU	0	0	0	0	0	0	0	643,573	643,573	n/a	643,573	100.00%
11	LGS Bright Community Solar	LGS-BC	898	976	-898	-976	0	0	0	0	0	0.00%	0	0.00%
12	Large General Service	LGS	21,574,476	24,416,757	-471,036	-2,649,801	21,103,440	21,766,956	42,870,396	8,246,263	(37,744,970)	-82.07%	(34,624,133)	-419.88%
13	Large General Service TOU	LGS - TOU	121,380	186,059	133,252	187,517	254,632	373,576	628,208	1,346,500	1,039,061	337.97%	718,292	53.35%
14	General Service Unbilled		138,446	-146,516	-138,446	146,516	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	-1,258,960	2,258,222	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	31,928	47,197	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	-3,702,992	-1,659,144	3,191,840	4,254,913	7,446,752	6,687,468	(6,121,421)	-47.79%	(759,284)	-11.35%
18	Lighting	LTG	505,944	22,415	0	18,594	505,944	41,009	546,954	599,578	71,219	13.48%	52,625	8.78%
19	Total Electric Service		$75,676,172	$92,210,280	-$6,021,912	-$6,906,362	$69,654,260	$85,303,918	$154,958,178	$169,987,977	$1,860,238	1.11%	$15,029,800	9.70%

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.

UNS Electric, Inc.
Comparison of Present and Proposed Rates
Test Year Ended December 31, 2014

	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	$0.028700	$0.009727	51.27%
Energy Charge, all additional kWhs	$0.035400	$0.048100	$0.012700	35.88%
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	$5.00	N/A	N/A
Energy Charge (kWhs)	N/A	$0.015340	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.105800	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	$0.086300	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	$0.030100	$0.010800	55.96%
Energy Charge 401-1,000 kWhs	$0.034350	$0.040100	$0.005750	16.74%
Energy Charge, all additional kWhs	$0.038499	$0.058100	$0.019601	50.91%
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	$0.035300	$0.004950	16.31%
Energy Charge 401-1,000 kWhs	$0.030350	$0.035300	$0.004950	16.31%
Energy Charge, all additional kWhs	$0.030350	$0.035300	$0.004950	16.31%
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	$5.00	N/A	N/A
Energy Charge (kWhs)	N/A	$0.015340	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.105800	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	$0.086300	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	$0.030100	$0.005100	20.40%
Energy Charge, all additional kWhs	$0.035000	$0.040100	$0.005100	14.57%
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%

UNS Electric, Inc.
Comparison of Present and Proposed Rates
Test Year Ended December 31, 2014

	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	$0.030000	-$0.000176	-0.58%
Energy Charge 401 -7,500 kWh	$0.041042	$0.039900	-$0.001142	-2.78%
Energy Charge >7,500 kWh	$0.076042	$0.077300	$0.001258	1.65%
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	$5.05	N/A	N/A
Energy Charge (kWhs)	N/A	$0.015970	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.097800	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	$0.096800	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	$0.030000	-$0.000176	-0.58%
Energy Charge 401 -7,500 kWh	$0.043176	$0.039900	-$0.003276	-7.59%
Energy Charge >7,500 kWh	$0.076042	$0.077300	$0.001258	1.65%
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	$5.05	N/A	N/A
Energy Charge (kWhs)	N/A	$0.015970	N/A	N/A
Base Power Supply Charge, Summer On-Peak all kWhs	N/A	$0.097800	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	$0.096800	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	$13.47	$0.66	5.15%
Energy Charge (kWhs)	$0.005470	$0.005480	$0.000010	0.18%
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	$13.47	$0.66	5.15%
Energy Charge (kWhs)	$0.005470	$0.005480	$0.000010	0.18%
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	$12.88	$0.07	0.55%
Energy Charge (kWhs)	$0.005470	$0.005300	-$0.000170	-3.11%
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	$12.88	$0.07	0.55%
Energy Charge (kWhs)	$0.005470	$0.005300	-$0.000170	-3.11%
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	$12.88	-$9.12	-41.45%
Demand Charge ≥69kV, per kW	$17.00	$12.48	-$4.52	-26.59%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005300	$0.004838	1047.19%
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	$0.000000	$0.049332	$0.049332	#DIV/0!
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	$12.88	-$9.12	-41.45%
Demand Charge ≥69kV, per kW	$17.00	$12.48	-$4.52	-26.59%
Energy Charge (kWhs) <69 kV	$0.000462	$0.005300	$0.004838	1047.19%
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	$0.125200	$0.001620	1.31%
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	$12.48	-$4.52	-26.59%
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	$5.52	$0.52	10.40%
Energy Charge (kWhs)	$0.019408	$0.014990	-$0.004418	-22.76%
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	$4.34	$0.00	0.00%
New 30' Metal or Fiberglass - Overhead	$8.66	$8.66	$0.00	0.00%
Existing Wood Pole - Underground	$2.18	$2.18	$0.00	0.00%
New 30' Wood Pole (Class 6) - Underground	$6.52	$6.52	$0.00	0.00%
New 30' Metal or Fiberglass - Underground	$10.81	$10.81	$0.00	0.00%
Wattage, per Watt	$0.051681	$0.058707	$0.007026	13.59%
Lighting Base Power Supply Charge, per kWh	$0.010113	$0.014505	$0.004392	43.43%
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	$13.47	N/A	N/A
Energy Charge 1st 400 kWh	$0.030176	$0.005480	-$0.024696	-81.84%
Energy Charge 401 -7,500 kWh	$0.043176	$0.005480	-$0.037696	-87.31%
Energy Charge >7,500 kWh	$0.076042	$0.005480	-$0.070562	-92.79%
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	$12.88	$0.07	0.55%
Energy Charge (kWhs)	$0.005470	$0.005300	-$0.000170	-3.11%
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.

[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	$0.030100	$0.040100	$0.058100	$0.000000	$0.055090	0.000%			
Xsmall	111	111	0	0	$15.00	$3.34	$0.00	$0.00	$0.00	$6.12	$0.00	$24.46	$5.27	27.4%
Small	330	330	0	0	$15.00	$9.93	$0.00	$0.00	$0.00	$18.18	$0.00	$43.11	$5.78	15.5%
Medium	664	400	264	0	$15.00	$12.04	$10.59	$0.00	$0.00	$36.58	$0.00	$74.21	$5.25	7.6%
Large	1,144	400	600	144	$15.00	$12.04	$24.06	$8.37	$0.00	$63.02	$0.00	$122.49	$5.96	5.1%
Xlarge	2,162	400	600	1,162	$15.00	$12.04	$24.06	$67.51	$0.00	$119.11	$0.00	$237.72	$17.35	7.9%
Mean	830	400	430	0	$15.00	$12.04	$17.22	$0.00	$0.00	$45.70	$0.00	$89.96	$4.80	5.6%
Sum	983	400	583	0	$15.00	$12.04	$23.39	$0.00	$0.00	$54.17	$0.00	$104.60	$4.40	4.4%
Win	669	400	269	0	$15.00	$12.04	$10.80	$0.00	$0.00	$36.88	$0.00	$74.72	$5.24	7.5%
Annual												$1,075.95	$57.83	5.7%

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 kWh	401-1,000 kWh	1,000+ kWh				
				0-400	401-1,000	1,000+	$15.00	$0.030100	$0.040100	$0.058100	$0.000000	$0.055090	$0.000000	
Xsm	23%	0.6	100	100	0	0	$15.00	$3.01	$0.00	$0.00	$0.00	$5.51	$0.00	$23.52
Small	27%	1.5	294	294	0	0	$15.00	$8.85	$0.00	$0.00	$0.00	$16.20	$0.00	$40.05
Medium	30%	2.6	560	400	160	0	$15.00	$12.04	$6.42	$0.00	$0.00	$30.85	$0.00	$64.31
Large	32%	3.9	914	400	514	0	$15.00	$12.04	$20.61	$0.00	$0.00	$50.35	$0.00	$98.00
XLg	35%	6.5	1,653	400	600	653	$15.00	$12.04	$24.06	$37.94	$0.00	$91.06	$0.00	$180.10
AnnAvg	32%	3.6	830	400	430	0	$15.00	$12.04	$17.22	$0.00	$0.00	$45.70	$0.00	$89.96
WinAvg	31%	3.0	669	400	269	0	$15.00	$12.04	$10.80	$0.00	$0.00	$36.88	$0.00	$74.72

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	$5.00	$0.01534	$0.000000						
Winter				0.26	0.74					$0.086300	$0.038610	0.000%			
Summer										$0.105800	$0.042830				
Xsm	23%	0.6	100	26	74	$15.00	$2.95	$1.53	$0.00	$2.24	$2.86	$0.00	$24.58	$1.06	4.51%
Small	27%	1.5	294	76	218	$15.00	$7.45	$4.51	$0.00	$6.56	$8.42	$0.00	$41.94	$1.89	4.72%
Medium	30%	2.6	560	145	415	$15.00	$12.85	$8.59	$0.00	$12.51	$16.02	$0.00	$64.97	$0.66	1.03%
Large	32%	3.9	914	237	677	$15.00	$19.50	$14.02	$0.00	$20.45	$26.14	$0.00	$95.11	-$2.89	-2.95%
XLg	35%	6.5	1,653	429	1,224	$15.00	$32.25	$25.36	$0.00	$37.02	$47.26	$0.00	$156.89	-$23.21	-12.89%
AnnAvg	32%	3.6	830	215	614	$15.00	$17.90	$12.73	$0.00	$18.55	$23.71	$0.00	$87.89	-$2.07	-2.31%
WinAvg	31%	3.0	669	174	496	$15.00	$14.95	$10.27	$0.00	$15.02	$19.15	$0.00	$74.39	-$0.33	-0.45%

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 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+	$15.00	$0.030100	$0.040100	$0.058100	$0.000000	$0.055090	$0.000000	
Xsm	24%	0.7	117	117	0	0	$15.00	$3.52	$0.00	$0.00	$0.00	$6.45	$0.00	$24.97
Small	28%	1.9	386	386	0	0	$15.00	$11.62	$0.00	$0.00	$0.00	$21.26	$0.00	$47.88
Medium	32%	3.5	813	400	413	0	$15.00	$12.04	$16.56	$0.00	$0.00	$44.79	$0.00	$88.39
Large	34%	5.6	1,395	400	600	395	$15.00	$12.04	$24.06	$22.95	$0.00	$76.85	$0.00	$150.90
XLg	37%	9.1	2,471	400	600	1,471	$15.00	$12.04	$24.06	$85.47	$0.00	$136.13	$0.00	$272.70
AnnAvg	32%	3.6	830	400	430	0	$15.00	$12.04	$17.22	$0.00	$0.00	$45.70	$0.00	$89.96
SumAvg	33%	4.1	983	400	583	0	$15.00	$12.04	$23.39	$0.00	$0.00	$54.17	$0.00	$104.60
														$1,075.95

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	$5.00	$0.01534	$0.000000						
Winter											$0.086300	$0.038610				
Summer				0.24	0.76						$0.105800	$0.042830	0.000%			
Xsm	24%	0.7	117	28	89		$15.00	$3.40	$1.79	$0.00	$2.96	$3.81	$0.00	$26.96	$1.99	7.96%
Small	28%	1.9	386	93	293		$15.00	$9.35	$5.92	$0.00	$9.84	$12.55	$0.00	$52.66	$4.78	9.99%
Medium	32%	3.5	813	196	617		$15.00	$17.60	$12.47	$0.00	$20.74	$26.43	$0.00	$92.24	$3.85	4.35%
Large	34%	5.6	1,395	336	1,059		$15.00	$27.95	$21.40	$0.00	$35.55	$45.36	$0.00	$145.26	-$5.64	-3.74%
XLg	37%	9.1	2,471	595	1,876		$15.00	$45.35	$37.91	$0.00	$62.95	$80.35	$0.00	$241.56	-$31.14	-11.42%
AnnAvg	32%	3.6	830	200	630		$15.00	$17.90	$12.73	$0.00	$21.16	$26.98	$0.00	$93.77	$3.81	4.23%
SumAvg	33%	4.1	983	237	747		$15.00	$20.70	$15.08	$0.00	$25.07	$31.99	$0.00	$107.84	$3.24	3.10%

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

WINTER

BILL IMPACTS CURRENT 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				
							$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsm	23%	0.6	100	100	0	0	$10.00	$1.93	$0.00	$0.00	$0.11	$6.45	-$0.21	$18.28
Small	27%	1.5	294	294	0	0	$10.00	$5.67	$0.00	$0.00	$0.34	$18.97	-$0.63	$34.36
Medium	30%	2.6	560	400	160	0	$10.00	$7.72	$5.50	$0.00	$0.64	$36.13	-$1.20	$58.79
Large	32%	3.9	914	400	514	0	$10.00	$7.72	$17.66	$0.00	$1.04	$58.96	-$1.96	$93.42
XLg	35%	6.5	1,653	400	600	653	$10.00	$7.72	$20.61	$25.14	$1.88	$106.64	-$3.54	$168.45
AnnAvg	32%	3.6	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
WinAvg	31%	3.0	669	400	269	0	$10.00	$7.72	$9.25	$0.00	$0.76	$43.18	-$1.43	$69.48

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	$5.00	$0.01534	$0.000000						
Winter				0.26	0.74						$0.086300	$0.038610	0.000%			
Summer											$0.105800	$0.042830				
Xsm	23%	0.6	100	26	74		$15.00	$2.95	$1.53	$0.00	$2.24	$2.86	$0.00	$24.58	$6.30	34.49%
Small	27%	1.5	294	76	218		$15.00	$7.45	$4.51	$0.00	$6.56	$8.42	$0.00	$41.94	$7.58	22.08%
Medium	30%	2.6	560	145	415		$15.00	$12.85	$8.59	$0.00	$12.51	$16.02	$0.00	$64.97	$6.18	10.52%
Large	32%	3.9	914	237	677		$15.00	$19.50	$14.02	$0.00	$20.45	$26.14	$0.00	$95.11	$1.69	1.81%
XLg	35%	6.5	1,653	429	1,224		$15.00	$32.25	$25.36	$0.00	$37.02	$47.26	$0.00	$156.89	-$11.56	-6.86%
AnnAvg	32%	3.6	830	215	614		$15.00	$17.90	$12.73	$0.00	$18.55	$23.71	$0.00	$87.89	$2.73	3.21%
WinAvg	31%	3.0	669	174	496		$15.00	$14.95	$10.27	$0.00	$15.02	$19.15	$0.00	$74.39	$4.91	7.06%

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 CURRENT 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+	$10.00	$0.019300	$0.034350	$0.038499	$0.001140	$0.064510	-$0.002139	
Xsm	24%	0.7	117	117	0	0	$10.00	$2.26	$0.00	$0.00	$0.13	$7.55	-$0.25	$19.69
Small	28%	1.9	386	386	0	0	$10.00	$7.45	$0.00	$0.00	$0.44	$24.90	-$0.83	$41.96
Medium	32%	3.5	813	400	413	0	$10.00	$7.72	$14.19	$0.00	$0.93	$52.45	-$1.74	$83.55
Large	34%	5.6	1,395	400	600	395	$10.00	$7.72	$20.61	$15.21	$1.59	$89.99	-$2.98	$142.13
XLg	37%	9.1	2,471	400	600	1,471	$10.00	$7.72	$20.61	$56.63	$2.82	$159.40	-$5.29	$251.90
AnnAvg	32%	3.6	830	400	430	0	$10.00	$7.72	$14.75	$0.00	$0.95	$53.51	-$1.77	$85.16
SumAvg	33%	4.1	983	400	583	0	$10.00	$7.72	$20.04	$0.00	$1.12	$63.43	-$2.10	$100.20

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	$5.00	$0.01534	$0.000000						
Winter											$0.086300	$0.038610				
Summer				0.24	0.76						$0.105800	$0.042830	0.000%			
Xsm	24%	0.7	117	28	89		$15.00	$3.40	$1.79	$0.00	$2.96	$3.81	$0.00	$26.96	$7.27	36.94%
Small	28%	1.9	386	93	293		$15.00	$9.35	$5.92	$0.00	$9.84	$12.55	$0.00	$52.66	$10.70	25.49%
Medium	32%	3.5	813	196	617		$15.00	$17.60	$12.47	$0.00	$20.74	$26.43	$0.00	$92.24	$8.69	10.40%
Large	34%	5.6	1,395	336	1,059		$15.00	$27.95	$21.40	$0.00	$35.55	$45.36	$0.00	$145.26	$3.13	2.20%
XLg	37%	9.1	2,471	595	1,876		$15.00	$45.35	$37.91	$0.00	$62.95	$80.35	$0.00	$241.56	-$10.34	-4.10%
AnnAvg	32%	3.6	830	200	630		$15.00	$17.90	$12.73	$0.00	$21.16	$26.98	$0.00	$93.77	$8.61	10.11%
SumAvg	33%	4.1	983	237	747		$15.00	$20.70	$15.08	$0.00	$25.07	$31.99	$0.00	$107.84	$7.64	7.62%

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	$0.028700	$0.048100	$0.000000	$0.050260	0.000%				
Xsmall	220	220	0	$9.00	$6.31	$0.00	$0.00	$11.06	$0.00	$18.46	$2.77	17.65%	30.00%
Small	360	360	0	$9.00	$10.33	$0.00	$0.00	$18.09	$0.00	$29.94	$3.08	11.45%	20.00%
Medium	607	400	207	$9.00	$11.48	$9.96	$0.00	$30.51	$0.00	$54.86	$3.87	7.58%	10.00%
Large	990	400	590	$9.00	$11.48	$28.38	$0.00	$49.76	$0.00	$88.76	$4.64	5.51%	10.00%
Xlarge	1,843	400	1,443	$9.00	$11.48	$69.41	$0.00	$92.63	$0.00	$174.52	$7.08	4.23%	$8.00
Mean	753	400	353	$9.00	$11.48	$16.98	$0.00	$37.84	$0.00	$67.77	$4.16	6.54%	10.00%
Sum	867	400	467	$9.00	$11.48	$22.46	$0.00	$43.57	$0.00	$77.86	$4.37	5.95%	10.00%
Win	638	400	238	$9.00	$11.48	$11.45	$0.00	$32.07	$0.00	$57.60	$3.91	7.28%	10.00%
Annual										$812.75	$49.67	6.51%	

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	$0.028700	$0.048100	$0.000000	$0.050260	0.000%				
Xsmall	365	365	0	$9.00	$10.48	$0.00	$0.00	$18.34	$0.00	$26.47	$2.68	11.3%	30.00%
Small	564	400	164	$9.00	$11.48	$7.89	$0.00	$28.35	$0.00	$39.70	$2.93	8.0%	30.00%
Medium	878	400	478	$9.00	$11.48	$22.99	$0.00	$44.13	$0.00	$70.08	$3.92	5.9%	20.00%
Large	1,340	400	940	$9.00	$11.48	$45.21	$0.00	$67.35	$0.00	$132.94	$18.54	16.2%	10.00%
Xlarge	2,304	400	1,904	$9.00	$11.48	$91.58	$0.00	$115.80	$0.00	$219.86	$8.11	3.8%	$8.00
Mean	1,034	400	634	$9.00	$11.48	$30.48	$0.00	$51.95	$0.00	$82.33	$4.20	5.4%	20.00%
sum	1,199	400	799	$9.00	$11.48	$38.42	$0.00	$60.25	$0.00	$95.32	$4.48	4.9%	20.00%
win	871	400	471	$9.00	$11.48	$22.66	$0.00	$43.78	$0.00	$69.54	$3.90	5.9%	20.00%
Annual										$989.14	$50.26	5.4%	

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			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.028700	$0.048100	$0.048100	$0.000000	$0.050260	$0.000000		
Xsm	26%	1.1	198	198	0	0	$9.00	$5.68	$0.00	$0.00	$0.00	$9.95	$0.00	$17.24	30.00%
Small	28%	1.6	324	324	0	0	$9.00	$9.30	$0.00	$0.00	$0.00	$16.28	$0.00	$27.66	20.00%
Medium	30%	2.4	525	400	125	0	$9.00	$11.48	$6.01	$0.00	$0.00	$26.39	$0.00	$47.59	10.00%
Large	32%	3.6	831	400	431	0	$9.00	$11.48	$20.73	$0.00	$0.00	$41.77	$0.00	$74.68	10.00%
XLg	35%	5.9	1,496	400	600	496	$9.00	$11.48	$28.86	$23.86	$0.00	$75.19	$0.00	$140.39	$8.00
AnnAvg	31%	3.3	753	400	353	0	$9.00	$11.48	$16.98	$0.00	$0.00	$37.84	$0.00	$67.77	10.00%
WinAvg	31%	2.9	638	400	238	0	$9.00	$11.48	$11.45	$0.00	$0.00	$32.07	$0.00	$57.60	10.00%

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	5.00	$0.01534	$0.000000							
Winter				0.26	0.74						$0.086300	$0.038610	0.000%				
Summer											$0.105800	$0.042830					
Xsm	26%	1.1	198	51	147		$15.00	$5.50	$3.04	$0.00	$4.40	$5.68	$0.00	$16.62	-$0.62	-3.6%	$17.00
Small	28%	1.6	324	84	240		$15.00	$8.00	$4.97	$0.00	$7.25	$9.27	$0.00	$27.49	-$0.17	-0.6%	$17.00
Medium	30%	2.4	525	136	389		$15.00	$12.00	$8.05	$0.00	$11.74	$15.02	$0.00	$44.81	-$2.78	-5.8%	$17.00
Large	32%	3.6	831	216	615		$15.00	$18.00	$12.75	$0.00	$18.64	$23.75	$0.00	$71.14	-$3.54	-4.7%	$17.00
XLg	35%	5.9	1,496	388	1,108		$15.00	$29.50	$22.95	$0.00	$33.48	$42.78	$0.00	$126.71	-$13.68	-9.7%	$17.00
AnnAvg	31%	3.3	753	195	558		$15.00	$16.50	$11.55	$0.00	$16.83	$21.54	$0.00	$64.42	-$3.35	-4.9%	$17.00
WinAvg	31%	2.9	638	166	472		$15.00	$14.50	$9.79	$0.00	$14.33	$18.22	$0.00	$54.84	-$2.76	-4.8%	$17.00

