BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
DOUG LITTLE, Chairman
BOB STUMP
BOB BURNS
TOM FORESE
ANDY TOBIN

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

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Frank Radigan and Lon Huber on Rate Design, in the above referenced matter.

RESPECTFULLY SUBMITTED this 24th day of June, 2016.

Daniel W. Pozefsky
Chief Counsel

AN ORIGINAL AND THIRTEEN COPIES
of the foregoing filed this 24th day
of June, 2016 with:

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

COPIES of the foregoing hand delivered/
mailed this 24th day of June, 2016 to:

Michael W. Patten
Jason D. Gellman
Snell & Wilmer LLP
One Arizona Center
400 E. Van Buren Street
Phoenix, AZ 85004
mpatten@swlaw.com
bcarroll@tep.com
jhoward@swlaw.com
docket@swlaw.com
Consented to Service by Email

Barbara La Wall
Charles Wesselhoft
Pima County Attorneys Office
32 N. Stone Ave., Suite 2100
Tucson, AZ 85701
Charles.Wesselhoft@pcao.pima.gov
Consented to Service by Email

C. Webb Crockett
Patrick J. Black
Fennemore Craig, P.C.
2394 E. Camelback Rd, Suite 600
Phoenix, AZ 85016
wcrockett@fclaw.com
pblack@fclaw.com
Consented to Service by Email

Nicholas J. Enoch
Jarrett J. Haskovek
Emily A. Tornabene
Lubin & Enoch, PC
349 N. Fourth Ave.
Phoenix, AZ 85003
Attorneys for IBEW Local 1116

Lawrence V. Robertson, Jr.
P.O. Box 1448
Tubac, AZ 85646
Attorney for Noble Solutions and SAHBA

Meghan H. Grabel
Osborn Maledon, PA
2929 N. Central Ave., Suite 2100
Phoenix, AZ 85012
Attorneys for AIC
mgrabel@omlaw.com
Consented to Service by Email

Gary Yaquinto
Arizona Investment Council
2100 N. Central Ave., Suite 210
Phoenix, AZ 85004
gyaquinto@arizonaaic.org
Consented to Service by Email

Court S. Rich
Loren Ungar
Rose Law Group, PC
7144 E. Stetson Dr., Suite 300
Scottsdale, AZ 85251
Attorney for TASC & EFCA

Timothy M. Hogan
Arizona Center for Law in the Public Interest
514 W. Roosevelt St.
Phoenix, AZ 85003
Attorney for Vote Solar, ACAA, WRA and SWEEP
thogan@aclpi.org
Consented to Service by Email

Rick Gilliam
The Vote Solar Initiative
1120 Pearl St., Suite 200
Boulder, Co 80302
rick@votesolar.org
Consented to Service by Email

Briana Kobor
Vote Solar
360 22nd St., Suite 730
Oakland, CA 94612
briana@votesolar.org
Consented to Service by Email

Michael Hiatt
Katie Dittelberger
Earthjustice Rocky Mountain Office
633 17th St., Suite 1600
Denver, CO 80202
mhiatt@earthjustice.org
kdittelberger@earthjustice.org
Consented to Service by Email

Craig A. Marks
Craig A. Marks, PLC
10645 N. Tatum Blvd., Suite 200-676
Phoenix, AZ 85028
Craig.Marks@azbar.org
Consented to Service by Email

Thomas A. Loquvam
Pinnacle West Capital Corp.
P.O. Box 53999, MS 8695
Phoenix, AZ 85072
Thomas.Loquvam@pinnaclewest.com
Consented to Service by Email

Kerri A. Carnes
Arizona Public Service Company
P.O. Box 53072, MS 9712
Phoenix, AZ 85072
Kerri.Carnes@aps.com
Consented to Service by Email

Travis Ritchie
Sierra Club Environmental Law Program
85 Second St., 2nd Floor
San Francisco, CA 94105
Travis.ritchie@sierraclub.org
Consented to Service by Email

Scott Wakefield
Hienton & Curry, PLLC
5045 N. 12h St., Suite 110
Phoenix, AZ 85014
Attorney for Wal-Mart

Steven W. Chriss
Wal-Mart Stores, Inc.
2011 S.E. 10th St.
Bentonville, AR 72716

Ken Wilson
Western Resource Advocates
2260 Baseline Rd, Suite 200
Boulder, CO 80302

Jeff Schlegel
SWEEP
1167 W. Samalayuca Dr.
Tucson, AZ 85704

Ellen Zuckerman
SWEEP
1627 Oak View Ave.
Kensington, CA 94707

Cynthia Zwick
Kevin Hengehold
Arizona Community Action Assoc.
2700 N. 3rd St., Suite 3040
Phoenix, AZ 85004

Bryan Lovitt
3301 W. Cinnamon Dr.
Tucson, AZ 85741

Kevin M. Koch
P.O. Box 42103
Tucson, AZ 85733

Karen White
139 Barnes Dr., Suite 1
Tyndall Air Force Base, FL 32401

Kyle J. Smith
9275 Gunston Rd, Suite 1300
JALS RL/IP
Fort Belvoir, VA 22060

Jeffrey W. Crockett
Crockett Law Group, PLLC
2198 E. Camelback Rd, Suite 305
Phoenix, AZ 85016

Bruce Plenk
2958 N. St. Augustine Pl
Tucson, AZ 85712

Garry D. Hays
Law Offices of Garry D. Hays, PC
2198 E. Camelback Rd, Suite 305
Phoenix, AZ 85016

Camila Alarcon
Gammage & Burnham, PLC
Two N. Central Ave., 15th Floor
Phoenix, AZ 85004
calarcon@gblaw.com
Attorneys for SOLON Corp.
Consented to Service by Email

Michele L. Van Quathem
Law Offices of Michele Van Quathem, PLLC
7600 N. 15th St., Suite 150-30
Phoenix, AZ 85020
mvq@mvqlaw.com
Attorneys for SOLON Corp.
Consented to Service by Email

Greg Patterson
Munger Chadwick
916 W. Adams, Suite 3
Phoenix, AZ 85007
Attorneys for AZ Competitive Power Alliance

By Cheryl Fraulob
Cheryl Fraulob

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-01933A-15-0322

DIRECT TESTIMONY

OF

LON HUBER

ON

RATE DESIGN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 24, 2016

TABLE OF CONTENTS

Exhibits

EXECUTIVE SUMMARY

The Residential Utility Consumer Office ("RUCO") has reviewed the testimony of Tucson Electric Power, Inc. ("Company" or "TEP") on rate design. The Company's proposal can be summarized by the following four points;

- Increasing the basic service charge for residential and general service customers,
- Reducing the number of volumetric tiers from four to two tiers,
- Creating a new net-metering rider for DG customers with the export rate linked to a utility scale PPA price.
- Requiring all new distributed generation (DG) customers to move to a three-part rate.

The Company's proposal for DG customers focuses on fixed cost recovery. While RUCO thinks this is important, RUCO also believes better price signals can and should be sent to DG adopters. A balance between fixed cost recovery and accurate price signals that reduce long-term costs for ratepayers must be obtained.

The attached rate designs are for illustrative purposes, using preliminary numbers to give parties an indication of the level of price signals RUCO deems appropriate to send. Full rate schedules will be developed once RUCO reviews the positions of other parties and receives further input from stakeholders.

RUCO continues to recommend a traditional rate design for the vast majority of TEP customers along with a serious commitment to rate modernization and peak demand reduction.

To achieve this, RUCO presents the following recommendations:

- Stable fixed charge
- Three tier inclining block rate
- A default three tier time of use (TOU) rate for high energy users with a three-hour peak
- Optional three part TOU rate

RUCO continues to believe that DG customers need to be treated fairly but uniquely given their distinct attributes from adopting advanced technology. Therefore, RUCO is putting forward four options for these partial requirements customers:

- Advanced DG rate
- Renewable Energy Standard Credit Option
- DG Volumetric TOU with Grid Export Fee
- All Rate Option
    - Opt-out Adjustment Fee
    - Market Based Export Option

I. INTRODUCTION

Q. Please state your name, position, employer and address for the record.

A. Lon Huber. I am a Director at Strategen Consulting LLC located at 2150 Allston Way # 210, Berkeley, CA 94704.

Q. Please state your educational background and work experience.

A. My career in the energy industry began in 2007 when I started working at a research institute housed within the University of Arizona. In 2010, I became the governmental affairs staffer for TFS Solar, a solar photovoltaic ("PV") integration company based in Tucson. I was hired by Suntech America in 2011 where I led the company's regulatory and policy efforts in numerous US states until December 2012. In 2013 I served as a consultant for the Residential Utility Consumer Office ("RUCO") on energy issues. I joined RUCO as a full time employee in January 2014. Since March 2015 I have worked at Strategen Consulting where I continue to advise RUCO on energy policy matters. I obtained a Bachelor of Science Public Administration degree in Public Policy and Management from the University of Arizona in 2009. I also received a Master's of Business Administration from the Eller College of Management at the same university. A full resume is attached in Exhibit LH-1.

Q. What is the purpose of your testimony?

A. My testimony will address the Company's rate design proposals and present RUCO's proposed rate design and policy.

Q. How is your testimony organized?

A. My testimony is presented in five sections. Section I is the introduction. Section II provides a summary of the issues with Company's proposal for all customers. Section III addresses RUCO's rate design and policy recommendations for all customers. Section IV summarizes the issues with the Company's proposal regarding DG customers. Finally, section V is RUCO's rate design and policy recommendations for DG customers.

Q. In summary, what are RUCO's comments regarding the Company's proposal?

- As proposed, a 100% increase in customer fixed charges is unprecedented and unwarranted.
- RUCO agrees that four tiers are not necessary, but disagrees that two is the optimal number of tiers.
- Rates should begin to send time and season differentiated price signals to all customers.
- Reforming distributed generation compensation is necessary, but RUCO has concerns with the Company's approach.

- RUCO supports optional three part rates, carefully crafted volumetric time of use rates, and a renewable portfolio standard linked kWh credit rate for solar customers.

Q. What principles does RUCO believe should inform this rate-making proceeding?

A. RUCO uses the following principles as a guide to rate-making in this case:

1. Do not inhibit conservation related price signals
2. No substantial changes for 98% of TEP ratepayers to accommodate 2% of DG adopters; however, standard rates do need to start evolving
3. Send more accurate price signals to DG customers through peak demand focused TOUs
4. Create options for future solar customers through RES compliance driven fixed solar credit

Additionally, RUCO supports Bonbright's principles or rate design, particularly the following summarized by the National Association of Regulatory Utility Commissioners ("NARUC")[1];

- Simplicity, understandability, public acceptability and feasibility of application and interpretation

[1] http://pubs.naruc.org/pub/538EA65C-2354-D714-5107-44736A60B037

- Stability of rates themselves, minimal unexpected changes that are seriously averse to existing customers
- Fairness in apportioning cost of service among different consumers
- Avoidance of "undue discrimination"
- Efficiency, promoting efficient use of energy and competing products and services

Q. Does RUCO believe TEP's proposed rates follow the above principles?

A. Not entirely.

Q. What changes could TEP make to better align with the above principles?

A. As further defined below in section II, RUCO recommends the Company implement the following for standard customers:

1. Stable fixed charge linked to customer specific costs
2. Three tier inclining block rate
3. A default three tier TOU rate with a three-hour peak for high use customers
4. Optional three part TOU rate

II. ISSUES WITH THE COMPANY'S PROPOSAL FOR ALL RESIDENTIAL CUSTOMERS

Q. What are the primary issues of concern that RUCO has identified within the Company's proposal that affect all residential customers?

A. RUCO has identified two primary issues of concern that affect all residential customers: 1) the Company's proposal to increase its basic service charge (or fixed customer charge); and 2) the Company's proposal to eliminate the top tiers from its inclining block volumetric rate.

1) BASIC SERVICE CHARGE

Q. Has RUCO adopted a general position regarding fixed customer charge increases?

A. RUCO is a member of the National Association of State Utility Consumer Advocates ("NASUCA"), which has taken a position on this issue.

Q. What is NASUCA?

A. NASUCA is an association comprised of many consumer advocates from numerous states and the District of Columbia. NASUCA's members are designated by the laws of their respective jurisdictions to represent the interests of utility consumers before state and federal regulators and in the courts.

Q. What is NASUCA's position on increased fixed customer charges?

A. NASUCA recently adopted resolution 2015-1, which opposes utility efforts to increase fixed customer charges. I have included a copy of this resolution with this testimony (see Exhibit LH-2).

Q. Does the Company's proposal include an increased fixed customer charge?

A. Yes, the Company proposes to double its basic service charge, increasing it from \$10 to \$20 per month for standard residential customers of tariffs TE-R-01, TE-201A, TE-R01BC, TER-01LL, TE-R01LB, and TE-201AL. The Company has also proposed to increase its basic charge from \$6.90 to \$12.00 for limited income customers on tariffs TE4-01, TE5-01, TE6-01, TE6-201A, TE8-01, TE8-201A, and TE6-01BC. Similar increases are proposed for customers on all other residential tariffs.

Q. Does RUCO support the Company's proposal to increase in the basic service charge for residential customers?

A. No.

Q. Why does RUCO oppose the Company's proposal to increase its basic service charge?

A. There are several reasons. First, the proposal is based on the faulty premise that fixed costs must be recovered through fixed charges. Second, the proposal deviates from common utility practice. Third, the proposal does not adhere to the principle of cost causation. Fourth, the Company's proposal is regressive and would disproportionately impact limited income customers. Fifth, the proposal reduces the incentive for customers to conserve energy. Sixth, the proposal does not adequately account for impacts to the Company's risk profile. I will explain each of these in more detail in my testimony below

Q. What is the Company's rationale for increasing the basic service charge?

A. The Company believes that its basic service charge should be increased as a means to recover its fixed costs. The Company states, "Considering that all electric utilities incur substantial fixed costs to serve residential customers, and that those fixed costs typically exceed the higher basic service charges approved for those utilities, TEP's current monthly service charge should be increased."[2]

Q. Does RUCO agree with the premise that fixed costs should be recovered through higher fixed charges?

A. No. There is no fundamental reason that fixed costs must be recovered through fixed prices. In fact, many industries in the global economy incur fixed costs that are ultimately recovered through prices that are not fixed. For example, gasoline is priced on a volumetric basis ($ per gallon), despite the fact that there are many fixed costs associated with its production (e.g. refineries, pipelines, etc.).

[2] Testimony of Craig Jones, p 43.

According to Bonbright, "Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of a complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation, but subject to the market forces of competition."3 Thus, if rates are intended to emulate prices charged by competitive enterprises, there is no rationale for regulated utilities to implement fixed charges instead of other pricing options. Bonbright goes on to say that "regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions."[4] By proposing to recover more its costs through fixed charges the Company is in essence attempting to insulate itself in part from adverse business conditions.

Q. Other than increasing fixed charges, are there other ways utilities such as TEP could recover fixed costs?

A. Yes there are several. These range from implementing time-of-use rates to simply increasing TEP's current volumetric rates.

Q. How does the Company's proposed increase in the basic service charge deviate from common utility practice?

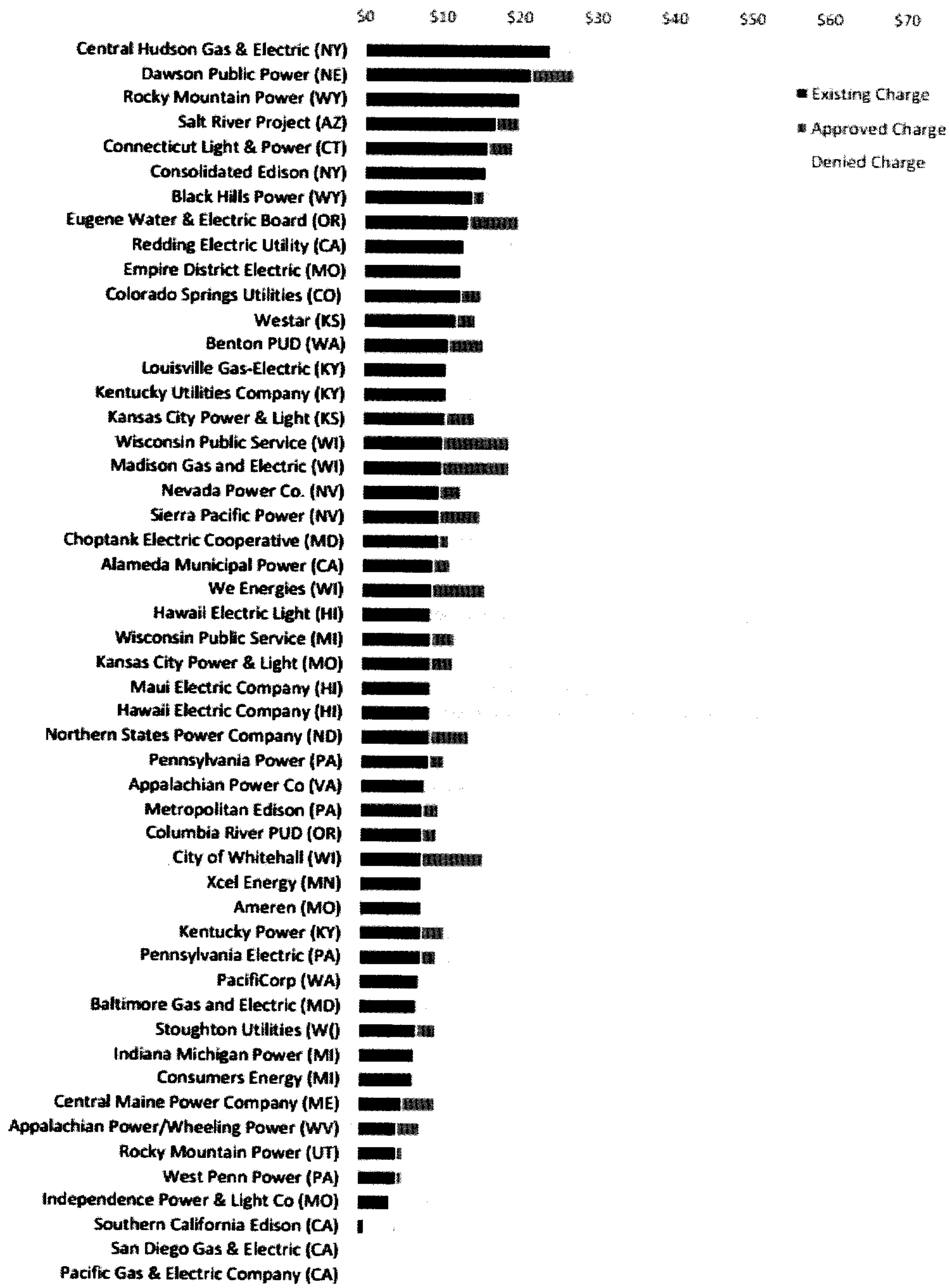
A. Recent decisions by commissions in several states have either denied entirely or scaled back proposals to increase fixed charges proposed by utilities. Synapse

[3] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 141
[4] *Ibid.* page 382

recently analyzed 51 proposals decided between September 2014 and November 2015 and found that 41% of these proposals were rejected, while 33% were scaled back. The average approved fixed charge for these decisions is $11.87.[5] These decisions are summarized below.[6]

Ibid. page 382
Whited, M., Woolf, T., Daniel, J. (2016). Caught in a Fix: The Problem with Fixed Charges for Electricity. p *43.*
[6] *Ibid.* p 46

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

Q. What are some of the reasons that these proposals were denied or scaled back?

A. There are many reasons why these proposals were denied or scaled back. Some include: concerns about reduced customer control; concerns about rate shock; concerns about inequitable impacts to low usage customers; concerns about inequitable impacts to low income customers; concerns about reduced incentives to invest in energy efficiency; and concerns about inefficient price signals.

Q. Can you provide a few examples of Commission decisions regarding fixed charges?

A. Yes. When the Missouri Public Service Commission denied Ameren Missouri's request to increase its fixed charge it stated, "There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy."[7] Similarly, when the State of Illinois Commerce Commission rejected Peoples Gas and North Shore Gas' proposals, it stated, "It is patent that high customer charges mean the Companies' lowest users bear the brunt of rate increases, and subsidize the highest energy users. Steadily increasing customer charges diminish the incentives to engage in conservation and energy efficiency because a smaller

[7] Missouri Public Service Commission (2015). Report and Order in the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Its Revenues for Electric Service. See discussion on page 76-77.

portion of the bill is subject to variable usage charges and customer efforts to reduce usage."[8] Finally, the Minnesota Public Utilities Commission (MPUC) recently rejected CenterPoint's proposed customer charge increase and ruled to maintain it at the existing level. Similar to the present case, the CenterPoint argued that "increasing the customer charges would reduce intraclass subsidies." However, the MPUC noted in its decision that "this conclusion is based on the premise that the charges are currently set below cost—a premise on which the OAG has cast significant doubt."[9]

Q. Did the Company provide examples of any utilities with basic service charges at or near the $20 level?

A. Yes. The Company stated in their testimony that, "APS, Trico Electric Cooperative, Inc. and Salt River Project ("SRP") have basic service charges ranging from $15.00 to $20.00 per month."[10]

Q. Does RUCO believe these examples lend support to the Company's proposal?

A. No. For APS, the current basic service charge for standard residential customers is actually $0.285 per day, or about $8.67 per month – significantly less than the

---

[8] State of Illinois Commerce Commission (2015). Order North Shore Gas Company, proposed general increase in gas rates; The Peoples Gas Light and Coke Company, Proposed general increase in gas rates. See discussion on page 176.
[9] Minnesota Public Service Commission (2016). In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Minnesota Gas for Authority to Increase Natural Gas Rates in Minnesota, Docket No. G-008/GR-15-424. p 64.
[10] Testimony of Craig Jones, p 43

$20 per month proposed. Of the remaining utilities, only SRP reaches $20 per month for standard residential customers. However, RUCO believes this example is an extreme outlier that was established under very different circumstances than the Company's present case and is not representative of recent trends. For example, RUCO recently reviewed the basic service charge for 25 investor-owned utilities in the Southwestern U.S. and found that 18 of them (72%) have a basic service charge of $10 per month or less.

Q. How does the Company's proposed basic service charge fail to adhere to the principle of cost causation?

A. RUCO believes that rates should reflect the principle of cost causation, absent policy considerations. As such, RUCO further believes that customer charges should only be used to recover the incremental costs that arise from serving individual customers. This includes costs associated with metering, billing, and service line drops. Meanwhile, it excludes costs related to overall demand on the system, such as transformers or distribution poles and wires. Such costs are common to (i.e. "attributable to" or "caused by") a larger group of customers and, therefore, should not be recovered on an individual customer basis. The Company's proposal of a $20 basic customer charge appears to greatly exceed the individual customer cost elements.

Q. What is the minimum distribution system approach or "minimum system method"?

A. Under the minimum system method, a portion of distribution plant costs (e.g. lines, poles, transformers) are allocated to a customer class based on the number of customers. The Company relies on this method as justification for its proposed basic service charge.

Q. Does RUCO support this approach?

A. No, RUCO does not. The minimum system method is flawed in that it assumes that the configuration of the distribution network is a given. However, the placement of substations, the number of feeder lines, and the current-carrying capacity of distribution system components are all dependent upon expectations about demand, voltage drop, and other factors. Additionally, the number of poles and length of power lines is also partly dependent on the size and spacing of customer properties, not on the number of customers. Recovering a large share of distribution system costs through customer charges is equivalent to assessing a per person tax that reflects neither the customer's ability to pay nor the benefits received. Given these considerations, RUCO agrees with Bonbright's statement that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to me clearly indefensible."[11]

[11] Bonbright, James Cummings (1961) Principles of Public Utility Rates page 348

Q. Have other commissions weighed in on the use of the minimum system method?

A. Yes. For example, the Illinois Commerce Commission explicitly rejected its use, stating the following:

"As it has in the past, see, e.g. Dockets 05-0597, 99-0121 and 00-0802, the Commission rejects the minimum distribution or zero-intercept approach for purposes of allocating distribution costs between the customer and demand functions in this case. In our view, the coincident peak method is consistent with the fact that distribution systems are designed primarily to serve electric demand. The Commission believes that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic. We reject the use of the MDS in this proceeding, and find that ComEd's ECOSS was correct in not reflecting the MDS concept. Accordingly, the Commission rejects the use of IIEC's COSS because it relies on the use of MDS."[12]

Q. What method does RUCO support instead of the minimum system method?

A. RUCO supports the basic customer method, which only allocates customer-specific costs (and not other distribution costs) based on the number of customers.

Q. Is this method used in other jurisdictions?

A. Yes. Several states including Maryland, Texas, Arkansas, Colorado, and Illinois all use the basic customer method for allocating customer costs.

[12] Illinois Commerce Commission, Docket No. 07-0566, Final Order dated Sept. 10, 2008, p. 208.

Q. How would the calculation of the basic service charge differ under this method?

A. Under the basic customer method, the cost elements for individual customers are significantly lower than the Company's proposed $20 basic customer charge.