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			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.028700	$0.048100	$0.048100	$0.000000	$0.050260	$0.000000		
Xsm	26%	1.3	243	243	0	0	$9.00	$6.97	$0.00	$0.00	$0.00	$12.21	$0.00	$19.73	30.00%
Small	29%	2.0	413	400	13	0	$9.00	$11.48	$0.63	$0.00	$0.00	$20.76	$0.00	$33.49	20.00%
Medium	31%	3.1	709	400	309	0	$9.00	$11.48	$14.86	$0.00	$0.00	$35.63	$0.00	$63.88	10.00%
Large	33%	4.8	1,161	400	600	161	$9.00	$11.48	$28.86	$7.74	$0.00	$58.35	$0.00	$107.43	$8.00
XLg	36%	7.8	2,078	400	600	1,078	$9.00	$11.48	$28.86	$51.85	$0.00	$104.44	$0.00	$197.63	$8.00
AnnAvg	31%	3.3	753	400	353	0	$9.00	$11.48	$16.98	$0.00	$0.00	$37.84	$0.00	$67.77	10.00%
SumAvg	32%	3.7	863	400	463	0	$9.00	$11.48	$22.29	$0.00	$0.00	$43.39	$0.00	$77.54	10.00%

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	$5.00	$0.01534	$0.000000							
Winter										$0.086300	$0.038610					
Summer				0.24	0.76					$0.105800	$0.042830	0.000%				
Xsm	26%	1.3	243	58	185	$15.00	$6.50	$3.73	$0.00	$6.14	$7.92	$0.00	$22.29	$2.56	13.0%	$17.00
Small	29%	2.0	413	99	314	$15.00	$10.00	$6.34	$0.00	$10.47	$13.45	$0.00	$38.26	$4.77	14.2%	$17.00
Medium	31%	3.1	709	171	538	$15.00	$15.50	$10.88	$0.00	$18.09	$23.04	$0.00	$65.51	$1.63	2.6%	$17.00
Large	33%	4.8	1,161	279	882	$15.00	$24.00	$17.81	$0.00	$29.52	$37.78	$0.00	$107.11	-$0.32	-0.3%	$17.00
XLg	36%	7.8	2,078	500	1,578	$15.00	$39.00	$31.88	$0.00	$52.90	$67.59	$0.00	$189.37	-$8.26	-4.2%	$17.00
AnnAvg	31%	3.3	753	181	572	$15.00	$16.50	$11.55	$0.00	$19.15	$24.50	$0.00	$69.70	$1.93	2.8%	$17.00
SumAvg	32%	3.7	863	208	656	$15.00	$18.50	$13.24	$0.00	$22.01	$28.10	$0.00	$79.85	$2.31	3.0%	$17.00

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

WINTER

BILL IMPACTS CURRENT RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) 0-400	Delivery (kWh) 401-1,000	Delivery (kWh) 1,000+	Basic Service Charge	Delivery 0-400 kWh	Delivery 401-1,000 kWh	Delivery 1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
							$4.90	$0.018973	$0.035400	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsm	26%	1.1	198	198	0	0	$4.90	$3.76	$0.00	$0.00	$0.23	$12.22	-$0.42	$14.48	30.00%
Small	28%	1.6	324	324	0	0	$4.90	$6.15	$0.00	$0.00	$0.37	$19.99	-$0.69	$24.57	20.00%
Medium	30%	2.4	525	400	125	0	$4.90	$7.59	$4.43	$0.00	$0.60	$32.39	-$1.12	$43.90	10.00%
Large	32%	3.6	831	400	431	0	$4.90	$7.59	$15.26	$0.00	$0.95	$51.27	-$1.78	$70.37	10.00%
XLg	35%	5.9	1,496	400	600	496	$4.90	$7.59	$21.24	$17.56	$1.71	$92.30	-$3.20	$134.10	$8.00
AnnAvg	31%	3.3	753	400	353	0	$4.90	$7.59	$12.49	$0.00	$0.86	$46.45	-$1.61	$63.61	10.00%
WinAvg	31%	2.9	638	400	238	0	$4.90	$7.59	$8.43	$0.00	$0.73	$39.37	-$1.37	$53.69	10.00%

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	
						15.00	5.00	$0.01534	$0.000000							
Winter				0.26	0.74					$0.086300	$0.038610	0.000%				
Summer										$0.105800	$0.042830					
Xsm	26%	1.1	198	51	147	$15.00	$5.50	$3.04	$0.00	$4.40	$5.68	$0.00	$16.62	$2.14	14.8%	$17.00
Small	28%	1.6	324	84	240	$15.00	$8.00	$4.97	$0.00	$7.25	$9.27	$0.00	$27.49	$2.92	11.9%	$17.00
Medium	30%	2.4	525	136	389	$15.00	$12.00	$8.05	$0.00	$11.74	$15.02	$0.00	$44.81	$0.91	2.1%	$17.00
Large	32%	3.6	831	216	615	$15.00	$18.00	$12.75	$0.00	$18.64	$23.75	$0.00	$71.14	$0.77	1.1%	$17.00
XLg	35%	5.9	1,496	388	1,108	$15.00	$29.50	$22.95	$0.00	$33.48	$42.78	$0.00	$126.71	-$7.39	-5.5%	$17.00
AnnAvg	31%	3.3	753	195	558	$15.00	$16.50	$11.55	$0.00	$16.83	$21.54	$0.00	$64.42	$0.81	1.3%	$17.00
WinAvg	31%	2.9	638	166	472	$15.00	$14.50	$9.79	$0.00	$14.33	$18.22	$0.00	$54.84	$1.15	2.1%	$17.00

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 CURRENT 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+	$4.90	$0.018973	$0.035400	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsm	26%	1.3	243	243	0	0	$4.90	$4.61	$0.00	$0.00	$0.28	$14.99	-$0.52	$16.98	30.00%
Small	29%	2.0	413	400	13	0	$4.90	$7.59	$0.46	$0.00	$0.47	$25.48	-$0.88	$30.41	20.00%
Medium	31%	3.1	709	400	309	0	$4.90	$7.59	$10.94	$0.00	$0.81	$43.75	-$1.52	$59.82	10.00%
Large	33%	4.8	1,161	400	600	161	$4.90	$7.59	$21.24	$5.70	$1.32	$71.63	-$2.48	$101.89	$8.00
XLg	36%	7.8	2,078	400	600	1,078	$4.90	$7.59	$21.24	$38.16	$2.37	$128.21	-$4.45	$190.02	$8.00
AnnAvg	31%	3.3	753	400	353	0	$4.90	$7.59	$12.49	$0.00	$0.86	$46.45	-$1.61	$63.61	10.00%
SumAvg	32%	3.7	863	400	463	0	$4.90	$7.59	$16.40	$0.00	$0.98	$53.27	-$1.85	$73.17	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	$5.00	$0.01534	$0.000000							
Winter											$0.086300	$0.038610					
Summer				0.24	0.76						$0.105800	$0.042830	0.000%				
Xsm	26%	1.3	243	58	185		$15.00	$6.50	$3.73	$0.00	$6.14	$7.92	$0.00	$22.29	$5.31	31.3%	$17.00
Small	29%	2.0	413	99	314		$15.00	$10.00	$6.34	$0.00	$10.47	$13.45	$0.00	$38.26	$7.85	25.8%	$17.00
Medium	31%	3.1	709	171	538		$15.00	$15.50	$10.88	$0.00	$18.09	$23.04	$0.00	$65.51	$5.69	9.5%	$17.00
Large	33%	4.8	1,161	279	882		$15.00	$24.00	$17.81	$0.00	$29.52	$37.78	$0.00	$107.11	$5.22	5.1%	$17.00
XLg	36%	7.8	2,078	500	1,578		$15.00	$39.00	$31.88	$0.00	$52.90	$67.59	$0.00	$189.37	-$0.65	-0.3%	$17.00
AnnAvg	31%	3.3	753	181	572		$15.00	$16.50	$11.55	$0.00	$19.15	$24.50	$0.00	$69.70	$6.09	9.6%	$17.00
SumAvg	32%	3.7	863	208	656		$15.00	$18.50	$13.24	$0.00	$22.01	$28.10	$0.00	$79.85	$6.68	9.1%	$17.00

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	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$9.00	$0.028700	$0.048100	$0.048100	$0.000000	$0.050260	$0.000000		
Xsm	28%	1.6	323	323	0	0	$9.00	$9.27	$0.00	$0.00	$0.00	$16.23	$0.00	$24.15	30.00%
Small	29%	2.3	495	400	95	0	$9.00	$11.48	$4.57	$0.00	$0.00	$24.88	$0.00	$34.95	30.00%
Medium	31%	3.3	763	400	363	0	$9.00	$11.48	$17.46	$0.00	$0.00	$38.35	$0.00	$61.03	20.00%
Large	33%	4.6	1,115	400	600	115	$9.00	$11.48	$28.86	$5.53	$0.00	$56.04	$0.00	$88.73	20.00%
XLg	36%	7.2	1,887	400	600	887	$9.00	$11.48	$28.86	$42.66	$0.00	$94.84	$0.00	$168.16	10.00%
AnnAvg	33%	4.3	1,034	400	600	34	$9.00	$11.48	$28.86	$1.62	$0.00	$51.95	$0.00	$82.33	20.00%
WinAvg	32%	3.7	871	400	471	0	$9.00	$11.48	$22.66	$0.00	$0.00	$43.78	$0.00	$69.54	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	5.00	$0.01534	$0.000000							
Winter				0.26	0.74					$0.086300	$0.038610	0.000%				
Summer										$0.105800	$0.042830					
Xsm	28%	1.6	323	84	239	$15.00	$8.00	$4.95	$0.00	$7.25	$9.23	$0.00	$17.43	-$6.72	-27.8%	$27.00
Small	29%	2.3	495	128	367	$15.00	$11.50	$7.59	$0.00	$11.05	$14.17	$0.00	$32.31	-$2.64	-7.6%	$27.00
Medium	31%	3.3	763	198	565	$15.00	$16.50	$11.70	$0.00	$17.09	$21.81	$0.00	$55.10	-$5.93	-9.7%	$27.00
Large	33%	4.6	1,115	289	826	$15.00	$23.00	$17.10	$0.00	$24.94	$31.89	$0.00	$84.93	-$3.80	-4.3%	$27.00
XLg	36%	7.2	1,887	490	1,397	$15.00	$36.00	$28.95	$0.00	$42.29	$53.94	$0.00	$149.18	-$18.98	-11.3%	$27.00
AnnAvg	33%	4.3	1,034	268	765	$15.00	$21.50	$15.86	$0.00	$23.13	$29.54	$0.00	$78.03	-$4.30	-5.2%	$27.00
WinAvg	32%	3.7	871	226	645	$15.00	$18.50	$13.36	$0.00	$19.50	$24.90	$0.00	$64.26	-$5.28	-7.6%	$27.00

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) 0-400	401-1,000	1,000+	Basic Service Charge	Delivery 0-400 kWh	401-1,000 kWh	1,000+ kWh	TCA	Base Fuel	PPFAC	Net Bill	Discounts
							$9.00	$0.028700	$0.048100	$0.048100	$0.000000	$0.050260	$0.000000		
Xsm	29%	2.0	414	400	14	0	$9.00	$11.48	$0.67	$0.00	$0.00	$20.81	$0.00	$29.37	30.00%
Small	31%	3.0	663	400	263	0	$9.00	$11.48	$12.63	$0.00	$0.00	$33.30	$0.00	$53.13	20.00%
Medium	33%	4.3	1,035	400	600	35	$9.00	$11.48	$28.86	$1.68	$0.00	$52.02	$0.00	$82.43	20.00%
Large	35%	6.2	1,572	400	600	572	$9.00	$11.48	$28.86	$27.49	$0.00	$78.98	$0.00	$140.23	10.00%
XLg	38%	9.5	2,601	400	600	1,601	$9.00	$11.48	$28.86	$77.01	$0.00	$130.73	$0.00	$249.08	$8.00
AnnAvg	33%	4.3	1,034	400	600	34	$9.00	$11.48	$28.86	$1.62	$0.00	$51.95	$0.00	$82.33	20.00%
SumAvg	33%	4.9	1,194	400	600	194	$9.00	$11.48	$28.86	$9.32	$0.00	$60.00	$0.00	$94.93	20.00%

BILL IMPACTS PROPOSED RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh) On-Peak	Off-Peak	Basic Service Charge	Delivery All kW	All kWh	TCA	Base Fuel On-Peak	Base Fuel Off-PeaK	PPFAC	Net Bill	$ Change	% Change	
						$15.00	$5.00	$0.01534	$0.000000							
Winter										$0.086300	$0.038610					
Summer				0.24	0.76					$0.105800	$0.042830	0.000%				
Xsm	29%	2.0	414	100	314	$15.00	$10.00	$6.35	$0.00	$10.58	$13.45	$0.00	$28.38	-$0.99	-3.4%	$27.00
Small	31%	3.0	663	159	503	$15.00	$15.00	$10.16	$0.00	$16.82	$21.54	$0.00	$51.52	-$1.61	-3.0%	$27.00
Medium	33%	4.3	1,035	249	786	$15.00	$21.50	$15.88	$0.00	$26.34	$33.66	$0.00	$85.38	$2.95	3.6%	$27.00
Large	35%	6.2	1,572	378	1,193	$15.00	$31.00	$24.11	$0.00	$39.99	$51.10	$0.00	$134.20	-$6.03	-4.3%	$27.00
XLg	38%	9.5	2,601	626	1,975	$15.00	$47.50	$39.90	$0.00	$66.23	$84.59	$0.00	$226.22	-$22.86	-9.2%	$27.00
AnnAvg	33%	4.3	1,034	249	785	$15.00	$21.50	$15.86	$0.00	$26.34	$33.62	$0.00	$85.32	$2.99	3.6%	$27.00
SumAvg	33%	4.9	1,194	287	907	$15.00	$24.50	$18.31	$0.00	$30.36	$38.85	$0.00	$100.02	$5.09	5.4%	$27.00

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 CURRENT RATES

	Load Factor	Demand (kW)	Total kWh	Delivery (kWh)			Basic Service Charge	Delivery			TCA	Base Fuel	PPFAC	Net Bill	Discounts
				0-400	401-1,000	1,000+		0-400 kWh	401-1,000 kWh	1,000+ kWh					
							$4.90	$0.018973	$0.035400	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsm	28%	1.6	323	323	0	0	$4.90	$6.13	$0.00	$0.00	$0.37	$19.93	-$0.69	$21.45	30.00%
Small	29%	2.3	495	400	95	0	$4.90	$7.59	$3.36	$0.00	$0.56	$30.54	-$1.06	$32.13	30.00%
Medium	31%	3.3	763	400	363	0	$4.90	$7.59	$12.85	$0.00	$0.87	$47.08	-$1.63	$57.33	20.00%
Large	33%	4.6	1,115	400	600	115	$4.90	$7.59	$21.24	$4.07	$1.27	$68.80	-$2.39	$84.39	20.00%
XLg	36%	7.2	1,887	400	600	887	$4.90	$7.59	$21.24	$31.40	$2.15	$116.43	-$4.04	$161.70	10.00%
AnnAvg	33%	4.3	1,034	400	600	34	$4.90	$7.59	$21.24	$1.19	$1.18	$63.78	-$2.21	$78.14	20.00%
WinAvg	32%	3.7	871	400	471	0	$4.90	$7.59	$16.68	$0.00	$0.99	$53.75	-$1.86	$65.63	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	5.00	$0.01534	$0.000000							
Winter				0.26	0.74						$0.086300	$0.038610	0.000%				
Summer											$0.105800	$0.042830					
Xsm	28%	1.6	323	84	239		$15.00	$8.00	$4.95	$0.00	$7.25	$9.23	$0.00	$17.43	-$4.02	-18.7%	$27.00
Small	29%	2.3	495	128	367		$15.00	$11.50	$7.59	$0.00	$11.05	$14.17	$0.00	$32.31	$0.18	0.6%	$27.00
Medium	31%	3.3	763	198	565		$15.00	$16.50	$11.70	$0.00	$17.09	$21.81	$0.00	$55.10	-$2.23	-3.9%	$27.00
Large	33%	4.6	1,115	289	826		$15.00	$23.00	$17.10	$0.00	$24.94	$31.89	$0.00	$84.93	$0.54	0.6%	$27.00
XLg	36%	7.2	1,887	490	1,397		$15.00	$36.00	$28.95	$0.00	$42.29	$53.94	$0.00	$149.18	-$12.52	-7.7%	$27.00
AnnAvg	33%	4.3	1,034	268	765		$15.00	$21.50	$15.86	$0.00	$23.13	$29.54	$0.00	$78.03	-$0.11	-0.1%	$27.00
WinAvg	32%	3.7	871	226	645		$15.00	$18.50	$13.36	$0.00	$19.50	$24.90	$0.00	$64.26	-$1.37	-2.1%	$27.00

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.

Exhibit CAJ-RJ-2

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

Schedule H-4

Page 9a of 34

RESIDENTIAL SERVICE DEMAND - CARES MEDICAL

SUMMER

BILL IMPACTS CURRENT 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+	$4.90	$0.018973	$0.035400	$0.035400	$0.001140	$0.061700	-$0.002139		
Xsm	29%	2.0	414	400	14	0	$4.90	$7.59	$0.50	$0.00	$0.47	$25.54	-$0.89	$26.68	30.00%
Small	31%	3.0	663	400	263	0	$4.90	$7.59	$9.29	$0.00	$0.76	$40.88	-$1.42	$49.60	20.00%
Medium	33%	4.3	1,035	400	600	35	$4.90	$7.59	$21.24	$1.24	$1.18	$63.86	-$2.21	$78.24	20.00%
Large	35%	6.2	1,572	400	600	572	$4.90	$7.59	$21.24	$20.23	$1.79	$96.96	-$3.36	$134.41	10.00%
XLg	38%	9.5	2,601	400	600	1,601	$4.90	$7.59	$21.24	$56.68	$2.97	$160.48	-$5.56	$240.29	$8.00
AnnAvg	33%	4.3	1,034	400	600	34	$4.90	$7.59	$21.24	$1.19	$1.18	$63.78	-$2.21	$78.14	20.00%
SumAvg	33%	4.9	1,194	400	600	194	$4.90	$7.59	$21.24	$6.86	$1.36	$73.66	-$2.55	$90.44	20.00%

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	
							$15.00	$5.00	$0.01534	$0.000000							
Winter											$0.086300	$0.038610					
Summer				0.24	0.76						$0.105800	$0.042830	0.000%				
Xsm	29%	2.0	414	100	314		$15.00	$10.00	$6.35	$0.00	$10.58	$13.45	$0.00	$28.38	$1.70	6.4%	$27.00
Small	31%	3.0	663	159	503		$15.00	$15.00	$10.16	$0.00	$16.82	$21.54	$0.00	$51.52	$1.92	3.9%	$27.00
Medium	33%	4.3	1,035	249	786		$15.00	$21.50	$15.88	$0.00	$26.34	$33.66	$0.00	$85.38	$7.14	9.1%	$27.00
Large	35%	6.2	1,572	378	1,193		$15.00	$31.00	$24.11	$0.00	$39.99	$51.10	$0.00	$134.20	-$0.21	-0.2%	$27.00
XLg	38%	9.5	2,601	626	1,975		$15.00	$47.50	$39.90	$0.00	$66.23	$84.59	$0.00	$226.22	-$14.07	-5.9%	$27.00
AnnAvg	33%	4.3	1,034	249	785		$15.00	$21.50	$15.86	$0.00	$26.34	$33.62	$0.00	$85.32	$7.18	9.2%	$27.00
SumAvg	33%	4.9	1,194	287	907		$15.00	$24.50	$18.31	$0.00	$30.36	$38.85	$0.00	$100.02	$9.58	10.6%	$27.00

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	$0.035300	$0.035300	$0.035300	$0.000000	$0.091550	$0.038610	0.000%		$ Change	% Change
	Summer											$0.111001	$0.042830				
Xsm	150	36	114	150	0	0	$15.00	$5.30	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.00	$3.85	15.94%
Small	286	69	217	286	0	0	$15.00	$10.10	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$39.77	$4.15	11.65%
Medium	641	154	487	400	241	0	$15.00	$14.12	$8.51	$0.00	$0.00	$14.08	$18.81	$0.00	$70.52	$4.98	7.60%
Large	1,043	250	793	400	600	43	$15.00	$14.12	$21.18	$1.52	$0.00	$22.92	$30.61	$0.00	$105.35	$5.91	5.94%
XLg	1,810	434	1,376	400	600	810	$15.00	$14.12	$21.18	$28.59	$0.00	$39.77	$53.11	$0.00	$171.77	$7.68	4.68%
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.12	$21.18	$0.28	$0.00	$22.15	$29.58	$0.00	$102.31	$5.82	6.03%
Avg Win	801	192	608	400	401	0	$15.00	$14.12	$14.14	$0.00	$0.00	$17.59	$23.49	$0.00	$84.34	$5.34	6.76%

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	$0.035300	$0.035300	$0.035300	$0.000000	$0.091550	$0.038610				
Summer												$0.111001	$0.042830	0.000%		$ Change	% Change
Xsm	261	60	201	261	0	0	$15.00	$9.21	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.48	$4.58	13.12%
Small	525	121	404	400	125	0	$15.00	$14.12	$4.41	$0.00	$0.00	$13.40	$17.31	$0.00	$64.24	$5.67	9.69%
Medium	983	226	757	400	583	0	$15.00	$14.12	$20.58	$0.00	$0.00	$25.10	$32.42	$0.00	$107.22	$7.59	7.62%
Large	1,611	371	1,240	400	600	611	$15.00	$14.12	$21.18	$21.57	$0.00	$41.13	$53.13	$0.00	$166.13	$10.20	6.54%
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.12	$21.18	$59.34	$0.00	$68.45	$88.42	$0.00	$266.51	$14.64	5.81%
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.12	$21.18	$0.28	$0.00	$25.74	$33.25	$0.00	$109.57	$7.70	7.56%
Avg Sum	1,195	275	920	400	600	195	$15.00	$14.12	$21.18	$6.87	$0.00	$30.50	$39.40	$0.00	$127.07	$8.47	7.14%