Q. Does RUCO have any evidence to support this?

A. Yes. According to Exhibit CAJ-1 of the Company's testimony, the marginal cost of serving a residential customer was $353.86 in 2015. However, this total includes certain shared costs items such as $81.49 for "Line Transformers" and $148.28 for "Conductors & Devices." As explained previously, it is not appropriate for these shared cost items to be recovered through the basic service charge. Once these elements are removed, RUCO calculates the marginal cost to serve an individual customer to be $124.09 or about $10.34 per month. This is roughly equal to the Company's current basic service charge and far less than the proposed $20 amount.

Q. What is the significance of the fact that these are marginal costs?

A. Marginal costs reflect the incremental costs to serve customers on a forward looking basis. However, utility rates are frequently set to recover average or embedded costs. Meanwhile, embedded costs are typically lower than the marginal cost, a notion that is demonstrated in the Company's testimony.[13] Thus,

[13] See Craig Jones, Table 1, p 31.

RUCO believes the customer cost of $10.43 calculated should serve as an upper bound when considering how to set an appropriate basic service charge.

Q. On what basis should the costs of shared distribution infrastructure be recovered?

A. RUCO believes that shared distribution costs should be recovered based on "benefits received." As an example, the logic of benefits received would tell us that a household using 500 kWh a month should not have to pay the exact same price for utility poles as a household using 2,000 kWh a month.

Q. Please explain why "benefits received" is a sound basis for recovery of shared costs?

A. In most forms of shared infrastructure in the civic sector, costs are recovered either through usage fees (e.g. bridge tolls) or taxes (e.g. property taxes). The latter reflects the notion of a customer's "ability-to-pay" while the former reflects the notion of "benefits-received" by the customer. While recovery of costs through an ability-to-pay approach (e.g. through tax subsidies) can be common for municipal utility systems (e.g. water and sewer), it is not practically feasible for privately owned utilities. This leaves benefits-received as the primary basis for recovering shared infrastructure from private electric utilities. Meanwhile, the best measure of benefits-received for an electric utility is energy consumption.

Q. Can you please provide an example?

A. Yes. Consider two customers on a shared distribution system that are similar in all respects except that one is consuming electricity 24-7, while the other only operates for eight hours a day. Under this scenario, the 24-7 customer is receiving more benefits from the shared distribution system.

Q. How does the Company's proposed basic service charge reduce the incentive for customers to conserve energy?

A. Under the company's proposal, a significantly greater share of each customer's bill will be collected through a fixed charge as opposed to a volumetric energy rate. Thus, if the company's proposal were adopted, each customer would have a much smaller portion of their bill over which he or she has control. For example, Schedule H-4 demonstrates that an average residential bill for a TEP customer in winter would be about $86.78 under present rates, with $10 recovered through the basic service charge and $98.62 under proposed rates, with $20 recovered through the basic service charge.[14] This means that under present rates, customers are unable to control 11.5% of their energy costs, but under the proposed rates they would be unable to control 20% of their energy costs. Thus, under the Company's proposal there would be significant increase in the portion of customers' bills over which they would have not be able to manage through energy conservation or other means.

[14] Schedule H-4, page 1 of 85, Winter.

Additionally, by proposing to recover more of the Company's fixed costs through a fixed rate, the resulting volumetric rate included in the Company's proposal is lower than it otherwise might have been. A lower volumetric rate dampens the price signal customers receive, further reducing the incentive for customers to conserve energy. RUCO supports strong incentives for customers to conserve energy due to the significant benefits that peak reducing energy efficiency can bring to all ratepayers. As such, RUCO does not support the Company's proposal to recover increased share of its costs through fixed rates.

Q. Has RUCO considered how the Company's proposed basic service charge would impact limited income customers?

A. Yes. In general, limited income customers also tend to be low-use customers.[15] Thus, any proposal that has a greater impact on low-use customers will also have a greater impact on limited income customers. Meanwhile, proposals to increase fixed charges often have a greater impact on low-use customers.[16]

[15] According to the EIA's Residential Energy Consumption survey, households in the Western U.S. that are 150% above the federal poverty line consume 29% less energy than households with incomes below that level. Also, total household energy consumption in Western U.S. households increases by 11% on average per $20,000 increase in household income.
Source: U.S. Energy Information Administration, Office of Energy Consumption and Efficiency Statistics, Forms EIA-457 A and C-G of the 2009 Residential Energy Consumption Survey.

[16] Expenditures on energy as a percent of household income was 8% for the median low income household in Phoenix versus 4% of all households (Tucson data not available).
Source: American Council for an Energy-Efficient Economy and Energy Efficiency for All (2016) Lifting the High Energy Burden in America's Largest Cities.

Q. Has RUCO compared the impact of the Company's proposal on low-use versus high-use customers?

A. Yes. For example, RUCO compared the average bill increase for a low-use residential customer (822 kWh, summer) as estimated by the Company under its proposal would be $11.49 or about 12.2%.[17] Meanwhile, the summer bill increase for a high-use residential customer (2,430 kWh, summer) is only $5.21 or about 1.8%. In both cases, the bill increase is primarily attributable to the same increase in the basic service charge. However, it is clear that the low-use customer's bill increases by a much greater percentage. RUCO is particularly concerned with this higher impact on low-use customers since many of these customers are on fixed incomes and have less ability to increase payment for electric service without decreasing payment for other fundamental needs (e.g. food, medicine, etc.). In RUCO's view, the proposed basic service charge increase is a regressive policy that is harmful to Arizona's most vulnerable population.

Q. How does the Company's proposed basic service charge fail to account for impacts to the Company's risk profile?

A. Under the Company's proposal, a much greater portion of the overall revenue requirement would be recovered through the basic customer charge. Although revenue collected through this charge presents some risk of under recovery (i.e. if customers leave the service territory), this risk is substantially lower than revenue recovered through volumetric energy or demand based rates, which depend on

[17] Schedule H-4, page 2 of 85, Summer.

factors such as weather and economic growth. In its proposal, the Company fails to account for this reduced risk in developing the appropriate rate of return to utility investors.

Q. Please explain the connection between risk and reward for utility investors as it pertains to this proposal.

A. Generally speaking, utility company shareholders take on some risk when providing capital for utility investments. In exchange for putting their capital at risk, investors have the opportunity to earn a return on that investment, which is determined in part by the Return on Equity (ROE) set by the Commission. Ideally, the ROE set by the Commission will perfectly reflect the risk and reward preferences (i.e. the cost of capital) of utility investors. Thus, if the risk of capital cost recovery is substantially altered, the ROE should also be modified to reflect that fact. The Company's proposal does not appear to include any adjustments to the proposed ROE that account for the fact that substantially more of the company's revenue is collected through a lower-risk mechanism.

2) <u>MODIFIED TIERS</u>

Q. Please describe how the Company proposes to change its volumetric rates for standard residential customers.

A. Presently, the Company implements an inclining block rate for standard residential customers that includes four usage tiers.[18] The Company proposes to eliminate

[18] Tier 1 ranges from 0-500 kWh

the third and fourth tiers of the residential rate class. This would leave only two usage tiers: 0-500 kWh usage and usage above 500 kWh.

Q. Does RUCO support the Company's proposal to eliminate the top two usage tiers for residential customers?

A. Partially. RUCO believes it is appropriate to eliminate the top usage tier (>3,500 kWh). However, RUCO does not support the elimination of the third usage tier (>1,000 kWh).

Q. Why does RUCO support the elimination of the top usage tier (>3,500 kWh)?

A. The elimination of this tier is likely to have minimal impact on the vast majority of residential customers. Based on RUCO's analysis of customer billing data provided by the Company, it appears that only a small number of customer bills and revenues collected (approximately 1% each) are associated with this tier.[19]

Q. Why does RUCO oppose the elimination of the third usage tier (>1,000 kWh)?

A. Unlike the top tier, a significant number of customer bills and revenues collected are associated with this usage tier.[20] The elimination of this tier therefore will have a significant impact on a large number of customers.

---

[19] Calculated from data presented in Schedule H-5 of the Company's testimony.

[20] Based on data presented in Schedule H-5 of the Company's testimony, RUCO estimates that approximately 40% of customer bills and 34% of revenue collected are presently associated with tier 3.

Q. Are there specific customer impacts RUCO is concerned about if this tier is eliminated?

A. Yes, there are two impacts we are most concerned about. One relates to bill impacts for low use customers, the other relates to the price signal for energy conservation.

Q. Please elaborate.

A. First, by eliminating the third tier, a greater share of the utility's costs must be recovered through the first and second tiers. This means that the rate increase proposed for first and second tier customers is significantly higher than it otherwise might have been if the third tier remained intact. RUCO is concerned about this because lower usage customers, who also tend to have less income and less discretion over their energy consumption, will likely experience significant bill and rate increases. For example, the table below illustrates the proposed rate increase for customers in the first two usage tiers will be 5% and 18% respectively in the summer.

Table 1. Summary of Proposed Changes to Rates and Customer Bills for Volumetric Rate Tiers[21]

Tier	**Present Rates (Summer)**	**Proposed Rates (Summer)**	**Rate Increase (%)**	**Customer Bill Count (% of total, Summer)**
0-500 kWh	$0.0562	$0.0591	5%	30%
501-1000 kWh	$0.0672	$0.0791	18%	29%
1,001-3,500 kWh	$0.0798	$0.0791	-1%	40%
>3,500 kWh	$0.0882	$0.0791	-10%	1%

RUCO believes that concentrating bill increases on lower usage customers is a regressive policy that should be avoided. Additionally, it is counterintuitive since these customers generally contribute less to overall system costs. Moreover, these issues would be exacerbated by the adoption of the Company's proposed increase in the basic service charge.

Second, by eliminating the higher tier, higher usage customers will actually experience a decrease in the marginal price per kWh consumed. RUCO is concerned about this because it will reduce the price signal to save energy for the group of customers with the highest consumption. For example, the table above summarizes the changes to the tiered rates for each usage tier under the Company's proposal. It suggests that approximately 41% of customers who are higher-use customers will experience a rate decrease in the summer. The Company has proposed this despite the fact that these high-use customers are

[21] TEP Testimony, Schedule H-5.

likely to have the greatest discretion over their energy usage. Since reducing overall energy consumption provides a benefit to all customers over the long run, RUCO supports strong price signals for energy conservation.

III. RUCO'S PROPOSED RATE DESIGN AND POLICY FOR ALL CUSTOMERS

Q. Please detail RUCO's proposed changes to the fixed customer charge.

A. RUCO proposes the customer charge remain at current levels across the board. For the typical non-TOU residential customer, the charge would be $10.

Q. How does RUCO's method to determine the fixed charge differ from the Company's method?

A. RUCO uses the Basic Customer method for determining a customer's fixed charge. This method accounts for service drop, meters, and billing and allows TEP's rate to remain unchanged in this proceeding. The Company chose to use the Minimum System method to expand the charge to include shared infrastructure expenses that are partly demand related including poles, wires, and transformers. These expenses are not customer charges and should not be recovered as such.

Q. Please detail RUCO's proposed changes to the volumetric rate.

A. RUCO proposes to implement a three-tiered inclining block structure. Such a structure relieves pressure off of low users and prevents less revenue from being shifted to collection via basic service charge over which customers have no control.

Q. Please detail RUCO's proposed changes to high use customers.

A. For customer using 950 kWh or more per month on average over an entire year, RUCO proposes transitioning these customers to a three-tier volumetric TOU rate with a summer peak from 3:00 PM to 7:00 PM and a winter peak from 6:00 AM to 9:00 AM. These customers would be placed on the TOU rate plan by default. However, for the time being, these customers would also have the ability to opt-out and return to the inclining block rate plan. According to studies RUCO has reviewed, most customers tend to stay on their default rate plan. Thus, if designed correctly, the number of customers that choose to opt-out should remain low.[22]

Q. Why does RUCO support a four-hour summer peak period?

A. RUCO believes that a four-hour period will be easier for customers to manage than TEP's current six hour TOU peak, particularly for customers lacking advanced technology. Meanwhile, the four-hour period RUCO is proposing will still align with the top peak hours of residential demand. An estimate of the on-peak and off-peak rates are attached in exhibit LH-3.

[22] Cappers, Peter C., et al. (2016) *Time-of-Use as a Default Rate for Residential Customers: Issues and Insights*, pg. 14

Q. Why did RUCO select 950 kWh of consumption as the basis for the default TOU rate?

A. About 25% of the residential TEP customer base falls into this category. RUCO believes that this level of energy indicates enough usage to load shift during all or parts of the on-peak window.

Q. What are the benefits of RUCO's proposed change?

A. This change would introduce hourly as well as seasonal variations in residential rates, thereby providing price signals that more accurately reflect utility cost drivers. Moreover, this structure would help to reduce intraclass subsidies between winter and summer customers as well as between customers whose usage primarily occurs either on-peak or off-peak. Finally, it is gradual and optional.

Q. What implementation strategies can help ensure successful adoption?

A. RUCO encourages the Company to undergo bill redesign and form educational efforts around the TOU rates. These educational efforts could include bill inserts, advertising and media campaigns, online information, and outreach to local community groups. Once the default TOU rate plan is successfully in place for this group of high-use customers, other customer groups (e.g. new customers) could also be considered for placement on a default TOU rate. RUCO also recommends that a study be conducted on the effectiveness of this rate plan for reducing peak demand.

IV. ISSUES WITH THE COMPANY'S PROPOSAL FOR DG CUSTOMERS

Q. Please detail the Company's proposed for customers with distributed generation.

A. The Company proposes to create a new net metering rider with three-part rates. This new net metering rider will be default for all partial requirement customers that submitted an interconnection application after June 1, 2015. Currently interconnected customers will stay on their current rates until they expire in 20 years.

Q. How will the new net-metering rider compensate DG customers?

A. New DG customers will be compensated for excess energy at a Renewable Credit Rate. The Renewable Energy Credit rate is a variable proxy for the price TEP will pay for energy from utility scale assets. The variability in the Renewable Energy Credit rate would be based on most recent utility scale PPA price. The Company "believes it is appropriate that Net Metering customers receive the same financial compensation for their distributed energy that is available from other, larger, more cost-effective resources."[23] The Company also proposes to eliminate the banking option by purchasing excess energy during each billing cycle.

[23] Direct Testimony of Carmine Tilghman, pg. 10

Q. What is a partial requirement customer?

A. The Company defines partial requirement customers as DG customers with net metering.[24]

Q. Does RUCO agree with this classification?

A. Yes. RUCO witness Frank Radigan will comment on this topic.

Q. Does the Company's proposal send accurate price signals to new DG customers?

A. No. The proposed structure is intended to increase fixed cost recovery, rather than send correct price signals to customers. RUCO understands the need to recover fixed costs, but strongly believes a new net-metering rider should also send correct price signals to customers. A balance between fixed-cost recovery and proper price signals must be reached.

Q. What components of the proposed rate do not represent accurate price signals?

A. If the proposed rate is intended to send correct price signals rather than recover fixed costs, the demand component needs to be redesigned. In particular, the proposed demand rate, which is based on the customer's peak demand, regardless of timing or alignment with system peak demand, does not send correct price signals. To illustrate, a peak power draw at 1:00 AM in July would be priced

[24] Direct Testimony of Dallas Dukes pg. 5

the same as a peak power draw at 6:00 PM. A more correct price signal would apply the demand charge specifically during the hours of system peak demand as proposed below.

Q. Does RUCO have any other concerns to the Company's proposed rate?

A. Yes. Any export would be valued at the latest signed solar PPA rate. This means that at any time a single future project can significantly change the economics of a rooftop solar installation. The fact that it is linked to just one project and thus one data point adds concern over the details of that latest PPA. For instance, was it an add-on to an existing array? Did the developer subsidize a portion of the facility for research or publicity ends? Should ratepayers also cut the price paid to other developers if cheaper PPAs are executed 5 years from now?

Q. Are RUCO's proposed options complicated?

A. To potential customers, yes. I find it hard to imagine that customers will understand that the exports of their PV system (which is hard enough to quantify) will be subject to an ever-changing export rate influenced by a PPA proxy of a distant solar PV system.

V. RUCO'S PROPOSED RATE DESIGN AND POLICY FOR DG CUSTOMERS

Q. What is RUCO's proposal concerning DG customers?

A. RUCO agrees that the compensation method for DG needs reform, especially with the growing popularity of DG. However, RUCO believes that the company's proposal can be improved. By creating more options for DG and traditional customers, a win-win solution can be achieved. As such, it is RUCO's goal to find a balanced path that allows the solar industry to mature while maintaining a fair approach for all ratepayers and balancing cost-recovery with pro-conservation price signals. To meet these goals, RUCO proposes making four options available to DG customers going forward. These options are summarized in the table below and described in more detailed in the remainder of my testimony.

DG Rate Option	Description
Advanced DG Rate	• Three-part rate • $11.50 minimum bill • On-peak and off-peak volumetric energy rate, with monthly net metering • On-peak winter and summer demand rate • Customer must remain on rate for full calendar year • $3 metering fee ($0 if RECs are exchanged)
RES Credit Option	• Buy-all, sell-all like transaction. Customer side of meter. • Standard rates apply for all energy consumed on site (customer can select from any available residential rate option) • 20 year fixed credit rate applies to all DG output • Credit rate is adjusted annually for new DG systems through REST plan approval process
DG Volumetric TOU Option	• Two-part rate • $11.50 fixed customer charge • On-peak and off-peak volumetric energy rate, with monthly net metering • Hourly fee applied to all exports • $6 metering fee ($3 if RECs are exchanged)
All Rate Option	• Any full requirements rate plan would be available. • Monthly net metering • Customer chooses one of the following: 1. $/kW Adjustment Fee, based on size of DG system 2. Market Export Rate - Exports are credited at the MCCCG rate • $6 metering fee ($3 if RECs are exchanged)

Q. How does RUCO propose a customer would choose a rate plan and how would this transition be handled?

A. RUCO proposes each of the above rates be available to DG customers at the time of their installation. Customers will be made aware of the different aspects of each rate and the status of grandfathering for that rate. There would be no mandatory or default rate and new DG customers would be able to select one of the available options. Some restrictions may exist, such as a customer not exchanging their RECs with TEP may not be allowed to be on the RES Bill Credit option. Customers would have the option to switch to a different rate plan once per calendar year. However, to avoid gaming, customers that select the Advanced DG TOU rate option would be required to remain on it for one calendar year.

Q. Do these options solve all of RUCO's concerns with DG?

A. No. RUCO would like to begin to solve these concerns by ensuring that rooftop DG can be a neutral cost proposition for ratepayers as soon as possible. Once that milestone is reached RUCO would like to see DG be a net benefit to all ratepayers. Finally, the third milestone, RUCO would like to see a closer cost parity between wholesale grid-connected solar and rooftop solar. While subsidies exist throughout our current regulated policy and rate designs, RUCO believes these cross-subsidies should be quantified, examined and debated. However, simply because other subsidies exist, does not warrant ignoring fast-growing subsidies. RUCO believes incremental and gradual progress to address DG related cross subsidies is fair and will send more accurate price signals to the benefit of all ratepayers.

Q. Please provide details on RUCO's proposed Advanced DG Time of Use rate.

A. The Advanced DG TOU rate is a three-part rate with TOU energy and TOU demand components designed to recover fixed costs while sending more accurate price signals. Fixed costs are recovered through a minimum bill, a variable TOU kWh energy charge, and a TOU kW demand charge over peak hours during summer months. The starting point for designing the DG TOU Rate was to approximate the value of south facing fixed tilt PV on the TEP system. Absent a Commission policy in this regard, I performed a basic calculation of the cost of the next marginal unit of generation needed for the TEP system while still acknowledging the uniqueness and intermittency of solar PV. I set this value as the volumetric offset portion of the plan. I then created a TOU demand charge to send accurate on-peak price signals to the DG adopter while allowing for cost recovery by the Company if the customer fails to reduce peak demand.

Q. How do the time periods for on-peak and off-peak correspond to existing TEP TOU offerings?

A. The months and hours I chose correspond to what the Company currently outlines for their TOU based rates.

Q. Could the Advanced DG TOU be available to non-DG customers?

A. Not at this time. However, RUCO is proposing an optional three-part rate for standard customers should a customer seek a demand charge based rate.

Q. What is a demand charge?

A. A demand charge is a monthly charge based on a customer's peak energy usage for a single billing cycle. Generally, demand charges are calculated by multiplying the highest level of power drawn by a customer over a certain interval during peak demand times (measured in kW) by a demand rate ($/kW). For purposes of the Advanced DG rate, the interval will be the highest peak hour of a given month.

Q. Does RUCO believe demand charges should be applied to general residential customers?

A. In this case, RUCO believes if residential demand charges are implemented, they should be optional for standard residential customers. Furthermore, RUCO believes demand charges should be limited to peak demand hours and peak demand season when system demand is highest. RUCO expresses concern that utilities can easily design demand rates that do not follow this practice, essentially creating demand charges that are essentially unavoidable fixed charges and do not reduce system costs.

A 24/7 demand charge as proposed does not send accurate price signals. The Company's proposal treats all demand equal despite unequal effects of demand on the company's system. A high power draw in the early morning hours of spring would have the same demand charge as a high power draw during a hot mid-evening summer day. This proposal does not reflect costs to the utility, does not represent accurate price signals, and is a poorly designed demand charge.

Because residential demand charges are a departure from traditional volumetric rates, RUCO recommends TEP commit to a customer education plan. Most customers are likely to be unfamiliar with the concept of demand and will require education programs and tools from the Company to understand and respond to the rates. RUCO would like a commitment from TEP to provide customers with these plans in their next DSM plan. Such a commitment should include energy efficiency and demand response programs as discussed in the Commission's technology and innovation workshops.

Q. Please describe in more detail how you determined the volumetric energy rate level for the Advanced DG Rate.

A. I performed a simple, yet fair, calculation of the long-term avoided costs of south facing rooftop PV. I generally followed the outline expressed by Chairman Little in his letter in the Value of Solar docket.[25]

Q. How detailed was your analysis on Value and Cost of DG?

A. As there is no official Commission position or guidance on this issue and due to the fact that many of the possible cost-benefit categories are 1) speculative in nature, 2) rely on policy decisions, 3) are nearly impossible to quantify, and 4) may not have a significant impact on the analysis, RUCO has only examined the major categories of benefits. In addition, RUCO believes that many of the hard to quantify environmental and societal benefits are captured in the preferential treatment

[25] http://images.edocket.azcc.gov/docketpdf/0000167384.pdf

given to resources like solar energy. Treatment such as procurement not tied directly to demand driven need, assumed adoption levels to avoid lumpy generation expenses, fixed payments based on future levelized amounts, and the avoidance of any cost effectiveness tests like energy efficiency measures undergo, are examples of this preferential treatment.

Q. What are the results of your analysis?

A. Using a 30% capacity value from the TEP 2016 preliminary IRP, and cost of a new peaking facility from their 2014 IRP, I obtain approximately 4.25 cents/kWh in possible capacity savings. This includes losses and generation connected transmission. I then added the MCCCG figure from the Company's 2016 REST plan. This yielded 3.9 cents/kWh, which includes losses. I performed another calculation to gain more confidence in this number. I levelized 2015 market pricing from the Palo Verde spot market out 20 years at a 2.5% escalator.[26] I received 3.65 cents/kWh from this calculation, adjusted for 6% losses.[27] When I combined this number with the previous capacity savings figure, I arrived at 7.9 cents/kWh. This represents the approximate long term avoided cost figure for the next marginal rooftop PV system. Meaning that if a solar adopter is paid at this rate, it will offer a breakeven proposition to non-solar ratepayers.

---

[26] Market pricing for EIA can be found here: http://www.eia.gov/electricity/wholesale/
[27] Energy Losses from the 2016 TEP Preliminary IRP https://www.tep.com/doc/planning/2016-TEP-IRP.pdf

Q. Are there other details you would like to share about the DG TOU rate?

A. Yes, the demand charge would be determined by the top hour of demand in a given month during the applicable on-peak window. Also, I propose a minimum bill to recover customer related charges. RUCO initially proposes $11.5 to match the residential TOU rate; however, given that a minimum bill has different dynamics than a fixed charge, RUCO would consider slightly increasing the minimum bill upwards. Finally, if a customer does not exchange renewable energy credits ("RECs") the customer will be assessed a $3 per month meter fee. This lower rate reflects the fact that TEP may not be getting "green" energy from DG customers if the rights to that claim have already been sold or exchanged away to other states or companies.

Q. Please detail the DG Volumetric TOU Option.

A. RUCO proposes a Volumetric TOU option consisting of no tiers, a higher fixed charge, an hourly DG export fee, and monthly banking.

Q. Why does RUCO propose a monthly banking mechanism?

A. With correct hourly and seasonal pricing through the underlying TOU rate, the inherent subsidy of banking is greatly reduced. Therefore, monthly netting instead of hourly can be a more gradual approach to reforming net metering without harmful impacts to non-participant ratepayers.