	Net Bill	$ Change	% Change
Current Annual	$1,185.62		
Proposed Annual	$1,268.46	$82.84	6.99%

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 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	$0.035300	$0.035300	$0.035300	$0.000000	$0.091550	$0.038610	0.000%	
	Summer											$0.111001	$0.042830		
Xsm	150	36	114	150	0	0	$15.00	$5.30	$0.00	$0.00	$0.00	$3.30	$4.40	$0.00	$28.00
Small	286	69	217	286	0	0	$15.00	$10.10	$0.00	$0.00	$0.00	$6.28	$8.39	$0.00	$39.77
Medium	641	154	487	400	241	0	$15.00	$14.12	$8.51	$0.00	$0.00	$14.08	$18.81	$0.00	$70.52
Large	1,043	250	793	400	600	43	$15.00	$14.12	$21.18	$1.52	$0.00	$22.92	$30.61	$0.00	$105.35
XLg	1,810	434	1,376	400	600	810	$15.00	$14.12	$21.18	$28.59	$0.00	$39.77	$53.11	$0.00	$171.77
AnnAvg	1,008	242	766	400	600	8	$15.00	$14.12	$21.18	$0.28	$0.00	$22.15	$29.58	$0.00	$102.31
WinAvg	801	192	608	400	401	0	$15.00	$14.12	$14.14	$0.00	$0.00	$17.59	$23.49	$0.00	$84.34

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	$5.00	$0.01534	$0.000000						
Winter		0.24	0.76								$0.086300	$0.038610	0.000%			
Summer											$0.105800	$0.042830				
Xsm	150	36	114	25%	0.8		$15.00	$4.00	$2.30	$0.00	$3.11	$4.40	$0.00	$28.81	$0.81	2.89%
Small	286	69	217	27%	1.4		$15.00	$7.00	$4.39	$0.00	$5.92	$8.39	$0.00	$40.70	$0.93	2.34%
Medium	641	154	487	30%	2.9		$15.00	$14.50	$9.83	$0.00	$13.28	$18.81	$0.00	$71.42	$0.90	1.28%
Large	1,043	250	793	33%	4.4		$15.00	$22.00	$16.00	$0.00	$21.60	$30.61	$0.00	$105.21	-$0.14	-0.13%
XLg	1,810	434	1,376	36%	7.0		$15.00	$35.00	$27.77	$0.00	$37.49	$53.11	$0.00	$168.37	-$3.40	-1.98%
AnnAvg	1,008	242	766	33%	4.2		$15.00	$21.00	$15.46	$0.00	$20.88	$29.58	$0.00	$101.92	-$0.39	-0.38%
WinAvg	801	192	608	32%	3.5		$15.00	$17.50	$12.28	$0.00	$16.58	$23.49	$0.00	$84.85	$0.51	0.60%

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	$0.035300	$0.035300	$0.035300	$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	$9.21	$0.00	$0.00	$0.00	$6.66	$8.61	$0.00	$39.48
Small	525	121	404	400	125	0	$15.00	$14.12	$4.41	$0.00	$0.00	$13.40	$17.31	$0.00	$64.24
Medium	983	226	757	400	583	0	$15.00	$14.12	$20.58	$0.00	$0.00	$25.10	$32.42	$0.00	$107.22
Large	1,611	371	1,240	400	600	611	$15.00	$14.12	$21.18	$21.57	$0.00	$41.13	$53.13	$0.00	$166.13
XLg	2,681	617	2,064	400	600	1,681	$15.00	$14.12	$21.18	$59.34	$0.00	$68.45	$88.42	$0.00	$266.51
AnnAvg	1,008	232	776	400	600	8	$15.00	$14.12	$21.18	$0.28	$0.00	$25.74	$33.25	$0.00	$109.57
SumAvg	1,195	275	920	400	600	195	$15.00	$14.12	$21.18	$6.87	$0.00	$30.50	$39.40	$0.00	$127.07

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		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	$5.00	$0.01534	$0.000000						
Winter											$0.086300	$0.038610				
Summer		0.23	0.77								$0.105800	$0.042830	0.000%			
Xsm	261	60	201	27%	1.3		$15.00	$6.50	$4.00	$0.00	$6.35	$8.61	$0.00	$40.46	$0.98	2.48%
Small	525	121	404	30%	2.4		$15.00	$12.00	$8.05	$0.00	$12.80	$17.30	$0.00	$65.15	$0.91	1.42%
Medium	983	226	757	32%	4.1		$15.00	$20.50	$15.08	$0.00	$23.91	$32.42	$0.00	$106.91	-$0.31	-0.29%
Large	1,611	371	1,240	35%	6.3		$15.00	$31.50	$24.71	$0.00	$39.25	$53.11	$0.00	$163.57	-$2.56	-1.54%
XLg	2,681	617	2,064	38%	9.7		$15.00	$48.50	$41.13	$0.00	$65.28	$88.40	$0.00	$258.31	-$8.20	-3.08%
AnnAvg	1,008	232	776	33%	4.2		$15.00	$21.00	$15.46	$0.00	$24.55	$33.24	$0.00	$109.25	-$0.32	-0.29%
SumAvg	1,195	275	920	33%	4.9		$15.00	$24.50	$18.33	$0.00	$29.10	$39.40	$0.00	$126.33	-$0.74	-0.58%

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.

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 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
WinAvg	801	192	608	400	401	0	$11.50	$24.30	$0.91	$24.90	$19.10	($1.71)	$79.00

BILL IMPACTS PROPOSED RATES

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)		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	$5.00	$0.01534	$0.000000						
Winter		0.24	0.76								$0.086300	$0.038610	0.000%			
Summer											$0.105800	$0.042830				
Xsm	150	36	114	25%	0.8		$15.00	$4.20	$2.30	$0.00	$3.11	$4.40	$0.00	$29.01	$4.86	20.12%
Small	286	69	217	27%	1.5		$15.00	$7.25	$4.39	$0.00	$5.92	$8.39	$0.00	$40.95	$5.33	14.96%
Medium	641	154	487	30%	2.9		$15.00	$14.40	$9.83	$0.00	$13.28	$18.81	$0.00	$71.32	$5.78	8.82%
Large	1,043	250	793	33%	4.4		$15.00	$21.80	$16.00	$0.00	$21.60	$30.61	$0.00	$105.01	$5.57	5.60%
XLg	1,810	434	1,376	36%	7.0		$15.00	$34.85	$27.77	$0.00	$37.49	$53.11	$0.00	$168.22	$4.13	2.52%
AnnAvg	1,008	242	766	33%	4.2		$15.00	$21.20	$15.46	$0.00	$20.88	$29.58	$0.00	$102.12	$5.63	5.83%
WinAvg	801	192	608	32%	3.5		$15.00	$17.40	$12.28	$0.00	$16.58	$23.49	$0.00	$84.75	$5.75	7.28%

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 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		
	Summer									$0.129605	$0.039605	-$0.002139	
Xsm	261	63	198	261	0	0	$11.50	$7.92	$0.30	$8.12	$7.86	($0.56)	$35.14
Small	525	126	399	400	125	0	$11.50	$15.93	$0.60	$16.33	$15.80	($1.12)	$59.04
Medium	983	236	747	400	583	0	$11.50	$29.83	$1.12	$30.58	$29.59	($2.10)	$100.52
Large	1,611	387	1,224	400	600	611	$11.50	$48.89	$1.84	$50.11	$48.49	($3.45)	$157.38
XLg	2,681	643	2,038	400	600	1,681	$11.50	$81.37	$3.06	$83.39	$80.70	($5.74)	$254.28
AnnAvg	1,008	242	766	400	600	8	$11.50	$30.59	$1.15	$31.36	$30.34	($2.16)	$102.78
WinAvg	1,195	287	908	400	600	195	$11.50	$36.26	$1.36	$37.16	$35.96	($2.56)	$119.68

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	$5.00	$0.01534	$0.000000						
Winter											$0.086300	$0.038610				
Summer		0.23	0.77								$0.105800	$0.042830	0.000%			
Xsm	261	60	201	27%	1.3		$15.00	$6.70	$4.00	$0.00	$6.35	$8.61	$0.00	$40.66	$5.52	15.71%
Small	525	121	404	30%	2.4		$15.00	$12.15	$8.05	$0.00	$12.80	$17.30	$0.00	$65.30	$6.26	10.60%
Medium	983	226	757	32%	4.2		$15.00	$20.75	$15.08	$0.00	$23.91	$32.42	$0.00	$107.16	$6.64	6.61%
Large	1,611	371	1,240	35%	6.3		$15.00	$31.55	$24.71	$0.00	$39.25	$53.11	$0.00	$163.62	$6.24	3.96%
XLg	2,681	617	2,064	38%	9.7		$15.00	$48.70	$41.13	$0.00	$65.28	$88.40	$0.00	$258.51	$4.23	1.66%
AnnAvg	1,008	232	776	33%	4.2		$15.00	$21.20	$15.46	$0.00	$24.55	$33.24	$0.00	$109.45	$6.67	6.49%
SumAvg	1,195	275	920	33%	4.9		$15.00	$24.45	$18.33	$0.00	$29.10	$39.40	$0.00	$126.28	$6.60	5.51%

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	$0.030100	$0.037500	$0.037500	$0.000000	$0.159790	$0.040810	0.000%			
	Summer											$0.159790	$0.040810				
Xsm	150	15	135	150	0	0	$15.00	$4.52	$0.00	$0.00	$0.00	$2.40	$5.51	$0.00	$27.43	$4.86	21.53%
Small	286	29	257	286	0	0	$15.00	$8.61	$0.00	$0.00	$0.00	$4.57	$10.50	$0.00	$38.68	$6.06	18.58%
Medium	641	64	577	400	241	0	$15.00	$12.04	$9.04	$0.00	$0.00	$10.24	$23.54	$0.00	$69.86	$8.61	14.06%
Large	1,043	104	939	400	600	43	$15.00	$12.04	$22.50	$1.61	$0.00	$16.67	$38.31	$0.00	$106.13	$11.18	11.77%
XLg	1,810	181	1,629	400	600	810	$15.00	$12.04	$22.50	$30.38	$0.00	$28.92	$66.48	$0.00	$175.32	$16.09	10.10%
AnnAvg	1,008	101	907	400	600	8	$15.00	$12.04	$22.50	$0.30	$0.00	$16.11	$37.03	$0.00	$102.98	$10.98	11.93%
AvgWin	801	80	721	400	401	0	$15.00	$12.04	$15.02	$0.00	$0.00	$12.79	$29.41	$0.00	$84.26	$9.64	12.92%

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	$0.030100	$0.037500	$0.037500	$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	$7.86	$0.00	$0.00	$0.00	$5.84	$9.16	$0.00	$37.86	$4.97	15.11%
Small	525	74	452	400	125	0	$15.00	$12.04	$4.69	$0.00	$0.00	$11.74	$18.43	$0.00	$61.90	$6.12	10.98%
Medium	983	138	845	400	583	0	$15.00	$12.04	$21.86	$0.00	$0.00	$21.99	$34.50	$0.00	$105.39	$7.50	7.66%
Large	1,611	226	1,385	400	600	611	$15.00	$12.04	$22.50	$22.91	$0.00	$36.04	$56.54	$0.00	$165.03	$9.41	6.04%
XLg	2,681	375	2,306	400	600	1,681	$15.00	$12.04	$22.50	$63.04	$0.00	$59.98	$94.09	$0.00	$266.65	$12.65	4.98%
AnnAvg	1,008	141	867	400	600	8	$15.00	$12.04	$22.50	$0.30	$0.00	$22.55	$35.38	$0.00	$107.77	$7.59	7.57%
AvgSum	1,195	167	1,027	400	600	195	$15.00	$12.04	$22.50	$7.30	$0.00	$26.73	$41.93	$0.00	$125.50	$8.16	6.95%

		$ Change	% Change
Current Annual	$1,151.78		
Proposed Annual	$1,258.56	$106.78	9.27%

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) 1-400	Delivery (kWh) 401-7500	Delivery (kWh) 7501+	TCA	Base Fuel	PPFAC	Net Bill
		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) 1-400	Delivery (kWh) 401-7500	Delivery (kWh) 7501+	TCA	Base Fuel	PPFAC	Net Bill	$ Change	% Change
		1-400	401-7500	7501+	$30.00	$0.030000	$0.039900	$0.077300	$0.000000	$0.053290	0.000%			
Xsm	200	200	0	0	$30.00	$6.00	$0.00	$0.00	$0.00	$10.66	$0.00	$46.66	$14.67	45.85%
Small	350	350	0	0	$30.00	$10.50	$0.00	$0.00	$0.00	$18.65	$0.00	$59.15	$14.06	31.18%
Medium	561	400	161	0	$30.00	$12.00	$6.42	$0.00	$0.00	$29.90	$0.00	$78.32	$13.03	19.96%
Large	1,447	400	1,047	0	$30.00	$12.00	$41.78	$0.00	$0.00	$77.11	$0.00	$160.89	$8.53	5.60%
XLg	4,078	400	3,678	0	$30.00	$12.00	$146.75	$0.00	$0.00	$217.32	$0.00	$406.07	-$4.89	-1.19%
Mean	1,131	400	731	0	$30.00	$12.00	$29.17	$0.00	$0.00	$60.27	$0.00	$131.44	$10.13	8.35%
sum	1,277	400	877	0	$30.00	$12.00	$35.00	$0.00	$0.00	$68.07	$0.00	$145.07	$9.38	6.91%
win	980	400	580	0	$30.00	$12.00	$23.16	$0.00	$0.00	$52.25	$0.00	$117.41	$10.90	10.23%
Annual												$1,574.88	$121.68	8.37%

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	$0.030000	$0.039900	$0.077300	$0.000000	$0.053290	$0.000000	
Xsm	34%	0.7	173	173	0	0	$30.00	$5.19	$0.00	$0.00	$0.00	$9.22	$0.00	$44.41
Small	36%	1.2	303	303	0	0	$30.00	$9.09	$0.00	$0.00	$0.00	$16.15	$0.00	$55.24
Medium	38%	1.8	486	400	86	0	$30.00	$12.00	$3.43	$0.00	$0.00	$25.90	$0.00	$71.33
Large	41%	4.2	1,254	400	854	0	$30.00	$12.00	$34.07	$0.00	$0.00	$66.83	$0.00	$142.90
XLg	46%	10.6	3,535	400	3,135	0	$30.00	$12.00	$125.09	$0.00	$0.00	$188.38	$0.00	$355.47
AnnAvg	41%	3.8	1,131	400	731	0	$30.00	$12.00	$29.17	$0.00	$0.00	$60.27	$0.00	$131.44
WinAvg	40%	3.3	980	400	580	0	$30.00	$12.00	$23.16	$0.00	$0.00	$52.25	$0.00	$117.41

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	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter			0.30	0.70						$0.096800	$0.040036	0.000%			
	Summer										$0.097800	$0.045800				
Xsm	34%	0.7	173	53	120		$30.00	$3.54	$2.76	$0.00	$5.09	$4.82	$0.00	$46.21	$1.80	4.06%
Small	36%	1.2	303	92	211		$30.00	$6.06	$4.84	$0.00	$8.92	$8.44	$0.00	$58.26	$3.02	5.47%
Medium	38%	1.8	486	148	338		$30.00	$9.09	$7.76	$0.00	$14.30	$13.54	$0.00	$74.69	$3.36	4.71%
Large	41%	4.2	1,254	381	873		$30.00	$21.21	$20.03	$0.00	$36.90	$34.94	$0.00	$143.08	$0.18	0.13%
XLg	46%	10.6	3,535	1,075	2,460		$30.00	$53.53	$56.45	$0.00	$104.02	$98.50	$0.00	$342.50	-$12.97	-3.65%
AnnAvg	41%	3.8	1,131	344	787		$30.00	$19.19	$18.06	$0.00	$33.28	$31.52	$0.00	$132.05	$0.61	0.47%
WinAvg	40%	3.3	980	298	682		$30.00	$16.67	$15.66	$0.00	$28.85	$27.32	$0.00	$118.50	$1.09	0.93%

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

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	$0.030000	$0.039900	$0.077300	$0.000000	$0.053290	$0.000000	
Xsm	35%	0.9	226	226	0	0	$30.00	$6.78	$0.00	$0.00	$0.00	$12.04	$0.00	$48.82
Small	37%	1.5	395	395	0	0	$30.00	$11.85	$0.00	$0.00	$0.00	$21.05	$0.00	$62.90
Medium	39%	2.3	634	400	234	0	$30.00	$12.00	$9.34	$0.00	$0.00	$33.79	$0.00	$85.12
Large	42%	5.3	1,634	400	1,234	0	$30.00	$12.00	$49.24	$0.00	$0.00	$87.08	$0.00	$178.31
XLg	47%	13.5	4,605	400	4,205	0	$30.00	$12.00	$167.78	$0.00	$0.00	$245.40	$0.00	$455.18
AnnAvg	41%	3.8	1,131	400	731	0	$30.00	$12.00	$29.17	$0.00	$0.00	$60.27	$0.00	$131.44
SumAvg	41%	4.2	1,277	400	877	0	$30.00	$12.00	$35.00	$0.00	$0.00	$68.07	$0.00	$145.07

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	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter										$0.096800	$0.040036				
	Summer			0.27	0.73						$0.097800	$0.045800	0.000%			
Xsm	35%	0.9	226	60	166		$30.00	$4.55	$3.61	$0.00	$5.86	$7.61	$0.00	$51.63	$2.81	5.75%
Small	37%	1.5	395	105	290		$30.00	$7.58	$6.31	$0.00	$10.24	$13.30	$0.00	$67.43	$4.53	7.20%
Medium	39%	2.3	634	168	466		$30.00	$11.62	$10.12	$0.00	$16.43	$21.34	$0.00	$89.51	$4.39	5.15%
Large	42%	5.3	1,634	433	1,201		$30.00	$26.77	$26.09	$0.00	$42.35	$55.00	$0.00	$180.21	$1.90	1.06%
XLg	47%	13.5	4,605	1,220	3,385		$30.00	$68.18	$73.54	$0.00	$119.36	$155.01	$0.00	$446.09	-$9.09	-2.00%
AnnAvg	41%	3.8	1,131	300	831		$30.00	$19.19	$18.06	$0.00	$29.31	$38.07	$0.00	$134.63	$3.19	2.43%
SumAvg	41%	4.2	1,277	339	939		$30.00	$21.21	$20.40	$0.00	$33.11	$43.00	$0.00	$147.72	$2.65	1.83%

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

WINTER

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+	$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	34%	0.7	173	173	0	0	$14.50	$5.22	$0.00	$0.00	$0.20	$10.08	-$0.37	$29.62
Small	36%	1.2	303	303	0	0	$14.50	$9.14	$0.00	$0.00	$0.35	$17.65	-$0.65	$40.99
Medium	38%	1.8	486	400	86	0	$14.50	$12.07	$3.53	$0.00	$0.55	$28.31	-$1.04	$57.92
Large	41%	4.2	1,254	400	854	0	$14.50	$12.07	$35.05	$0.00	$1.43	$73.03	-$2.68	$133.40
XLg	46%	10.6	3,535	400	3,135	0	$14.50	$12.07	$128.67	$0.00	$4.03	$205.88	-$7.56	$357.59
AnnAvg	41%	3.8	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
WinAvg	40%	3.3	980	400	580	0	$14.50	$12.07	$23.82	$0.00	$1.12	$57.10	-$2.10	$106.52

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	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter			0.30	0.70						$0.096800	$0.040036	0.000%			
	Summer										$0.097800	$0.045800				
Xsm	34%	0.7	173	53	120		$30.00	$3.54	$2.76	$0.00	$5.09	$4.82	$0.00	$46.21	$16.59	55.99%
Small	36%	1.2	303	92	211		$30.00	$5.86	$4.84	$0.00	$8.92	$8.44	$0.00	$58.06	$17.07	41.65%
Medium	38%	1.8	486	148	338		$30.00	$8.94	$7.76	$0.00	$14.30	$13.54	$0.00	$74.54	$16.62	28.70%
Large	41%	4.2	1,254	381	873		$30.00	$21.06	$20.03	$0.00	$36.90	$34.94	$0.00	$142.93	$9.53	7.14%
XLg	46%	10.6	3,535	1,075	2,460		$30.00	$53.73	$56.45	$0.00	$104.02	$98.50	$0.00	$342.70	-$14.89	-4.16%
AnnAvg	41%	3.8	1,131	344	787		$30.00	$19.19	$18.06	$0.00	$33.28	$31.52	$0.00	$132.05	$10.74	8.85%
WinAvg	40%	3.3	980	298	682		$30.00	$16.87	$15.66	$0.00	$28.85	$27.32	$0.00	$118.70	$12.18	11.44%

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+				
							$14.50	$0.030176	$0.041042	$0.076042	$0.001140	$0.058241	-$0.002139	
Xsm	35%	0.9	226	226	0	0	$14.50	$6.82	$0.00	$0.00	$0.26	$13.16	-$0.48	$34.26
Small	37%	1.5	395	395	0	0	$14.50	$11.92	$0.00	$0.00	$0.45	$23.01	-$0.85	$49.03
Medium	39%	2.3	634	400	234	0	$14.50	$12.07	$9.60	$0.00	$0.72	$36.92	-$1.36	$72.47
Large	42%	5.3	1,634	400	1,234	0	$14.50	$12.07	$50.65	$0.00	$1.86	$95.17	-$3.50	$170.75
XLg	47%	13.5	4,605	400	4,205	0	$14.50	$12.07	$172.58	$0.00	$5.25	$268.20	-$9.85	$462.75
AnnAvg	41%	3.8	1,131	400	731	0	$14.50	$12.07	$30.00	$0.00	$1.29	$65.87	-$2.42	$121.31
SumAvg	41%	4.3	1,277	400	877	0	$14.50	$12.07	$36.00	$0.00	$1.46	$74.39	-$2.73	$135.69