Q. Why an hourly DG export fee?

A. A two-part volumetric rate over compensates DG adopters because of how fixed costs are recovered. Therefore, grid related fixed costs need to be recovered through a separate mechanism. This export fee concept affords a solar adopter the use of a non-demand charge based plan while still offering some fixed cost recovery.

Q. Why a metering fee?

A. Currently all customers pay for the extra meter solar customers get installed on their premises. The total estimated cost is around $6 per month[28]. About 50% of this cost is covered through the yearly REST budget. Since RECs are used to satisfy the REST compliance targets, the $3 of metering expenses recovered through yearly implementation plans can be fairly avoided if RECs are exchanged. However, non-REST related costs still need to be recovered. It is important to note that the Advanced DG rate does not recover these outside of implementation plan costs because of the improved fixed cost recovery inherent in the rate design. However, if RECs are not exchanged that $3 fee must be still assessed.

Q. Please detail the All Rate Option.

A. The proposed All Rate option consists of an Opt-out Adjustment or a differential market based export rate. Under this rate, DG customers can choose any rate if

[28] FERC, 18 Cfr Part 101 - *Uniform System Of Accounts Prescribed For Public Utilities And Licensees Subject To The Provisions Of The Federal Power Act*

they pay an opt-out fee. The Opt-out Adjustment would be a $/kW fee based on installed PV capacity, and charged monthly. RUCO will determine the level of this fee upon finalization of rate schedules. RUCO also proposes a Market Export Rate option. Again, a DG customer can select any rate but the level of compensation for exports would be set to MCCCG level on an hourly basis.

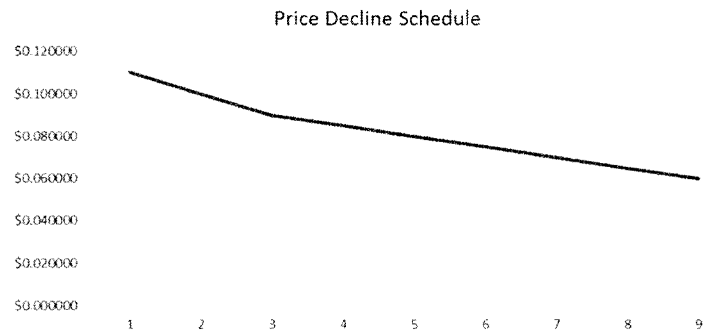
Q. Please detail the RES Credit Option.

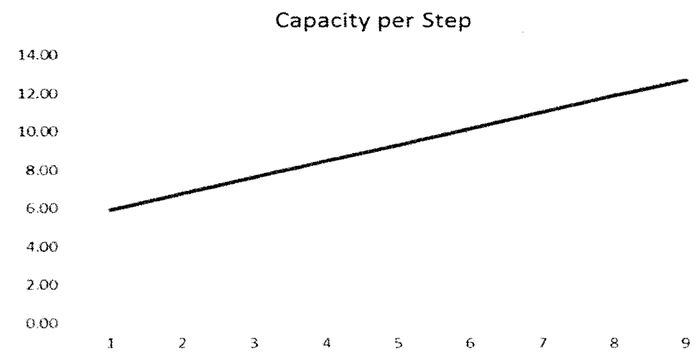
A. To meet the Company's residential renewable energy target, the utility needs ~85MW additional distributed generation[29]. To meet this, RUCO proposes a "buy-all sell-all" like credit structure. This credit rate is fixed and linked to REST targets. Based on the 2016 TEP REST implementation plan, TEP requires about 85 MW residential DG to meet the Commission's 2025 target. It is likely this number will change, reflective of the number of systems installed during the course of the rate case and whether the Commission chooses to recognize systems that have not exchanged their REC's.

This RES credit option would work conceptually much like the declining upfront incentives, the Commission used a few years ago. A credit would begin at a set rate (RUCO proposes close to current retail) and gradually declines in a predictable way over time. RUCO proposes to start at a decline rate pegged to historical system price decreases. Below is an illustration of the concept and the step downs RUCO proposes:

[29] 2016 TEP REST plan - E-01933A-15-0239

Capacity per Tranche	Price per Tranche
6.0	$0.110
6.8	$0.100
7.7	$0.090
8.5	$0.085
9.4	$0.080
10.3	$0.075
11.1	$0.070
12.0	$0.065
12.8	$0.060





A fixed rate for 20 years will avoid grandfathering issues and provide predicable financing for adopters. Systems taking service under the RES credit option would be on the customer side of the meter and receive a monthly bill credit monthly. This would prevent the rate design from impacting the economics of the installation and electrons produced by the system would serve local load of the customer.

The Commission and stakeholders would have the opportunity to recommend and adjust the terms in each annual REST plan. This would allow changes to the payment of future customers as well as accounting for possibly increasing payments based on system orientation or inverter capabilities. To participate in this rate option, customers must assign RECs to the Company.

Q. How would the RES Credit Option interface with the Advanced DG TOU rate?

A. Similar to the Upfront Incentive programs a few years ago, the RES credit rate will predictably decline as more solar capacity comes online. This would include capacity installed under the Advanced DG TOU rate and would contribute to capacity step downs despite not receiving the RES credit.

Q. What is RUCO's anticipated ratepayer acceptance of each of the DG rate options?

A. RUCO believes the most popular rate will be the RES Bill Credit Option, particularly early in the program due to the declining credit structure. During the time that RES Bill Credit Option remains the most popular, the industry can prepare for the Advanced DG TOU rate. With the credit rate beginning at $0.11/kWh this option is most similar to the current rate design. It is likely that some customers will immediately choose the Advanced DG TOU rate, particularly customers with more knowledge and tools to control peak load. The choice of rates allows the solar industry to mature rather than deal with a new defaulted rate. The solar industry will have the ability of developing business plans around the Advanced DG TOU rate that may be more advantageous than other proposed options.

The DG TOU Option creates a floor for the offset rate for DG customers. The Bill Credit Option will decline and approach the Advanced DG TOU rate as more customers take service under the RES Bill Credit Option. This is beneficial for the industry as it can begin to rely on the on-peak price signals provided by the

Advanced DG TOU rate. The All Rate options further supplement these offerings. The DG opt out adjustment levels the economic playing field between DG and standard rates while the Market Export Option would be popular among DG customers with small systems and large load. These options were designed to address the concerns of DG advocates who have insisted that DG customers "not be treated differently." The Market Export option provides exactly that.

Q. Please describe RUCO's view on grandfathering existing solar customers

A. RUCO believes there are several options to fairly grandfather DG customers. Customers that installed DG during the REST UFI program era should continue to be grandfathered at current rates, no questions asked. These customers were incentivized to install DG to ensure utilities met Renewable Energy Standard targets. Following the conclusion of the incentive program, customers were advised of possible changes that could affect their investment in DG. Despite these warnings, RUCO feels many customers did not fully understand the effect a rate design change could bring. Therefore, changes to these customers must be small and incremental and generally grandfathered up to the date of the UNS rate case decision. To ensure future customers are fully aware of the possible economic implications of tariff reform, new disclaimers must be crafted after the UNS decision to explain the choices and economics they may face should those polices be adopted in the TEP case.

Q. Does Grandfathering also impact TEP's residential utility owned rooftop program or TORS?

A. Yes it does. To explain, if the cost shift of existing NEM systems changes and the TEP owned systems become more expensive to non-participants, then TEP will have adjust downward the amount TEP recovers from ratepayers. I plan to address more on this topic in the next round of testimony once I receive answers to a pending data request.

Q. Any other issue you would like to address?

A. Yes, on my preliminary rate designs attached to this testimony. In designing the rates, I tried to keep the prices grounded to the economics of marginal supply side resources. Meaning, I try to send price signals not too much greater or less than comparably timed supply side resources. For example, my demand charges and peak rates are both within the range of the cost of a new combustion turbine peaker.

Q. Does this conclude your testimony?

A. Yes it does.

EXHIBIT LH-1

Lon Huber

928-380-5540
lhuber@strategen.com

EDUCATION

January 2010 – May 2011
Eller College of Management - University of Arizona
Masters of Business Administration (MBA)

August 2005 – May 2009
School of Government & Public Policy - University of Arizona
Bachelor of Science - Public Policy and Management

RELEVANT WORK EXPERIENCE

Strategen Consulting
Director –March 2015 to present

Arizona's Residential Utility Consumer Office (RUCO)
Special Projects Advisor and former consultant – April 2013 to March 2015

- Responsibilities: policy analysis and design, advocacy, case testimony, constituent outreach, and financial analysis.
    - Team lead on net metering, utility-owned rooftop solar, and new resource procurement policies.
    - Graduate of NARUC Rate Design School, 2014

Suntech America
Manager, Regional Policy – September 2011 to December 2012

- Point person for the company in every key state solar market except California.
    - Worked to balance cost effective utility-scale solar with state distributed generation policy goals.
    - Elected by SEIA member companies to be the state lead in Arizona.

TFS Solar
Government Affairs – September 2010 to September 2011

- Created a solar financing program for faith based organizations in Tucson.
- Instrumental in forming the Southern Arizona Solar Standards Board.
- Advocated for polcies in front of ACC.

Arizona Research Institute for Solar Energy at the University of Arizona
"Founding employee" and Policy Program Associate – August 2007 to September 2010

- Helped build the institute while gaining experience with the technical attributes and challenges of various energy technologies.

Lon Huber

928-380-5540

lhuber@strategen.com

Congressional Fellow – D.C.

January 2009 to May 2009

- Responsibilities included weekly memos to the Congress member on energy issues, forming energy related legislation (Solar Schools Act - H.R. 4967), and creating educational presentations on energy.

COMMUNITY INVOLVEMENT

- Appointed to the Arizona Governor's Solar Task Force, 2013
- Chairman - Southern Arizona Regional Solar Partnership at the Pima Association of Governments, 2011
- Founding Chairman - University of Arizona Green Fund, 2010 to 2011
- Member of UA President's Campus Sustainability Advisory Board, 2008 to 2011
- Big Brother for a child in special needs program - Tucson Big Brothers Big Sisters, 2006 to 2008

AWARDS AND HONORS

- *Arizona Daily Star's* "40 Under 40" winner for leadership, community impact, and professional accomplishment, 2011
- University of Arizona Honors College Young Alumni Award Winner, 2011
- Outstanding Professional Staff Member – University of Arizona, 2010
- Arizona Foundation Outstanding Senior Award for the Eller College of Management, 2009
- Honors College Pillars of Excellence Award, March 2009
- Congressional Recognition Award, May 2008

EXHIBIT LH-2

THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES RESOLUTION 2015-1

OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES

Whereas, the National Association of State Utility Consumer Advocates ("NASUCA") has a long-standing interest in issues and policies that ensure access to least-cost gas and electric utility services, which are basic necessities of life in modern society; and

Whereas, in recent years, gas and electric utilities have sought to substantially increase the percentage of revenues recovered through the portion of the bill known as the customer charge, which does not change in relation to a residential customer's usage of utility service, through proposals to increase the customer charge or through the imposition of what have been called Straight Fixed Variable or SFV rates; and

Whereas, these gas and electric utilities have sought to justify such increases by arguing that all utility delivery costs are "fixed" and do not vary with the volume of energy supply delivered to customers, and that reductions in customer usage due to conservation and energy efficiency increase the risk of non-recovery of utility costs; and

Whereas, based on these arguments, these gas and electric utilities have proposed that a greater percentage of utility costs (distribution costs such as electric transformers and poles and natural gas mains, traditionally recovered through volumetric rates) should be collected from customers through flat, monthly customer charges; and

Whereas, gas and electric utilities' own embedded cost of service studies,[1] in fact, show that a substantial portion of utility delivery service costs are usage-related, and therefore, subject to variation based on customer usage of utility service; and

Whereas, increasing the fixed, customer charge through the imposition of SFV rates or other high customer charge structures creates disproportionate impacts on low-volume consumers within a rate class, such that the lowest users of gas and electric service shoulder the highest percentage of rate increases, and the highest users of utility service experience lower-than-average rate increases, and even rate decreases,[2] in some instances; and

Whereas, nationally recognized utility rate design principles call for the structuring of delivery service rates that are equitable, fair and cost-based; and

Whereas, SFV and other high customer charge rate design proposals, in which low-use customers would see greater than average increases, while high-use customers would experience lower-than-average increases and even decreases in their total distribution bill, are unjust and inconsistent with sound rate design principles; and

Whereas, data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains,"[3] low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts;[4] and

Whereas, these data also show that in every reportable domain but one, elderly residential customers (65 years of age or older) use less electricity on average than the statewide residential average and less than their younger counterparts;[5] and

Whereas, these data also show that in a vast majority of reportable domains, minority (African American, Asian and Hispanic) utility customers on average use less electricity than the statewide residential average and less than their Caucasian counterparts;[6] and

Whereas, data from the U.S. Department of Energy's Residential Energy Consumption Survey for the Midwest Census region, show that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units,[7] thereby increasing the likelihood of higher gas utility usage, and that natural gas usage increases as income increases in the vast majority of reportable domains throughout the U.S;[8] and

Whereas, given these documented usage patterns, the imposition of high customer charge or SFV rates unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general; and

Whereas, because the imposition of high customer charge or SFV rates results in a smaller percentage of a customer's utility bill consisting of variable usage charges, customers' incentive to engage in conservation as well as federal and state energy efficiency programs is significantly reduced; and

Whereas, NASUCA supports the adoption of cost-effective energy efficiency programs as a means to reduce customer utility bills, help mitigate the need for new utility infrastructure, and provide important environmental benefits; and

Whereas, given that the imposition of high customer charge or SFV rates means that a smaller percentage of a customer's utility bill is derived from variable usage charges, the imposition of SFV-type rates reduces the ability of utility customers to manage and control the size of their utility bills;

Now, therefore, be it resolved, that NASUCA continues its long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers;

Be it further resolved, that NASUCA *opposes* proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills and the imposition of SFV rates;

Be it further resolved, that NASUCA urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States;

Be it further resolved, that state public service commissions should promote and adopt gas and electric rate design policy that minimizes monthly customer charges of residential gas and electric utility customers in order to ensure that delivery service rates are equitable, cost-based, least-cost, and encourage customer adoption of conservation and federal and state energy efficiency programs.

Be it further resolved that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution.

Submitted by Consumer Protection Committee

Approved June 9, 2015
Philadelphia, Pennsylvania

No Vote: Wyoming
Abstention: Vermont

---

[1]*See, e.g.,* Illinois Commerce Commission Docket No. 14-0244/0225, *Peoples Gas Light & Coke Co. – Proposed Increase in Delivery Service Rates,* PGL Ex. 14.2, p. 1, lines 8, 14, 38 and 42, col. D; Illinois Commerce Commission Docket No. 13-0384, *Commonwealth Edison Company,* AG Ex. 1.0 at 12-13, *citing* ComEd Ex. 3.01, Sch. 2A, p. 13, col. Tot. ICC, line 248.

[2]ICC Docket No. 14-0224/0225, AG Ex. AG/ELPC Ex. 3.0 at 15, 25.

[3]The U.S. Energy Information Administration's Residential Energy Consumption Survey provides detailed household energy usage and demographic data for 27 states or regions of the U.S. referred to as "reportable domains."

[4]*See* Wis. Pub. Serv. Com'n Docket No. 3270-UR-120, *Application of Madison Gas and Electric Co. for Authority to Adjust Electric and Natur4al Gas Rates,* Public Comments of John Howat, National Consumer Law Center, October 3, 2014, *citing* 2009 U.S. EIA Residential Energy Consumption Survey data by "Reportable Domain" at 5-6.

[5] *Id.* at 7-8.

[6] U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

[7] *See* ICC Docket No. 14-0224/0225, *North Shore Gas, Peoples Gas Light & Coke Company – Proposed Increase in Gas Rates,* AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

[8] U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

EXHIBIT LH-3

Default TOU for Full Requirements

Basic Monthly Service Charge	$11.50

Delivery (kWh)	Summer	Winter
On-Peak	0.18	0.10
Off-Peak	0.06	0.05

Base Power	Low	Medium	High
Tier Floor (kWh)	0	501	1001
Tier Ceiling (kWh)	500	1000	
Rate	0.02	0.03	0.045

Peak Hours	Summer	Winter
Peak Hour Start	3:00 PM	6:00 AM
Peak Hour End	7:00 PM	9:00 AM

Partial Requirements Volumetric TOU Rate

Basic Monthly Service Charge	$11.50
Solar Meter Fee	$6.00
Meter Fee if RECs are Exchanged	$3.00

Delivery (kWh)	Summer	Winter
On-Peak	0.18	0.10
Off-Peak	0.04	0.035

Base Power (kWh)	Low	Medium	High
Rate	0.036	0.036	0.036

Peak Hours	Summer	Winter	Winter
Peak Hour Start	2:00 PM	6:00 AM	6:00 PM
Peak Hour End	8:00 PM	9:00 AM	9:00 PM

Hourly Export Charge (kWh)	2 cents/kWh

Three Part Optional Rate

Basic Monthly Service Charge	$11.50
Meter Fee if no RECs are Exchanged	$3.00

Demand Charges	Summer	Winter	Summer Shoulder	Winter Shoulder	kW Break Point
Below Break Point	$4	$2	$0	$0	4.5
Above Break Point	$12	$4	$0	$0	

Delivery (kWh)	Summer	Winter
On-Peak	0.16	0.09
Off-Peak	0.03	0.02

Base Power (kWh)	Low	Medium	High
Rate	0.036	0.036	0.036

	Summer	Winter
Start Month	May	October
End Month	September	April

Peak Hours	Summer	Winter
Peak Hour Start	3:00 PM	6:00 AM
Peak Hour End	7:00 PM	9:00 AM

Advanced DG Rate

Minimum Bill	$11.50
Meter Fee if no RECs are Exchanged	$3.00

Demand Charges	Summer	Winter
$/kW	$16	$6

Delivery (kWh)	Summer	Winter
On-Peak	0.16	0.09
Off-Peak	0.03	0.02

Base Power (kWh)	Low	Medium	High
Rate	0.036	0.036	0.036

	Summer	Winter
Start Month	May	October
End Month	September	April

Peak Hours	Summer	Winter	Winter
Peak Hour Start	2:00 PM	6:00 AM	6:00 PM
Peak Hour End	8:00 PM	9:00 AM	9:00 PM

TUCSON ELECTRIC POWER COMPANY

DOCKET NOS. E-01933A-15-0322

DIRECT TESTIMONY

OF

FRANK RADIGAN

ON

RATE DESIGN

ON BEHALF OF THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 24, 2016

TABLE OF CONTENTS

EXHIBITS

INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services in electric, gas and water utility industry matters, and specializing in the fields of rates, planning and utility economics. My office address is 235 Lark Street, Albany, New York 12210.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes, on June 3, 2016 I submitted testimony on behalf of the Residential Utility Consumer Office ("RUCO") with respect to certain revenue requirement issues in this case. In this testimony I address other aspects of Tucson Electric Power Company's presentation ("TEP" or "the Company") with respect to revenue allocation and rate design. RUCO witness Lon Huber will also be submitting testimony with respect to rate design issues.

Q. WERE YOUR TESTIMONY AND EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were. I have two exhibits Exhibit_FWR-20 - Select Discovery Questions and Replies Relating to DG, and Exhibit_FWR-21 - RUCO Schedule H which contains schedules H1-H-4 inclusive.

SCOPE OF TESTIMONY

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been asked to review the revenue allocation of the rate increase amongst service classes, the proposed consolidation/elimination of many of the lifeline rate rates and the need for better, clearer and more thorough presentation of cost of service studies in future rate proceedings.

Q. HAVE YOU PREPARED AND EXHIBITS IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes, I have prepared one Exhibit, Exhibit_FWR-20 RUCO-Schedule H, which contains 28 pages that summarizes the revenue allocation, rates for all customers and bill impacts for residential customers.

SUMMARY OF TESTIMONY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. While TEP proposed revenue allocation does follow the general results of the embedded cost of service study, I believe the relative rates of return of the service classes could be better improved if one more closely followed the results of the cost of service study and use the following principles 1) the Lighting Class should be given the largest relative increase followed by the Residential Class with a slightly larger than average increase, 2) the General Service and Large Power Service Classes should get less than average increases, and 3) the Large General Service should get about an average increase.

For rate design, starting with the Residential Service Class, R-01, I kept the Basic Service Charge at $10 per month in accordance with the recommendation of Mr. Huber. For energy charges, I eliminated the fourth block, again according with the recommendation of Mr. Huber, and increased the rates for the first three blocks on an equal percentage basis to recover the remainder of the revenue requirement. For the other Residential Tariff Classes I applied the same methodology of keeping the basic service charge at current levels and apply the rate increase to existing rates.

For Lifeline rates, given the very large rate increase that the Company is proposing I do not support the Company's proposal to reduce the current 27 rate offerings down to 5. While I do not object to the Company's proposal for new customers where they will receive a fixed discount, the proposal for the existing customers is unacceptable from a customer impact point of view. I propose that the Company reconsider its proposal and 1) develop a new one where existing frozen classes remain as is, and 2) for non-frozen classes, redevelop a rate proposal that does not result in undue customer rate impacts.

As to the continued use of serving net metered customers through a rider, I propose that they become their own service class in the future. The Company makes compelling arguments as to how this class of customers is different than others and may be more costly to serve. That said, the Company reports that it does little to track these customers. Since roof top solar continues to grow as a resource, this continue will continue to grow and become more pronounced so setting the proper rates for these customer will become more important going forward. As such, I recommend that the utility start treating these customers as a separate class of customers and gather the appropriate cost and load data to track them for presentation in future cost of service studies. I also recommend that the Company improve its cost of service presentations generally so that parties can better understand the source data.

REVENUE ALLOCATION

Q. COULD YOU PLEASE DISCUSS THE ISSUEOF REVENUE ALLOCATION?

A. Revenue allocation is a two part exercise where the first step is to correct for any imbalances that exist between service classes in providing the utility an adequate rate of return and the second is to allocate the rate increase among service classes. In the first step, the results of the cost of service study are reviewed to determine how each service classification is doing with respect to providing the utility with the earned rate of return. If a service class is providing less than the average, in an ideal world, it should be given a greater than average increase to bring its earned rate of return up to the average. For example, if the utility is earning a 10% overall average rate of return and one particular service class is earning a 7% rate of return while another is earning a 13% rate of return, then the rate designed would give a higher than average increase to the first service class, in the example, and a lower than average increase to the second service class, in the example. Generally, a tolerance band, +/-10% or +/-15% is applied to determine what an acceptable rate of return is. The tolerance band is used to allow for the fact that any cost of service study is a snap shot in time and for inaccuracies in sample data and allocation methodologies. A review of relative rates of return from cost of service to study to cost of service study is also reviewed and used as a tool in determining how to allocate revenues between rate classes.

Q. WHAT HAS THE COMPANY PROPOSED IN THIS CASE?

A. Company witness Craig Jones sponsors the cost of service and revenue allocation in this case. As Mr. Jones summarizes TEP's position in his testimony

> "TEP is proposing the necessary steps to improve its price signals and to transition over time to more appropriate rate design. Thus, our proposal uses: (1) the results of the embedded cost study to provide important guidance for the class allocation of revenues; and (2) the embedded cost study and the marginal cost study to determine the level of specific charges that taken together create just and reasonable rates." (Jones Direct at page 12)

The results of the embedded cost of service study and Mr. Jones proposed revenue allocation of the requested rate increase as taken from Schedule G is shown below.

	ECOS Rate of Return	Relative Rate of Return	TEP Allocation of Base Rate Increase	% Increase	Relative to Total
Residentail	-1.93%	-0.35	$ 65,402,412	15.9%	0.88
General Service	22.40%	4.06	$ 8,019,784	4.3%	0.24
Large General Service	6.47%	1.17	$ 38,006,508	55.5%	3.07
Large Power Service	12.72%	2.30	$ 1,466,326	2.0%	0.11
Lighting	-13.61%	-2.47	$ 1,245,909	37.8%	2.09
Total	5.52%	1.00	$ 109,534,118	18.1%	1.00

Q. COULD YOU PLEASE COMMENT ON TEP'S PROPOSAL?

A. Yes. Generally, TEP proposal does follow the general results of the embedded cost of service study in that it gives lower than average rate increase to the General Service and Large Power Service Classes and an above average increase to the Lighting Class. It also gives a disproportionate increase to the Large General Service Class even though this class is earning an above average rate of return. I believe the relative rates of return of the service classes could be better improved if one more closely followed the results of the cost of service study and use the following principles; 1) the Lighting Class should be given the largest relative increase followed by the Residential Class with a slightly larger than average increase, 2) the General Service and Large Power Service Classes should get less than average increases, and 3) the Large General Service should get about an average increase. My proposed revenue allocation using RUCO recommended rate increase is shown below.

	RUCO Allocation	% Increase	Relative to Total
Residentail	$ 11,780,417	2.9%	1.60
General Service	$ 1,844,489	0.7%	0.39
Large General Service	$ 2,053,817	1.8%	1.03
Large Power Service	$ 733,028	0.5%	0.30
Lighting	$ 140,858	3.0%	1.66
Total	$ 16,542,000	1.8%	1.00

RATE DESIGN

Q. COULD PLEASE DISCUSS YOUR ISSUES WITH RESPECT TO RATE DESIGN?

A. Yes, starting with the Residential Service Class, R-01, I kept the Basic Service Charge at $10 per month in accordance with the recommendation of Mr. Huber. For energy charges, I eliminated the fourth block, again according with the recommendation of Mr. Huber, and increased the rates for the first three blocks on an equal percentage basis to recover the remainder of the revenue requirement. For the other Residential Tariff Classes, I applied the same methodology of keeping the basic service charge at current levels and apply the rate increase to existing rates.

Q. WHAT IS YOUR RECOMMENDED RATE DESIGN FOR THE LIFELINE RATES?

A. As described by Company witness Jones, the Company is proposing major changes to its low income rates which are referred to as Lifeline rates. The Company proposes to change the current rates that give either a fixed discount or discounts from the otherwise applicable rates to a single uniform discount off of each of the residential rates (Jones Direct at 57). The modifications would reduce the 27 existing tariffs down to five different open rate options, one for each of the five existing residential rates, and apply a flat $15.00 per month discount, limited to a reduction of the bill down to zero dollars (Ibid). The Company is also proposing changes to its frozen Lifeline rate options that will reduce them from 22 to five different options (Jones Direct at 58).

Q. WHAT IS THE COMPANY'S REASONING BEHIND THESE CHANGES?

A. As explained by Company Witness Jones, the 27 different variations of Lifeline discounts differ by consumption in any given month and also apply to Bright Community Solar customers, net metering customers and even Super Peak TOU customers (Ibid). He argues then that it has become overly burdensome to train customer service representatives to explain the variations, maintain the multiple tariffs needed to explain the variations and maintain and update the processes in the billing system. He also states that 11 of the 27 different Lifeline rates contain fewer than 20 customers, and two of the rates being maintained have just one customer on them.

Q. WHAT IS THE QUALITATIVE IMPACT OF THE PROPOSED CHANGE?

A. As explained by Company Witness Jones, all existing Lifeline customers on rates "that are not frozen" will stay on the fixed credit version of the Lifeline rate that they are currently on but rate increases will apply so that most typical Lifeline customers will experience a total dollar increase on an annual basis that is in a range similar to the dollar increase for a non-Lifeline residential customer (Jones Direct at 59). Customers on "the old frozen rates" will have the same fixed discount available to them as the open Lifeline rates, but the frozen Lifeline customers will have a lower basic service charge of $12.00 per month since they were receiving substantially larger discounts (Ibid)

Any new customer qualifying for the Lifeline program (or existing Lifeline customer moving to a new location) will become a standard residential customer and pay a non-Lifeline residential rate with a flat $15.00 per month discount applied to the bill, with the discount limited to no more than the actual bill in order to prevent a bill from being below zero (Ibid).

Q. WHAT IS THE QUANTITATIVE IMPACT OF THE COMPANY'S PROPOSAL?

A. The table below is taken from Schedule H which is Schedule H 2-2 which summarizes the rate impact by the individual rate schedules from the Company's proposal. As one can see the quantitative impact of the Company's proposal results in rate impacts that can increase a customer's bill by as much as 50%.

	Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue		Proposed Revenues		Proposed Increase to Test		Proposed Increase to	
Rate Description	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
Lifeline Rate Schedules											
TE4-01	187,990	89,256	(23,299)	175,417	78,529	197,746	78,529	(970)	-0.35%	22,328	8.79%
TE4-21	1,612	1,028	(57)	1,567	1,016	2,372	1,016	748	28.34%	805	31.15%
TE4-70	3,139	1,644	(76)	3,077	1,629	4,143	1,629	989	20.68%	1,066	22.64%
TE5-01	571,226	277,370	(46,143)	547,423	255,030	613,101	255,030	19,535	2.30%	65,678	8.18%
TE5-21	1,242	807	(856)	738	455	1,057	455	(537)	-26.23%	319	26.74%
TE5-70	5,466	2,786	(786)	5,162	2,304	6,226	2,304	278	3.37%	1,064	14.26%
TE6-01	3,730,879	1,828,957	(803,104)	3,203,498	1,553,234	3,690,634	1,553,234	(315,967)	-5.68%	487,137	10.24%
TE6-21	12,269	7,969	(2,560)	10,790	6,887	16,656	6,887	3,306	16.33%	5,866	33.18%
TE6-70	43,687	23,012	(15,364)	34,101	17,235	43,346	17,235	(6,119)	-9.17%	9,245	18.01%
TE6-201A	169,675	102,562	(47,539)	149,713	74,985	210,290	74,985	13,037	4.79%	60,576	26.96%
TE6-201B	2,038	1,298	(571)	1,840	926	3,005	926	595	17.83%	1,165	42.14%
TE8-01	386,096	196,771	(49,567)	329,967	203,333	468,115	203,333	88,582	15.20%	138,148	25.90%
TE8-21	4,771	3,238	613	4,722	3,898	9,061	3,898	4,951	61.83%	4,338	50.32%
TE8-70	9,942	5,317	(670)	8,887	5,702	14,437	5,702	4,880	31.98%	5,550	38.04%
TE8-201A	7,659	4,895	(2,503)	6,028	4,023	10,975	4,023	2,444	19.47%	4,947	49.22%
TE6-01BC	9,626	4,699	(2,038)	8,290	3,997	9,566	3,997	(762)	-5.32%	1,276	10.39%
TE-R-01LL	2,674,986	1,311,018	862,874	3,316,275	1,532,603	4,281,775	1,532,603	1,828,373	45.87%	965,500	19.91%
TE-R01LB	8,347	4,190	1,367	9,438	4,466	11,808	4,466	3,738	29.81%	2,370	17.05%
TE-201AL	74,180	40,970	31,728	102,638	44,240	140,855	44,240	69,945	60.74%	38,217	26.02%
TE-201BL	1,323	877	1,975	2,746	1,429	4,753	1,429	3,982	180.98%	2,007	48.06%
TE-R80LL	35,808	19,187	5,372	40,408	19,959	60,378	19,959	25,342	46.08%	19,970	33.08%
TE-R8LL	707	334	(21)	674	346	926	346	231	22.15%	252	24.66%

Q. COULD YOU PLEASE COMMENT ON THE COMPANY'S PROPOSAL?

A. Given the very large rate increase that the Company is proposing, I do not support the Company's proposal as presented. While I do not object to the Company's proposal for new customers, where they will receive a fixed discount, the proposal for the existing customers is unacceptable from a customer impact point of view. Moreover, the Company's proposal is not supported by the facts as presented. Many of these existing rates receive either a fixed discount in dollars or a discount as a percentage. As these are existing in the current billing program there is little administration to them. In addition, many of these rates are frozen, 22 of them, and don't even apply to new customers. The fact that the Company states that 11 of the 27 rate schedules have less than 20 customers on them so the question must be asked as to why even bother going to so much effort for so few. Also, the Company states it is making its proposal to reduce its administrative workload but I can find no evidence that it has proposed a pro-forma adjustment to share that savings with customers. In sum therefore, I propose that the Company reconsider its proposal and develop a new one where existing frozen classes remain as is, and for non-frozen classes redevelop a rate proposal that does not result in undue customer rate impacts.

Q. PLEASE DISCUSS YOUR PROPOSAL FOR THE NON-RESIDENTIAL RATE CLASSES.

A. For non-demand metered rates classes, General Service and Lighting, I kept the basic service charge at current rates and then increased the per unit charges on an equal percentage basis to recover the proposed rate increase. Keeping the basic service charge at current rates for the General Service class is consistent with Mr. Huber's reasoning for the Residential Class. The basic service charge for the Lighting Class is zero and the Company proposed to keep it at zero and I agree.

For the demand metered classes, Large General Service and Large Power Services, because of the small rate increases being recommended - both because of RUCO's proposed rate increase and the recommended revenue allocation - I kept the energy rates unchanged and changed the demand charge to recover the remaining revenue share. In both cases this resulted in a decrease in the existing demand charge because the Company is proposing to move a substantial amount of sales from the unmetered General Service class to the Large General Service Class and eliminate the non-TOU Large Power Service Class. The TOU Large Power Service Class has a higher energy charge and basic service charge than the non-TOU which resulted in an increase in Class revenues that offset the need for a rate increase in base rate.

FUTURE COST OF SERVICE STUDIES

Q. COULD YOU PLEASE DISCUSS THE ISSUE OF FUTURE COST OF SERVICE STUDIES?

A. As explained by Company Witness Dukes the Company proposes to create a new Rider R-1, post June 1, 2015, where partial requirement customers qualifying for the new Rider R-15 to choose from either a non-TOU or TOU three-part rate tariffs which includes a demand charge for their service requirement (Dukes direct at 8 and 27). As Mr. Dukes explains TEP is making these proposals to better align rate design with cost-causation and to reduce inter-class inequities (Dukes Direct at 7).

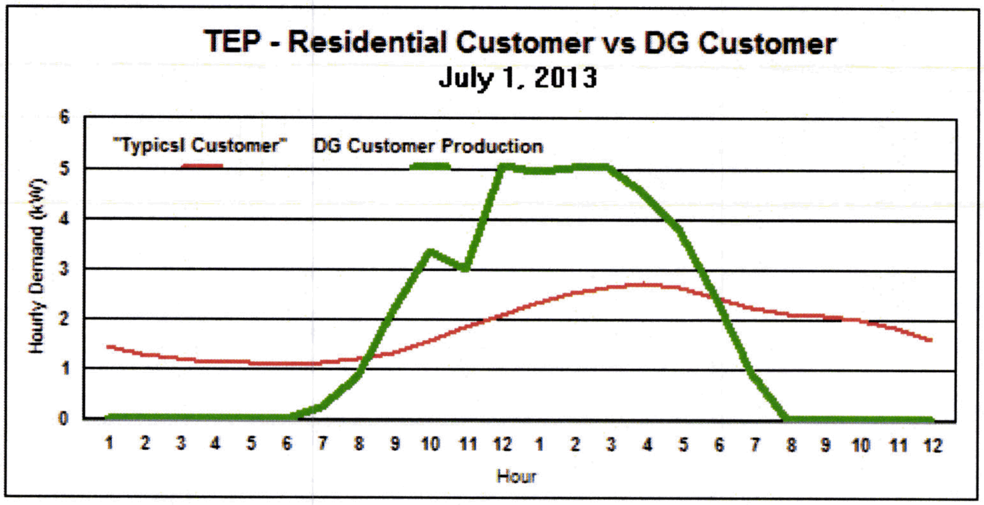
In addition to the rate design changes being proposed Company Witness Jones states that traditional rate classes are no longer homogeneous and the availability of self-generation (particularly solar distributed generation) has created a second class of customers within the typical residential service class (Jones Direct at 15). Mr. Jones further states that partial requirements customers require various utility services, including standby service, supplemental service, delivery service for both in-bound and out-bound power flow, regulation services, power factor correction and balancing (Ibid). For distribution services, the cost of serving these partial requirements customers is typically the same or higher than it was when the customer was a full service customer because the DG customer may require additional investments in the distribution system to provide frequency control and power factor correction (Ibid).

Q. PLEASE COMMENT.

A. My understanding is that there are currently over 11,000 of these customers whose distributed generation supplies over 170 MW of power. The number of new applicants for roof-top solar has been generally consistent at 300 applications per month. Thus, the issue of DG and its impact of cost and cost inequities between different types of customers will continue to grow and perhaps become more pronounced. If a cost inequity does exist then the partial requirements customers are being subsidized by other customers and the amount of cross subsidization will only grow over time. As such, both partial requirements customers and full service customers should know the true cost to serve a partial requirements customer, so the appropriate rate and rate structure can be designed to fairly serve them, the utility, and other customers on the system.

The Company's presentation points to the many ways that DG customers may increase the cost on the system. Both Staff and RUCO sent out a series of discovery questions to verify the validity of the claims, discovery questions and replies attached as Exhibit_-(FWR-20) Select Discovery Questions and Replies Relating to DG. Some of the costs are still in the academic/theoretical cost category but others are not. For example, the Company has a pilot experiment for installation of advanced inverters to control PV generation at the source (See STF 1.22). If this pilot is successful, this service will be a unique cost directly attributable to DG. Company witness Tilghman points outs increased cost for load following and frequency regulation (Tilghman Direct at 8). This is a true cost but at current levels this concern seems to be for larger utility scale renewables rather than a customer with a roof-top solar unit (See RUCO3-17). With 170 MW of DG and growing by the Company's next rate case, this might grow to be a real operational concern and costs. As the saturation of DG becomes more pronounced the instances of reverse power flow conditions will increase. This will require more monitoring of load at the feeder level which is not generally done today (See RUCO 3.14-3.16).

The graph below shows some load data that I received from the Company in response to RUCO 7.11. The graph shows the average demand for a sample of almost 3,000 residential customers and the production curve for a typical roof top solar customer at the average size of applications received between January 2015 and April 2015 (See Tilghman Direct at 6:2). TEP usually experiences peaks between 5 and 7 pm so the demands placed on the system for these two types of customers are quite different. If the peak demand is at 5 pm and there are no clouds, then the DG customer is responsible for less demand on the Company's system (though the DG customer is still reliant on other grid services hidden within the bundled kWh rate). On the other hand, if the peak occurs at 7 pm, then the DG customer is placing demands on the system just like any other customer, while not necessarily covering the system costs due to a credit build up from non-peak hours. While I am not testifying that these two load shapes are 100% accurate, given the amount of data provided, I do think it illustrates the fact that a DG customer is not the same as a typical residential customer and they should not be treated the same for rate making purposes.



In my direct testimony in this case I presented a discovery response which shows that the utility does little to track partial requirement customers load shapes or usage patterns (See Exhibit FWR-11). Moreover, the Company could not produce a typical load curve for a year round residential customer but instead supplied a spreadsheet with hourly load date for a sample of over 1,600 customers. This data is relatively useless as it provides no statistically reliable data to measure load by usage. To be reliable, a stratification of customers by monthly usage must be developed, a statically significant sample would then have to be selected for each strata and hourly load data collected and then extrapolated to get a meaningful typical load pattern for a customer type. As it is, one cannot verify that the peak demand, as reported by the Company and used as an input into its cost of service study, is anywhere near accurate. I am not saying that the utility is wrong, but I am saying that the Company's presentation leaves a lot to be desired for the typical residential customer. As to the partial requirements customer, the lack of presentation provides little basis to support the price signals a 24/7 demand charge would send. This is in stark contrast to the demand charge RUCO witness Lon Huber proposes, which is grounded by system peak demand statistics. As the utility notes, the cost to serve partial requirements customers is higher than traditional full service requirements customers. Yet until the Company provides a more detailed statistical presentation, it will be hard to address the issue on highly precise terms. As such, unless the utility starts collecting and tracking detailed data by customer type, we can only make broad, but still highly justified reforms to rate design. .

Q. DOES THIS CONCLUDE YOUR RATE DESIGN TESITMONY?

A. Yes, it does.

EXHIBIT FWR-1

FRANK W. RADIGAN

EDUCATION

B.S., Chemical Engineering -- Clarkson University, Potsdam, New York (1981)

Certificate in Regulatory Economics -- State University of New York at Albany (1990)

SUMMARY OF PROFESSIONAL EXPERIENCE

1998–Present **Principal, Hudson River Energy Group, Albany, NY --** Provide research, technical evaluation, due diligence, reporting, and expert witness testimony on electric, steam, gas and water utilities. Provide expertise in electric supply planning, economics, regulation, wholesale supply and industry restructuring issues. Perform analysis of rate adequacy, rate unbundling, cost-of-service studies, rate design, rate structure and multi-year rate agreements. Perform depreciation studies, conservation studies and proposes feasible conservation programs.

1997–1998 **Manager Energy Planning, Louis Berger & Associates, Albany, NY –** Advised clients on rate setting, rate design, rate unbundling and performance based ratemaking. Served a wide variety of clients in dealing with complexities of deregulation and restructuring, including OATT pricing, resource adequacy, asset valuation in divestiture auctions, transmission planning policies and power supply.

1981–1997 **Senior Valuation Engineer, New York State Public Service Commission, Albany, NY –** Starting as a Junior Engineer and working progressively through the ranks, served on the Staff of the New York State Department of Public Service in the Rates and System Planning Sections of the Power Division and in the Rates Section of the Gas and Water Division. Responsibilities included the analysis of rates, rate design and tariffs of electric, gas, water and steam utilities in the State and performing embedded and marginal cost of service studies. Before leaving the Commission, was responsible for directing all engineering staff during major rate proceedings.

FIELDS OF SPECIALIZATION

Electric power restructuring, wholesale and retail wheeling rates, analysis of load pockets and market power, divestiture, generation planning, power supply agreements and expert witness testimony, retail access, cost of service studies, rate unbundling, rate design and depreciation studies.

PROJECT HIGHLIGHTS

Wholesale Commodity Markets

Transmission Expansion Planning – Various Utilities -- Member of Transmission Expansion Advisory Committee in the New England Power Pool – the Committee is charged with the study of transmission expansion needs in the deregulated New England electric market. Ongoing

Locational Based Pricing – Reading Municipal Light Department -- Using GE multi-area production simulation model (MAPS), analyzed New England wholesale power market to cost differences between various generators and load centers. 2003

Merchant Plant Analysis – Confidential client – Using GE multi-area production simulation model (MAPS), analyzed New York City wholesale power market to determine economics of restructuring PURPA era contract to market priced contract. 2002

Market Price Forecasting – El Paso Merchant Energy – Analyzed New England power market using MAPS for purpose of pricing natural gas supply in order to ensure that plant was dispatched at 70% capacity factor as required under its gas supply contract. 2002

Market Price Analysis – Novo Windpower – Analyzed hourly market price data in New York for each load zone in State in order to optimize location of new wind power projects. 2002

Gas Aggregation – Village of Ilion – Advised client on costs/benefits of aggregating residential gas customers for purpose of gas purchasing. 2002

Gas Procurement – Albany County, New York – Assisted client in analysis of economics of existing gas purchase contract; negotiated termination of contract; designing request for proposal for new natural gas supply. 2000

HQ Prudence Review – Selected by Vermont Public Service Board to perform prudence review power supply contract between Hydro Quebec and Central Vermont Public Service Corporation. 1998

Wholesale Power Supply – Prepared comprehensive RFP to optimize power supply for Solvay municipal utility by complementing existing low cost power supplies in order to entice new industrial load to locate within Village. 1997

Analysis of Load Pockets and Market Power – Performed analysis of load pockets and market power in New York State; determined physical and financial measures that could mitigate market power. 1996

Study of IPP Contracts and Impacts in New York Performed study to determine rate impacts of power purchase contracts entered into by investor owned utilities and independent power producers (IPPs); separately measured rate impacts resulting from statewide excess-capacity; determined level of non-optimal reserves for each utility. 1995

Power Purchase Contract Policies and Procedures – Directed NYSPSC Staff teams in formulation of short- and long-run avoided cost estimates (LRACs) using production simulation model (PROMOD); forecasted load and capacity requirements; developed utility buy-back rates; presented expert witness testimony on buy-back rate estimates and calculation methodologies, thereby implementing curtailment of IPPs as allowed under PURPA. 1990-1994

Integrated Resource Planning - Led NYSPSC Staff team's examination of each utility's IRP process and examination of impacts of processes and regulatory policies influencing the decision making process. 1994

Intrastate Wheeling Commission Transmission Analysis and Assessment – Chairman of NYSPSC Proceeding to examine plans for meeting future electricity needs in New York State. Addressed measures for estimating and allocating costs of wheeling, including embedded cost, short-run marginal cost and long run incremental cost methods. 1990

Rate Setting

Rate Setting – Dover Plains Water Company – Case 14-W-0378 -- Prepared rate filing before the New York Public Service Commission for the Dover Plains Water Company to increase its annual water revenues. 2014

Rate Setting – Village of Castile – Case No. 14-E-0358 – Prepared rate filing before the New York Public Service Commission for the Village of Castile Electric Department to increase its annual electric revenues. 2014

Depreciation Study – Village of Swanton – On behalf of the Village of Swanton, Vt. Electric Department prepared a depreciation study for use in setting new depreciation rates to be submitted to the Vermont Public Service Board. 2014

Rate Setting – Village of Hamilton – Case 13-G-0584 – On behalf of the Village of Hamilton, NY designed initial rates for new municipal gas utility. 2013

Rate Setting – Fillmore Gas Company - Case No. 13-G-0039 - Prepared rate filing before the New York Public Service Commission for the Fillmore Gas Company to increase its annual gas revenues. 2013

Rate Setting – Alliance Energy - Case No. 12-G-0256 - Prepared rate filing before the New York Public Service Commission for the Alliance Energy Transmission, LLC to increase its annual gas transportation. 2012

Rate Study – Atmos Energy – Docket No. 11-UN-184 – On behalf of the Mississippi Public Service Commission, submitted report on reasonableness of Company's depreciation study. 2012

Rate Study – Entergy Mississippi –Docket No. 11-UA-83 -- On behalf of the Mississippi Public Service Commission, prepared report on the reasonableness of Entergy Mississippi's depreciation study. 2012

Rate Case Cost of Service Study – Mississippi Power Company – On behalf of the Mississippi Public Service Commission, prepared report on reasonableness of embedded cost of service study submitted by Mississippi Power Co. 2012

Rate Case Cost of Service Study – Boonville, NY – Prepared class load study and embedded cost of service study to justify change in rate design for the purpose of conserving energy. 2010-2012

Rate Setting – Alliance Energy Transmission - Case No. 12-G-0256 – Prepared rate filing before the New York Public Service Commission for Alliance Energy Transmission. 2012

Rate Setting – Hamilton, NY - Case No. 12-E-0286 - Prepared rate filing before the New York Public Service Commission for the Village of Hamilton, NY to increase its annual electric revenues. 2012

Rate Setting – Fairport, NY – Case No. 11-E-0357 - Prepared rate filing before the New York Public Service Commission for the Village of Fairport, NY to increase its annual electric revenues. 2011

Jurisdictional Cost of Service – Mississippi Power Company – On behalf of the Staff of the Mississippi Public Utilities Staff prepared a report on the reasonableness of the Company's jurisdictional cost of service study. 2010

Rate Analysis – Southwestern Power Company – On behalf of a coalition of retail customers analyzed reasonableness of utility's request to include the costs of Construction Work In Progress Expenditures in rates for a power plant known as the Turk Plant. 2010

Rate Study – Stowe Electric Department, VT – Docket No. 8169 – For small municipal electric utility, filed rate case before the Vermont Public Service Board. 2010

Docket No. 10-10-03 – Assisted in the CT OCC's review and development of recommendations for the Review of the 2011 Conservation and Load Management Plan. 2010

Rate Setting – Endicott, NY - Case No. 10-E-0588 – Prepared rate filing before the New York Public Service Commission for the Village of Endicott, NY to increase its annual electric revenues. 2010

Rate Case Cost of Service Study – Heritage Hills Water Works – For small water company, performing cost of service study for the preparation of a full cost of service study before the New York Public Service Commission. 2009

Rate Case Cost of Service Study – Stowe Electric Department, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the Vermont Public Service Board. 2009

Rate Setting Training – MMWEC – Assisted in training MMWEC staff on rate setting process so that they could provide service to members. 2009

Rate Setting – Connecticut Natural Gas -- Docket No. 08-12-06 - Assisted the Connecticut Office of Consumer Counsel on the analysis of the reasonableness of the of the Company's proposed revenue requirement. 2009

Rate Filing – Heritage Hills Water Works – Case No. 08-W-1201 – Prepared rate filing before the New York PSC for the Heritage Hills Water Works Corporation to increase its annual water revenues. 2008

Rate Study – Hudson River Black River Regulating District -- For regulating body performed detailed cost of service allocation in order to allocate costs among beneficiaries of water regulation. 2008

Rate Case Cost of Service Study – Village of Greene, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Bath, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Rate Case Cost of Service Study – Village of Richmondville, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2008

Economic Development Rate – Massena Electric Department – For municipal electric utility, developed tariffs for economic development rates for new or expanded load.