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	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter										$0.096800	$0.040036				
	Summer			0.27	0.73						$0.097800	$0.045800	0.000%			
Xsm	35%	0.9	226	60	166		$30.00	$4.49	$3.61	$0.00	$5.86	$7.61	$0.00	$51.57	$17.31	50.54%
Small	37%	1.5	395	105	290		$30.00	$7.42	$6.31	$0.00	$10.24	$13.30	$0.00	$67.27	$18.24	37.20%
Medium	39%	2.3	634	168	466		$30.00	$11.41	$10.12	$0.00	$16.43	$21.34	$0.00	$89.30	$16.83	23.23%
Large	42%	5.3	1,634	433	1,201		$30.00	$26.77	$26.09	$0.00	$42.35	$55.00	$0.00	$180.21	$9.46	5.54%
XLg	47%	13.5	4,605	1,220	3,385		$30.00	$68.23	$73.54	$0.00	$119.36	$155.01	$0.00	$446.14	-$16.61	-3.59%
AnnAvg	41%	3.8	1,131	300	831		$30.00	$19.19	$18.06	$0.00	$29.31	$38.07	$0.00	$134.63	$13.32	10.98%
SumAvg	41%	4.3	1,277	339	939		$30.00	$21.46	$20.40	$0.00	$33.11	$43.00	$0.00	$147.97	$12.28	9.05%

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	$ Change	% Change
		On-Peak	Off-Peak	0-400	401-7,500	7,500+		0-400	401-7,500	7,500+							
	Winter	0.23					$30.00	$0.030000	$0.039900	$0.077300	$0.000000	$0.108800	$0.040036	0.000%			
	Summer	0.18										$0.109800	$0.045800				
Xsm	394	91	303	394	0	0	$30.00	$11.81	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$63.79	$14.57	29.61%
Small	636	146	490	400	236	0	$30.00	$12.00	$9.42	$0.00	$0.00	$15.92	$19.61	$0.00	$86.95	$14.49	20.00%
Medium	1,633	376	1,257	400	1,233	0	$30.00	$12.00	$49.20	$0.00	$0.00	$40.86	$50.34	$0.00	$182.40	$14.08	8.37%
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.00	$76.93	$0.00	$0.00	$58.26	$71.77	$0.00	$248.96	$13.82	5.88%
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.00	$107.37	$0.00	$0.00	$77.35	$95.29	$0.00	$322.01	$13.50	4.38%
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.00	$45.93	$0.00	$0.00	$38.81	$47.82	$0.00	$174.56	$14.12	8.80%

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					$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	$0.030000	$0.039900	$0.077300	$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	$12.00	$15.20	$0.00	$0.00	$15.44	$29.33	$0.00	$101.97	$14.15	16.11%
Small	1,220	220	1,000	400	820	0	$30.00	$12.00	$32.72	$0.00	$0.00	$24.11	$45.82	$0.00	$144.65	$13.82	10.56%
Medium	2,350	423	1,927	400	1,950	0	$30.00	$12.00	$77.79	$0.00	$0.00	$46.44	$88.24	$0.00	$254.47	$12.97	5.37%
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.00	$106.85	$0.00	$0.00	$60.83	$115.60	$0.00	$325.28	$12.38	3.96%
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.00	$129.28	$0.00	$0.00	$71.94	$136.70	$0.00	$379.92	$11.97	3.25%
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.00	$74.07	$0.00	$0.00	$44.59	$84.74	$0.00	$245.40	$13.02	5.60%

	Net Bill	$ Change	% Change
Current Annual	$2,356.95		
Proposed Annual	$2,519.76	$162.81	6.91%

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	$0.030000	$0.039900	$0.077300	$0.000000	$0.108800	$0.040036	0.000%	
	Summer	0.18										$0.109800	$0.045800		
Xsm	394	91	303	394	0	0	$30.00	$11.81	$0.00	$0.00	$0.00	$9.85	$12.13	$0.00	$63.79
Small	636	146	490	400	236	0	$30.00	$12.00	$9.42	$0.00	$0.00	$15.92	$19.61	$0.00	$86.95
Medium	1633	376	1,257	400	1,233	0	$30.00	$12.00	$49.20	$0.00	$0.00	$40.86	$50.34	$0.00	$182.40
Large	2,328	535	1,793	400	1,928	0	$30.00	$12.00	$76.93	$0.00	$0.00	$58.26	$71.77	$0.00	$248.96
XLg	3,091	711	2,380	400	2,691	0	$30.00	$12.00	$107.37	$0.00	$0.00	$77.35	$95.29	$0.00	$322.01
WinAvg	1,551	357	1,194	400	1,151	0	$30.00	$12.00	$45.93	$0.00	$0.00	$38.81	$47.82	$0.00	$174.56

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	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.096800	$0.040036	0.000%			
	Summer	0.18										$0.097800	$0.045800				
Xsm	394	91	303	37%	1.5			$30.00	$7.58	$6.28	$0.00	$8.76	$12.13	$0.00	$64.75	$0.96	1.50%
Small	636	146	490	39%	2.3			$30.00	$11.62	$10.16	$0.00	$14.16	$19.61	$0.00	$85.55	-$1.40	-1.61%
Medium	1633	376	1,257	42%	5.3			$30.00	$26.77	$26.08	$0.00	$36.36	$50.34	$0.00	$169.55	-$12.85	-7.04%
Large	2,328	535	1,793	44%	7.3			$30.00	$36.87	$37.18	$0.00	$51.83	$71.77	$0.00	$227.65	-$21.31	-8.56%
XLg	3,091	711	2,380	45%	9.4			$30.00	$47.47	$49.36	$0.00	$68.82	$95.29	$0.00	$290.94	-$31.07	-9.65%
WinAvg	1,551	357	1,194	42%	5.1			$30.00	$25.76	$24.77	$0.00	$34.53	$47.82	$0.00	$162.88	-$11.68	-6.69%

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	$0.030000	$0.039900	$0.077300	$0.000000	$0.108800	$0.040036		
	Summer	0.18										$0.109800	$0.045800	0.000%	
Xsm	781	141	640	400	381	0	$30.00	$12.00	$15.20	$0.00	$0.00	$15.44	$29.33	$0.00	$101.97
Small	1220	220	1,000	400	820	0	$30.00	$12.00	$32.72	$0.00	$0.00	$24.11	$45.82	$0.00	$144.65
Medium	2350	423	1,927	400	1,950	0	$30.00	$12.00	$77.79	$0.00	$0.00	$46.44	$88.24	$0.00	$254.47
Large	3,078	554	2,524	400	2,678	0	$30.00	$12.00	$106.85	$0.00	$0.00	$60.83	$115.60	$0.00	$325.28
XLg	3,640	655	2,985	400	3,240	0	$30.00	$12.00	$129.28	$0.00	$0.00	$71.94	$136.70	$0.00	$379.92
SumAvg	2,256	406	1,850	400	1,856	0	$30.00	$12.00	$74.07	$0.00	$0.00	$44.59	$84.74	$0.00	$245.40

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	5.05	$0.015970	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.096800	$0.040036				
	Summer	0.18										$0.097800	$0.045800	0.000%			
Xsm	781	141	640	39%	2.7			$30.00	$13.64	$12.47	$0.00	$13.75	$29.33	$0.00	$99.19	-$2.78	-2.73%
Small	1,220	220	1,000	41%	4.1			$30.00	$20.71	$19.48	$0.00	$21.48	$45.82	$0.00	$137.49	-$7.16	-4.95%
Medium	2,350	423	1,927	44%	7.4			$30.00	$37.37	$37.52	$0.00	$41.36	$88.24	$0.00	$234.49	-$19.98	-7.85%
Large	3,078	554	2,524	45%	9.4			$30.00	$47.47	$49.16	$0.00	$54.19	$115.60	$0.00	$296.42	-$28.86	-8.87%
XLg	3,640	655	2,985	46%	10.9			$30.00	$55.05	$58.13	$0.00	$64.08	$136.70	$0.00	$343.96	-$35.96	-9.47%
SumAvg	2,256	406	1,850	44%	7.1			$30.00	$35.86	$36.03	$0.00	$39.72	$84.74	$0.00	$226.35	-$19.05	-7.76%

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.

															$ Change	% Change
Current Annual														$2,519.76		
Proposed Annual														$2,335.38	($184.38)	-7.32%

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 CURRENT 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					$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	1,633	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

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			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	5.05	$0.015970	$0.000000						
	Winter	0.23										$0.096800	$0.040036	0.000%			
	Summer	0.18										$0.097800	$0.045800				
Xsm	394	91	303	37%	1.5			$30.00	$7.58	$6.28	$0.00	$8.76	$12.13	$0.00	$64.75	$15.53	31.55%
Small	636	146	490	39%	2.3			$30.00	$11.62	$10.16	$0.00	$14.16	$19.61	$0.00	$85.55	$13.09	18.07%
Medium	1,633	376	1,257	42%	5.3			$30.00	$26.77	$26.08	$0.00	$36.36	$50.34	$0.00	$169.55	$1.23	0.73%
Large	2,328	535	1,793	44%	7.3			$30.00	$36.87	$37.18	$0.00	$51.83	$71.77	$0.00	$227.65	-$7.49	-3.19%
XLg	3,091	711	2,380	45%	9.4			$30.00	$47.47	$49.36	$0.00	$68.82	$95.29	$0.00	$290.94	-$17.57	-5.70%
WinAvg	1,551	357	1,194	42%	5.1			$30.00	$25.76	$24.77	$0.00	$34.53	$47.82	$0.00	$162.88	$2.44	1.52%

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 CURRENT 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					$16.50	$0.030176	$0.043176	$0.076042	$0.001140	$0.129605	$0.031385		
	Summer	0.18										$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	1,220	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	2,350	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

	Total kWh	Delivery (kWh)		Load Factor	Demand (kW)			Basic Service Charge	Delivery		TCA	Base Fuel		PPFAC	Net Bill	$ Change	% Change
		On-Peak	Off-Peak					30.00	All kW 5.05	All kWh $0.015970	$0.000000	On-Peak	Off-Peak				
	Winter	0.23										$0.096800	$0.040036				
	Summer	0.18										$0.097800	$0.045800	0.000%			
Xsm	781	141	640	39%	2.7			$30.00	$13.64	$12.47	$0.00	$13.75	$29.33	$0.00	$99.19	$11.37	12.95%
Small	1,220	220	1,000	41%	4.1			$30.00	$20.71	$19.48	$0.00	$21.48	$45.82	$0.00	$137.49	$6.66	5.09%
Medium	2,350	423	1,927	44%	7.4			$30.00	$37.37	$37.52	$0.00	$41.36	$88.24	$0.00	$234.49	-$7.01	-2.90%
Large	3,078	554	2,524	45%	9.4			$30.00	$47.47	$49.16	$0.00	$54.19	$115.60	$0.00	$296.42	-$16.48	-5.27%
XLg	3,640	655	2,985	46%	10.9			$30.00	$55.05	$58.13	$0.00	$64.08	$136.70	$0.00	$343.96	-$23.99	-6.52%
SumAvg	2,256	406	1,850	44%	7.1			$30.00	$35.86	$36.03	$0.00	$39.72	$84.74	$0.00	$226.35	-$6.03	-2.59%

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

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	$5.52	$0.014990	$0.000000	$0.053090	0.000%			
Xsm	40.3%	1,116	66	$75.00	$366.01	$16.72	$0.00	$59.23	$0.00	$516.96	$70.64	15.83%
Small	27.4%	14,651	108	$75.00	$597.52	$219.61	$0.00	$777.80	$0.00	$1,669.93	$169.73	11.31%
Medium	30.7%	29,389	154	$75.00	$848.94	$440.55	$0.00	$1,560.28	$0.00	$2,924.77	$277.63	10.49%
Large	44.3%	71,334	237	$75.00	$1,307.03	$1,069.29	$0.00	$3,787.10	$0.00	$6,238.42	$580.63	10.26%
XLg	58.4%	384,599	887	$75.00	$4,893.96	$5,765.14	$0.00	$20,418.37	$0.00	$31,152.47	$2,846.16	10.05%
AnnAvg	56.0%	97,708	239	$75.00	$1,319.35	$1,464.65	$0.00	$5,187.34	$0.00	$8,046.34	$766.79	10.53%
AvgWin	52.0%	83,072	219	$75.00	$1,208.00	$1,245.25	$0.00	$4,410.30	$0.00	$6,938.55	$661.82	10.54%
AvgSum	62.0%	112,958	250	$75.00	$1,377.66	$1,693.24	$0.00	$5,996.93	$0.00	$9,142.83	$875.25	10.59%
Annual										$96,488.28	$9,222.42	10.57%

UNS Electric, Inc.

Typical Bill Comparison - Present and Proposed Rates

Test Period Ending December 31, 2014

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	$13.47	$0.005480	$0.000000	$0.053290	0.000%			
Xsm	0.46	20	4,040	$100.00	$269.39	$22.14	$0.00	$215.29	$0.00	$606.82	$49.82	8.9%
Small	0.46	20	6,400	$100.00	$269.39	$35.07	$0.00	$341.06	$0.00	$745.52	$47.08	6.7%
Medium	0.46	36	12,160	$100.00	$487.76	$66.64	$0.00	$648.01	$0.00	$1,302.41	$44.05	3.5%
Large	0.46	80	26,880	$100.00	$1,078.21	$147.30	$0.00	$1,432.44	$0.00	$2,757.95	$36.88	1.4%
Xlarge	0.46	294	98,640	$100.00	$3,956.64	$540.55	$0.00	$5,256.53	$0.00	$9,853.72	$1.81	0.0%
AnnAvg	0.46	80	26,796	$100.00	$1,074.85	$146.84	$0.00	$1,427.98	$0.00	$2,749.67	$36.90	1.4%
sum	0.46	90	30,153	$100.00	$1,209.50	$165.24	$0.00	$1,606.87	$0.00	$3,081.61	$35.27	1.2%
win	0.46	70	23,520	$100.00	$943.41	$128.89	$0.00	$1,253.36	$0.00	$2,425.66	$38.51	1.6%
Annual										$33,043.60	$442.66	1.4%

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	$13.47	$0.005480	$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	$1,122.09	$153.30	$0.00	$819.74	$629.41	$0.00	$2,824.54	$124.42	4.6%
Small	0.46	28,067	84	8,139	19,928	$100.00	$1,125.82	$153.81	$0.00	$822.46	$631.50	$0.00	$2,833.59	$124.66	4.6%
Medium	0.46	48,453	144	14,051	34,402	$100.00	$1,943.54	$265.52	$0.00	$1,419.85	$1,090.19	$0.00	$4,819.10	$180.36	3.9%
Large	0.56	62,572	186	18,146	44,426	$100.00	$2,509.88	$342.89	$0.00	$1,833.59	$1,407.86	$0.00	$6,194.22	$218.91	3.7%
XLg	0.66	193,470	576	56,106	137,364	$100.00	$7,760.44	$1,060.22	$0.00	$5,669.37	$4,353.06	$0.00	$18,943.09	$576.50	3.1%
AnnAvg	0.58	69,713	208	20,217	49,496	$100.00	$2,796.32	$382.03	$0.00	$2,042.84	$1,568.53	$0.00	$6,889.72	$238.43	3.6%
AvgWin	0.56	65,673	196	19,045	46,628	$100.00	$2,634.27	$359.89	$0.00	$1,924.46	$1,477.64	$0.00	$6,496.26	$227.41	3.6%

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	$13.47	$0.005480	$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	$1,122.09	$153.30	$0.00	$642.76	$749.70	$0.00	$2,767.85	-$15.90	-0.6%
Small	0.46	28,067	84	5,613	22,454	$100.00	$1,125.82	$153.81	$0.00	$644.90	$752.20	$0.00	$2,776.73	-$16.11	-0.6%
Medium	0.46	48,453	144	9,691	38,762	$100.00	$1,943.54	$265.52	$0.00	$1,113.31	$1,298.54	$0.00	$4,720.91	-$62.69	-1.3%
Large	0.56	62,572	186	12,514	50,058	$100.00	$2,509.88	$342.89	$0.00	$1,437.73	$1,676.93	$0.00	$6,067.43	-$94.96	-1.5%
XLg	0.66	193,470	576	38,694	154,776	$100.00	$7,760.44	$1,060.22	$0.00	$4,445.40	$5,185.00	$0.00	$18,551.06	-$393.97	-2.1%
AnnAvg	0.58	69,713	208	13,943	55,770	$100.00	$2,796.32	$382.03	$0.00	$1,601.81	$1,868.31	$0.00	$6,748.47	-$111.25	-1.6%
AvgSum	0.56	73,609	219	14,722	58,887	$100.00	$2,952.58	$403.37	$0.00	$1,691.32	$1,972.71	$0.00	$7,119.98	-$120.16	-1.7%

												$ Change	% Change	
Current Annual												$81,053.94		
Proposed Annual												$81,697.44	$643.50	0.8%

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%	487	108,698	$50.00	$6,238.47	$594.58	$210.82	$6,152.66	-$232.54	$13,013.99
Small	46%	584	200,005	$50.00	$7,486.16	$1,094.03	$252.99	$11,320.89	-$427.88	$19,776.19
Medium	66%	701	344,357	$50.00	$8,983.40	$1,883.63	$303.58	$19,491.61	-$736.69	$29,975.52
Large	75%	842	469,577	$50.00	$10,780.08	$2,568.59	$364.30	$26,579.47	-$1,004.58	$39,337.85
XLg	95%	1,010	713,757	$50.00	$12,936.09	$3,904.25	$437.16	$40,400.80	-$1,526.96	$56,201.34
AnnAvg	54%	768	310,000	$50.00	$9,838.08	$1,695.70	$332.47	$17,546.93	-$663.19	$28,799.99

	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	$12.88	$0.005300	$0.00000	$0.053290	0.000%			
Xsm	30%	487	108,698	$300.00	$6,272.56	$576.10	$0.00	$5,792.54	$0.00	$12,941.20	-$72.79	-0.6%
Small	46%	584	200,005	$300.00	$7,527.07	$1,060.03	$0.00	$10,658.27	$0.00	$19,545.37	-$230.83	-1.2%
Medium	66%	701	344,357	$300.00	$9,032.49	$1,825.09	$0.00	$18,350.76	$0.00	$29,508.34	-$467.19	-1.6%
Large	75%	842	469,577	$300.00	$10,838.98	$2,488.76	$0.00	$25,023.76	$0.00	$38,651.50	-$686.35	-1.7%
XLg	95%	1,010	713,757	$300.00	$13,006.78	$3,782.91	$0.00	$38,036.12	$0.00	$55,125.81	-$1,075.53	-1.9%
AnnAvg	54%	768	310,000	$300.00	$9,891.84	$1,643.00	$0.00	$16,519.90	$0.00	$28,354.74	-$445.25	-1.5%

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	$12.88	$0.005300	$0.00000	$0.053290	0.000%			
Xsm	44%	747	240,000	$300.00	$9,623.91	$1,272.00	$0.00	$12,789.60	$0.00	$23,985.51	-$3,624.95	-13.1%
Small	46%	893	300,000	$300.00	$11,506.85	$1,590.00	$0.00	$15,987.00	$0.00	$29,383.85	-$3,918.26	-11.8%
Medium	66%	844	406,600	$300.00	$10,869.67	$2,154.98	$0.00	$21,667.71	$0.00	$34,992.36	-$1,485.58	-4.1%
Large	75%	1,553	850,000	$300.00	$19,996.35	$4,505.00	$0.00	$45,296.50	$0.00	$70,097.85	-$101.75	-0.1%
XLg	75%	2,192	1,200,000	$300.00	$28,230.14	$6,360.00	$0.00	$63,948.00	$0.00	$98,838.14	$226.94	0.2%
AnnAvg	65%	992	470,630	$300.00	$12,774.95	$2,494.34	$0.00	$25,079.87	$0.00	$40,649.16	-$1,721.36	-4.1%

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	$12.88	$0.005300	$0.00000	$0.139880	$0.034927	0.000%			
	Summer								$0.143771	$0.038600				
Small	433,335	1,281	69,334	364,001	$300.00	$16,499.28	$2,296.68	$0.00	$9,698.38	$12,713.48	$0.00	$41,507.82	-$2,257.16	-5.2%
Medium	517,000	1,380	82,720	434,280	$300.00	$17,774.40	$2,740.10	$0.00	$11,570.87	$15,168.10	$0.00	$47,553.47	-$1,102.25	-2.3%
Large	600,000	1,400	96,000	504,000	$300.00	$18,032.00	$3,180.00	$0.00	$13,428.48	$17,603.21	$0.00	$52,543.69	$790.63	1.5%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,221.60	$4,107.50	$0.00	$17,345.12	$22,737.48	$0.00	$64,711.70	$3,560.50	5.8%
Mean	642,400	1,430	102,784	539,616	$300.00	$18,418.40	$3,404.72	$0.00	$14,377.43	$18,847.17	$0.00	$55,347.72	$1,568.62	2.9%
AvgWin	627,900	1,416	100,464	527,436	$300.00	$18,238.08	$3,327.87	$0.00	$14,052.90	$18,421.76	$0.00	$54,340.61	$1,338.29	2.5%

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	$12.88	$0.005300	$0.00000	$0.139880	$0.034927				
	Summer								$0.143771	$0.038600	0.000%			
Small	433,335	1,281	69,334	364,001	$300.00	$16,499.28	$2,296.68	$0.00	$9,968.16	$14,050.45	$0.00	$43,114.57	-$3,660.03	-7.8%
Medium	517,000	1,380	82,720	434,280	$300.00	$17,774.40	$2,740.10	$0.00	$11,892.74	$16,763.21	$0.00	$49,470.45	-$2,775.96	-5.3%
Large	600,000	1,400	96,000	504,000	$300.00	$18,032.00	$3,180.00	$0.00	$13,802.02	$19,454.40	$0.00	$54,768.42	-$1,151.78	-2.1%
XLg	775,000	1,570	124,000	651,000	$300.00	$20,221.60	$4,107.50	$0.00	$17,827.60	$25,128.60	$0.00	$67,585.30	$1,051.54	1.6%
Mean	642,400	1,430	102,784	539,616	$300.00	$18,418.40	$3,404.72	$0.00	$14,777.36	$20,829.18	$0.00	$57,729.66	-$511.07	-0.9%
AvgSum	656,700	1,444	105,072	551,628	$300.00	$18,598.72	$3,480.51	$0.00	$15,106.31	$21,292.84	$0.00	$58,778.38	-$332.07	-0.6%

		$ Change	% Change
Current Annual	$672,676.62		
Proposed Annual	$678,713.94	$6,037.32	0.90%

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	$12.48	$0.000500	$0.00000	$0.049332	0.000%			
Xsm	0.42	506	155,000	$1,500.00	$6,309.20	$77.50	$0.00	$7,646.43	$0.00	$15,533.13	-$711.39	-4.4%
Small	0.42	1,267	388,500	$1,500.00	$15,813.70	$194.25	$0.00	$19,165.41	$0.00	$36,673.36	-$2,235.01	-5.7%
Small	0.46	1,336	448,600	$1,500.00	$16,672.21	$224.30	$0.00	$22,130.26	$0.00	$40,526.77	-$1,997.02	-4.7%
Medium	0.75	2,416	1,322,700	$1,500.00	$30,150.31	$661.35	$0.00	$65,251.21	$0.00	$97,562.87	$1,070.83	1.1%
Medium	0.75	2,817	1,542,200	$1,500.00	$35,153.71	$771.10	$0.00	$76,079.54	$0.00	$113,504.35	$1,198.74	1.1%
Large	0.89	4,775	3,102,500	$1,500.00	$59,595.51	$1,551.25	$0.00	$153,051.99	$0.00	$215,698.75	$6,522.98	3.1%
Large	0.89	5,379	3,494,900	$1,500.00	$67,133.06	$1,747.45	$0.00	$172,409.80	$0.00	$242,790.31	$7,310.06	3.1%

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	$12.48	$0.000500	$0.00000	$0.092110	$0.030410	0.000%			
	Summer								$0.125200	$0.033410				
Small	2,790,000	5,083	306,900	2,483,100	$1,500.00	$63,435.84	$1,395.00	$0.00	$28,268.56	$75,511.07	$0.00	$170,110.47	$1,277.17	0.76%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500.00	$63,435.84	$1,575.00	$0.00	$31,916.12	$85,254.44	$0.00	$183,681.40	$4,651.73	2.60%
Large	2,115,000	5,083	232,650	1,882,350	$1,500.00	$63,435.84	$1,057.50	$0.00	$21,429.39	$57,242.26	$0.00	$144,664.99	-$5,050.11	-3.37%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500.00	$63,435.84	$1,358.50	$0.00	$27,528.92	$73,535.33	$0.00	$167,358.59	$592.89	0.36%
AvgWin	2,726,000	5,083	299,860	2,426,140	$1,500.00	$63,435.84	$1,363.00	$0.00	$27,620.10	$73,778.92	$0.00	$167,697.86	$677.25	0.41%

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	$12.48	$0.000500	$0.00000	$0.092110	$0.030410				
	Summer								$0.125200	$0.033410	0.000%			
Small	2,790,000	5,083	306,900	2,483,100	$1,500	$63,436	$1,395	$0.00	$38,423.88	$82,960.37	$0.00	$187,715	$3,283.49	1.78%
Medium	3,150,000	5,083	346,500	2,803,500	$1,500	$63,436	$1,575	$0.00	$43,381.80	$93,664.94	$0.00	$203,558	$6,916.92	3.52%
Large	2,115,000	5,083	232,650	1,882,350	$1,500	$63,436	$1,058	$0.00	$29,127.78	$62,889.31	$0.00	$158,010	-$3,529.19	-2.18%
Mean	2,717,000	5,083	298,870	2,418,130	$1,500	$63,436	$1,359	$0.00	$37,418.52	$80,789.72	$0.00	$184,503	$2,546.71	1.40%
AvgSum	2,790,000	5,083	311,600	2,478,400	$1,500	$63,436	$1,395	$0.00	$39,012.32	$82,803.34	$0.00	$188,147	$3,250.24	1.76%

	Total Net Bill	$ Change	% Change
Current Annual	$2,111,501		
Proposed Annual	$2,135,066	$23,565	1.12%

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	$4.34	$0.91
New 30' Metal or Fiberglass - Overhead	$8.66	$8.66	
Existing Wood Pole - Underground	$2.18	$2.18	
New 30' Wood Pole (Class 6) - Underground	$6.52	$6.52	
New 30' Metal or Fiberglass - Underground	$10.81	$10.81	
Wattage, per Watt	$0.051681	$0.058707	
Base Power Supply	$0.010113	$0.014505	
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	$5.87	$0.70	13.54%
150 Watt	$7.75	$8.81	$1.06	13.68%
200 Watt	$10.34	$11.74	$1.40	13.54%
250 Watt	$12.92	$14.68	$1.76	13.62%
400 Watt	$20.67	$23.48	$2.81	13.59%
Existing Wood Pole OH	$4.34	$4.34	$0.00	0.00%
New 30' Wood Pole OH	$8.66	$8.66	$0.00	0.00%
New 30' Metal or FG OH	$2.18	$2.18	$0.00	0.00%
Existing Wood Pole UG	$6.52	$6.52	$0.00	0.00%
New 30' Wood Pole UG	$10.81	$10.81	$0.00	0.00%
New 30' Metal or FG UG	$0.05	$0.06	$0.01	13.59%
Base Power Supply	$1.52	$2.18	$0.66	43.42%
PPFAC	($0.32)	$0.00	$0.32	-100.00%
Typical	$13.29	$15.33	$2.04	15.35%

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

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Rejoinder Testimony of

H. Edwin Overcast

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

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. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes. I filed rebuttal testimony in this proceeding.

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

A. I will respond to the testimony of witness Fulmer of TASC, Witness Quinn of AURA, witness Alston of AURA, witness Rubin of AURA, witness Kobor of Vote Solar, witness Huber of RUCO, witness Zwick of ACCA, witness Wilson of Western Resource Advocates, and witness Schlegel of SWEEP. Since many of these witnesses cover the same issues, at some points I will refer to them collectively for ease of discussion

Q. How is your rejoinder testimony organized?

A. In addition to this Introduction, Section 2 provides some comments related to general arguments and conclusions made by these witnesses collectively in some cases or in general. Section 3 addresses cost allocation as it relates to the development of customer related costs. Section 4 addresses those witness who conclude that TOU rates without a demand charge provide a cost-based solution to the issues of cost recovery. Section 5 discusses the recommendation for a minimum bill. Section 6 corrects some broad-based misunderstandings about the measurement of demand. Section 7 provides a correction associated with the use of data that claims DG customers are like all other residential customers. Section 8 provides my summary and recommendations.

II. GENERAL ISSUES

Q. Do various witnesses make statements in support of their position that have common themes?

A. Yes. Several witnesses rely on the same article from the so called Regulatory Assistance Project (RAP) as support for their opposition to demand rates without making any effort to vet that article for theoretical or practical accuracy; witnesses also indicate broad agreement among other parties as a basis for concluding their position is correct; and witnesses claim that UNSE has not provided evidence to support its proposal.

Q. Please comment on the RAP article used to support the opposition to demand charges.

A. Unfortunately that reliance is misplaced. The RAP article, and by extension the witnesses relying on that article to develop opposition to demand charges, have failed to understand that the premises of the article are actually inconsistent with cost causation and even with the rationale for demand charges. From the beginning of the electric industry the pricing concept has been based on rates that include customer, demand and energy charges. Originally neither energy nor demand could be measured. Rates were typically "flat demand" rates- rates per kilowatt or per horsepower. In the 1890s two British engineers independently developed demand rates that have been applied in one form or another for over 100 years. Those rates are known by the names of the engineers who developed them- the Wright Rate and the Hopkinson Rate.

Initially it was not cost effective to measure power factor and demand for small customers and therefore "compromise rates are necessary, with the result that the demand charge is sometimes included as part of the energy charge."[1] (This is a point made by APS witness

[1] Electric Utility Rate Economics, Russel E. Caywood, McGraw-Hill Book Company, Inc., 1972, p. 27.

Brown.) Thus the gold standard of cost-based rates-- billing customer, demand and energy charges has historically been uneconomic. With today's technology compromise is no longer necessary. This fundamental point is missed by all of those witnesses who oppose the demand charge. All residential customers and indeed all customers were billed on a demand basis in the early years of the industry. As early as 1956 Russell Caywood noted:

> "Demand charges have come in for serious consideration from the standpoint of the need for them in rates for small users and their relationship to the stability of revenue from larger customers. The more electrical devices that become available to the residential customer, the greater the variation in use of individual customers, both as to amount and the character of the load, i.e., the less homogeneous is the group. This suggests the desirability of using the demand charge to recognize differences in load factor."[2]

Turning to the key issues of the RAP article: "diversity, impact on low use customers (the vast majority of whom are low income), multi-family dwellings and time variation,"[3] it is in fact diversity that necessitates the demand charges in residential rates as noted by Mr. Caywood above. I have explained the issue of demand diversity in great detail in my rebuttal testimony and will not repeat all of that discussion here. The concepts of capacity and demand are not a single number and the UNS proposal recognizes that fact. The key point is that an on-peak demand charge reflects the cost of generation capacity determined by coincident peaks (but allocated based on AED/4CP). Other demand costs based on customer NCP and class NCP are still recovered in energy charges with the shortcoming that solar DG customers still avoid some of the costs they cause and under net metering get too large a credit for costs they do not avoid. For example, the peak energy charge of over $0.10 per kWh plus the about $0.017 base energy charge per kWh exceeds the highest

---

[2] Id., p.78

[3] "Use Great Caution in Design of Residential Demand Charges" Jim Lazar, FEBRUARY 2016, NATURAL GAS & ELECTRICITY, p.13

hourly marginal cost for the test year of $0.05915 per kWh by over $0.05 kWh. This remains as a subsidy for DG customers under net metering compared to avoided costs for ratemaking and adds to the bill credit an additional amount of subsidy under three part rates. The same is true for the winter off-peak charge that exceeds the winter marginal costs.

Low-use customer impacts is another issue and to be clear it must be analyzed independent of low income customer impacts because low use is not the same as low income; indeed the correlation of income and usage is weak or in some cases non-existent. The claim in the RAP article that the vast majority of low use bills are low income customers is not credible or supported by the data. Customers who are low usage customers on a year round basis have fewer electric loads than other customers and hence lower demand and use so there is no adverse impact unless the customer is a standalone, separately metered garage with an arc welder that is used. In that case the demand charge and the high impact are actually related to the cost to serve the customer. Other low use customers may be a lighted barn with no major demand, a boat house, a seasonal dwelling and the demand charge correctly recovers the cost based on the low load factor and so forth. In short, for true low use customers there is low demand and no adverse impact beyond eliminating the current subsidy, albeit still not a lot of dollars.

Multi-family dwellings are another example of lower use because of fewer major appliances. If they are electrically heated, as some are, the NCP loads will actually be highly correlated because they occur when temperature is the lowest. If not, there is diversity among the loads but billing maximum demand based on an allocation of NCP demand costs means that the charges are lower and the average payment reflects the average coincidence with the class NCP. This is in fact the kind of averaging that occurs naturally within a rate class but does not result in any major deviation in cost recovery because of the cost allocation based on class NCP. A simple example may help here. Suppose we have a class that is responsible for NCP dollars in the amount of $5000 annually. If the sum of 50 customers NCP average 4 kW per customer per month or 2400 kW billing units per year, the demand charge would be about $2 per kW or an average of $8 per month. The distribution system must be designed to meet the expected maximum demand of the customers when load is coincident on the delivery facilities. By definition of average that number must be larger than 4 kW per customer and at some point the aggregate load will exceed 200 kW by some amount requiring both larger wires and larger transformers than the typical residential customers. There is no reason to believe that payment based on the average of all these factors can result in a significant deviation from cost causation.

The issue of time variance actually demonstrates the same confusion that exists among various witnesses in this proceeding about cost causation. The statement in the article states that the demand charge must be focused on key peak hours to send the correct price signals. In this case, the article incorrectly assumes that all capacity costs are caused by a few peak hours. As I have explained in rebuttal, different capacity requirements are determined in different ways. While the conclusion about peak hours is correct for generation, it may not be true for any other functional cost category. It is easy to see that this is true simply by comparing the capacity of delivery substations and transformers to that of peak system demand. For the typical utility, delivery substation capacity is greater than peak load and the transformer capacity is also greater than substation capacity. Peak demand does not reflect cost causation for even all of the capacity cost of generation because some costs are incurred to produce lower cost energy and are properly recovered separate from the peak period demand charge that reflects marginal capacity costs. The article is neither theoretically sound nor does it reflect the practical aspects of utility planning and operations.

Q. Please explain the issue of general agreement as the basis for concluding that a position is correct.

A. To be clear, agreement among the parties is not the same as evidence. There are many examples of broad agreement that is incorrect. In this case, agreement among the parties does not get to the truth of the matter. The goal of any regulatory proceeding is to get to the truth of the matter based on credible evidence. General agreement is not evidence.

Q. Has the Company provided evidence to support its proposal?

A. Yes. The Company has provided evidence in this filing to support its filing. The purpose of the hearing is to determine if that evidence results in a decision supported by the facts and not the assertions unsupported by evidence.

III. <u>CUSTOMER COSTS AND COST OF SERVICE</u>

Q. Does a group of witnesses raise issues related to the allocation of customer costs?

A. Yes. A number of witnesses recommend the concept of the basic customer method for allocating customer costs in the cost study and determining the customer charge. There are two issues with the basic customer method that must be addressed separately. The first is the use of this method in cost allocation and the second is whether this method is valid for determining the customer charge. I will discuss both these issues.

Q. Is it reasonable to use the basic customer charge and NCP allocation of all other distribution in the cost study?

A. No. To begin, the classification is inconsistent with public utility accounting theory, the cost allocation as developed by NARUC, cost causation, empirical analysis and the economics of efficient rates for a utility that is a declining cost firm. I discuss each of the points below.

Q. Please explain the inconsistency with utility cost accounting and NARUC cost allocation.

A. In classifying all of the distribution plant in Accounts 364 through 368 to demand and allocating those plant costs on non-coincident peak (NCP), these positions do not fairly allocate plant to customer classes for a variety of reasons. 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."[4] 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. The recommendations advanced by these advocates of the basic customer method fail to recognize that class NCP is more appropriately used in circumstances where there is far more diversity in load (e. g., at the substation). Class NCP alone is inappropriate for local facilities that are closer in proximity to customers they serve.

Diversity can be seen by the fact that distribution substation transformer capacity is more than transmission transformer capacity measured in MVA. Typically, distribution transformer capacity is greater than substation capacity and that excludes all customer owned transformers that would increase the difference. These statistics further indicate the way diversity impacts loads as you move closer to customers. For that reason alone, those parties that support the basic customer method and class NCP demand allocation of accounts 364-368 are misguided because that allocation cannot be used as it does not

[4] Public Utility Accounting: Theory and Practice, James E. Suelflow, The Institute of Public Utilities at Michigan State University, 1974, p.241

reflect cost causation and cannot be relied upon as a basis for revenue allocation or for rate design.

Public utility regulatory accounting, including the NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") supports the classification of distribution plant between customer and demand. In fact, the NARUC Manual does not even mention the basic customer method as an alternative for classifying and allocating distribution plant.

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.*"[5] (Emphasis added.)

This is not a new concept. In 1963 Constantine Bary published his treatise <u>Operational Economics of Electrical Utilities</u>. This rigorous study of utility costs and how loads cause those costs provides a summary chart of cost causation that is attached as Exhibit HEO- 1. This exhibit shows that a portion of the distribution plant beginning with primary lines is customer related. In the parlance of uniform system of accounts this is accounts 364-368.

Q. Is there empirical analysis to support the use of the minimum system?

A. By using class NCP as opposed to classifying these distribution accounts as customer and capacity, the parties incorrectly allocate more costs to larger customers who may not even use any of the facilities allocated to them. A simple example will illustrate this point. Consider a company with one industrial customer who has a 2500 kVa transformer

[5] <u>Electric Utility Cost Allocation Manual</u>, National Association of Regulatory Utility Commissioners, February 1991, p.95

installed. A typical installed cost for this transformer would be about $40,000. Also assume that the system served the same 2500 kVa of residential load using 50 50 kVa underground transformers that serve 400 residential customers. Those transformers typically cost about $4200 per transformer installed or about $210,000. Allocation of these costs on NCP would allocate the industrial customer $125,000[6] of rate base and the same amount to residential customers. Thus the advocates of the basic customer method would allocate less plant to residential customers than they actually use and at a lower cost than those actually caused by residential customers. The minimum system method would classify 70% of transformer cost on customers and the remainder would be allocated on capacity. That allocation results in about $193,000 of transformer costs to the residential class. Thus the minimum system method allocates cost more closely to causation and shares some of the scale economies between the customer classes. This same principle applies for conductor and for poles in the case that overhead transformers are used. Thus the basic customer method appears to be more results oriented than based on the principle that those customers who cause the costs should be responsible for the costs.

The fundamental point is that there are substantial economies of scale for all sizes of transformers, overhead and underground conductor and poles. In each case the per kVa cost of industrial transformers is below the cost for every size of residential transformer except for the largest and least used size of residential transformer. Some industrial transformers are even lower cost per kVa than the lowest cost single phase transformers used for residential customers. Using a demand allocation factor implicitly makes the incorrect assumption that the cost of transformer capacity is the same for all classes. It is not. This is the type of empirical analysis that is necessary to develop an appropriate determination of the best available method for allocating costs between classes. By classifying plant between customer and demand, the residential class receives a higher

[6] Based on 50% of the sum of the classes NCP

weighting of transformer costs consistent with cost causation since the unit costs per kVa for residential transformers is higher and they use many more transformers than other classes of customers. The basic customer charge method cannot recognize this reality. By allocating the cost of transformers on NCP only, the parties supporting the basic customer method unfairly and incorrectly allocate all of the economies of scale in transformer costs to the residential class and compounds that error by allocating fewer transformers to the class than residential customers actually use. Any witness advocating the use of the Basic Customer Method would produce a result that is inconsistent with cost causation as demonstrated above. Essentially, the basic customer method is not a method for calculating the customer component of costs that is based on the gold standard of cost causation because it fails to reflect any costs more than meter, service and direct customer accounting costs such as meter reading and billing in the customer costs.

The basic customer method relies on an empirically incorrect assumption. Similar economies of scale occur for other distribution accounts with the result that allocation without the minimum system significantly under allocates costs to the residential class and over allocates costs to larger demand customers who use far less of the distribution assets than residential customers. Since scale economies apply across all components of the minimum system including conductor and poles, the same conclusion applies to the other distribution accounts. For conductor, larger customers are typically located closer to substations than residential customers and therefore require less conductor. The NCP allocator over allocates distribution line significantly to larger customers and that does not take into account the lower unit cost per kVa of line capacity to serve these customers. Namely, absent the use of the minimum system the costs for smaller customers is under allocated and is over allocated for larger load customers.

Q. Is it fair to conclude that the advocates of the basic customer charge support the resulting higher energy charges in rates?

A. Yes. As the cost study filed by the Company illustrates, there are no energy-related costs for any component of the transmission or distribution costs and virtually none for production plant. Despite this fact, the parties who oppose demand charges have assumed that all of the fixed production, transmission and distribution costs should be allocated to the energy component of the rate and would have higher energy charges for all customers. By collecting costs that are demand related in energy charges the rates that result violate the matching principle, which provides that the rates charged should match the costs for all customers. Recovery of fixed costs in the energy component of the rate cannot match cost causation for demand unless all customers in a class have identical or near identical load factors. (This is the point noted by Caywood above.) That is not the case, particularly for solar DG customers. Failure to follow the minimum system classification and in addition putting these costs in the energy charge would unfairly cause customers who use more kWh to pay more for the same customer services provided to customers who consume less, and for customers with the same delivery services to pay more than identical customers with lower load factors. In the case of net metering, it also means that solar DG customers are not paying the actual cost of the facilities they use related to the distribution system. I should also note that it is not necessary to provide a separate class cost study for solar DG customers to reach this conclusion. It is as simple as the cost of service study allocates the minimum system costs and the class NCP costs and production demand costs properly to the residential class including the load shape of solar DG customers. In my view, this allocation is conservative because of the different load characteristics of DG solar customers. The problem is not that the cost of service study needs to be changed; it is the rate design that recovers the allocated fixed cost, both customer and demand, on energy. Since over half of the solar DG bills are for zero kWh, and nearly all of the bills do not exceed the first block, the company collects far less than the average class costs for those customers. It is impossible that solar DG produces revenue enough to cover their allocated costs with so few billed kWh.

Q. Some advocates of the basic customer charge method rely on Bonbright to support their method. Please comment.

A. I have discussed above that the accepted method for classifying these costs is to classify them as both demand and customer. Parties opposing various aspects of cost allocation use Bonbright to support the basic customer method. In fact, Bonbright states his position regarding customer costs as "operating and capital costs found to vary with the number of customers, regardless, or almost regardless, of power consumption."[7] I also note that Bonbright states that the minimum system costs should not be allocated to the customer component. Bonbright also continues on to say that the exclusion of minimum system costs from demand stands on "much firmer ground."[8] The key point is that customer costs vary with the number of customers. As I have shown above transformer and other distribution costs vary with the number of customers. Further the relationship between customers and cost is an empirical relationship that has been reviewed by economists. The correlation between customers and 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

[7] <u>Principles of Public Utility Rates</u>, James C. Bonbright, 1961. p. 347
[8] P.348

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 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 number 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 distribution system costs in accounts 364-368 as both customer and demand. I conclude that this empirical evidence, not available in 1961, would have Bonbright supporting the minimum system because it aligns with his principle definition noted above. The goal in this case, as dictated by not only regulation but affirmed by the courts, is to allocate costs based on the principle of cost causation.