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Study – Pascoag Utility District – Reviewed the application of the Power Authority of the State of New York to increase rates to its wholesale power customers. 2003

Rate Study - Kennebunk Power and Light Department – Performed rate study of new multi-year wholesale power contract against existing rates to determine impact on overall revenue recovery and cash flows of utility. 2003

Rate Case Cost of Service Study – Village of Arcade, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Philadelphia, NY – For small municipal electric utility, assisted in the preparation full cost of service study before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Village of Hamilton, NY – For small municipal electric utility, prepared full cost of service study before the New York Public Service Commission. 2004

Rate Case Cost of Service Study – Fillmore Gas Company – For small natural gas local distribution company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Rate Case Cost of Service Study – Rowlands Hollow Water Works – For small water company, performing cost of service study for internal budget controls and formal rate case before the New York Public Service Commission. 2003

Standby Rates – Independent Power Producers of New York – Analyzed reasonableness of proposed standby rates of Niagara Mohawk Power Corporation; proposed alternate rate designs; participated in settlement negotiations for new rates. 2002

Economic Development Rates – Pascoag Utility District – Designed new cost based economic development rates charged to large industrial customer contemplating locating within the municipality. 2002

Municipalization Study – Kennebunk Power and Light Department – Performed economic analysis of municipal utility serving remaining portions of Village not already served; performed valuation of the plant currently owned by Central Maine Power. 2001

Water Rate Study – Pascoag Utility District – Performed cost of service study for water utility; presented alternate methods of funding revenue requirement. 2001

Pole Attachment Rates – Middleborough Gas and Electric Department – Designed cost based pole attachment rates charged to CATV customers. 2000

ISO Service Tariff -- On behalf of three municipal utilities, analyzed cost basis and proposed rate design of ISO Service Tariffs. 2000

Pole Attachment Rates – City of Farmington, New Mexico municipal electric department – Designed cost based pole attachment rates for CATV customers. 1999

OATT Rates – On behalf of four municipal utilities in New England – Developed cost based annual revenue requirements for regional network transmission rates; represent utilities before ISO New England committees on transmission rate setting issues. 1998-2004

Consolidated Edison Restructuring – Member NYPSC Staff team – Negotiated major restructuring settlement with Consolidated Edison, which decreased utility's rates by $700 million over five years; implemented retail access program; performed rate unbundling; divestiture of utility generation and the allowance of the formation of a holding company; accelerated depreciation of generation; established customer education programs on restructuring; established service quality and service reliability incentive to ensure that provision of electric service will diminish as competitive market emerges. The agreement served as the template for restructuring in New York. 1997

Cost-of-service Review and Rate Unbundling – Performed rate unbundling of retail rates of Orange & Rockland Utilities, Inc. to facilitate delivery of New York Power Authority energy to customer located in Orange & Rockland's service territory. 1992

Vintage Year Salvage and Study - Managed joint study of staff from Rochester Gas and Electric Corporation and NYSPSC to determine feasibility of using vintage year salvage accounting for determining future salvage rates. 1985

Environmental Issues

Energy Conservation Study – Pascoag Utility District – Designed energy conservation rebate program based on cost benefit study of various alternatives. Program funded through State mandated collection of energy conservation monies from ratepayers. 2002

Clean Air Act Lawsuit – New York State Attorney General – Investigated modifications made at coal fired generating units of New York utilities to determine whether major modifications were made with obtaining pre-construction permits as required by the prevention of Significant Deterioration (PSD) provisions of the Act. 1999-2002.

Environmental Impact Study and Simulation Modeling Analysis – Analyzed potential environmental impacts of restructuring electric industry in NY using production simulation model PROMOD. 1996

Renewable Resources – Project Leader in NYSPSC proceeding regarding development and implementation of utility plans to promote use of renewable resources. 1995

Environmental and Economic Impacts Study – Directed study of pool-wide power plant dispatch with environmental adders to determine environmental and economic effects of dispatching electric power plants with monetized environmental adders. 1994

Clean Air Impact Study – Directed study of effects of the Clean Air Act of 1990. Measured statewide cost savings if catalytic reductions control facilities were elected to comply with 1990 Clean Air Act Amendments; installed components on units in metropolitan NY region. 1994

Environmental Externalities and Socioeconomic Impacts Study – Managed NYSPSC proceeding to determine whether to incorporate environmental costs into Long-Run Avoided Costs for the State's electric utilities. Study purposes: explore the socioeconomic impacts of electric production as compared with DSM; monetize environmental impacts of electricity. 1993

EXPERT WITNESS TESTIMONY

Case 9344 – Green Ridge Utilities – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2014

FC 1115 – Washington Gas Light -- On behalf of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's proposal for the recovery of costs and funding aspects of Washington Gas Light Company's Revised Accelerated Pipe Replacement Plan. 2014

Case No. EC-123-0082-00 – Entergy Mississippi – On behalf of Mississippi Public Utilities Staff reviewed and testified on the reasonableness of Entergy Mississippi, Inc.'s proposed depreciation rates and cost of service study. 2014

Case 9345 – Maryland Water Services – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2014

Case No. 2013-00167 – Columbia Gas of Kentucky – On behalf of the Office of Rate Intervention of the Attorney General for the Commonwealth of Kentucky testified on the reasonableness of the Company proposed rate increase. 2013

Docket 13-G-1301 – Consolidated Edison – On behalf of US Power Generating Company testified on the reasonableness of proposed modifications to natural gas balancing services. 2013

Docket No. 13-01-09 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2013

Case U-17169 - Semco Energy - On behalf of the Michigan Department of Attorney General testified on the reasonableness of the Company's proposal to modify its accelerated main replacement form for gas distribution facilities. 2013

Docket No. 13-06003 – Sierra Power Company - On behalf of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed depreciation rates. 2013.

Docket No. E-01 933A-I 2-0291 – Tucson Electric Power -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's rate increase. 2012

Case No. FC 1093 - Washington Gas and Light – On behalf of the People's Counsel of the District of Columbia, testified on the reasonableness of the Company's proposal to replace and/or remediate certain gas distribution facilities that are subject of this case, 2012.

Docket No. C-2011-2226096 — Pennsylvania American Water Co. - In a class-action lawsuit, testified before the PA PUC on behalf of C. Leslie Pettko on the reasonableness of the surcharges imposed by Pennsylvania American Water Company. 2012

Docket No. 11-06007 – Nevada Power Company – On behalf of the Nevada Public Service Commission, testified on the reasonableness of the Company electric depreciation study on Nevada Power Co. 2011

MEUA –On behalf of the Municipal Electric Utilities Association, filed testimony with the New York Power Authority (NYPA) on the reasonableness of the Authority's 2011 Rate Modification Plan for the Niagara Power Project. 2011

Case No. 9283 – Green Ridge Utilities, Inc. – On behalf of Maryland Office of People's Counsel testified on the reasonableness of the water utility's proposed revenue requirement. 2011

Case No. 11-G-0280 – Corning Natural Gas -- On behalf of the Village of Bath, NY, analyzed the construction program, revenue requirement, and rate design proposed by the gas distribution company serving the Village. 2011

Case No. 10-G-0598 – Bath Electric Gas and Water Systems - Testified as to the reasonableness of the Village of Bath's request for a refund relating to overcharges for gas purchased from the Corning Natural Gas Co. 2011

Case No. U-16472 – Detroit Edison -- On behalf of four large hospitals – Detroit Medical Center, Henry Ford Health Systems, William Beaumont Hospital, and Trinity Health Michigan – testified on the reasonableness of the continuation of a service class for large customers with special contracts. 2011

Case No. 9252 – Artesian Water Maryland, Inc. - On behalf of the Maryland Office of People's Counsel, analyzed proposed revenue requirement of Artesian Water Maryland, Inc. 2011.

Case No. 10-E-0362 – Orange and Rockland Utilities, Inc. - On behalf of a coalition of municipalities, testified on the reasonableness of the proposed revenue requirement of Company. 2010.

Docket No. 05-10-RE04 – Connecticut Light and Power Co. – On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the assist in its review of the application of Company for approval of full deployment of its Advance Metering Infrastructure ("AMI"). 2010

Docket Nos. 10-06003 and 10-06004 – Sierra Power Company - On behalf of the Nevada Public Service Commission, testified on the reasonableness of Company's proposed depreciation rates. 2010.

Case No. 10-E-0050 – Niagara Mohawk Power Corporation -- On behalf of a coalition of municipalities, testified on the reasonableness of utility's proposal to eliminate contracts to provide street lighting service. 2010

Case No. 9248 – Maryland Water Services - On behalf of the Maryland Office of the People's Counsel, testified on the reasonableness of the proposed revenue requirement of Maryland Water Services, Inc. 2011

Docket No. 10-12-02 – Yankee Gas Services Company -- On behalf of the Connecticut Office of Consumer Counsel, testified on the reasonableness of the Company's proposed depreciation rates. 2010

Case 09-E-0715 – New York State Electric and Gas Corporation -- On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed construction program, revenue allocation, rate design and decoupling mechanism. 2010

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of a Report Regarding Steam Price Elasticity and Long Term Steam Revenue Requirement Forecast 2010

Docket No. 09-01299 – Utilities, Inc. of Central Nevada - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the appropriate level of rate case expense, and allocation of corporate salaries. 2010

Docket No. 09-12-11 – Connecticut Water Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed Water Conservation Adjustment Mechanism. 2010

Case 9217 – Potomac Electric Power Company – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed jurisdictional cost of service study, revenue allocation and rate design. 2010

Docket No. 09-12-05 – Connecticut Light & Power Company – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the proposed depreciation rates, revenue allocation and rate design. 2010

Case 09-S-0794 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 09-G-0795 – Consolidated Edison – Gas Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail rates. 2010

Case 10-S-0001 – Project Orange Associates, LLC -- On behalf of Project Orange Associates testified to the reasonableness of whether the steam customers of Syracuse University could benefit if a steam transportation tariff were adopted by the New York Public Service Commission. 2009

Docket No. E-7, Sub 900 – Duke Energy Carolinas, LLC – On behalf of the Sierra Club, Southern Alliance for Clean Energy testified on the reasonableness of the Company's request to recover construction work in progress in rate base and to comment on whether the costs incurred by the Company for the supercritical coal plant Cliffside Unit 6 are reasonable and prudent. 2009

D.P.U. 8-64 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the accuracy of the Company's accounting data as it related to affiliate transaction with the parent Company. 2009

Formal Case No. 1027 – Washington Gas Light Company – On behalf of the Office of People's Counsel of the District of Columbia testified to the reasonableness of the Company's use of mechanical couplings and problems related thereto. 2009

Docket No. G-04204A-08-0571 -- UNS Gas, INC. -- On behalf of the on behalf of the Arizona Residential Utility Consumer Office examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, and proposed rate design. 2009

Case 09-S-0029 – Consolidated Edison – On behalf of the County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2009

Docket No. 09-0407 – Commonwealth Edison – On behalf of the People of the State of Illinois testified to the reasonableness of Company's Chicago Area smart Grid Initiative. 2009

Docket No. E-01345A-08-0172 – Arizona Public Service – On behalf of the on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposal regarding demand side management cost recovery. 2009

Case 9182 – Maryland Water Service, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed bulk purchased water rate increase. 2009

Case 9182 – Artesian Water Maryland, Inc. – On behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed advance fees to connect new water customers in the Whitaker Woods subdivision. 2009

Case 08-E-0539 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by $854 million. 2008

Docket No. 08-07-04 – United Illuminating – On behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's proposed construction budget. 2008

Docket No. 08-06036 – Spring Creek Utilities - On behalf of the Nevada Attorney General's Bureau of Consumer Protection testified on the overall revenue requirement, the cost allocation and amortization of a new financial accounting system, the appropriate level of rate case expense, allocation of corporate salaries, recovery of property taxes, and rate design. 2008

D.P.U. 8-35 – New England Gas Company – On behalf of the Massachusetts Attorney General testified to the reasonableness of the Company's request to increase rates in light of the terms of a previous settlement, the level of expenses being charged from the parent Company to the affiliate, the proposed increase in depreciation expense and the proposed revenue allocation and rate design. 2008

Docket No. 08-96 – Artesian Water Company - on behalf of the Staff of the Delaware Public Service Commission examined the reasonableness of the Company's cost of service study and proposed revenue allocation and rate design. 2008

Docket No. 05-03-17PH02 – Southern Connecticut Gas Company – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded costs of service study and proposed revenue allocation and rate design. 2008

Docket No. 06-03-04PH02 – Connecticut Natural Gas Corporation – on behalf of the Connecticut Office of Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study and proposed revenue allocation and rate design. 2008

Docket No. G-01551A-07-0504 – Southwest Gas Corporation – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding revenue decoupling. 2008

Docket No. E-01933A-07-0402 – Tucson Electric Power Company – on behalf of the Arizona Corporation Commission examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation, proposed rate design and proposals regarding mandatory time of use rates. 2008

Docket No. 07-09030 – Southwest Gas Corporation – on behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates. 2008

Civil Action 05-C-457-1 – Dominion Hope – on behalf of former employee of the utility examined the utility's hedging and sales for resale practices between affiliates. 2008

Case 07-829-GA-AIR – Dominion East Ohio – on behalf of the Office of the Ohio Consumer's Counsel examined the reasonableness of the Company's embedded cost of service study, proposed revenue allocation and rate design and examined the reasonableness of proposals on revenue decoupling and straight fixed variable rate design. 2008

Case 07-S-1315 – Consolidated Edison Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2008

Case No. 9134 – Green Ridge Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case No. 9135 -- Provinces Utilities, Inc. – on behalf of the Maryland Office of People's Counsel examined the reasonableness of the utility's proposed rate application including the appropriate cost allocation and amortization period for expenses incurred to develop and implement Project Phoenix (a new software and financial accounting system project), the appropriate level of rate case expense, the requested rate of return and the appropriate level and allocation for common expenses from the parent company. 2008

Case 07-M-0906 – Energy East and Iberdrola – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the proposed Acquisition of Energy East Corporation by Iberdrola merger. 2008

Case 07-E-0523 – Consolidated Edison – Electric Rates -- On behalf of County of Westchester testified to the reasonableness of the Company's proposal to increase retail electric rates by over $1.2 billion or 33%. 2007

Docket Nos. ER07-459-002, ER07-513-002, and EL07-11-002 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville on whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission 2007

Docket No. 07-05-19 – Aquarion Water Company – On behalf of the Connecticut Office of Peoples Counsel examined the reasonableness of the utility's proposed revenue allocation, rate design, weather normalization and depreciation rates 2007

Docket No. E-04204A-06-0783 – UNS Electric – On behalf of the Arizona Corporation Commission testified on the reasonableness of the utility's proposed revenue allocation and rate design. 2007

Docket Nos. 06-11022 and 06-11023 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2007

Case 06-G-1186 – KeySpan Delivery Long Island – on behalf of the Counties of Nassau and Suffolk analyzed the Company's proposed rate design for amortization of costs for expenditures relating to Manufactured Gas Plants. 2007

Case 06-M-0878 – National Grid and KeySpan Corporation -- on behalf of the Counties of Nassau and Suffolk analyzed the public benefit of the proposed merger, customer service, demand side management programs, rate relief as it relates to competition and customer choice, the repowering of the existing generating stations on Long Island, and the remediation of contamination caused by Manufactured Gas Plants. 2007

Docket No. 06-07-08 – Connecticut Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, revenue allocation and rate design. 2006

Docket No. EL07-11-000 – Vermont Transco -- on behalf of the Vermont Towns of Stowe and Hardwick, and the Villages of Hyde Park, Johnson and Morrisville evaluated whether the proposed and subsequently abandoned allocation of costs for the Lamoille County Project was reasonable and whether the direct assignment and rate impacts of a proposed transmission line were with current policy of the Federal Energy Regulatory Commission. 2006

Case 05-S-1376 – Consolidated Edison – Steam Rates -- On behalf of County of Westchester testified to the reasonableness of the method of allocating costs between the utility's steam system and its electric system. 2006

Docket No. 06-48-000 – Braintree Electric Light Department – On behalf of the municipal utility presented an cost of service study used to calculate the annual revenue requirement for a generating station that was deemed to be required for reliability purposes. 2006

Case 05-E-1222 – New York State Electric and Gas Corporation – On behalf of Nucor Steel, Auburn, Inc. examined the reasonableness of the utility's proposed average service lives, forecast net salvage figures, and proposal to switch from whole life to remaining life method. 2006

Docket No. 05-10004 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed electric depreciation rates and expense levels. 2006

Docket No. 05-10006 – Sierra Pacific Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed gas depreciation rates and expense levels. 2006

Docket No. ER06-17-000 – ISO New England, Inc. – On behalf of a group of municipal utilities in Massachusetts prepared an affidavit on the reasonableness of proposed changes to the Regional Network Service transmission revenue requirements rate setting formula. 2005

Case 04-E-0572 – Consolidated Edison – Electric Rate – On behalf of the County of Westchester testified to the reasonableness of the Company's revenue allocation amongst service classes and the company's fully allocated embedded cost of service study. 2004

Docket No. 04-02-14 – Aquarion Water Company – On behalf of the Connecticut Department of Utility Control examined the reasonableness of the utility's proposed depreciation rates, weather normalization proposal and certain operation and maintenance expense forecasts. 2004

Docket No. U-13691 – Detroit Thermal, LLC – On behalf of the Henry Ford Health Systems testified on the reasonableness of the utility's proposed default tariffs for steam service. 2004

Docket No. 04-3011 – Southwest Gas Corporation – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Docket No. ER03-563-030 -- Devon Power, LLC, *et al.* – On behalf of the Wellesley Municipal Light Plant filed a prepared affidavit with FERC with respect the proposal of ISO New England, Inc. to establish a locational Installed Capability market in New England. 2004

Docket No. 03-10002 – Nevada Power Company – On behalf of the Staff of the Nevada Public Utilities Commission testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 2004

Case 03-E-0765 – Rochester Gas and Electric Corporation - Before the New York Public Service Commission submitted testimony on rate design, rate unbundling, depreciation, commodity supply and reasonableness and ratemaking treatment of proceeds from the sale of a nuclear generating plant. 2003

New York State Department of Taxation and Finance Versus Brooklyn Navy Yard Cogeneration Partners – Testified on behalf of independent power producer in income tax case regarding tax payments associated with gas used to produce electricity. Testimony focused on ratemaking policies and practices in New York State. 2003

Docket No. 2930 – Narragansett Electric – Before the Rhode Island Public Utilities Commission submitted testimony on the reasonableness of the utility's proposed shared savings filing and its implications for the overall reasonableness of the Company's distribution rates. 2003

Docket No. 03-07-01 – Connecticut Light and Power Company – Before the Connecticut Department of Public Utility Control testified to the recovery of "federally mandated" wholesale power costs. 2003

Docket No. ER03-1274-000 – Boston Edison Company – Before the Federal Energy Regulatory Commission submitted affidavit on the reasonableness of the utility's proposed depreciation rates and expense levels. 2003

Case 210293 – Corning Incorporated – Before the New York Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 332311 – Nucor Steel Auburn, Inc. – Before the New York State Public Service Commission submitted an affidavit on certain actions of New York State Electric & Gas Corporation regarding the wholesale price of power in New York and the utility's billing practices as they relate to flex rate contracts. 2003

Case 6455/03 – Prepared affidavit for consideration by the Supreme Court of the State of New York as to the purpose, need and fuel choice for the Jamaica Bay Energy Center (Jamaica Bay) as it related to good utility planning practice for meeting the energy needs of utility customers. 2003

Case 00-M-0504 – New York State Electric and Gas Corporation – Reviewed reasonableness of utility's fully allocated embedded cost of service study and proposed unbundled delivery rates. 2002

Docket No. TX96-4-001 – On behalf of the Suffolk County Electrical Agency proposed unbundled embedded cost rates for wheeling of wholesale power across distribution facilities. 2002

Case 00-E-1208 – Consolidated Edison: Electric Rate Restructuring – On behalf of Westchester County, addressed reasonableness of having differentiated delivery services rates for New York City and Westchester. 2001

Case 01-E-0359 – Petition of New York State Electric & Gas – Multi-Year Electric Price Protection Plan – Addressed reasonableness of Price Protection Plan (PPP); presented alternative rate plan that called for 20% decrease in utility's base rates. 2001

Case 01-E-0011 – Joint Petition of Co-Owners of Nine Mile Nuclear Station – Addressed the reasonableness of the proposed nuclear asset sale and the ratemaking treatment of the after gain sale proposed by NYSEG. 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of ISO's proposed $4.75/kW/month Installed Capability Deficiency Charge. June 2001

Docket No. EL00-62-005 – ISO New England Inc. – Submitted affidavit on reasonableness of proposed $0.17/kW/month Installed Capability Deficiency Charge. January 2001

Docket No. 2861 – Pascoag Fire District: Standard Offer, Charge, Transition Charge and Transmission Charge – Testified on elements of individual charges, procedures for calculation and reasons for changes from previous filed rates. 2001

Case 96-E-0891 – New York State Electric & Gas: Retail Access Credit Phase – On behalf of a large industrial customer, testified on cost of service considerations regarding NYSEG's earnings performance under the terms of a multi-year rate plan and the appropriate level of Retail Access Credit for customers seeking alternate service from alternate suppliers. 2000

Docket No. ER99-978-000 – Boston Edison Company: Open Access Transmission Tariff – Testified on design, revenue requirement, and reasonableness of proposed formula rates proposed by Boston Edison Company for calculating charges for local network transmission service under open access tariff. 1999

Docket Nos. OA97-237-000, et. al. – New England Power Pool: OATT – Testified on design, revenue requirement, and reasonableness of proposed formula rate for transmission service; testified to proposed rates, charges, terms and conditions for ancillary services. 1999

Docket No. 2688 – Pascoag Fire District: Electric Rates – Testified on elements of savings resulting from renegotiation of contract with wholesale power supplier and presented analysis that justified need for and amount of base rate increase. 1998

New York State Department of Taxation and Finance Versus Zapco Energy Tactics Corporation – Testified on behalf of independent power producer in income tax case regarding tax payments associated with electric interconnection equipment. Testimony focused on policies and practices faced in doing business in New York State. 1998

Docket No. 2516 – Pascoag Fire District: Utility Restructuring – Testified on manner and means for utility's restructuring in compliance with Rhode Island Utility Restructuring Act of 1996. Testimony presented a methodology for calculating stranded cost charge, unbundled rates, and new terms and conditions of electric services in deregulated environment. 1997

Case 94-E-0334 – Consolidated Edison: Electric Rates – Led Staff team in review of utility's multi-year rate filing seeking increased rates of $400 million. Directed team in review of resource planning, power purchase contract administration, and fuel and purchased power expenses and testified on reasonableness of company's actions regarding buy-out of contract with an independent power producer and renegotiation of contract with another independent power producer. Lead negotiations for multi-year settlement and performance-based ratemaking package that resulted in a three-year rate freeze. 1994

Case 93-G-0996 – Consolidated Edison: Gas Rates – Testified on reasonableness of utility's proposed depreciation rates. 1994

Case 93-S-0997 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's resource planning for steam utility system. 1994

Case 93-S-0997 and 93-G-0996 – Consolidated Edison: Steam Rates – Testified on reasonableness of multi-year rate plan proposed by the utility. 1994

Case 94-E-0098 – Niagara Mohawk: Electric Rates – Reviewed utility's management of its portfolio of power purchase contracts with independent power producers for the reasonableness of recovery of costs in retail rates. 1994

Case 93-E-0807 – Consolidated Edison: Electric Rates – Testified on rate recovery mechanism for costs associated with termination of five contracts with independent power producers. 1993

Case 92-E-0814 – Petition for Approval of Curtailment Procedures – Testified on methodology for estimating amount of power required to be curtailed and staff's estimate of curtailment. 1992

Case 90-S-0938 – Consolidated Edison: Steam Rates – Testified on reasonableness of utility's embedded cost of service study, and proposed revenue re-allocation and rate design. 1991

Case 91-E-0462 – Consolidated Edison: Electric Rates – Implementation of partial pass-through fuel adjustment incentive clause. 1991

Case 90-E-0647 – Rochester Gas and Electric: Electric Rates – Analysis and estimation of monthly fuel and purchased power costs for use in utility's performance based partial pass-through fuel adjustment clause. 1990

Case 29433 – Central Hudson Gas and Electric: Electric Rates – Analysis of utility's construction budgeting process, rate year electric plant in service forecast, lease revenue forecast, forecast and rate treatment of profits from sales of wholesale power and estimation of fuel and purchased power expenses for use in the utility's partial pass-through fuel adjustment clause. 1987

Case 29674 – Rochester Gas and Electric: Electric Rates – Review of utility's historic and forecast O&M expenditure levels forecast and rate treatment of profits from wholesale power, and estimation of fuel and purchased power expenses, and price out of incremental revenues from increased retail sales. 1987

Case 29195 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process, analysis of rate year electric plant in service, forecast and rate treatment of profits from sales of wholesale power, and estimation of fuel and purchased power expenses. 1986

Case 29046 – Orange and Rockland Utilities: Electric Rates – Testified on the reasonableness of the utility's proposed depreciation rates and expense levels. 1985

Case 28313 – Central Hudson Gas and Electric: Electric Rates – Review of utility's construction budgeting process; analysis of rate year electric plant in service forecast; review of rate year operations and maintenance expense forecast; forecast and rate treatment of profits from sales of wholesale power; estimation of fuel and purchased power expenses. 1984

Case 28316 – Rochester Gas and Electric: Steam Rates – Price out of steam sales including the review of historic sales growth, usage patterns and forecast number of customers. 1984

PRESENTATIONS

National Association of State Utility Consumer Advocates Annual Conference, 2012 – Speaker accelerated main replacement programs

National Association of State Utility Consumer Advocates Annual Conference, 2008 – Speaker on a case study of "Smart Metering"

Multiple Intervenors Annual Conference – What Will Impact Market Prices? 1998, Syracuse, New York – Speaker on the impact that deregulation would have on market prices for large industrial customers.

IBC Conference – Successful Strategies for Negotiating Purchased Power Contracts, 1997, Washington, DC – Speaker on NY power purchase contract policies, ratepayer valuation, contract approval process and policy on recovery of buyout costs.

Gas Daily Conference – Fueling the Future: Gas' Role in Private Power Projects, 1992, Houston, Texas – Panel member addressing changing power supply requirements of electric utilities.

MEMBERSHIPS/ASSOCIATIONS

Member Municipal Electric Utility Association
Northeast Public Power Association
New York State Independent System Operator

EXHIBIT FWR-2

RUCO 8.06

Hutchens Direct 13:11-24 – 18:1-18 - Please provide the monthly energy sales for TEP's retail delivery customers from January 2006-December 2015 on an actual basis and weather normalized basis.

RESPONSE:

Please see RUCO 8.06.xlsx for the monthly weather normalized sales. The Excel file is not identified by Bates numbers.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-3

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 28, 2016

RUCO 8.05

Hutchens Direct 13:11-24 – 18:1-18 - Please provide the monthly peak demand for TEP's retail delivery customers from January 2006-December 2015 on an actual basis and weather normalized basis.

RESPONSE:

Please see file RUCO 8.05 City Load Data.xlsx, sheet "Monthly Summary" for the monthly peak data requested. The Excel file is not identified by Bates numbers. The Company cannot provide weather normalized peak data as it does not perform such adjustments. This is because the peak model has a high degree of complexity, thus making peak normalizing very difficult and normalized peak values are of little value for system planning.

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-4

STF 3.3

Jurisdictional Allocations: Please provide the workpapers and supporting documents used to derive the jurisdictional allocations used for each pro-forma adjustment.

RESPONSE:

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Please see STF 3.3 Jurisdictional Allocation-Confidential.xlsm. The Excel file is not identified by Bates numbers.

Within this file, extracts for the Rate Base-Orig Cost and Rev-Exp tabs were taken from UDR 1.001 – 2015 TEP Rev Req Model.xlsm.

The jurisdictional allocation calculation and the ACC Jurisdiction pro-forma adjustments are shown in columns AF – BS of the Rate Base-Orig Cost Tab and columns BZ-FM of the Rev-Exp Tab.

Each individual cell formula within these columns support the jurisdictional allocations.

Also included in the Excel file provided herein are separate supporting tabs for the following allocators:

1. Demand
2. Energy
3. Ancillary
4. Payroll

RESPONDENT:

Anne Liu

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY
ACC/FERC JURISDICTION - DEMAND ALLOCATION FACTOR

DEMAND ALLOCATON - 2015											
Line No.	**Date**	**Retail System Peak**	**SRP**	**NTUA**	**TOUA**	**Shell**	**Trico**	**Sub-Total FERC**	**Removes SRP & Shell**	**Total**	**Line No.**
		(a)	(b)	(c)	(d)	('e)	(f)	(g)	(h)	(i)	
1	June, 2015	2,206	100	41	5	100	50	296	96	2,302	1
2	July, 2015	2,066	100	48	5	100	50	303	103	2,169	2
3	August, 2015	2,214	100	40	5	100	50	295	95	2,309	3
4	September, 2015	1,995	100	35	5	100	50	290	90	2,085	4
5	Total	8,481						1,185	385	8,866	5
6	Average (Line 5/ 4)	**2,120.25**							**96.2**	**2,216.5**	6
7	Demand Allocation Factor (Line 6 - (a)/(i) and (h)/(i)	95.66%							4.34%		7

EXHIBIT FWR-5

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Salt River Project Agricultural	LF	Tariff 3 S.A. 12			
2	Improvement and Power District					
3	Navajo Tribal Utility Authority	LF	Tariff 3 S.A. 11			
4	Tohono O'odham Utility Authority	LF	Tariff 3 S.A. 13			
5	Shell Energy North America (US) LP	LF	WSPP			
6	EDF Trading North America, LLC	LF	ISDA			
7	Trico Electric Cooperative	LF	Tariff 3 S.A. 13			
8	Ajo Improvement District	SF	AJO Contract			
9	Morenci Water and Electric	SF	Morenci Agreement			
10	Arizona Electric Power Cooperative	SF	WSPP			
11	Arizona Public Service Company	SF	WSPP			
12	Black Hills Power, Inc.	SF	WSPP			
13	BP Energy Company	SF	ISDA			
14	Cargill Power Markets, LLC	SF	ISDA			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

EXHIBIT FWR-6

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO AECC TWELFTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE DOCKET NO. E-01933A-15-0322
May 2, 2016

AECC 12.4

Please identify the margins earned by TEP on the Shell Long Term Energy Sales contract for each month since its effective date.

RESPONSE: April 19, 2016

The Company objects to this question as it relates to non-ACC jurisdictional margins that are outside the scope of this rate case.

RESPONDENT:

Jeanine Tracey

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: May 2, 2016

Per discussions between counsel for the Company and counsel for AECC, please see AECC 12.4-12.6 4-12-16 (Test Year)-Competitive Sensitive Confidential.xlsx. The Excel file is <u>not</u> identified by Bates numbers.

The Shell contract was put into place after the acquisition of Gila River Unit 3. The contract expires December 31, 2017.

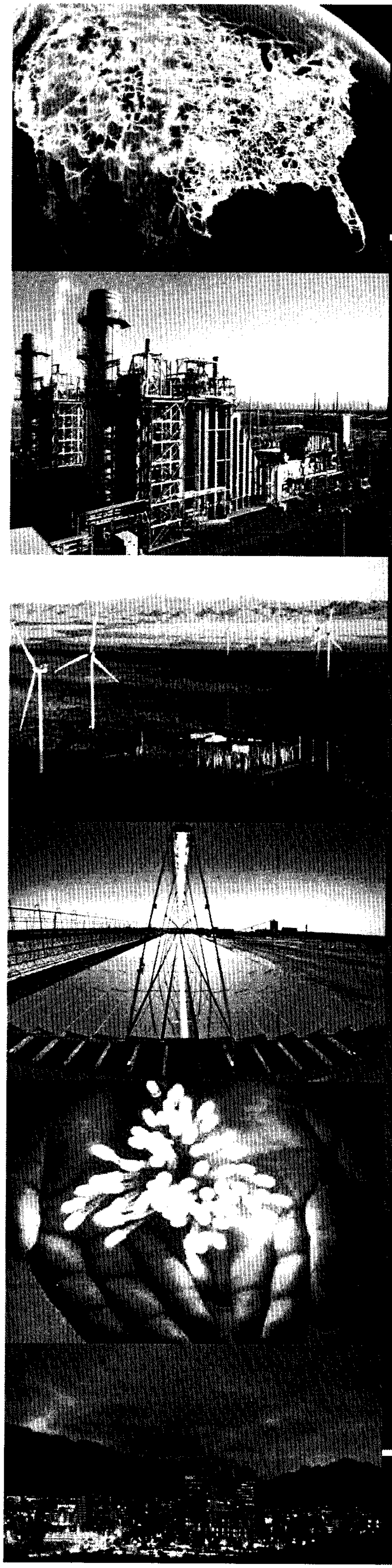
RESPONDENT:

Jeanine Tracey / Michael Sheehan

WITNESS:

Dallas Dukes

EXHIBIT FWR-7



TUCSON ELECTRIC POWER

2014 Integrated Resource Plan

April 1, 2014

EXHIBIT FWR-8

CONFIDENTIAL

EXHIBIT FWR-9

CONFIDENTIAL

EXHIBIT FWR-10

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.03

Weather Normalization – Please provide the results and adjustment to test-year revenue by year under the Company's new model if a nine year, eight year, seven year, six year, five year, four year, and three year model were used. In addition, please provide the statistical outputs, such as p-values and r-squared values associated with each year requested above.

RESPONSE:

The Company objects to the request as it is overly burdensome. The time required to generate each of the models above and to calculate the total adjusted revenue is significant. Please see RUCO 7.05b for an explanation as to why this process is highly burdensome and resource intensive.

For the model statistics of the model the Company used for the weather normalization, please see file RUCO 7.03 TEP Weather Normalization Model Statistics.pdf, Bates Nos. TEP\021852-021889.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.04

Weather Normalization – Please provide the results and adjustment to test-year revenue under the Company's new model if a fifteen year, twenty year, twenty five year and thirty year model were used. In addition, please provide the statistical outputs, such as p-values and r-squared values associated with each year requested above.

RESPONSE:

Please refer to RUCO 7.03.

RESPONDENT:

Greg Strang

WITNESS:

Craig Jones

EXHIBIT FWR-11

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 18, 2016

RUCO 7.11

Residential Customers - RE: Dukes Direct at page 11:22-25, please provide the following:

a. the number of seasonal residential customers that TEP has together with their energy use, by month, for a typical year;

b. the number of year round residential customers that TEP has together with their energy use, by month, for a typical year;

c. the estimated number of residential vacant homes, by month, for the years 2011-2015.

d. Please provide typical load profiles for a residential seasonal customer, a residential vacant home, a residential year round customer, and a residential customer with distributed generation. The load profiles should be for the winter period, the summer period, and the peak day.

RESPONSE:

a./b. The Company does not currently track seasonal versus year round customers and therefore does not have their energy use as requested.

c. The Company does not track vacant homes.

d. For the reasons above, the company does not have load profiles for the requested customer types. The company has a large swath of hourly data for a number of customers which include some of the customer types listed. Although there are not distributed generation customers in the sample, the Company is also including the NREL SAM 8760 production curve for the Tucson area for use in estimating solar DG customer hourly load shapes.

Please see the following files for the 8760 production curve.

File Name	Bates Numbers
RUCO 7.11 Individual Customer Sample 2-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 3-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 4-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample 5-Confidential.xlsx	N/A
RUCO 7.11 Individual Customer Sample-Confidential.xlsx	N/A
RUCO 7.11 NREL SAM DATA-Confidential.xlsx	N/A

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-12

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
April 28, 2016

RUCO 8.04

Re: Response to RUCO 3.11 and Dukes Direct at 14:6-9 - FERC Form 1 data shows that the UPC for Residential rate class has been declining since 2007 when it peaked at 10,922 kWh per year (See 2007 FERC Form 1, page 304, column e, line 2). For 2007 please provide the weather normalized UPC. For each year 2008-2015, please provide the actual annual UPC for the Residential Regular service class together with the UPC change due to DG, due to energy efficiency and due to economic changes.

RESPONSE:

Please see the table below for the breakout of weather normalized residential UPC and the change due to EE and DG. Please note, when the Company performs the weather normalization, that the Company weather normalizes the entire residential class and not just R01. This is why the Company is starting with the 2007 UPC of 11,129 instead of 10,922. The Company cannot accurately quantify what is due to economic changes versus some other effect. Thus the values are labeled as other changes.

Year	Residential UPC	Weather Normalized UPC	Y/Y EE Change	Y/Y DG Change	Y/Y Other Change
2007	11,129	10,956			
2008	10,621	10,802	(9)	(2)	(144)
2009	10,708	10,713	(24)	(3)	(62)
2010	10,579	10,579	(45)	(7)	(82)
2011	10,606	10,450	(140)	(29)	40
2012	10,375	10,350	(174)	(32)	106
2013	10,424	10,108	(182)	(50)	(10)
2014	9,960	9,805	(265)	(38)	1
2015	9,894	9,684	(231)	(78)	189

RESPONDENT:

Greg Strang

WITNESS:

Dallas Dukes

EXHIBIT FWR-13

RUCO 7.20

TEP Headquarters – Please answer the following questions as they relate to the TEP Headquarters:

a. Based on the Company's last rate case the Company identified the following two components of building costs:

TEP New HQ-IT	$ 7,363,145
TEP New HQ-Facilities	$ 84,604,455
Total	$ 91,967,600

Please update these two cost components to reflected other capital improvements and/or additions. Further, update the response for any other capitalized cost component not already reflected in these two components. In addition, include the FERC sub account numbers for these capitalized assets and amounts (e.g. 311 Structures and Improvements).

b. Based on the Company's last rate case the Company identified the following cost per square foot.

Office	$263/sf
Retail	$178/sf
Parking	$64/sf

Please update these costs to reflect the current cost per square foot for the above three areas. In addition provide the work sheets, and calculations to substantiate the response.

c. Do the dollar per square foot (Office, Retail, Parking) cited in b. include a capitalized portion and an operating and maintenance ("O&M") expense portion?

d. If no to c. provide the capitalized portion and the O&M portion per square foot. Further providing a listing of components that are listed in the capitalized and O&M portions (e.g. property taxes, depreciation expense, etc.).

e. Based on the Company's last rate case, the Company indicated that 12,000 gross square feet of retail space was unused. Please update the gross square feet of retail space to reflect both used and unused space.

f. Based on the Company's last rate case, the Company indicated that 8,540 gross square feet of vacant and unused cubical space. Please update the gross square feet of office space to reflect both used and unused space.

g. Please provide the gross square feet of parking space to reflect both used and unused space.

h. List by floor and square footage the portion of the building that has been allocated to TEP employees, UNS electric employees, UNS gas employees, and any other TEP affiliates.

i. List by floor and square footage the portion of the building that is rented/leased to other non-affiliate entities (e.g. insurance company)?

j. Is a profit component built into the rental/lease payment that each affiliate member pays to the parent company, if so, what is that percentage, and what is the amount of profit charged to each affiliate member?

k. Is a profit component built into the rental/lease payment that each non-affiliate member pays to the parent company, if so, what is that percentage, and what is the amount of profit charged to each non-affiliate member?

RESPONSE: **April 18, 2016**

TEP is in the process of gathering this information and will provide it as soon as possible

RESPONDENT:

Anne Liu

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: **May 2, 2016**

a. The cost components for the TEP Headquarters at June 30, 2015 are as follows:

FERC Sub Account	Description	Net
E397	Communication Equipment	$ 714,308
E391-CP	Computer Equip.	3,574,387
	TEP HQ-IT Total	4,288,695
E390	Structures & Improvements-General Plant	68,371,896
E391-OE	Office Equip	1,331,752
E389-LD	Land	8,549,938
E398-RW	Right a ways	41,468
	TEP HQ-Facilities Total	78,295,053
	Total at June 30, 2015	$ 82,583,748

b. The cost per square foot provided in the last rate case was an approximation based on total construction costs and gross square footage. Construction costs included land, direct construction costs for shell building, permits, impact fees, etc. For your reference, please see file RUCO 7.20.pdf, Bates Nos. TEP\023766-023770, for the response to STF 22.06 (r) provided in the 2012 TEP Rate Case.

The net balance of the HQ Building decreased by 11.62% as compared to the balance in the last rate case. To provide an approximation of the current cost per square feet, the prior amounts were decreased accordingly.

	June 30, 2015	Dec. 31, 2011	Change
Cost	98,679,260	94,745,693	
Reserve	(16,095,511)	(1,300,437)	
Net Balance	82,583,748	93,445,256	-11.62%

	Cost Per Square Ft - Adjusted by % Change	
	Prior Rate Case	Current
Office	263	232
Retail	178	157
Parking	64	57

c. No, it does not include an O&M expense portion. The cost per square foot figures in the last rate case were based on capitalized one-time construction costs. It included land costs, direct construction costs, and one time sales tax/ plans, permits and impact fees.

d. The Company does not maintain dollar per square foot data by Office, Retail, Parking for capitalized and O&M expenses. As noted above, the total capitalized portion of the building is $82,583,748 at June 30, 2015.

Expenses for the test year by component are:

O&M Expense	1,657,958
Property Taxes	1,111,450
Depreciation	3,881,648
	6,651,056

e. The 12,000 square footage of retail space supplied in the last rate case should be revised to 10,185. It is 100% unused.

f. The square footage of space built out excluding retail and the garage levels is 267,625. This includes workstations, offices, hallways, common areas, rest rooms, mechanical rooms, etc. Of the 267,625 total square footage, 263,365 square feet is used. 4,260 square feet is unused workstation and office space.

g. The square footage of the parking space is 224,600. 100% used.

h. The headquarters building is 100% occupied by TEP employees or contract personnel doing work on behalf of TEP, UNS Electric and UNS Gas.

i. None of the headquarters building is currently being rented/leased to others.

j. There are no rental/lease payments from affiliate members for the headquarters as the building is 100% occupied by TEP. However, within the building allocation cost charged to affiliates, through a labor allocation; a return component of 5.04% as per the agreed upon return in the last rate case.

k. Not applicable. There are no rental/lease payments paid by non-affiliated members.

RESPONDENT:
Anne Liu (a, b, c, d, h-k) / Ryan Companies (e, f, g)
WITNESS:
Dallas Dukes

EXHIBIT FWR-14

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 November 7, 2012

RUCO 7.13

Did TEP conduct a comprehensive cost-benefit analysis of building a new headquarters versus maintaining the existing facilities? If so, please provide the analysis. If not, why not?

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

The Company did an extensive evaluation before it decided to proceed with a new headquarters building. Management began considering adding and consolidating office space in mid-2007; a final decision to purchase the land for a new building was made in April 2009 and a final decision to begin building was made in October 2009. TEP was considering new space for numerous reasons including:

a. Even with the use of the temporary office trailers, the current facilities were at 99% occupancy and, in certain cases, TEP needed to rent space for project teams;

b. The lease at One South Church, where 80 employees were located, was up for renewal in June 2011;

c. Over 300 employees at the Irvington Campus were housed in 12 temporary office trailers that were costly to operate, and the employees were functionally separated from the other work groups;

d. Two permanent office facilities at the Irvington site (one built in the 1950's and one in the early 1980's) were due for renovation and mechanical upgrades (i.e., HVAC, bathrooms, ADA compliance, etc.);

e. TEP needed more conference space and larger conference/auditorium to facilitate employee meetings—at the time, the largest conference room could only handle 125 people, a small percentage of our employees based in Tucson at that time;

f. For compliance and business continuity reasons, the Company was evaluating backup locations for its IT data center, call center, control room and physical security. TEP met the need for backup facilities by incorporating them into the new secure headquarters.

g. The decision to proceed in the 2009-2010 time frame, which coincided with the weak economy, provided the opportunity to build a new headquarters at a reasonable lower cost level and support construction related jobs in Tucson;

Given the Company's situation, it developed objectives and a plan to resolve the long term office needs. The primary objectives included: a) eliminate existing capacity constraints and provide for growth; b) consolidate employees into fewer office locations to improve communications and reduce travel time and costs; c) consolidate all or at least a major portion of the corporate staff functions into one building to improve communications and reduce travel time and costs; d) choose office location(s) and parking that is convenient and safe for employees; and e) manage costs. In addition to the primary objectives, the Company also wanted to choose an office facility that was environmentally friendly (i.e., incorporating energy efficiency and renewable energy resources) and supported the Tucson community with economic development and/or office common facilities that could be used by the community including local charities.

To meet the objectives, the Company investigated and evaluated various alternatives. It compared the alternatives of a) expanding/remodeling current facilities; b) leasing additional space at One South Church Avenue; c) leasing existing office space at other Tucson locations; d) buying existing office space in Tucson; and e) building a new office building at numerous locations in Tucson. Please see the files listed below for the confidential materials that set forth the analyses conducted in connection with these options and the ultimate decision to build the new corporate headquarters.

File Name	Bates Numbers
RUCO 7.13 New Building Pres 2008 08-2011 12-Confidential.pdf	TEP\027864-027949
RUCO 7.13 NewBuildPresExh2009 04-HumanImpact-Confidential.pdf	TEP\027950-027978
RUCO 7.13 NewBuildPresExh2009 04-Irvington Modulars-Confidential.pdf	TEP\027979-027981
RUCO 7.13 NewBuildPresExh2009 04-ListDscrpProps-Confidential.pdf	TEP\027982-028006
RUCO 7.13 NewBuildPresExh2009 04-Map187482-Confidential.pdf	TEP\028007-028008

Based on the analyses and TEP's needs, it was ultimately determined that the best alternative was to build a corporate headquarters at 88 East Broadway. The key drivers in the decision were: a) there was not suitable existing office space of at least 100,000 square feet with parking for 250 employees available in Tucson; b) building a new building allowed the Company to design for its specific use and needs; c) building a new building allowed the facility to be sized to consolidate a larger number of employees into one location based on a space planning/adjacency study (see Response to RUCO 7.12); d) the downtown location is convenient for employees for commuting including access to public transportation and the downtown location supports the development of downtown Tucson; and e) the slow economy and weak construction industry allowed the company to closely manage costs, to build the facility in a short, tight time period and to provide jobs/economic activity to the local Tucson economy.

RESPONDENT:

Scott Rathbun/Kevin Larson

WITNESS:

Michael DeConcini

EXHIBIT FWR-15

CONFIDENTIAL

EXHIBIT FWR-16

CONFIDENTIAL

EXHIBIT FWR-17

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291 November 7, 2012

RUCO 7.23

When was ownership of the new facility transferred to Tucson Electric Power Company from UniSource, and why did this transfer occur?

RESPONSE:

The transfer date was November 1, 2011. The building was initially owned by UNS to provide greater flexibility in financing the asset construction. The transfer of ownership made economic and practical sense for many reasons, including:

1. UNS initially attempted to attain New Markets Tax Credits for the building, which were available for development in certain areas. The credits were available to a developer/lessor (a role UNS could have fulfilled by owning the building and leasing it to TEP), but were not available to an owner occupant such as TEP. When it became clear that the tax credits would not be available for this development project, it made more economic sense for TEP to own the asset directly rather than UNS (see additional reasons below).
2. TEP avoided a potential liability on its balance sheet by owning the asset instead of entering into a long-term lease obligation;
3. Use of the facility by TEP was ensured over the long-term, avoiding the need to consider purchase and lease renewal options at end of the lease term; and
4. Long-term financing for the facility could be obtained on better terms at TEP due to TEP's investment-grade credit rating (UNS is rated Ba1, a non-investment grade credit rating).

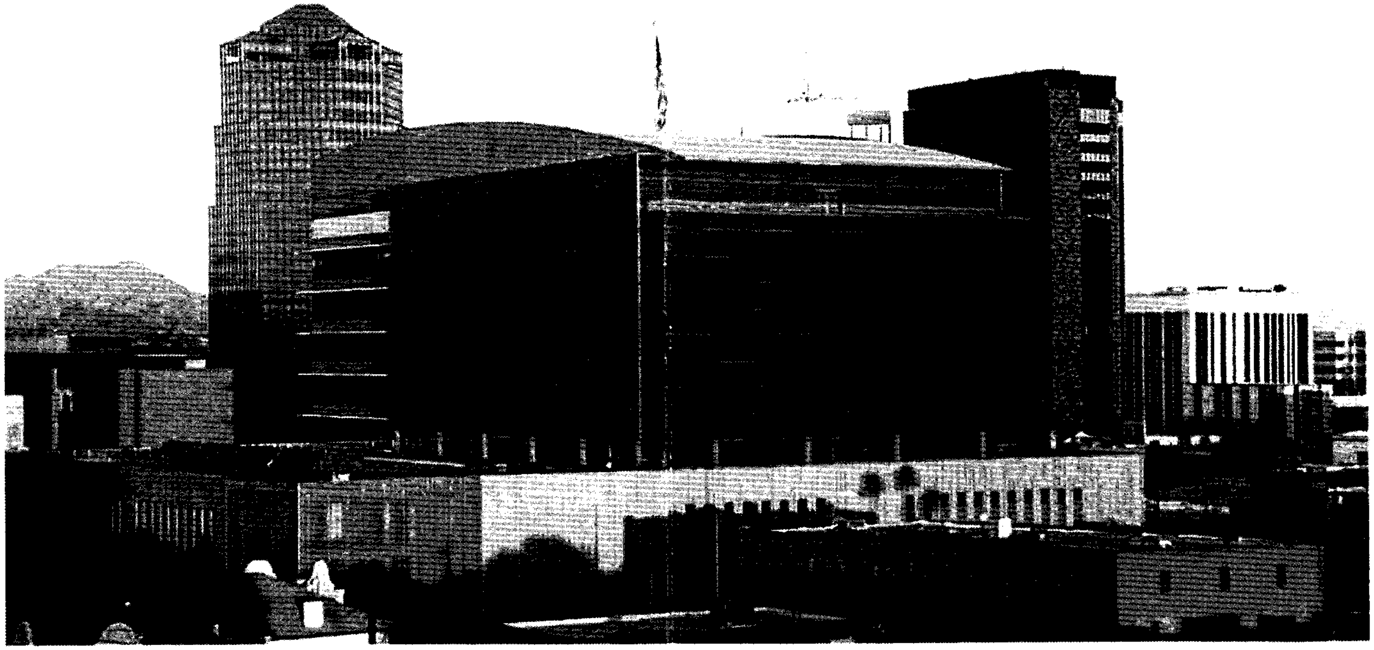
RESPONDENT:

Scott Rathbun, Karen Kissinger and Kentton Grant

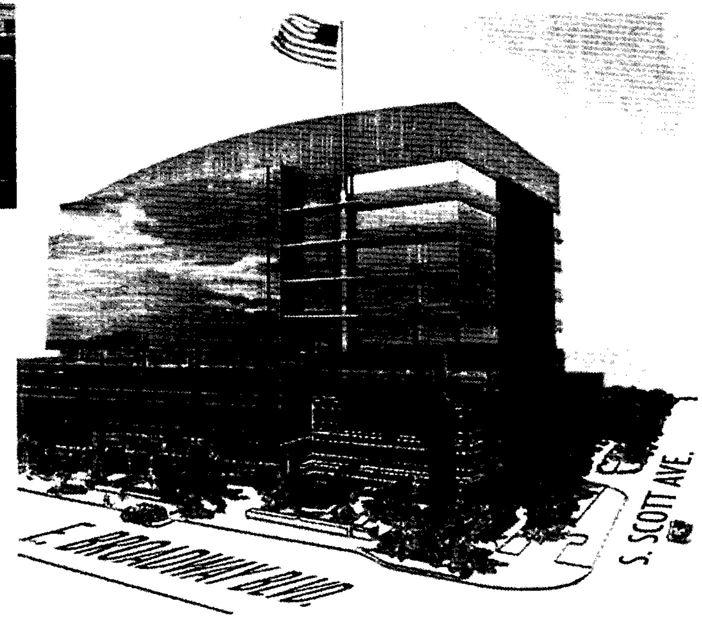
WITNESS:

Michael DeConcini

EXHIBIT FWR-18



There's a New Energy Downtown



UniSource Energy's solar-powered, energy-efficient Tucson headquarters

UniSource Energy's corporate headquarters is a showcase of green construction and design. Completed in November 2011, the building supports the efficient, effective operations of Tucson Electric Power (TEP) and UniSource Energy Services (UES) UniSource Energy's utility subsidiaries.