Q. Are there other authorities that support the use of the minimum system and demand charges?

A. Yes. Alfred Kahn clearly defines that the parameter of the defect in cost of service is where marginal costs diverge from average costs. That divergence occurs for any utility exhibiting economies of scale. Kahn also states that the full distribution of costs "is in part along the lines that reflect true causal responsibility."[9] He goes further in that same chapter to conclude that "for those segments of demand that do not have the requisite high elasticity—prices based on fully distributed costs have much to recommend them."[10] Kahn concludes by noting "the respective average historic cost responsibilities of the various classes of service plus proportionate contributions to overhead will most likely strike the various rate-payers as equitable and non-discriminatory."[11] There is nothing in Kahn's view that is in any way inconsistent with the Company's cost study. Kahn's views however are inconsistent with the those parties who advocate the basic customer method and inclusion of all costs in energy charges since they do not reflect cost causation as demonstrated by both theory and pragmatic analytics.

Q. What do you conclude about the use of the minimum system to classify cost between customer and demand?

A. Based on the above evidence, the minimum system classification reflects cost causation and is supported by regulatory accounting, the NARUC cost allocation manual, empirical evidence that is utility specific and empirical analysis that is applied to a wide array of utilities. The basic customer method must be rejected because the evidence shows it to be not cost based but outcome driven.

IV. <u>TWO PART TOU RATES</u>

Q. Do a number of intervenors support two-part TOU rates as a reasonable alternative to the proposed three-part of Staff and TEP?

A. Yes. A number of witness suggest that a TOU rate with a small customer charge is a better alternative rate design for residential customers than the three-part rate.

[9] The Economics of Regulation: Principles and Institutions, Alfred E. Kahn, John Wiley and Sons, Inc., New York, Sixth Printing, 1995, p. 150
[10] P. 158
[11] P. 158

Q. Please describe the two-part TOU rate.

A. A two-part TOU rate essentially consists of a customer charge and energy charges that are differentiated by peak and off-peak periods which may also be seasonally differentiated. This rate means that all fixed costs above those recovered in the customer charge continue to be recovered in kWh charges. It makes the implicit assumptions that patterns of energy consumption correspond with the various demands on capacity and load characteristics are sufficiently homogeneous that such a rate will fairly recover the various demand related costs. It also ignores the issue that it is the energy component of the rate that is provided in a competitive market and the fixed costs components are in the regulated monopoly portion of the market. This latter point means that energy is the most elastic component and recovery of fixed costs in the energy charge cannot ever match costs and revenues for individual customers or even for classes of customers because it is not energy that causes the fixed costs. Rather, it is various measures of demand that cause those fixed costs.

Q. Why are two-part, TOU rates not a good alternative to three-part rates?

A. In simplest terms it is impossible for two-part rates to reflect cost causation for the same reason that two-part inverted block energy rates cannot track costs. The only costs that vary by time of use with kWh consumption are those costs classified as energy. In that regard, having energy charges that reflect marginal cost differences reflect cost causation much better than inverted block energy charges and would be consistent with Alfred Kahn's concern above where marginal and average costs diverge. When fixed costs are added to the TOU energy charges, rates no longer match cost causation. It is as simple as the fact that if the difference in marginal cost is two cents and the energy charges are loaded with higher on-peak fixed costs so that the differential is now five cents, the customer signal is that by saving or shifting a kWh the utilities costs decrease by five cents, customers make decisions assuming that there action saves the utility five cents. In reality, the action saves two cents and the other three cents is the same type of fixed cost subsidy that exists in current non-TOU rates. That subsidy either comes from other customers or utility shareholders or some combination of the two sources. In any event the result is inefficient choices and wasteful use of society's resources.

Q. What do you conclude about the viability of two-part TOU rates as an alternative to three-part rates?

A. It is impossible for TOU rates to be as efficient, equitable and cost based as the three-part rate. That rate design does not address issues of cross subsidy and inefficient pricing.

V. THE MINIMUM BILL

Q. Do several witnesses recommend a minimum bill to resolve the issue of fixed cost recovery?

A. Yes. There are two versions of the minimum bill. The version that seems to be recommended by the witnesses is to continue the two-part rate with a low customer charge and impose a higher minimum bill. Given that these witnesses rely on Bonbright, I am somewhat surprised by the recommendation, because Bonbright says "From the standpoint of cost analysis, it (the minimum bill) is decidedly inferior to an unqualified customer charge."[12]

Q. Why is the minimum bill not a good alternative to the customer charge?

A. Actually, the minimum bill is mathematically equivalent to a customer charge equal to the minimum bill and some number of free kWhs. To actually recover the required level of fixed cost, say $10.00, with a minimum bill the amount of the minimum bill with a $0.08 per kWh charge and an average energy cost of $0.04 would need to be calculated as $0.08 - $0.04 or $0.04 divided into $10 or 250 kWh. This calculation further assumes that the

[12] Principles of Public Utility Rates, 1988 Edition, p. 401

fixed costs associated with the first 250 kWhs are zero and they are not. As a result if you needed to collect the $10 in a minimum bill you would need a first block charge of $0.12 per kWh and a declining block rate. In fact, even with a small customer charge this was the rationale behind the declining block rate with a steep first block for kWh that nearly every customer used every month.

Q. Is a minimum bill a solution for recovering fixed customer related costs?

A. No. Customer costs are best recovered in a fully allocated customer charge with no free energy. It is a better price signal and more efficient for customers as well.

VI. MEASURING DEMAND

Q. Does there appear to be confusion about measuring demand?

A. Yes. Several witnesses have used the wattage of an appliance as a measure of demand and estimated the peak load of customers at levels that would not be found except for a few residential customers. Peak demand for residential customers based on an hour demand cannot be determined by appliance wattage alone because as with customer diversity there is also premise diversity.

Q. Please explain premise diversity.

A. First, not all appliances in the home run together and in most cases could not all run at once without overloading a circuit. Some appliances cycle on and off. The result is that there is some diversity in a dwelling that occurs naturally. To use an example from other testimony, a microwave oven may have a range of wattage from 600 watts to 1200 watts. This is a range of 0.6 kW to 1.2 kW of connected load. The measured demand for billing purposes is based on one hour. It is unlikely that a microwave ever runs continually for one hour. For example it takes one minute and 15 seconds to poach two eggs in my microwave. With other appliances running in an hour the microwave oven would add 0.025 kW to the hourly demand. Another appliance mentioned was a blow dryer at 1500 watts. Neither a blow dryer nor a microwave is likely to run for the whole hour so the contribution of the blow dryer will be a fraction of a kW even if it runs at the same time as the microwave. For larger appliances such as a water heater the issue of diversity also applies. Water heaters have two elements typically rated at 4.5 kW that will not operate together. The upper element comes on to raise the water temperature back to the setting or about 120 degrees. At 8 gallons the water heater uses at most 1.4 kW because it only needs to run for less than 20 minutes. Air conditioners also cycle if properly designed meaning they do not run continually. The whole point is that the witnesses who have calculated substantial kW loads are not taking into account how these appliances operate. Most appliances do not run at full load continuously for an hour. For example, in a recent analysis of customer loads based on load research, a customer with electric heat and using 24,000 kWh plus solar DG had an individual peak load of just less than 14 kW at the winter peak of the utility. Since it is likely that the resistance heat alone would be at least 15 kW installed, it is obvious that premise diversity occurs.

Q. Are customer NCPs for low use customers likely to be as high as 18 kW claimed by witness Kobor, the 10 kW claimed by witness Schlegel or the 7 kW claimed by witness Zwick?

A. No. The simplistic approach of adding kW ratings of appliances is not representative of how demand is measured for billing purposes and the recommended interval is one hour in this case. Just as an example, the typical range element on a stove to scramble some eggs uses about 1500 watts per hour. Eggs on the range take about five minutes or less so the use would be about .125 kW not 10 kW. If it had been a fifteen minute interval the actual charge to recover the same demand costs as the hourly demand would have been much less than the proposed demand charge.

VII. SOLAR DG CUSTOMERS ARE NOT LIKE OTHER RESIDENTIAL CUSTOMERS

Q. Witness Kobor claims that the data you used to show that solar DG customers are different from standard customers shows just the opposite. Please comment on this claim.

A. The conclusions reached by witness Kobor are based on a number of errors. First, her conclusions that the bill frequency data demonstrates that NEM customer bills are not outliers but fall within the range of variance for the system as a whole is simply wrong. In reaching this conclusion witness Kobor has failed to account for difference in the number of customers in the NEM frequency as compared to the non-NEM frequency. She concludes that because the non-NEM customers have more zero bills than NEM customers these customers are just like the residential class. For NEM customers the bill frequency demonstrates that 6.8 bills per customer are for zero kWh while for non-NEM customers only one bill out of every 50 bills is for zero kWh. The frequency also shows that the average NEM bill is for 330 kWhs meaning that average NEM bill does not even get out of the lowest cost first energy block of the rate. (It is important to note that as it relates to fixed delivery costs this block of the rate is only about 54% of the fixed demand related costs it is designed to recover.) For non-NEM customers the average use is 837 kWhs more than twice the average of NEM customers. This data alone is sufficient to demonstrate that NEM customers differ significantly from the residential class. While this one point is sufficient to demonstrate that the solar DG customers are not the same as full requirements customers, there is much more to the supporting data than claimed by witness Kobor.

Q. Witness Kobor states at pages 12 and 13 that "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." Please comment on this claim.

A. First, it is an unfounded assertion and there is no evidence in the testimony of witness Kobor to support the claim. Second, with respect to the residential customers, these customers were full requirements customers before installing solar DG and their load shapes and load characteristics were reasonably the same as the average load shapes of other customers who consumed the same level of kWhs with some "inevitable diversity." After adding solar these customers are being billed for less than 40% of the kWhs and actually using more of the distribution system than they did as full requirements customers to deliver energy back to the system in low load periods. Third, despite the claim that I did not use any NEM customer data to reach my conclusions and that the Company did not use any NEM customer data for its conclusions, the bill frequency for NEM customers is an analysis of how the NEM customers actually used the system on a monthly basis. The use of actual solar PV output data in the service territory is also a reasonable, if conservative, basis for considering how the solar PV systems generate power and coupled with hourly load data on the residential class when that use is consumed on site and when it is delivered to the system. It is simply incorrect to say that the conclusions we reach are not based on information related to solar DG customers for UNS Electric.

The criticism that I have focused only on the costs and revenues for the test year is invalid as well. This is a rate case based on a test year. It is by its nature focused on test year revenue requirements and billing determinants. Longer term perspectives are handled in other ways such as the IRP filings.

Q. Please comment on the claim that "load reductions from seasonal and vacant homes and energy efficiency reductions far eclipse the reductions from DG."

A. This statement demonstrates a misunderstanding of the rate case process. Most utilities have seasonal and vacant homes every rate case. It would be only the growth of these categories between rate cases that would contribute to lower revenues and earnings. It is important also to understand that lost revenues between rate cases all come out of earnings and ultimately get transferred to other customers in the next rate case when rates are reset. There is no evidence to show that these issues are new or growing while the solar DG issue is growing and in any event is a much larger impact on revenues than seasonal and vacant homes. Witness Kobor simply does not understand the impact of solar DG as compared to other factors that are in every rate case and accounted for as part of costs and revenues in each case.

VIII. SUMMARY AND RECOMMENDATIONS

Q. Please summarize your rejoinder.

A. I show that the RAP article that several witnesses cite as a basis for rejecting demand rates is defective in a number of regards. As a result, residential demand rates should become the standard since the compromise that required volumetric only rates is no longer necessary. I show that the minimum system is a necessary component of cost of service in order to reflect cost causation. I show that the basic customer method coupled with NCP allocation of all distribution plant under allocates costs to residential customers and over allocates costs to larger customers. I show that the claims of superiority of a two-part TOU over demand rates cannot be proved and that such rates suffer from the defect that energy consumption is not a good measure of the various capacity components of costs.

I show that the minimum bill is inferior to a cost-based customer charge for recovery of fixed costs. I demonstrate that witnesses who believe that customers will have extremely large demands based on connected load do not understand how demand will be measured and have grossly overstated the impact of appliances on billing demand. Finally, I show that the purported evidence that solar DG customers are the same as full requirements customers results from misuse of the data relied on to conclude the customers are the same.

Q. Based on the testimony that has been filed, what recommendations would you make related to rates?

A. I recommend that the residential rates be designed initially as the proposed transition rates and the Commission approve the UNS proposed three part rates including TOU energy charges. I recognize that these rates are still a compromise and will need to be further modified over time to more closely match cost causation. Nevertheless moving to demand rates is a positive improvement over two-part rates. It is necessary to begin a transition and this is a reasonable starting point to have more efficient and just and reasonable rates for a 21st century utility.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit HEO-1

TABLE 11. ILLUSTRATIVE SUMMARY OF ASSIGNMENT OF FUNCTIONAL COST ELEMENTS TO PARAMETRIC COMPONENTS OF COST-TO-SERVE OF FOUR GENERAL CLASSES OF SERVICE

	"Customer" Component				"Customer Demand" Component				"Class Peak or Diversified Demand" Component				"Energy" Component			
	Mfg. & Nonmfg.			Res.	Mfg. & Nonmfg.			Res.	Mfg. & Nonmfg.			Res.	Mfg. & Nonmfg.			Res.
	HT	PD	Sec.	Sec.	HT	PD	Sec.	Sec.	HT	PD	Sec.	Sec.	HT	PD	Sec.	Sec.
Production system	–	–	–	–	–	–	–	–	X	X	X	X	X	X	X	X
Bulk transmission system	–	–	–	–	–	–	–	–	X	X	X	X	–	–	–	–
Distribution system																
High Tension distribution																
(Substations & lines)	–	–	–	–	X	–	–	–	–	X	X	X	–	–	–	–
Primary voltage distribution																
Substations	–	–	–	–	–	–	–	–	–	X	X	X	–	–	–	–
Capacitors	–	–	–	–	–	–	–	–	–	X	X	X	–	–	–	–
Feeders	–	–	–	–	–	X	–	–	–	–	X	X	–	–	–	–
Branches	–	X	X	X	–	–	X	X	–	–	–	–	–	–	–	–
Secondary voltage distribution																
Transformers	–	–	X	X	–	–	X	X	–	–	X	X	–	–	–	–
Capacitors	–	–	–	–	–	–	–	–	–	–	X	X	–	–	–	–
Mains	–	–	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Service conductors	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Metering and control system	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Work on consumers' premises	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Customers' accounting	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–
Sales promotion	X	X	X	X	X	X	X	–	–	–	–	–	–	–	–	–
General administrative:																
General plant (carrying charges)	←(at fixed rate per dollar of foregoing plant)→															
General & administrative expenses	← at fixed rate per dollar of direct expenses (excluding fuel, energy purchases, and fixed charges) →															
Total cost-to-serve per unit of the parameter as at meters	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X

Note: Functional costs include expenses and carrying charges on investment in plant and working capital.

STANDARD COMPONENT UNIT COSTS

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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

Rejoinder Testimony of

Denise A. Smith

on Behalf of

UNS Electric, Inc.

February 29, 2016

TABLE OF CONTENTS

Exhibits:

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Denise A. Smith. My business address is 88 E. Broadway Blvd., Tucson, Arizona 85702.

Q. Did you file Direct or Rebuttal Testimony in this proceeding?

A. Yes.

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

A. I address the Surrebuttal Testimonies filed by Candrea Allen, Eric Van Epps and Thomas M. Broderick of the Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission"); Cynthia Zwick on behalf of the Arizona Community Action Association ("ACAA"); and Jeff Schlegel on behalf of Southwest Energy Efficiency Project ("SWEEP").

II. RESPONSE TO REQUESTS FROM PARTIES REGARDING CUSTOMER EDUCATION

Q. How will the Company inform, educate and assist customers with understanding their demand charge and how to reduce their total electrical bill under a 3-part rate structure?

A. Several parties in this case have expressed a desire for customer education and programs around a 3-part rate structure. The specific witnesses I will address are Staff witness Thomas Broderick, Staff witness Eric Van Epps and SWEEP witness Jeff Schlegel. The Company is planning a multi-staged, multi-channel approach to supporting customers according to their preferred communications channel of traditional paper mailing, electronic (email) delivery and telephonic Interactive Voice Response (IVR) system. In addition, in late 2016 the Company will be launching a customer application supporting mobile access to account related data and messaging on cellular or WiFi enabled Apple and Android devices. The full plan was attached to UNSE witness Dallas Dukes' Rebuttal testimony.

Supporting customers' understanding of a 3-part rate structure will require new tools and programming that leverage the Company's existing platforms and Energy Efficiency programming. The Company is currently evaluating both modifications to existing programs and tools, as well as new technologies specifically addressing one or more of the following: (1) the identification of a customer's peak demand, (2) the disaggregation of devices that contribute to a customer's peak demand, and (3) recommendations on how to conveniently modify electrical usage to minimize the customer's demand profile.

Q. What enhancements will the Company make to existing programming to support customers' understanding of 3-part rates?

A. All existing DSM programs and measures aid customers in reducing their energy usage including demand charges under 3-part rates including high efficiency Heating Ventilating and Air Conditioning (HVAC), lighting, trees and appliances. The following programs and measures will be specially leveraged to assist customers' understanding their demand:

Education & Outreach: The transition to 3-part rates will require new enhancements to the Company's education & outreach materials. Media updates, print material, workshop & classroom content, public presentations and e-learning tools will be developed and implemented to assist customers in understanding their demand charge and how appliance management can help them reduce their demand profile.

Home Energy Calculator (https://www.uesaz.com/efficiency/tools/ezhome/)**:** this tool currently provides customers with a free, online and customized estimation of how they are using energy in their home. This tool may be leveraged by self-learners and also Company representatives directly supporting customers learning to disaggregate their monthly energy usage.

This type of tool will be used to create a new demand calculator with residential demand loads of various appliances and products averaged over an hour. The calculator will utilize the data prepared in Exhibit DAS-RJ-1.

Home Energy Reports: This program recently approved by the Commission will provide broad outreach through a customizable messaging platform built around educating customers on how to reduce their energy usage. Customized messages and recommendations can be targeted toward reducing demand in addition to consumption.

Q. What new programs and measures will assist customers with the implementation of 3-part rates?

A. The Company is reviewing a number of new DSM tools and technologies in anticipation of submitting a separate, timely DSM filing pending the approval of a 3-part rate structure. Most programs would include an incentive lowering the cost to the customer.

Smart Thermostats: This measure enables customers to optimize the operation of their air conditioning or Heat Pump which typically generates a customer's highest demand load. Smart Learning Thermostats have demonstrated residential customer savings on cooling and heating costs. Smart algorithms outperform user programming by analyzing actual equipment and building performance data, weather data, occupancy and user inputs for customers who wish to manage their heating and cooling. Smart Thermostat applications also offer an engagement platform for utilities to communicate additional energy saving tips and operate demand response programming.

Advanced Meters and Data Presentment: The Company's Meter Data Management system currently captures and stores hourly residential interval data which is processed and available on a day-in-arrears basis. The Company is currently evaluating opportunities to present this data to customers through account management tools in a variety of useful formats including the real time availability of interval data.

Home Energy Monitoring Systems: Home Energy Monitoring systems continue to evolve towards cloud-based content and analytics. The Company is reviewing market ready technologies such as the Efergy Engage platform (https://engage.efergy.com/) as potential support solutions. This type of solution utilizes sensors to measure current for real time demand. The web portal and mobile application display customers' demand in an effortless and understandable manner. The display shows the customer's demand in real time, hourly, daily, weekly, and monthly. See DAS-RJ-2 for an example.

Smart Plugs: Smart Plugs are WiFi-enabled home appliance plugs that allow customers to manage their plugged in devices without having to touch them and to automate their home through smart platform engagement. The technology focuses on controlling small appliances using 1800 watts or under, including lights, window air conditioners, fans, portable heaters, coffee makers, and home audio systems.

Demand Controllers: The Company is researching the potential option of hardwired demand control solution for residential load. Demand Controllers can be used in demand response and energy management applications. These controllers may be used for management and monitoring of HVAC compressors, water heaters, pool pumps, and other power circuits.

III. RESPONSE TO STAFF (Eric Van Epps)

Q. Please address Staff's witness Mr. Van Epps request for a Plan of Administration (POA) for the Demand Side Management surcharge adjustor.

A. The Company agrees that a POA is appropriate in this circumstance. UNS Electric's POA for the DSM surcharge is attached in Exhibit DAS-RJ-3. The POA is consistent with the Commission's Energy Efficiency Rules, A.A.C. R14-2-2401 to R14-2-2419. The POA addresses such items as allowable expenses, the true-up methodology, and the calculation of the adjustor mechanism. Schedules of the calculations are included as an attachment to the POA.

IV. RESPONSE TO STAFF (Candrea Allen)

Q. Please comment on Subsection 12.H. of the Rules and Regulations ("Rules")?

A. Staff initially did not recommend approval of UNS Electric's proposed language for Subsection 12.H. In Staff's Surrebuttal Testimony, Staff proposed that UNS Electric's proposed language should not apply to medical alert customers; it should apply to all other customers in lieu of disconnection of service. This program was not proposed to be deployed for customers in general who do not pay their bills, it was meant for medical alert customers and inclement weather situations. Therefore, as we only see a value for this language for medical alert customers, and certain weather situations, UNS Electric will withdraw its request for approval of Subsection 12.H if all parties agree.

Q. Do you agree with Staff's recommendations regarding the Subsection 3.B.1.a. of the Rules?

A. Yes, we will agree to Staff's recommendation to leave the words, "more than" in Subsection 3.B.1.a. of the Rules.

V. <u>RESPONSE TO ACAA</u>

Q. Do you agree with the ACAA's recommendations to hold CARES customer harmless from deposits?

A. No, UNS Electric believes all customers should be treated the same with respect to deposits. UNS Electric currently does and will continue to work with customers who need help. I'm reaffirming the position held in my Rebuttal Testimony (page 4) filed January 19, 2016.