The nine story building provides 232,000 square feet of space for more than 500 employees. It also includes 11,000 square feet of ground-floor retail space, a state-of-the-art conference center, on-site parking and a long list of environmentally responsible features.

UniSource Energy's corporate headquarters exemplifies the company's commitment to leadership in energy efficiency and renewable energy.

For more information about the green programs available to UniSource Energy's utility customers visit tep.com or uesaz.com

BRIGHT SOLUTIONS℠
from UniSource Energy

BRIGHT SOLUTIONS℠
from UniSource Energy

EXHIBIT FWR-19

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2009

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________.

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	**UNISOURCE ENERGY CORPORATION** (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	**TUCSON ELECTRIC POWER COMPANY** (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UniSource Energy Corporation	**Common Stock, no par value**	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Exchange Act: None

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UniSource Energy Corporation	Yes þ	No o
Tucson Electric Power Company	Yes o	No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

UniSource Energy Corporation	Yes o	No þ
Tucson Electric Power Company	Yes þ	No o

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such

Table of Contents

Cash used for investing activities is primarily a result of capital expenditures at TEP, UNS Gas and UNS Electric. Cash used for investing and financing activities can fluctuate year-to-year depending on: capital expenditures, repayments and borrowings under revolving credit facilities; debt issuances or retirements; capital lease payments by TEP; and dividends paid by UniSource Energy to its shareholders.

Operating Activities

In 2009, net cash flows from operating activities were $70 million higher than 2008 primarily due to: lower costs of fuel and purchased energy; increased retail revenues due to base rate increases at TEP and UNS Electric and hot summer weather; lower interest paid on capital leases and long-term debt; partially offset by lower wholesale sales, higher O&M and higher wages paid.

Investing Activities

Net cash used for investing activities was $156 million lower in 2009 compared with 2008 due to: a $133 million deposit made by TEP last year with the trustee for bonds that matured on August 1, 2008; and a $70 million decrease in capital expenditures in 2009; partially offset by a $31 million investment made by TEP in 2009 to purchase Springerville lease debt; and a $12 million decrease in proceeds from investment in lease debt.

Capital Expenditures

Business Segment	Actual 2009	Estimated 2010	2011	2012	2013	2014
	-Millions of Dollars-					
TEP	$ 235	$ 258	$ 217	$ 203	$ 225	$ 209
UNS Gas	14	14	16	16	16	18
UNS Electric	28	26	25	31	13	16
UniSource Energy Stand-Alone	10	16	27	1	—	1
UniSource Energy Consolidated	$ 287	$ 314	$ 285	$ 251	$ 254	$ 244

- Included in TEP's capital expenditures forecast for 2010 is $52 million for the proposed purchase of Sundt Unit 4.
- Items excluded from TEP's capital expenditures forecast are: the estimated cost to construct proposed Tucson to Nogales, Arizona transmission line of $120 million; estimated costs of $300 million between 2011-2014 to construct 75 to 150 MW of local generation that may be required in 2015.
- The estimated capital expenditures for UniSource Energy Stand-Alone are for the purchase of land and construction of a new corporate headquarters.

For more information see *TEP, Liquidity and Capital Resources, Investing Activities, Capital Expenditures,* below, and *Item 1. Business, TEP, Transmission Access, Tucson to Nogales Transmission Line,* above.

Financing Activities

Net cash proceeds from financing activities were $170 million lower in 2009 compared with 2008. In 2008, The Industrial Development Authority of Pima County issued, for the benefit of TEP, approximately $221 million of tax-exempt industrial development revenue bonds and UNS Electric issued $100 million of long-term debt used in part to refinance a $60 million debt maturity. Factors affecting proceeds from financing activities in 2009 included: $30 million of proceeds from the issuance of short-term debt at UED; a $70 million decrease in payments of long-term debt compared with 2008; a $50 million decline in payments on capital lease obligations compared with 2008; and a $7 million increase in dividends paid compared with 2008.

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

þ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2010

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from __________ to __________.

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification Number
1-13739	**UNISOURCE ENERGY CORPORATION** (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0786732
1-5924	**TUCSON ELECTRIC POWER COMPANY** (An Arizona Corporation) One South Church Avenue, Suite 100 Tucson, AZ 85701 (520) 571-4000	86-0062700

Securities registered pursuant to Section 12(b) of the Exchange Act:

Registrant	Title of Each Class	Name of Each Exchange on Which Registered
UniSource Energy Corporation	**Common Stock, no par value**	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Exchange Act: None

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933.

UniSource Energy Corporation	Yes þ	No o
Tucson Electric Power Company	Yes o	No þ

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Securities Exchange Act of 1934 (Exchange Act).

UniSource Energy Corporation	Yes o	No þ
Tucson Electric Power Company	Yes þ	No o

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Table of Contents

Capital Expenditures Forecast

Business Segment	Actual 2010	2011	2012	Estimated 2013	2014	2015
			-Millions of Dollars-			
TEP	$ 267	$ 306	$ 273	$ 372	$ 322	$ 286
UNS Gas	10	12	11	14	16	22
UNS Electric (1)	22	37	51	25	30	32
Other Capital Expenditures	17	36	1	—	—	—
	$ 316	$ 391	$ 336	$ 411	$ 368	$ 340

(1) UNS Electric is expected to purchase BMGS from UED for approximately $62 million during 2011. Since this is an inter-company transaction, it is not included in the chart, as it is eliminated from UniSource Energy consolidated capital expenditures. See *UNS Electric, Factors Affecting Results of Operations, Rates, 2010 UNS Electric Rate Order,* below, for more information.

TEP's capital expenditures in 2010 include $52 million for the purchase of Sundt Unit 4. TEP's estimated capital expenditures in 2015 exclude the potential purchase of Springerville Unit 1 and Springerville Coal Handling Facilities upon the expiration of their respective leases in January 2015.

Other capital expenditures reflect UniSource Energy's standalone capital expenditures, including the purchase of land and construction costs for a new corporate headquarters.

These estimates are subject to continuing review and adjustment. Actual capital expenditures may differ from these estimates due to changes in business conditions, construction schedules, environmental requirements, state or federal regulations and other factors.

For more information regarding TEP's capital expenditures, see *Tucson Electric Power Company, Liquidity and Capital Resources, Investing Activities, Capital Expenditures,* below.

Financing Activities

Net cash proceeds used for financing activities were $22 million higher in 2010 than they were in 2009 due to:

- $30 million of net revolving credit facility repayments in 2010 compared with net proceeds of $5 million in 2009;
- a $32 million increase in payments of capital lease obligations;
- $30 million of short-term debt proceeds in 2009 compared with none in 2010; and
- a $15 million increase in dividends paid to common shareholders; partially offset by
- an $82 million increase in proceeds from long-term debt net of repayments of long-term debt.

Capital Contributions

In the first quarter of 2010, UED paid a $9 million dividend to UniSource Energy, of which $4 million represented a return of capital distribution. In March 2010, UniSource Energy contributed $15 million in capital to TEP to help fund the purchase of Sundt Unit 4.

In 2009, UED paid a $30 million dividend to UniSource Energy which also represented a return of capital distribution. UniSource Energy used the proceeds to contribute $30 million of capital to TEP to purchase lease debt related to Springerville Unit 1.

See *Other Non-Reportable Business Segments, UED* and *Tucson Electric Power Company, Liquidity and Capital Resources*, below for more information.

UniSource Credit Agreement

In November 2010, UniSource Energy amended and restated its existing credit agreement (UniSource Credit Agreement). The UniSource Credit Agreement had previously included a $30 million term loan facility and a $70 million revolving credit facility. As amended, the UniSource Credit Agreement consists of a $125 million revolving credit and revolving letter of credit facility. The UniSource Credit Agreement will expire in November 2014. At December 31, 2010, there was $27 million outstanding at a weighted average interest rate of 3.26%.

EXHIBIT FWR-20

RUCO 3.14

Re: Grey Direct at 21:10-15, please provide any and all engineering analysis to support the statements that 1) with more distributed generation resources being deployed on the TEP distribution system puts demands on the T&D systems not previously contemplated. To meet these new demands, 2) requires TEP to utilize technology to add more sensing and measurement devices and new methods for managing and operating the distribution system.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

1)

File Name	Bates Numbers
RUCO 3.14 Los Reales Feeder 14 backflow-Confidential.pdf	TEP\021154-021155
RUCO 3.14 Sample Feasibility Study 100515-Redacted-Confidential.pdf	TEP\021156-021165

Please see the following technical articles with web addresses provided:

- Reiman, A. (2015). An Analysis of Distributed Photovoltaics on Singe-Phase Laterals of Distrution Systems. *D-Scholoarship Institutional Respository at the University of Pittsburg* [Website]. Retrieved from http://d-scholarship.pitt.edu/24047/.
- Jan-E-Alam, M., Muttaqi, K.M., and Sutanto, D. (2011, July 24-29). Assessment of distributed generation impacts on distribution networks using unbalanced three-phase power flow analysis. *IEEE.org* [Website]. Retrieved from http://ieeexplore.ieee.org/xpl/articleDetails.jsp?tp=&arnumber=6039789&url=http%3A%2F%2Fieeexplore.ieee.org%2Fxpls%2Fabs_all.jsp%3Farnumber%3D6039789
- Tang, J.H., Lim, Y.S., Morris, S., and Wong, J. (2012). Impacts on Centrally and Non-Centrally Planned Distributed Generation on Low Voltage Distribution Network. *International Journal of Smart Grid and Clean Energy*. Retrieved from http://www.ijsgce.com/uploadfile/2012/1016/20121016114245643.pdf.

1) The distribution network was designed to provide power flows from the substation to the customer. By adding generation at the customer level to feed into the distribution network voltage, power quality, protection schemes, network losses and load balancing of feeders is affected differently than the system was originally designed. Please see RUCO 3.14 Sample Feasibility Study 100515-Redacted.pdf for a sample TEP feasibility study indicating the work performed and issues identified. This type of study is typically performed for all interconnection's greater then 1MW in size. For reference are actual measurements taken from a TEP distribution feeder indicating power flow unbalance that has been introduced into the distribution network from DG sources. Please see RUCO 3.14 Los Reales back flow-Confidential.pdf for example. For reference are three other technical

articles describing the complexity in accurately modeling the effects of DG on a distribution network and the effects of DG sources on the distribution network.

2) Electrically modeling the distribution network is a complicated activity. The model is being further complicated by the introduction of DG items such as energy efficiency, solar, storage and demand response. For reference refer to the technical articles referenced for part 1. To validate the model information sensing and measurement devices can be installed to provide electrical parameters that can be incorporated in different ways (i.e. state estimation) to validate or modify the electrical model to represent actual measurements. This corrects the model to better model the actual electrical system. With better information and modeling, management and operation of the distribution network can be improved. Where improvement refers to the management of side effects caused by DG on the distribution network. The common side effects are described the technical articles referenced in part 1.

RESPONDENT:

Jim Taylor

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.15

Re: Grey Direct at 22:1-2, please provide any and all engineering analysis to support the statement that there is a need for a communications network that allows for intelligent electronic devices to be installed on the distribution system.

RESPONSE:

No engineering analysis is required to support this statement as the creation of a smarter grid is founded on the premise that new devices and technology will be implemented. The implementation is founded on the concept of having communications to provide status, alarms and control of the devices. This enables abilities such as remote control, abnormal condition indication and automated operation of devices. These type of capabilities are enabled through communications. Without communications these type of capabilities will not be able to be realized.

RESPONDENT:

Jim Taylor

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.16

Re: Grey Direct at 22:5-8, please provide any and all engineering analysis to support the statement a distribution management system is the central software application that is needed to provide distribution supervisory control and data acquisition, outage management and geographical information into a single operations view. Also, please provide a description of the current distribution supervisory control system that TEP uses and how it is different than what is contemplated to be used in the future.

RESPONSE:

No engineering analysis is required to support this statement. For discussion purposes a simple description of the three systems is provided herein. The data from distribution supervisory control and data acquisition indicates the substation distribution feeder or line recloser status as well as other distribution line measurements on the distribution network. The geographical information provides the geo spatial line locations and routes as well as an electrical model of the distribution network. The outage management system provides the indication of line switch status. A distribution management system can provide many new analytic capabilities and a single operations view of the distribution network. By incorporating the information from all three systems into a single view the information can be visualized and create an electrical model of the distribution network. The electrical model of the distribution network is a real time model of the network based on the distribution supervisory control and data acquisition and outage management information combined. In addition to the electrical model from the geographical information a distribution management system can also create a state estimation for the distribution network. The state estimation utilizes measurement information from the network to provide an adjustments to the electrical model to tune it to match actual measurements. The model also provides electrical values for all line segments in the distribution network. This provides many of the operation and planning capabilities that the manufactures offer within a distribution management system.

TEP does not have a distribution supervisory control system. TEP utilizes an energy management system to indicate the status of the distribution substation feeder status. The PI data historian is utilized to store the status and measurement information from the distribution network. TEP does have a geographical system that contains the geo spatial information and electrical model of the distribution network. The geographical system information has been integrated into the outage management system to provide the outage management system electrical model. The system operators manually update the distribution line switch statuses to indicate distribution feeder circuits. The energy management system substation feeder breaker information has also been integrated into the outage management system to indicate feeder status. A separate integration has been created with geographical electrical model information to an electrical modeling and planning software for distribution planning activities. The information from the distribution network for the distribution planning activities is a static model based on the last model update and needs to be manually updated to indicate actual feeder configuration. Moving towards a distribution management system would create the system and benefits described above. The existing systems require manual processes and updates to keep updated and providing information.

RESPONDENT:

Jim Taylor

WITNESS:

Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.17

RE: Tilghman Direct at 7:2-18, with respect to the discussion of impacts of intermittent generation, for distributed generation (DG) resources not owned by the Company, please provide the following:

a. a list of each and every operational metric that TEP is concerned about with respect to DG with a definition of what it is and how TEP tracks the metric,

b. for each metric provided in response to part a) of this question please provide and any all data that TEP tracks with respect to the metric,

c. please explain how each metric identified in part a) of this question is the same or different depending on the various voltage levels that TEP operates (e.g. 500 kV, 345kV, 138kV, 46 kV, 13.8 kV, 4.16 kV, etc.),

d. any and all data that proves that intermittent generation from DG is creating greater load imbalance,

e. any and all data that proves that intermittent generation from DG is creating greater fluctuations in voltage,

f. any and all data that proves that intermittent generation from DG is creating greater fluctuation in frequency,

g. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater load imbalance together with any and all engineering studies that support the explanation and cost by month for the last ten years.

h. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuations in voltage together with any and all engineering studies that support the explanation and cost by month for the last ten years.

i. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuation of frequency together with any and all engineering studies that support the explanation and cost by month for the last ten years.

RESPONSE:

Please see the following files, as referenced below.

File Name	Bates Numbers
RUCO 3.17(a) NERC Glossary_of_Terms.pdf	TEP\020589-020706
RUCO 3.17(b) BAL-001-1.pdf	TEP\020707-020718
RUCO 3.17(b) BAL-001-2.pdf	TEP\020719-020727
RUCO 3.17(b) BAL-002-1.pdf	TEP\020728-020732
RUCO 3.17(b) BAL-002-WECC-2.pdf	TEP\020733-020744
RUCO 3.17(b) BAL-003-1.1.pdf	TEP\020745-020756
RUCO 3.17(d) 2015_Sample_Variability.xlsx	N/A

a. Below is a list of Balancing Authority ("BA") Area metrics that TEP is concerned about with respect to DG. Metrics are calculated and stored by the Energy Management System ("EMS") in company databases.

Area Control Error ("ACE")

Per the NERC Glossary of Terms (see RUCO 3.17(a) NERC Glossary_of_Terms.pdf), "The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction ("ATEC"), if operating in the ATEC mode. ATEC is only applicable to Balancing Authorities in the Western Interconnection."

Frequency Response Measure ("FRM")

Per the NERC Glossary of Terms, "The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO. This will be calculated as MW/0.1Hz."

Frequency Response Obligation ("FRO")

Per the NERC Glossary of Terms, "The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz."

Disturbance Control Standard ("DCS")

Per the NERC Glossary of Terms, "The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range."

Balancing Authority ACE Limit ("BAAL")

A Balancing Authority-specific limit on ACE derived from the BA's frequency bias, scheduled frequency, actual interconnection frequency, and epsilon, a targeted frequency bound defined by NERC for each interconnection. Also referred to as "Reliability-based Control," or RBC. BAs may not exceed either a BAAL High or BAAL Low for longer than 30 minutes. Definitions and calculations from BAL-001-2 (see file RUCO 3.17(b) BAL-002-1.pdf), which goes into effect on July 1, 2016. RBC has been in effect as a field trial in WECC since March 1, 2010, and WECC has monitored BA compliance with RBC since then.

Contingency Reserve ("CR")

Per the NERC Glossary of Terms, "The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard ("DCS") and other NERC and Regional Reliability Organization contingency requirements. The provision of capacity that may be deployed by the Balancing Authority to respond to a Balancing Contingency Event and other contingency requirements…."

b. TEP objects to this request as providing all data collected by TEP with regard to the metrics in part a) would be overly burdensome. However, without waiver of objection, the data collected for metric calculations are specified in various NERC and WECC documents and are listed below.

The ACE calculation is comprised of the components specified in RUCO 3.17(b) BAL-001-1.pdf.

Frequency Response Measure is comprised of the components in RUCO 3.17(b) BAL-003-1.1.pdf.

Frequency Response Obligation is comprised of the components in RUCO 3.17(b) BAL-003-1.1.pdf.

Compliance with the Disturbance Control Standard is calculated in accordance with RUCO 3.17(b) BAL-002-1.pdf.

Balancing Authority ACE Limits are comprised of the components RUCO 3.17(b) BAL-001-2.pdf.

Contingency Reserve is comprised of the components in RUCO 3.17(b) BAL-002-WECC-2.pdf.

Data is collected and calculations are performed by the EMS every 2 seconds.

c. Voltage level is not taken into consideration for any of the metrics listed in part a).

d. The TEP Balancing Authority considers DG variability in 10 minute increments. This is because reserves, both spinning and non-spinning, are calculated by what they can provide within 10 minutes. Please see RUCO 3.17(d) 2015_Sample_Variability.xlsx.

Ten-minute output values from different large-scale distributed solar sites connected to the TEP system can be summed and compared to show an aggregate 10-minute variability. At the BA level, there is no differentiation between TEP-owned and PPA DG sites; these sites are all metered into the TEP Balancing Authority at the transmission or distribution level and do not reside behind customer meters, so the effect on the BA Area is the same regardless of whether they are TEP-owned or PPAs.

Site	AC MW Capacity	Location	TEP Owned
Picture Rocks (aka FRV)	20	Marana, AZ	No, PPA
Avra Valley (aka NRG)	25	Marana, AZ	No, PPA
Fort Huachuca Phase I	13.6	Sierra Vista, AZ	Yes
U of A Tech Park (UASTP I & II)	5.3	Tucson, AZ	Yes
U of A Tech Park (Amonix, Cogenra, E.On Tech Park, Gato Montes Solar)	12	Tucson, AZ	No, PPA

These example sites comprise about 76 MW of AC rated capacity, and they reside in Southern Arizona within the TEP metered boundary. These are sites which TEP either owns or has PPAs with, meters directly to its EMS for the calculation of generation and load, and do not reside behind any customer meters.

When generation within a Balancing Authority fluctuates, it causes other generation on Automatic Generation Control to fluctuate, as well as the amount of interchange over BA Area ties. These changes also cause fluctuations in the BA ACE, making it more difficult to comply with relevant reliability standards like BAAL because changes can happen so rapidly and unpredictably.

The maximum positive 10-minute variability measured in the aggregated 2015 data is 26.4 MW or 34.73%, and the maximum negative 10-minute variability measured is -44.7 MW or -58.94%.

The DG sites used in this example, which are geographically diverse within Southern Arizona and the Tucson Valley, can exhibit large changes over short periods of time, even when aggregated. Applying this behavior to the entirety of the distributed solar in the Tucson Valley shows the potential for the Valley's aggregated solar to have serious impacts to the requirements of traditional generation, the BA Area interchange ties, BA ACE, and ability to maintain operating reserves. The negative variability coupled with normal system disturbances can deplete reserves making it difficult to maintain compliance with the metrics mentioned above.

Positioned behind customer meters, distributed generation will change the amount of power the customer draws. Small fluctuations in customer load are expected and normal, and even larger fluctuations exhibited by a few customer meters will be less obvious at a system level. However, when many customers utilize distributed solar generation, the aggregated impacts will increase to levels that will impact the overall system and metrics.

Other studies regarding distributed generation and customer load may be viewed on the SVERI Public Access Data Portal at sveri.uaren.org.

e. Results from interconnection studies routinely performed for distributed generation facilities indicate that large penetration levels of distributed generation resources can cause fluctuations in distribution system voltage. TEP cannot provide copies of these studies since they contain sensitive customer information and require the consent of the customer.

f. Any and all generation within an interconnected system has an effect on system frequency; therefore, any new generation introduced to a power system, including DG, will contribute to deviations in frequency.

Due to the relative size of DG versus total system generation capacity, frequency deviations specifically attributable to solar DG have not been measured within the TEP BA Area. However, as DG penetration becomes a larger percentage of overall generation, TEP expects the adverse effects of DG to become more visible and more easily attributable.

g. While variability of solar distributed generation has been observed, TEP has not calculated the direct costs as of yet.

h. While variability of solar distributed generation has been observed, TEP has not calculated the direct costs as of yet.

i. As previously stated, due to the relative size of DG versus total system generation capacity, frequency deviations specifically attributable to solar DG have not been measured within the TEP BA Area. However, as DG penetration becomes a larger percentage of overall generation, TEP expects the adverse effects of DG to become more visible and more easily attributable.

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RESPONDENT:

Lauren Briggs / Ana Bustamante (e and h)

WITNESS:

Carmine Tilghman / Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.18

RE: Tilghman Direct at 7:2-18, with respect to the discussion of impacts of intermittent generation, for distributed generation (DG) resources owned by the Company, please provide the following:

a. a list of each and every operational metric that TEP is concerned about with respect to DG with a definition of what it is and how TEP tracks the metric,

b. for each metric provided in response to part a) of this question please provide any and all data that TEP tracks with respect to the metric,

c. please explain how each metric identified in part a) of this question is the same or different depending on the various voltage levels that TEP operates (e.g. 500 kV, 345kV, 138kV, 46 kV, 13.8 kV, 4.16 kV, etc.),

d. any and all data that proves that intermittent generation from DG is creating greater load imbalance,

e. any and all data that proves that intermittent generation from DG is creating greater fluctuations in voltage,

f. any and all data that proves that intermittent generation from DG is creating greater fluctuation in frequency,

g. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater load imbalance together with any and all engineering studies that support the explanation and cost by month for the last ten years.

h. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuations in voltage together with any and all engineering studies that support the explanation and cost by month for the last ten years.

i. please explain how, if any, intermittent generation from DG impacts the cost of providing service from TEP due to greater fluctuation of frequency together with any and all engineering studies that support the explanation and cost by month for the last ten years.

RESPONSE:

Please see TEP's responses to RUCO 3.17.