VI. <u>RESPONSE TO SWEEP</u>

Q. Do you agree with SWEEP's assessment that a mandatory demand charge will limit customers' options regarding how they control their bills?

A. No. To the contrary adding a demand component to the rate expands the opportunity for customers to manage their bills. As discussed by a number of witnesses, *customers who may not be able to reduce their volumetric consumption would now be rewarded for modifying their usage schedule to flatten their load profile*. DSM programs can be used as a tool to accomplish the objective of reducing demand charges. Demand charges are an important step in preparing customers toward a better understanding of their electrical bill.

Q. Do you share SWEEP's concern that mandatory demand charges might disproportionately shift cost to lower usage customers?

A. No, the demand rate component of the bill is designed to improve the alignment of customer charges with the cost of service. Demand charges do not disproportionately allocate costs to lower usage customer; rather, they correctly allocate costs across the customer classes.

Q. Does the Company still agree with Staff that monies associated with Energy Efficiency should still to be collected through the DSM adjustor, a position opposed by SWEEP?

A. Yes, the Company remains in agreement with Staff that monies associated with Energy Efficiency should continue to be collected through the DSM adjustor. This retains the flexibility to manage the Energy Efficiency portfolio more dynamically in response to its annual goals versus awaiting a future rate case.

Q. Does this conclude your Testimony?

A. Yes, it does.

Exhibit DAS-RJ-1

DAS – RJ – 01

Electric Demand (Appliances and Equipment)

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Refrigerators			
Energy Star Rated	0.225	30%	0.068
Old Unit - Not Energy Star Rated	0.7	30%	0.210
Freezers			
Energy Star Rated	0.225	30%	0.068
Old Unit - Not Energy Star Rated	0.7	30%	0.210
Large Appliances			
Oven	3.100	60%	1.860
Large Element	2.350	60%	1.410
Small Element	1.130	60%	0.678
Toaster Oven	1.500	50%	0.750
Microwave	1.500	30%	0.450
Dishwasher	1.100	60%	0.660
Water Cooler			
None	0.0000	60%	0.000
Water Cooler Cold	0.0050	60%	0.003
Water Cooler Hot&Cold	0.0100	60%	0.006
Laundry			
Clothes Washer	0.41	60%	0.246
Clothes Dryer	5.60	60%	3.360
Fans			
Ceiling Fan (no light)	0.06	100%	0.060
Portable Fan	0.06	100%	0.060
Water Heater			
Average for year	4.5	30.0%	1.350

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Winter Heating			
Baseboard 1000 Watt	1.00	40%	0.400
Baseboard-1500 Watt	1.50	40%	0.600
Furnace Blower (Average)	0.50	40%	0.200
HP-1 ton New - Standard Efficiency	0.92	40%	0.369
HP-1 ton New - High Efficiency	0.75	40%	0.300
HP-1 ton-Old	1.33	40%	0.533
HP-2 ton New - Standard Efficiency	1.85	40%	0.738
HP-2 ton New - High Efficiency	1.50	40%	0.600
HP-2 ton-Old	2.67	40%	1.067
HP-2.5 ton New - Standard Efficiency	2.31	40%	0.923
HP-2.5 ton New - High Efficiency	1.88	40%	0.750
HP-2.5 ton-Old	3.33	40%	1.333
HP-3 ton New - Standard Efficiency	2.77	40%	1.108
HP-3 ton New - High Efficiency	2.25	40%	0.900
HP-3 ton-Old	4.00	40%	1.600
HP-3.5 ton New - Standard Efficiency	3.23	40%	1.292
HP-3.5 ton New - High Efficiency	2.63	40%	1.050
HP-3.5 ton-Old	4.67	40%	1.867
HP-4 ton New - Standard Efficiency	3.69	40%	1.477
HP-4 ton New - High Efficiency	3.00	40%	1.200
HP-4 ton-Old	5.33	40%	2.133
HP-5 ton New - Standard Efficiency	4.62	40%	1.846
HP-5 ton New - High Efficiency	3.75	40%	1.500
HP-5 ton-Old	6.67	40%	2.667
Central Resistance-<1200 sqft	5.00	40%	2.000
Central Resistance-1200-1799 sqft	7.50	40%	3.000
Central Resisitance-1800-2599 sqft	15.00	40%	6.000
Central Resisitance->2600 sqft	20.00	40%	8.000

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Cooling Units			
AC-1 ton New - Standard Efficiency	0.92	50%	0.462
AC-1 ton New - High Efficiency	0.75	50%	0.375
AC-1 ton-Old	1.33	50%	0.667
AC-2 ton New - Standard Efficiency	1.85	50%	0.923
AC-2 ton New - High Efficiency	1.50	50%	0.750
AC-2 ton-Old	2.67	50%	1.333
AC-2.5 ton New - Standard Efficiency	2.31	50%	1.154
AC-2.5 ton New - High Efficiency	1.88	50%	0.938
AC-2.5 ton-Old	3.33	50%	1.667
AC-3 ton New - Standard Efficiency	2.77	50%	1.385
AC-3 ton New - High Efficiency	2.25	50%	1.125
AC-3 ton-Old	4.00	50%	2.000
AC-3.5 ton New - Standard Efficiency	3.23	50%	1.615
AC-3.5 ton New - High Efficiency	2.63	50%	1.313
AC-3.5 ton-Old	4.67	50%	2.333
AC-4 ton New - Standard Efficiency	3.69	50%	1.846
AC-4 ton New - High Efficiency	3.00	50%	1.500
AC-4 ton-Old	5.33	50%	2.667
AC-5 ton New - Standard Efficiency	4.62	50%	2.308
AC-5 ton New - High Efficiency	3.75	50%	1.875
AC-5 ton-Old	6.67	50%	3.333
EvapCooler-<1200 sqft	0.34	100%	0.34
EvapCooler-1200-1799sqft	0.46	100%	0.46
EvapCooler-1800-2599sqft	0.65	100%	0.65
EvapCooler->2600sqft	0.98	100%	0.98
MasterCool - Average Size	1.30	100%	1.30
Window AC-1.5 ton –New	1.50	50%	0.75
Window AC-1.5 ton- Old	2.00	50%	1.00
Window AC-1 ton – New	1.00	50%	0.50
Window AC-1 ton – Old	1.33	50%	0.67

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)

Miscellaneous			
Electronic Air Cleaner	0.05	100%	0.05
Hair Dryer	0.71	100%	0.71
Humidifier	0.011	100%	0.01
Iron	1.1	60%	0.66
Rechargable power tools	0.018	60%	0.01
Slow cooker	0.2	100%	0.20
Toaster	1.1	100%	1.10
Vacuum	0.542	100%	0.54
Well pump	0.725	100%	0.73
Aquarium equipment	0.024	100%	0.02
Oxygen Conventrator	0.4	100%	0.40
Phantom Loads	0.0500	100%	0.050
Coffee Maker	1.000	30%	0.300
Deep Fryer	1.000	80%	0.800

Office Equipment			
Desktop Computer and Monitor (On)	0.245	100%	0.245
Computer & Monitor (Sleep Mode)	0.01	100%	0.010
Laptop	0.045	100%	0.045
Notebook computer	0.025	100%	0.025
Inkjet Printer	0.013	100%	0.013
Multi-Function Printer	0.018	100%	0.018

Pool, Spa or Fountain Pump			
None	0	100%	0.000
1/2 hp	0.65	100%	0.650
3/4 hp	0.84	100%	0.840
1 hp	1.2	100%	1.200
1 1/2 hp	1.5	100%	1.500
2 hp	2.1	100%	2.100
1 hp -Variable Spd	0.36	100%	0.360
1 1/2 hp -Variable Spd	0.45	100%	0.450

2 hp -Variable Spd	0.63	100%	0.630

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Televisions/Stereo			
Plasma TV 42'	0.27	100%	0.270
Plasma TV 50"-56"	0.34	100%	0.340
Stereo System	0.033	100%	0.033
TV-analog < 40"	0.086	100%	0.086
TV-analog > 40"	0.156	100%	0.156
TV-ED/HD <40"	0.15	100%	0.150
TV-ED/HD >40"	0.234	100%	0.234
TV-LCD	0.15	100%	0.150
TV-Set-up box	0.02	100%	0.020
Cable/Gaming Systems			
HD-DVR	0.017	100%	0.017
HD-Cable Box	0.14	100%	0.140
Router/Cable modem	0.006	100%	0.006
Xbox	0.07	100%	0.070
Xbox 360	0.165	100%	0.165
Play Station 2	0.03	100%	0.030
Wii	0.0205	100%	0.021
CD Player	0.007	100%	0.007
Spa Heater			
None	0	0%	0.000
Spa Htr Summer- Covered	5.0	10%	0.500
Spa Htr Summer - No Cover	5.0	15%	0.750
Spa Htr Winter -Covered	5.0	35%	1.750
Spa Htr Winter - No Cover	5.0	55%	2.750

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Winter Heating			
Baseboard 1000 Watt	1.00	40%	0.400
Baseboard-1500 Watt	1.50	40%	0.600
Furnace Blower (Average)	0.50	40%	0.200
HP-1 ton New - Standard Efficiency	0.92	40%	0.369
HP-1 ton New - High Efficiency	0.75	40%	0.300
HP-1 ton-Old	1.33	40%	0.533
HP-2 ton New - Standard Efficiency	1.85	40%	0.738
HP-2 ton New - High Efficiency	1.50	40%	0.600
HP-2 ton-Old	2.67	40%	1.067
HP-2.5 ton New - Standard Efficiency	2.31	40%	0.923
HP-2.5 ton New - High Efficiency	1.88	40%	0.750
HP-2.5 ton-Old	3.33	40%	1.333
HP-3 ton New - Standard Efficiency	2.77	40%	1.108
HP-3 ton New - High Efficiency	2.25	40%	0.900
HP-3 ton-Old	4.00	40%	1.600
HP-3.5 ton New - Standard Efficiency	3.23	40%	1.292
HP-3.5 ton New - High Efficiency	2.63	40%	1.050
HP-3.5 ton-Old	4.67	40%	1.867
HP-4 ton New - Standard Efficiency	3.69	40%	1.477
HP-4 ton New - High Efficiency	3.00	40%	1.200
HP-4 ton-Old	5.33	40%	2.133
HP-5 ton New - Standard Efficiency	4.62	40%	1.846
HP-5 ton New - High Efficiency	3.75	40%	1.500
HP-5 ton-Old	6.67	40%	2.667
Central Resistance-<1200 sqft	5.00	40%	2.000
Central Resistance-1200-1799 sqft	7.50	40%	3.000
Central Resisitance-1800-2599 sqft	15.00	40%	6.000
Central Resisitance->2600 sqft	20.00	40%	8.000

Item	Rated kW (Peak kW)	% 'on' each hour (Estimate)	Usage (kWh/Hr)
Cooling Units			
AC-1 ton New - Standard Efficiency	0.92	50%	0.462
AC-1 ton New - High Efficiency	0.75	50%	0.375
AC-1 ton-Old	1.33	50%	0.667
AC-2 ton New - Standard Efficiency	1.85	50%	0.923
AC-2 ton New - High Efficiency	1.50	50%	0.750
AC-2 ton-Old	2.67	50%	1.333
AC-2.5 ton New - Standard Efficiency	2.31	50%	1.154
AC-2.5 ton New - High Efficiency	1.88	50%	0.938
AC-2.5 ton-Old	3.33	50%	1.667
AC-3 ton New - Standard Efficiency	2.77	50%	1.385
AC-3 ton New - High Efficiency	2.25	50%	1.125
AC-3 ton-Old	4.00	50%	2.000
AC-3.5 ton New - Standard Efficiency	3.23	50%	1.615
AC-3.5 ton New - High Efficiency	2.63	50%	1.313
AC-3.5 ton-Old	4.67	50%	2.333
AC-4 ton New - Standard Efficiency	3.69	50%	1.846
AC-4 ton New - High Efficiency	3.00	50%	1.500
AC-4 ton-Old	5.33	50%	2.667
AC-5 ton New - Standard Efficiency	4.62	50%	2.308
AC-5 ton New - High Efficiency	3.75	50%	1.875
AC-5 ton-Old	6.67	50%	3.333
EvapCooler-<1200 sqft	0.34	100%	0.34
EvapCooler-1200-1799sqft	0.46	100%	0.46
EvapCooler-1800-2599sqft	0.65	100%	0.65
EvapCooler->2600sqft	0.98	100%	0.98
MasterCool - Average Size	1.30	100%	1.30
Window AC-1.5 ton -New	1.50	50%	0.75
Window AC-1.5 ton- Old	2.00	50%	1.00

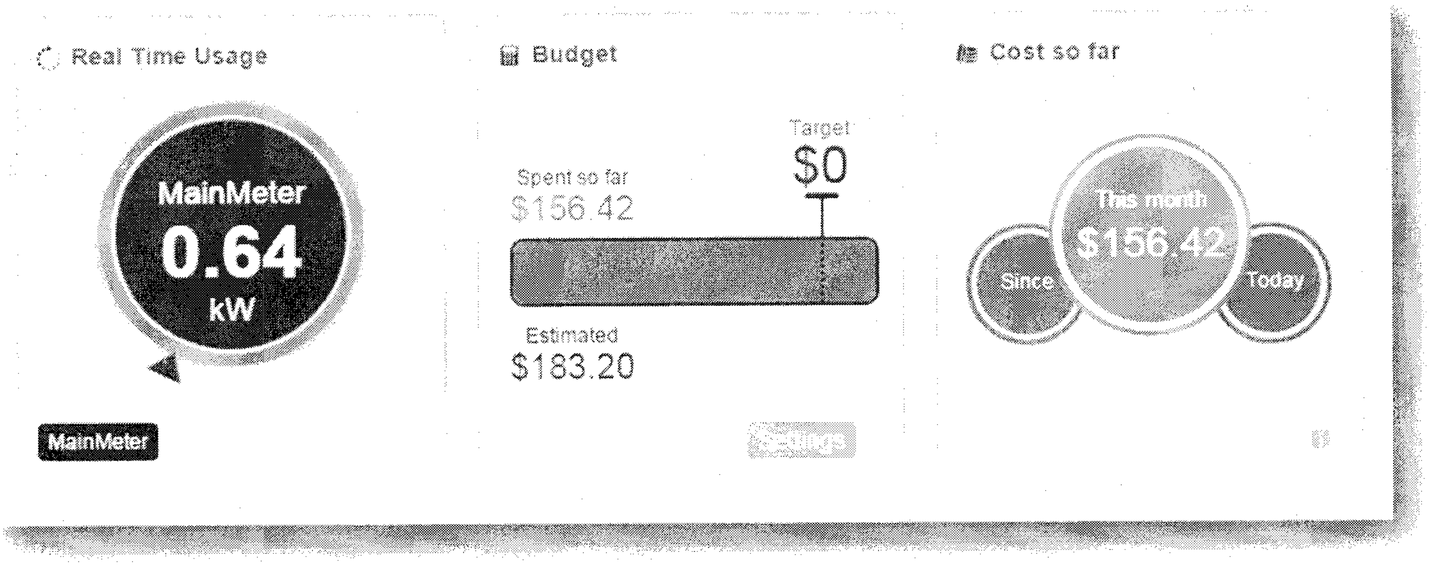
Window AC-1 ton - New	1.00	50%	0.50
Window AC-1 ton - Old	1.33	50%	0.67

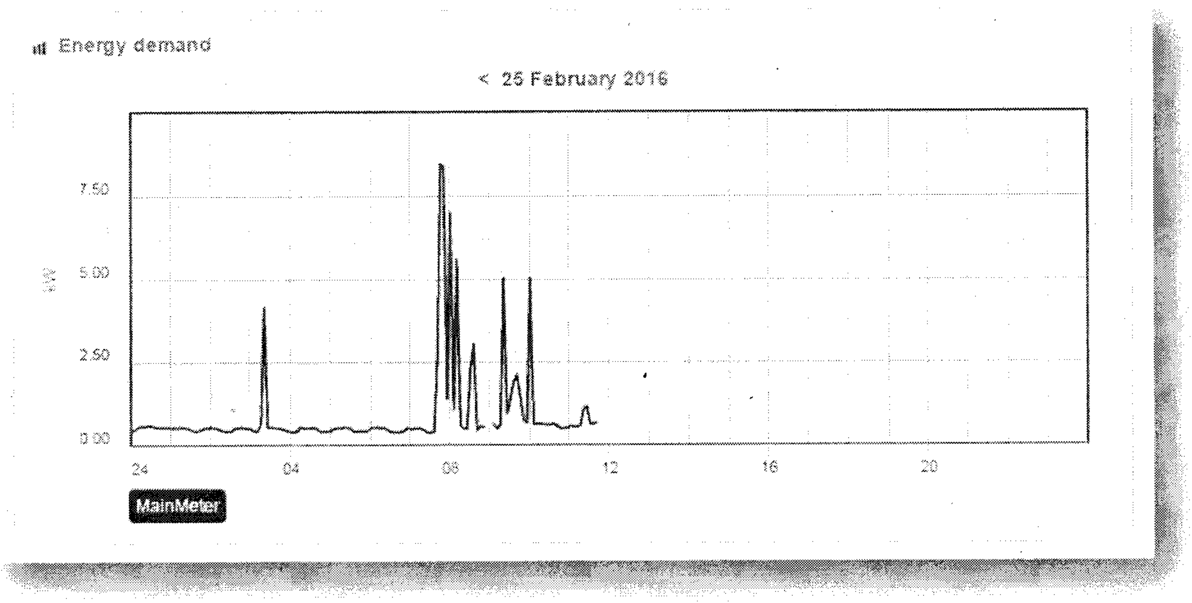
Exhibit DAS-RJ-2

DAS – RJ – 02

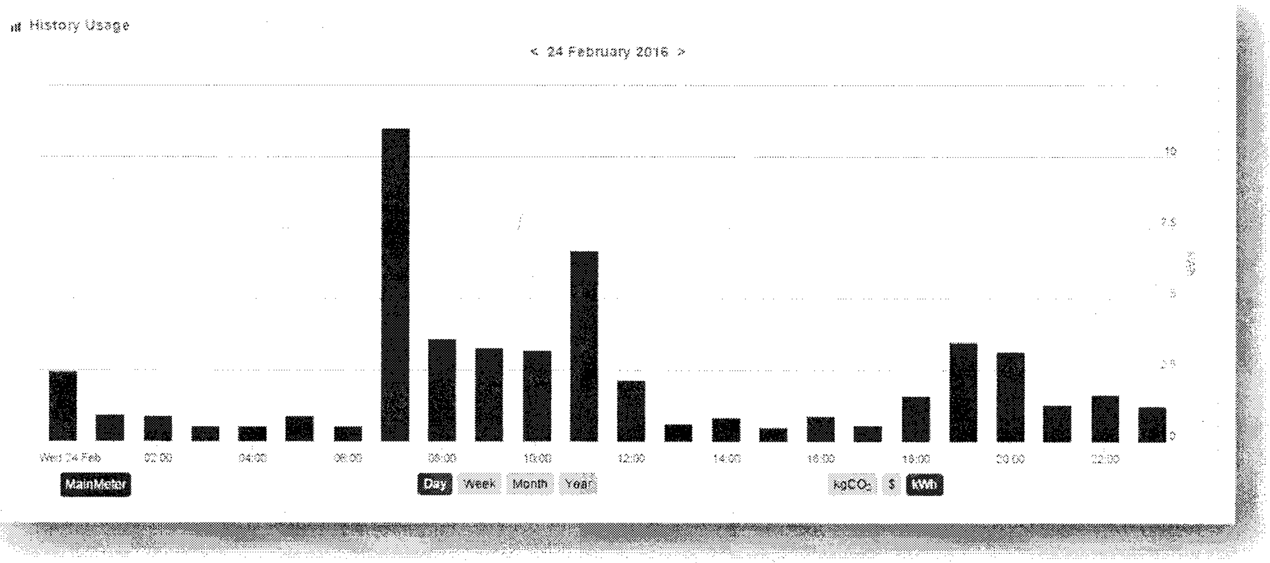
Demand Monitor

Allows customers to monitor their home energy use in real-time through your computer and mobile devices.

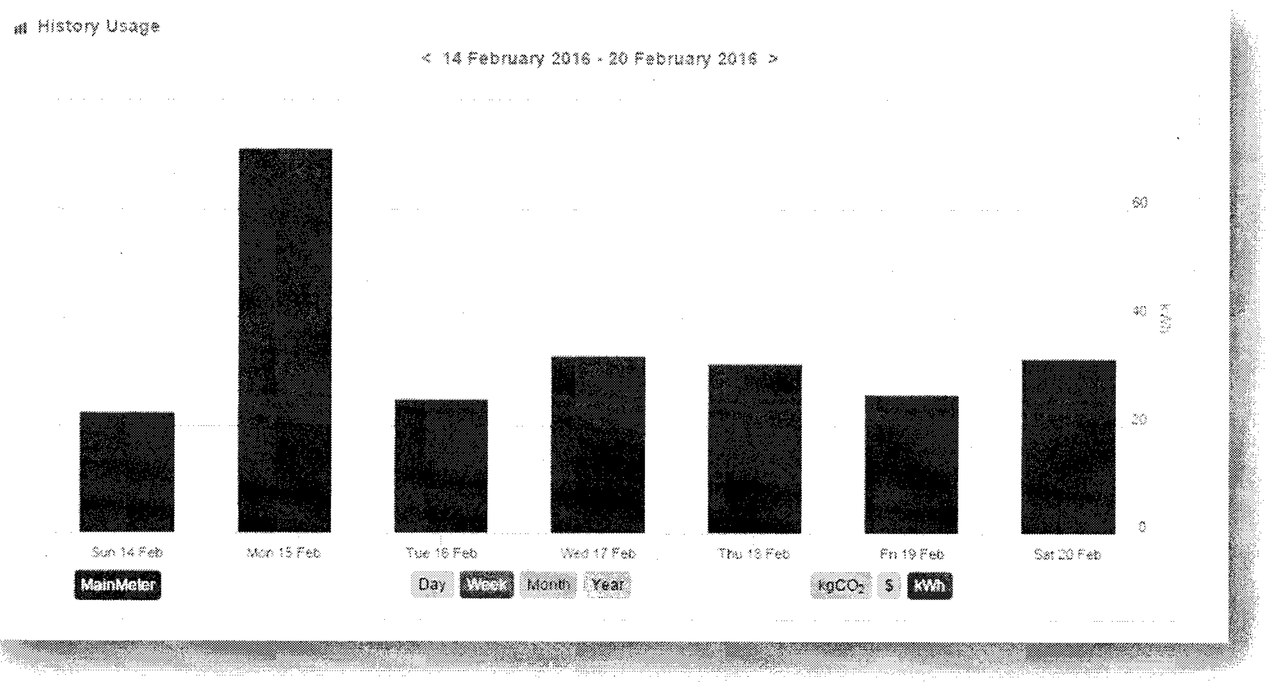




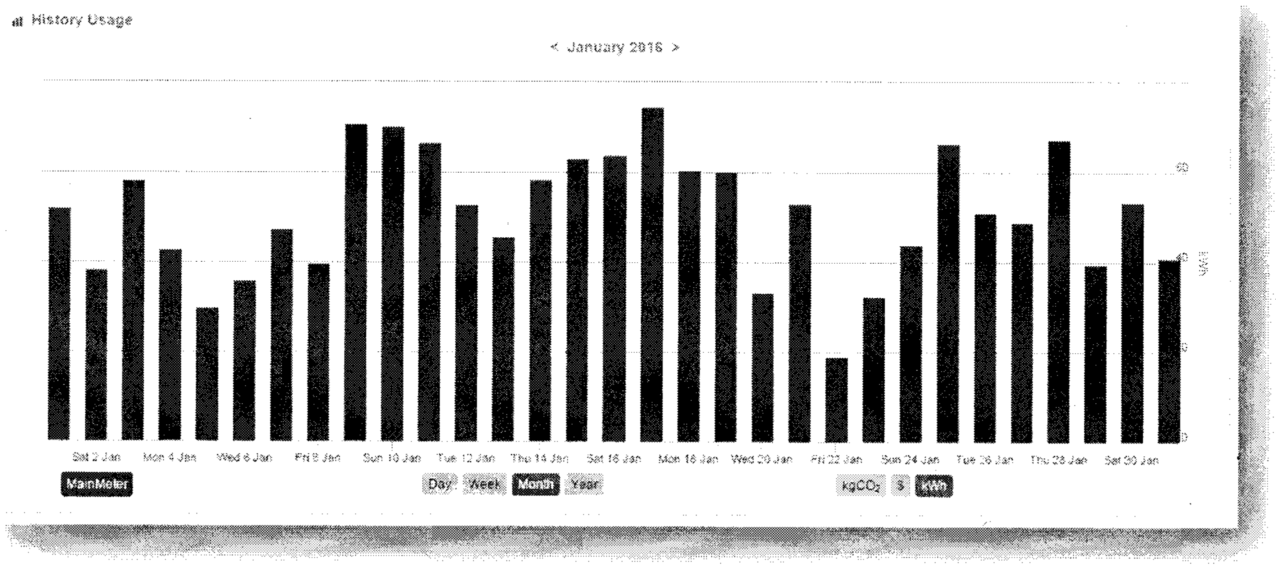
History – Hourly Usage



History – Daily for the Week



History – Daily for the Month



History – Monthly for the Year

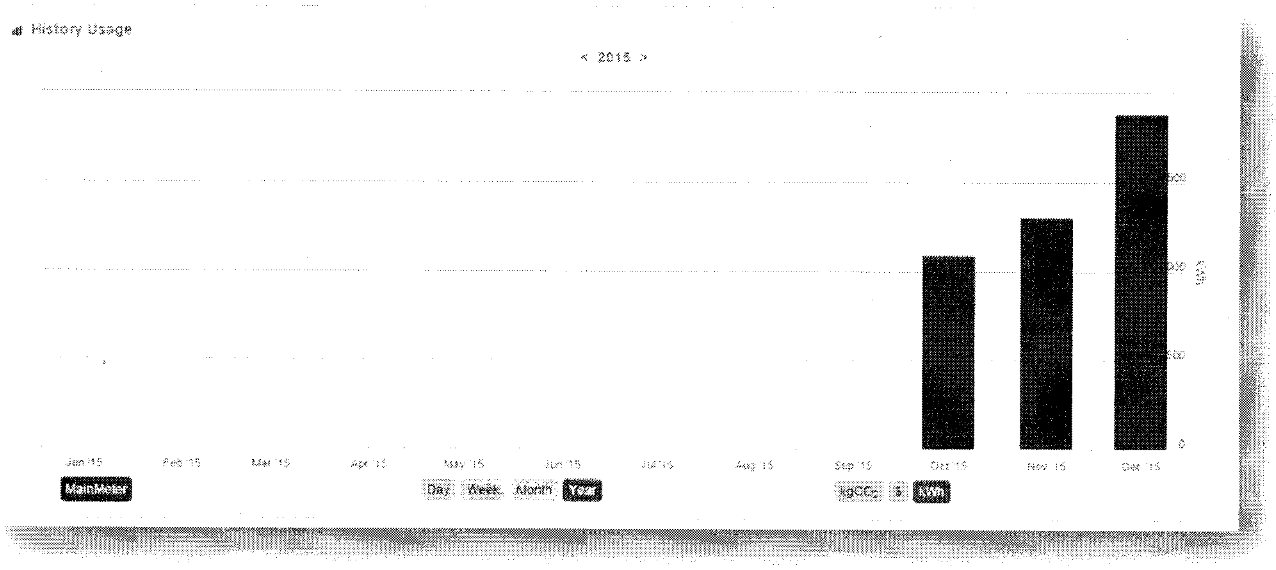


Exhibit DAS-RJ-3

UNS Electric, Inc.
Demand Side Management Adjustor Charge
Plan of Administration

Table of Contents

*1. **General Description***

This document describes the plan of administration for the Demand Side Management Adjustor Charge ("DSMAC") approved for UNS Electric, Inc. ("UNS Electric" or "Company") by the Arizona Corporation Commission ("ACC") in Decision No. 74235 (December 31, 2013). The DSMAC provides for the recovery of Demand Side Management ("DSM") program costs, including energy efficiency and demand response programs, and energy efficiency performance incentives. The DSMAC is applied to customer's bills as a monthly kilowatt-hour charge for Residential customers and on a percentage of bill basis for non-residential customers.

*2. **Definitions***

A. "Adjustment charge" means a Commission-approved provision in an affected utility's rate schedule allowing the affected utility to increase and decrease a certain rate or rates, in an established manner, when increases and decreases in specific costs are incurred by the affected utility.
B. "DSM" means demand-side management, the implementation and maintenance of one or more DSM programs.
C. "DSM program" means one or more DSM measures provided as part of a single offering to customers.
D. "DSM tariff" means a Commission-approved schedule of rates designed to recover an affected utility's reasonable and prudent costs of complying with the Energy efficiency standard.
E. "Energy efficiency" means the production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers.
F. "Energy efficiency standard" means the reduction in retail energy sales, in percentage of kWh, required to be achieved through an affected utility's approved DSM programs as prescribed in R14-2-2404.

G. "Energy savings" means the reduction in a customer's energy consumption directly resulting from a DSM program, expressed in kWh.
H. "Net benefits" means the incremental benefits resulting from DSM minus the incremental costs of DSM.
I. "Program costs" means the expenses incurred by an affected utility as a result of developing, marketing, implementing, administering, and evaluating Commission-approved DSM programs.

3. __Filing and Procedural Deadlines__

UNSE wishes to retain flexibility in filing EE Implementation Plans and modifications to the DSMAC. Changes to the EE Implementation Plans will be filed with the Commission in accordance with EE Standards R14-2-2405(A) shown below.

> *"Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article."*

Requested changes to the DSMAC will be filed with the Commission in accordance with the following sections of the EE Standards:

Implementation Plans R14-2-2405(B)(2):

> *"Except for the initial implementation plan, which shall describe only the next calendar year, a description of how the affected utility intends to comply with this Article for the next two calendar years, including an explanation of any modification to the rates of an existing DSM adjustment mechanism or tariff that the affected utility believes is necessary."*

Implementation Plans R14-2-2405(B)(5):

> *"A DSM Tariff filing complying with R14-2-2406(A) or a request to modify and reset an adjustment mechanism complying with R14-2-2406(C), as applicable;"*

DSM Tariffs R14-2-2406(C)

> *"If an affected utility has an existing adjustment mechanism to recover the reasonable and prudent costs associated with implementing DSM programs, the affected utility may, in lieu of making a tariff filing under subsection (A), file a request to modify and reset its adjustment mechanism by submitting the information required under subsections (A)(1) and(3)".*

Adjustor Reset and Reporting Requirements Decision No. 72447 (January 20, 2012)

> *"IT IS FURTHER ORDERED that, in any year during which the Company does not file an Implementation Plan, or does not address the DSM adjustor reset within its Implementation Plan, an adjustor reset application should be filed separately, no later than April 1."*

If UNSE chooses not to file an EE Implementation Plan in the even number year, UNSE may file new programs, measures or budget changes in a supplemental filing to the current EE Implementation Plan filing if UNSE or the Commission determines a change or addition is critical to the Company's ability to meet obligations under the EE Standard.

4. ***Rate Schedule Applicability:***

The DSMS shall be applied monthly to every customer unless exempted by order of the Commission. Currently there are no exemptions for UNS Electric.

5. ***Allowable Costs:***

Unless otherwise ordered by the Commission, UNSE includes allowable program costs for all approved programs and the Commission approved performance incentives in the DSMAC calculation. Allowable costs include but are not limited to the following:

A. Program Costs ("PC")
UNSE includes all allowable expenses in the DSMAC calculation. Allowable expenses include, but are not limited to: program development, implementation, promotion, administrative and general, training and technical assistance, marketing and communications, evaluation costs, monitoring and metering costs, advertising, educational expenditures, customer incentives, research and development, data collection (such as end-use), tracking systems, self-direction costs, measurement evaluation and research ("MER"), demonstration facilities and all other activities required to design and implement cost-effective DSM programs (energy efficiency and demand response) that are approved by the Commission in the Energy Efficiency Implementation Plan ("EEIP"). For those DSM programs that generate revenue, the revenue, if any, will be credited back to the DSMAC. Unrecovered fixed costs will not be recoverable through the DSMAC.

B. Wages and Salaries
During a general rate case UNSE includes wages or salaries for employees working to plan, implement, or manage EE Programs in UNSE base rate calculations. If, due to regulatory lag between rate cases, actual labor dollars for employees working to plan, implement, or manage EE Programs exceed the amount approved in rate base, the incremental labor dollars will be allocated to the calculation of DSMS.

C. Legal Expenses
Legal expenses for outside counsel working on DSM projects will be included as a recoverable DSM expense. Legal expenses for outside counsel is charged to a general DSM fund and then spread across all programs. Legal expenses from inside counsel are covered in item B above.

D. Reporting Requirements
Reporting Requirements for the EEIP are outlined in R-14-2-2409 of the EE Standard. Annual and Semi-Annual reporting details include no requirement for addressing carry-over funds. Carry-over funds are only used when requesting an adjustment to the DSMAC.

E. Performance Incentives ("PI")

UNSE includes a Commission approved percentage share of the economic benefits (benefits minus costs) from approved energy-efficiency programs in the DSMAC calculation but the total dollar amount is capped at the Commission approved $/kWh.

PI as % of Net Benefits	Capped at $/kWh
8%	$0.0125

The calculation of UNSE Performance Incentive will use the net benefits (total benefits minus total costs) derived from all Commission approved DSM programs unless otherwise ordered by the Commission. At this time, the Commission allows UNSE to include net benefits from all Commission approved programs in this calculation.

If the allowed % of net benefits exceeds the results from multiplying total kWh savings times $0.0125, the PI will be capped at the $/kWh calculation.

6. *Determination Of True-Up (Carry Over):*

UNSE makes significant effort to estimate the allowable budgeted costs for EE programs, the PI and the DSMAC revenue collection but because these items are only a prediction of what might occur in the future it is impossible to be 100% accurate. Therefore it is possible for UNSE to either over-collect or under-collect allowable costs through the DSMAC.

Using the actual values at the end of each year, UNSE develops a True-Up (TU) balancing account (allowable expenses minus amount collected). This balance will include past period PC, PI and

DSMAC revenue collection accruals as of December 31st of the previous year. Past period PC and PI, past period DSMAC revenue, and the TU balancing account computation will be provided annually in Schedule 2 of the DSMAC calculations.

The True-Up (TU) calculation for the new DSMAC will be based on the difference in the total allowable expenses and the amount in the TU balancing account. In the event that PC or PI are more or less than DSMAC revenues collected, the over or under collection will be subtracted from or added to the DSMAC calculation in the subsequent period.

7. *Determination Of The Adjustor Charge:*

UNSE may file a revised DSMAC with supporting documentation by June 1st of each year when UNSE files a revised EEIP. Or UNSE may file a request for a DSMAC adjustment in a supplemental filing by April 1st. The DSMAC will be calculated by projecting PC and PI for the upcoming year, adjusted by the over or under collection of previous periods. This calculation will be provided in the annual DSMAC calculation on Schedule 1.

The DSMAC for purposes of recovering PC and PI under the DSM Program will be developed based on the following formula:

DSMAC = PC + PI + TU

Sales

Where:

PC	=	Program Costs as defined in section 5(A) forecast for the upcoming year.
PI	=	Performance Incentives as defined in section 5(E) forecast for the upcoming year.
TU	=	Any "true-up" balance as defined in section 6.
Sales previous	=	Energy (kWh) sales under applicable electric rate schedules for the calendar year.
Adjustor Period	=	The 12 month period beginning for which the adjustor will be in effect.

The DSMAC for all customers will be calculated as a \$/kWh charge. To calculate the \$/kWh that will be applied to all customer bills, the recoverable costs (Program cost plus Incentives) shall be divided by the total retail sales (kWh) from all applicable customers. For billing purposes, the DSMAC will appear on the customer bills under the "Green Energy Charge".

*8. **Review Process:***

The proposed DSMAC for use during a specific Adjustor Period will be calculated as shown in Schedule 1. UNSE may file an updated adjustor charge each year with its EEIP or through a supplemental filing by April 1st as outlined R-14-2-2409 of the EE Standard. If approved by the Commission, changes in the DSMAC will be retroactive to the first day of January for the filing year.

*9. **Schedules***

- Schedule 1: DSM Calculation
- Schedule 2: UNSE Operating Revenue
- Schedule 3: Surcharge Summary

SCHEDULE 1

UNSE Existing Rule Option Rate

Line	Class	Column A	Column B	Column C
		20XX Retail Revenue ($)	20XX Retail Sales (kWh)	EE Proposed Revenue by class (Per kWh) with Proposed Budget
1	Residential	UNSE OpRev, Column E, Line 13	UNSE OpRev, Column C, Line 13	Column B, Line 1 * Column A, Line 12
2	Commercial	UNSE OpRev, Column E, Line 27	UNSE OpRev, Column C, Line 27	Column B, Line 2 * Column A, Line 12
3	Industrial	UNSE OpRev, Column E, Line 35	UNSE OpRev, Column C, Line 35	Column B, Line 3 * Column A, Line 12
4	Mining	UNSE OpRev, Column E, Line 40	UNSE OpRev, Column C, Line 40	Column B, Line 4 * Column A, Line 12
5	Other	UNSE OpRev, Column E, Line 48	UNSE OpRev, Column C, Line 48	Column B, Line 5 * Column A, Line 12
6	Total	Sum Column A, Lines 1:5	Sum Column B, Lines 1:5	Sum Column C, Lines 1:5
		Proposed Budget & Surcharge		**Budget Collection with Current Surcharge**
7	20XX Total DSM $ Jan - Dec 20XX	2016 EEIP, Table 1.2, Column 2, Line 2		UNSE OpRev Column D, Line 52 * .0015
8	True-up	Surcharge Summary Column E, Line 10		NA
9	20XX Performance Incentive	Surcharge Summary Column B, Line 8		NA
10	Total 20XX DSM Recovery	Sum Column A, Lines 7:9		Sum Column C, Lines 7:9
11	$ / kWh Residential	Round Column A, Line 10/Column B, Line 6,4		Round Column C, Line 10/UNSE OpRev Column D, Line 52

SCHEDULE 2

UNSE Rev Sum -- YTD

UNS Electric, Inc
Revenue Summary Report - Year-to-Date
DEC-XX
XX-JAN-20XX

Line	Final	Column A Customers DEC-XX	Column B Customers DEC-XX	Column C KWH DEC-XX	Column D KWH DEC-XX	Column E Revenue DEC-XX	Column F Revenue DEC-XX
	Retail Sales:						
1	**Residential:**						
2	**5098 Res Unbilled Revenue**	0	0	0	0	0	0
3	**5701 Santa Cruz Res**	0	0	0	0	0	0
4	**5702 RES-01 CARES**	0	0	0	0	0	0
5	**5703 R-01 Residential Electric**	0	0	0	0	0	0
6	**5704 Res-01 CARES Medical**	0	0	0	0	0	0
7	**5707 Small Gen Svc**	0	0	0	0	0	0
8	**5718 Dusk to Dawn Lgtng Svc**	0	0	0	0	0	0
9	**5725 R-01 Bright Community Sol**	0	0	0	0	0	0
10	**5726 Res UNSE Super Peak TOU**	0	0	0	0	0	0
11	**5769 RES-01-TOU**	0	0	0	0	0	0
12							
13	**Residential**	0	0	0	0	0	0
14	**Commercial:**						
15	**5298 Com Unbilled Revenue**	0	0	0	0	0	0
16	**5705 Santa Cruz Small Gen Svc**	0	0	0	0	0	0
17	**5707 Small Gen Svc**	0	0	0	0	0	0
18	**5713 Lrg Gen Svc**	0	0	0	0	0	0
19	**5714 Lrg Gen Svc TOU**	0	0	0	0	0	0
20	**5717 Interruptible Pwr Svc**	0	0	0	0	0	0
21	**5718 Dusk to Dawn Lgtng Svc**	0	0	0	0	0	0

22	**5770 SGS-10-TOU**	0	0	0	0	0	0
23	**5771 LGS-TOU-N**	0	0	0	0	0	0
24	**5781 General Service SGS-10 Br**	0	0	0	0	0	0
25	**5785 Large General Service LGS**	0	0	0	0	0	0
26							
27	**Commercial**	0	0	0	0	0	0
28	**Industrial:**						
29	**5348 Ind Unbilled Revenue**	0	0	0	0	0	0
30	**5709 Lrg Pwr Svc - Dist**	0	0	0	0	0	0
31	**5712 Lrg Pwr Svc - Trans TOU**	0	0	0	0	0	0
32	**5772 LPS-TOU (<69)**	0	0	0	0	0	0
33	**5773 LPS-TOU (>=69)**	0	0	0	0	0	0
34							
35	**Industrial**	0	0	0	0	0	0
36	**Mining:**						
37	**5398 Mining Unbilled Revenue**	0	0	0	0	0	0
38	**5719 Lrg Pwr Svc - Mining**	0	0	0	0	0	0
39							
40	**Mining**	0	0	0	0	0	0
41	**Other:**						
42	**5448 Pub St Lt Unbilled Rev**	0	0	0	0	0	0
43	**5705 Santa Cruz Small Gen Svc**	0	0	0	0	0	0
44	**5707 Small Gen Svc**	0	0	0	0	0	0
45	**5713 Lrg Gen Svc**	0	0	0	0	0	0
46	**5718 Dusk to Dawn Lgtng Svc**	0	0	0	0	0	0
47							
48	**Other**	0	0	0	0	0	0
49	**Add: REST & DSM**	0	0	0	0	0	0
50	**Add: LFCR**	0	0	0	0	0	0

51							
52	**Total Retail Sales**	0	0	0	0	0	0

(1) Represents incremental revenue from sale of Bright Community Solar blocks to customers included in other rates.

SCHEDULE 3

Line		Column A	Column B	Column C	Column D	Column E
	UNSE Historical DSM Expenses vs Surcharge Balance					
	Year	**DSM Expenses**	**Performance Incentive (Collected Following Year)**	**DSMS Collection**	**Annual Over(+)/Under(-) Collected**	**Cumulative Over(+)/Under(-) Collected**
1	**2008**					
2	**2009**					
3	**2010**					
4	**2011**	$0	$0	$0	$0	$0
5	**2012**	$0	$0	$0	$0	$0
6	**2013**	$0	$0	$0	$0	$0
7	**2014**	$0	$0	$0	$0	$0
8	**2015**	$0	$0	$0	$0	$0
9	**2016**					

Line						
	UNSE Forecasted DSM Expenses vs. Surcharge Balance					
	Year	**DSM Expenses (Forecasted)**	**Performance Incentive (Collected Following Year)**	**DSMS Collection (Forecasted)**	**Annual Over(+)/Under(-) Collected**	**Cumulative Over(+)/Under(-) Collected**
10	**2016**	2016 EEIP, Table 1.2, Column 2, Line 2	Column B, Line 8	UNSE OpRev Column C, Line 52 X DSM Calculation Column A, Line 12	Sum(Column A, Line 10: Column C, Line 10)	Column E, Line 8 + Column D, Line 10
11	**2017**	$0	$0	$0	$0	$0
12	**2018**	$0	$0	$0	$0	$0

Totals	**Sum Column A, Lines 4:9 + Sum Column A, Lines 10:12**	**Sum Column B, Lines 4:9 + Sum Column B, Lines 10:12**	**Sum Column C, Lines 4:9 + Sum Column C, Lines 10:12**	**Sum Column D, Lines 4:9 + Sum Column D, Lines 10:12**	**Sum Column E, Lines 4:9 + Sum Column E, Lines 10:12**