RESPONDENT:

Lauren Brigs (a-d, f, g) / Engineering (e, h, i)

WITNESS:

Carmine Tilghman / Susan Gray

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
March 14, 2016

RUCO 3.19

RE: Tilghman Direct at 8:4-27 through 9:1-2, please provide any and all engineering studies that TEP has performed that the excess energy from Distributed Generation resources not owned by TEP can result in increased

a. operations and maintenance costs,

b. equipment wear and tear,

c. energy flowing back up through the distribution system, and

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

RESPONSE:

a. TEP has not performed any engineering studies that specifically attribute an increase in operations and maintenance cost to Distributed Generation. However, on a regular basis TEP performs interconnection studies for large non-TEP owned distributed generation facilities which indicate that large penetration levels of distributed generation have impacts on system voltage during fluctuations of generation typically found with intermittent generation resources. During the intermittent generation periods, equipment upstream on the TEP distribution system are required to operate more frequently to compensate for the swings in system voltage. Maintenance costs for devices installed throughout the distribution system to control voltage, such as transformer load tap changers, line capacitors, and voltage regulators will increase as these devices are required to operate more frequently.

b. Distribution equipment will be required to operate more frequently as distributed generation penetration levels increase. As operation of these devices increase, wear and tear will increase, and additional maintenance will be required to maintain proper operation of the distribution system.

c. TEP performs feasibility studies as required by the company's Distributed Generation Interconnection Rules ("DGIRs") (https://www.tep.com/customer/construction/esr/). These studies generally include power flow simulations and voltage sag analysis, based upon assumptions of the customer's particular system characteristics as submitted in the interconnection application. TEP analyzes the voltage regulation issues arising from the intermittent solar availability, and based upon engineering analysis and calculations these reports can and do show energy flowing back into the distribution system as part of the engineering modeling. TEP is not able to provide these studies for non TEP owned facilities due to confidentiality constraints.

d. The same studies show an increase in reverse power to the grid during the light load case.

RESPONDENT:

Chis Lindsey

WITNESS:

Carmine Tilghman

STF 1.22

<u>Renewable Resources</u>: Please provide a narrative discussing how the Company has either implemented and/or researched the use of advanced inverters or other technologies to control PV generation at the source.

RESPONSE:

The Company is in the process of studying the impacts of implementing reactive power requirements to be provided by the inverters for Company-owned PV generation facilities. Advanced inverters have the ability to provide reactive power production day or night that may help support grid voltage where necessary.

The Company has constructed a test solar system with a Smart Inverter on the Irvington campus in Tucson with remote controls enabled. This system has been used to develop installation and communication standards and will allow for development of the new Smart Inverter control settings. The test system will be used to study the effects of time varying control settings versus active optimization control. Other control setting strategies will be investigated with the system as they are developed.

The Company has partnered with One Cycle Control ("OCC") to investigate their technologies that may support the integration of distributed generation. The OCC devices are small-scale dynamic VAR compensators that claim they can help control voltage at the distribution level more precisely and autonomously than other devices or technologies. This technology is planned for installation at an existing Company-owned PV facility by the end of the first quarter 2016.

The Company has been in collaboration with the University of Arizona at the Tech Park where a smart inverter and battery system are electrically tied to a solar field. The system has been used to assess the viability of controlling solar ramp rates, testing sensitivity of the grid to DG fluctuation and also using weather information to schedule curtailment to guaranty stable PV output on cloudy days.

The Company has identified the West Ina Substation as a preferred location for the installation of solar generation along with other supporting technologies. The goal of this project is to achieve increased energy delivery efficiency and system reinforcement cost avoidance for West Ina T1 and T2 thru installation and automation of distributed resources. There are 4 parts to achieving the goals of the project: the Residential Solar project, a central monitoring system, an autonomous decision application and a communication network. Engineering has been working on communication and control options to support these goals. The communication network is required to enable control of all DG resources.

RESPONDENT:

Carmine Tilghman / Chris Fleenor

WITNESS:

Carmine Tilghman

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S FIRST SET OF DATA REQUESTS REGARDING THE 2015 TEP RATE CASE
DOCKET NO. E-01933A-15-0322
February 2, 2016

STF 1.23

Renewable Resources: Please provide a narrative discussing how DG increases operating and maintenance costs and equipment wear and tear. [Tilghman 8:19]

RESPONSE:

In general, intermittent resources like solar DG are subject to fast and extreme changes in output. Conventional generation resources, which are used to follow the load and regulate frequency, are required to change their output more frequently and more quickly than before. More frequent operation at faster rates increases wear and tear on the equipment, and therefore maintenance costs.

In addition, the Company's operating and maintenance costs have increased related to interconnection facilities required for larger-scale DG. This includes the scheduled inspection and replacement of equipment required to support the proper integration and operations of larger DG facilities.

The idea that intermittent resources create additional challenges and service on the distribution grid is well documented throughout the industry. Whitepapers, presentations, and other forms of documentation are widely available from organizations such as National Renewable Engineering Laboratory ("NREL"), Massachusetts Institute of Technology ("MIT"), Lawrence Berkley Engineering Laboratory ("LBEL"), Solar Electric Power Association ("SEPA"), Southwest Variable Energy Resource Initiative's ("SVERI"), and others. Below is a partial list of publicly available documents from these entities covering a variety of issues associated variable generation.

1. Western Electricity Coordinating Council's Variable Generation Subcommittee Marketing Workgroup whitepaper – "Electricity Markets and Variable Generation Integration".
2. Western Electricity Coordinating Council's – "WECC Variable Generation Planning Reference Book: A Guidebook for Including Variable Generation in the Planning Process".
3. MIT Study on the Future of Solar Energy, specifically Chapter 7 – Integration of Distributed Photovoltaic Generators. https://mitei.mit.edu/futureofsolar
4. North American Electric Reliability Corporation (NERC) Special Report: Accommodating High Levels of Variable Generation, April 2009. http://www.nerc.com/files/IVGTF_Report_041609.pdf
5. Western Wind and Solar Integration Study – "Analysis of Cycling Costs in Western Wind and Solar Integration Study". http://www.nrel.gov/docs/fy12osti/54864.pdf
6. NREL – "Fundamental Drivers of the Cost and Price of Operating Reserves". http://www.nrel.gov/docs/fy13osti/58491.pdf
7. Intertek APTECH report prepared for NREL and WECC – "Power Plant Cycling Costs"

RESPONDENT:

Carmine Tilghman

WITNESS:

Carmine Tilghman

STF 1.24

Renewable Resources: Please provide a narrative discussing how the Company has estimated or measured individual feeders subject to reverse powerflow and overload conditions. [Tilghman 8:21]

RESPONSE:

The Company meters and monitors the specific cases where reverse powerflow occurs at the feeder level to ensure operations are within industry tolerance and Company-owned facilities are operating within design parameters.

The Company also monitors the amount of distributed generation installed by feeder and conducts specific feeder studies if necessary to estimate potential reverse powerflow conditions. Specifically, a recent interconnection study has identified feeder conductor overloads due to the installation of customer-owned generation at the end of the feeder.

RESPONDENT:

Carmine Tilghman / Jim Taylor / Chris Fleenor / Chris Lindsey

WITNESS:

Carmine Tilghman

EXHIBIT FWR-21

Tucson Electric Power Company
Summary of Revenues by Customer Class
Present and Proposed Revenues
Test Year Ended June 30, 2015

Line No.	Rate Description	Test Year Net Revenue	Net Increase	Proposed % Increase to Test Year	Adjusted Test Year Revenue	Proposed Dollar Increase	Proposed % Increase to Adjusted Test Year	Proposed Net Revenue
1	**Class Summary**	$	$	%	$	$	%	$
2	Residential	414,763,081	1,583,498	0.4%	404,566,465	11,780,113	2.9%	416,346,578
3	General Service	263,662,971	(12,728,689)	-4.8%	249,088,907	1,845,375	0.7%	250,934,282
4	Large General Service	112,713,124	8,550,248	7.6%	119,203,655	2,059,717	1.7%	121,263,372
5	Large Power Service	136,020,579	(7,421,310)	-5.5%	127,759,401	733,028	0.7%	128,599,270
6	Transmission Service 138kV	0	0	n/a	0	0	n/a	0
7	Lighting	4,772,245	23,056	0.5%	4,654,992	140,309	3.0%	4,795,301
8	Subtotal	931,931,999	(9,993,197)	-1.1%	905,273,421	16,558,541	1.8%	921,938,803
9	**Other Operating Revenue**	$31,728,877		N/A	$31,728,877	N/A	N/A	$31,728,877
10	**Total**	**$963,660,876**	**($9,993,197)**	**-1.0%**	**$937,002,298**	**$16,558,541**	**1.8%**	**$953,667,680**

Supporting Schedules
H-2-2

Recap Schedules
A-1

Links
Other Operating Revenues - Revenue Requirement Model

Note:
-1 Test Year Billed Margin Revenues calculated $50,952 more than Booked Revenues.
-2 Test Year Billed Fuel and PPFAC revenues calculated $28,842 less than Booked Revenues.
-3 Total increase is $22,110 more than Schedule A1, Line 10 due to difference from Test Year billed to booked revenues.
-4 Transmission Service 138kV is included with Large Power Service to conceal competitively sensitive confidential data.

Tucson Electric Power Company
Comparison of Sales by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	TEST YEAR UNADJUSTED			SALES ADJUSTMENTS	TEST YEAR ADJUSTED			PROPOSED		
Rate Description	Test Year Basic Service Charges	Test Year Sales (kWh)	Average Per Service Charge	kWh	Basic Service Charges	Adjusted Sales (kWh)	Average Per Service Charge	Basic Service Charges	Proposed Sales (kWh)	Average Per Service Charge
Class Summary										
Residential	4,618,963	3,675,966,286	796	(24,845,354)	4,624,515	3,651,120,932	790	4,624,515	3,651,120,932	790
General Service	461,846	2,133,735,714	4,620	(1,402,844)	462,775	2,132,332,869	4,608	460,877	1,839,512,456	3,991
Large General Service	7,013	1,189,053,400	169,550	(11,891,293)	6,931	1,177,162,108	169,835	8,865	1,477,690,240	166,682
Large Power Service	204	2,021,151,869	9,907,607	0	216	2,021,151,869	9,357,185	228	2,021,151,866	8,864,701
Transmission Service 138kV	0	0	0	0	0	0	0	0	0	0
Lighting	207,259	38,938,160	188	1,936	207,267	38,940,096	188	207,267	38,940,096	188
TOTAL COMPANY	5,295,285	9,058,845,428	1,711	(38,137,554)	5,301,705	9,020,707,874	1,701	5,301,753	9,028,415,591	1,703
Residential Schedules										
TE-R-01	4,179,070	3,280,964,594	785	(17,027,762)	4,184,314	3,263,936,831	780	4,184,314	3,263,936,831	780
TE-201A	138,080	130,588,706	946	(992,712)	138,058	129,595,994	939	138,058	129,595,994	939
TE-201B	7,903	8,666,134	1,097	(270,031)	7,755	8,396,104	1,083	7,755	8,396,104	1,083
TE-R80	98,375	110,682,540	1,125	(2,373,544)	96,994	108,308,996	1,117	96,994	108,308,996	1,117
TE-R8	754	579,737	769	643,017	1,368	1,222,754	894	1,368	1,222,754	894
TE-R01BC	13,711	11,172,024	815	231,296	14,020	11,403,320	813	14,020	11,403,320	813
Lifeline Rate Schedules										
TE4-01	6,104	3,418,618	560	(222,520)	5,794	3,196,098	552	5,794	3,196,098	552
TE4-21	36	34,185	950	(779)	36	33,406	928	36	33,406	928
TE4-70	72	59,862	831	(941)	72	58,921	818	72	58,921	818
TE5-01	14,084	9,286,821	659	(372,346)	13,698	8,914,475	651	13,698	8,914,475	651
TE5-21	22	25,179	1,145	(10,460)	13	14,719	1,132	13	14,719	1,132
TE5-70	138	94,379	684	(4,851)	134	89,528	669	134	89,528	669
TE6-01	84,662	61,762,560	730	(8,710,908)	74,767	53,051,652	710	74,767	53,051,652	710
TE6-21	228	262,501	1,151	(31,382)	208	231,119	1,112	208	231,119	1,112
TE6-70	839	782,644	933	(170,654)	683	611,990	896	683	611,990	896
TE6-201A	3,756	3,376,855	899	(386,675)	3,397	2,990,181	880	3,397	2,990,181	880
TE6-201B	63	46,930	745	(4,083)	60	42,848	714	60	42,848	714
TE8-01	8,307	8,093,719	974	(1,148,089)	7,336	6,945,630	947	7,336	6,945,630	947
TE8-21	84	124,764	1,485	(1,279)	84	123,485	1,470	84	123,485	1,470
TE8-70	225	223,584	994	(21,111)	211	202,473	958	211	202,473	958
TE8-201A	137	189,352	1,382	(39,071)	112	150,281	1,346	112	150,281	1,346
TE6-01BC	223	159,842	717	(22,220)	196	137,622	701	196	137,622	701
TE-R-01LL	59,739	39,538,976	662	9,350,601	72,257	48,889,577	677	72,257	48,889,577	677
TE-R01LB	149	123,563	829	15,799	166	139,362	838	166	139,362	838
TE-201AL	1,399	1,205,658	862	457,541	1,884	1,663,199	883	1,884	1,663,199	883
TE-201BL	20	27,399	1,370	30,026	40	57,425	1,454	40	57,425	1,454
TE-R80LL	767	625,652	816	76,511	846	702,163	830	846	702,163	830
TE-R8LL	16	11,669	729	(890)	13	10,779	808	13	10,779	808
Residential Unbilled		3,837,839								

Tucson Electric Power Company
Comparison of Sales by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	TEST YEAR UNADJUSTED			SALES ADJUSTMENTS	TEST YEAR ADJUSTED			PROPOSED		
Rate Description	Test Year Basic Service Charges	Test Year Sales (kWh)	Average Per Service Charge	kWh	Basic Service Charges	Adjusted Sales (kWh)	Average Per Service Charge	Basic Service Charges	Proposed Sales (kWh)	Average Per Service Charge
General Service										
TE-GS10	426,132	1,700,811,779	3,991	10,550,412	427,562	1,711,362,191	4,003	384,015	602,159,416	1,568
TE-GS11	3,580	48,768,661	13,623	(2,197,623)	3,451	46,571,038	13,495	3,451	46,571,038	13,495
TE-GS76	14,274	175,721,877	12,311	(2,109,763)	14,046	173,612,114	12,360	8,917	30,031,910	3,368
TE-G10BC	383	4,734,474	12,362	76,198	389	4,810,672	12,361	305	515,997	1,692
TE-GSM10	9,837	67,460,308	6,858	(827,799)	9,723	66,632,509	6,853	8,047	22,547,155	2,802
TE-G10MBC	526	27,240,424	51,788	(112,154)	524	27,128,270	51,785	0	0	0
TE-GS43	7,114	102,037,299	14,343	178,775	7,081	102,216,075	14,436	7,081	102,216,075	14,436
TE-MGS				0				43,456	889,460,744	
TE-MGSTOU				0				5,160	130,716,715	
TE-MGSBC								446	15,293,406	
General Service Unbilled		6,960,891								
Large General Service										
TE-LGS13	5,312	859,436,643	161,792	(4,638,491)	5,279	854,798,152	161,915	7,046	1,118,625,537	158,770
TE-LG85	1,606	310,229,617	193,169	(9,593,839)	1,556	300,635,778	193,249	1,561	321,206,987	205,790
TE-L13BC	95	21,576,660	227,123	151,518	96	21,728,178	225,812	259	37,857,717	146,221
Large General Service Unbilled		(2,189,520)								
Large Power Service										
TE-LLP14	26	139,880,570	5,380,022	(5,790,325)	24	134,090,245	5,587,094	0	0	0
Special	0	28,794,874	2,399,573	(28,794,874)	0	0	0	0	0	0
Large Power Service TOU	178	1,854,388,905	10,417,915	32,672,719	192	1,887,061,624	9,828,446	228	2,021,151,866	8,864,701
Large Power Service Unbilled		-1,912,480								
Transmission Service 138kV										
TE-T138kV	0	0	0	N/A	0	0	0	0	0	#DIV/0!
Lighting										
TE-P41	9,104	22,615,813	2,484	207,661	9,096	22,823,474	2,509	9,096	22,823,474	2,509
TE-P47	6,758	8,545,881	1,265	102,017	6,774	8,647,898	1,277	6,774	8,647,898	1,277
TE-R51 + TE-R51A	17,636	672,153	38	(3,839)	17,636	668,314	38	17,636	668,314	38
TE-C52 & 52A	135,544	4,930,591	36	(3,891)	135,544	4,926,700	36	135,544	4,926,700	36
TE-P50	38,217	1,852,451	48	21,259	38,217	1,873,710	49	38,217	1,873,710	49
Lighting Unbilled		321,271								

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue Plus Fuel Proforma		Proposed Revenues		Proposed Increase to Test Year Revenue		Proposed Increase to Adjusted Revenue	
Rate Description	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
Class Summary											
Residential	277,207,565	137,555,516	(10,196,615)	275,887,975	128,678,490	287,668,088	128,678,490	1,583,498	0.38%	11,780,113	2.9%
General Service	184,360,130	79,302,841	(14,574,064)	184,448,887	64,640,020	186,294,262	64,640,020	(12,728,689)	-4.83%	1,845,375	0.7%
Large General Service	68,297,227	44,415,897	6,490,532	68,460,569	50,743,086	70,520,286	50,743,086	8,550,248	7.59%	2,059,717	1.7%
Large Power Service	73,191,548	62,829,031	(8,261,178)	73,302,768	54,456,633	74,032,047	59,042,925	(2,945,607)	-2.17%	5,315,572	4.2%
Transmission Service Rate	0	0	0	0	0	0	0	0	N/A	0	N/A
Lighting	3,303,187	1,469,057	(117,253)	3,298,783	1,356,208	3,439,093	1,356,208	23,056	0.48%	140,309	3.0%
TOTAL COMPANY	606,359,658	325,572,341	(26,658,579)	605,398,982	299,874,438	621,953,775	304,460,731	(5,517,494)	-0.59%	21,141,085	2.3%
Residential Schedules											
TE-R-01	251,807,725	122,674,283	(6,715,851)	250,967,738	116,798,419	261,977,935	116,798,419	4,294,346	1.15%	11,010,197	2.99%
TE-201A	8,979,804	4,880,819	(1,014,765)	8,923,159	3,922,699	9,322,984	3,922,699	(614,940)	-4.44%	399,825	3.11%
TE-201B	462,115	298,135	(79,283)	449,399	231,569	468,742	231,569	(59,939)	-7.88%	19,343	2.84%
TE-R80	6,748,591	3,807,714	(430,112)	6,629,150	3,497,044	6,925,163	3,497,044	(134,099)	-1.27%	296,013	2.92%
TE-R8	39,021	17,725	68,302	84,240	40,808	87,918	40,808	71,980	126.85%	3,678	2.94%
TE-R01BC	851,640	373,656	17,298	870,889	371,706	909,362	371,706	55,771	4.55%	38,473	3.10%
Lifeline Rate Schedules											
TE4-01	187,990	89,256	(23,299)	175,417	78,529	158,537	78,529	(40,179)	-14.49%	(16,881)	-6.65%
TE4-21	1,612	1,028	(57)	1,567	1,016	1,537	1,016	(87)	-3.28%	(30)	-1.16%
TE4-70	3,139	1,644	(76)	3,077	1,629	3,161	1,629	8	0.16%	84	1.79%
TE5-01	571,226	277,370	(46,143)	547,423	255,030	507,429	255,030	(86,138)	-10.15%	(39,994)	-4.98%
TE5-21	1,242	807	(856)	738	455	677	455	(917)	-44.77%	(61)	-5.11%
TE5-70	5,466	2,786	(786)	5,162	2,304	4,604	2,304	(1,344)	-16.28%	(558)	-7.47%
TE6-01	3,730,879	1,828,957	(803,104)	3,203,498	1,553,234	3,047,830	1,553,234	(958,772)	-17.24%	(155,668)	-3.27%
TE6-21	12,269	7,969	(2,560)	10,790	6,887	10,304	6,887	(3,046)	-15.05%	(486)	-2.75%
TE6-70	43,687	23,012	(15,364)	34,101	17,235	32,696	17,235	(16,768)	-25.14%	(1,405)	-2.74%
TE6-201A	169,675	102,562	(47,539)	149,713	74,985	150,517	74,985	(46,736)	-17.17%	803	0.36%
TE6-201B	2,038	1,298	(551)	1,840	945	1,907	945	(483)	-14.49%	68	2.44%
TE8-01	386,096	196,771	(49,567)	329,967	203,333	382,282	203,333	2,749	0.47%	52,315	9.81%
TE8-21	4,771	3,238	613	4,722	3,898	5,664	3,898	1,555	19.41%	942	10.93%
TE8-70	9,942	5,317	(670)	8,887	5,702	10,732	5,702	1,174	7.69%	1,844	12.64%
TE8-201A	7,659	4,895	(2,503)	6,028	4,023	7,659	4,023	(872)	-6.95%	1,631	16.22%
TE6-01BC	9,626	4,699	(2,038)	8,290	3,997	7,873	3,997	(2,455)	-17.14%	(417)	-3.39%
TE-R-01LL	2,674,986	1,311,018	862,874	3,316,275	1,532,603	3,479,033	1,532,603	1,025,632	25.73%	162,758	3.36%
TE-R01LB	8,347	4,190	1,367	9,438	4,466	9,909	4,466	1,838	14.66%	471	3.39%
TE-201AL	74,180	40,970	31,728	102,638	44,240	107,724	44,240	36,814	31.97%	5,086	3.46%
TE-201BL	1,323	877	1,975	2,746	1,429	2,881	1,429	2,110	95.90%	135	3.22%
TE-R80LL	35,808	19,187	5,372	40,408	19,959	42,321	19,959	7,285	13.25%	1,913	3.17%
TE-R8LL	707	334	(21)	674	346	707	346	11	1.10%	32	3.18%
Residential Unbilled	376,000	1,575,000		Unbilled is included above		0	0	0	N/A	0	N/A

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

	Test Year Revenue		Revenue Adjustments	Adjusted Test Year Revenue Plus Fuel Proforma		Proposed Revenues		Proposed Increase to Test Year Revenue		Proposed Increase to Adjusted Revenue	
Rate Description	Margin ($)	Fuel ($)	$	Margin ($)	Fuel ($)	Margin ($)	Fuel ($)	$	%	$	%
General Service											
TE-GS10	153,865,268	63,703,857	(41,177,457)	155,070,441	21,321,226	67,938,091	21,321,226	(128,309,807)	-58.97%	(87,132,351)	-49.40%
TE-GS11	3,524,955	1,819,452	(325,112)	3,367,260	1,652,035	4,113,888	1,652,035	421,515	7.89%	746,628	14.88%
TE-GS76	13,847,635	6,008,984	(5,202,103)	13,712,568	941,948	3,259,956	941,948	(15,654,715)	-78.84%	(10,452,612)	-71.33%
TE-G10BC	420,954	145,939	(30,523)	427,972	108,399	57,591	108,399	(400,903)	-70.72%	(370,380)	-69.05%
TE-GSM10	5,066,210	2,108,192	(1,371,308)	5,004,641	798,454	2,485,321	798,454	(3,890,628)	-54.23%	(2,519,320)	-43.41%
TE-G10MBC	2,009,095	821,670	(454,729)	1,998,695	377,341	0	377,341	(2,453,424)	-86.67%	(1,998,695)	-84.12%
TE-GS43	4,858,013	3,651,746	(184,699)	4,867,310	3,457,751	6,197,742	3,457,751	1,145,734	13.46%	1,330,433	15.98%
TE-MGS	0	0	31,610,660	0	31,610,660	88,099,007	31,610,660	119,709,667	N/A	88,099,007	N/A
TE-MGSTOU	0	0	4,121,991	0	4,121,991	12,634,344	4,121,991	16,756,335	N/A	12,634,344	N/A
TE-MGSBC					250,216	1,508,321	250,216	1,758,537	N/A	1,508,321	N/A
General Service Unbilled	768,000	1,043,000		Unbilled is included above		0	0	0	N/A	0	N/A
Large General Service											
TE-LGS13	52,178,293	32,183,205	7,235,419	51,915,256	39,681,660	55,346,315	39,681,660	10,666,477	12.64%	3,431,058	3.75%
TE-LG85	15,878,358	10,579,443	(995,745)	15,386,190	10,075,866	13,330,654	10,075,866	(3,051,281)	-11.53%	(2,055,535)	-8.07%
TE-L13BC	1,151,576	720,248	272,859	1,159,123	985,560	1,843,317	985,560	957,052	51.13%	684,194	31.90%
Large General Service Unbilled	-911,000	933,000		Unbilled is included above		0	0	0	N/A	0	N/A
Large Power Service											
TE-LLP14	6,004,077	4,773,275	(9,605,725)	5,757,919	-4,586,292	0	0	0	0	N/A	N/A
Special	882,693	777,092	(1,659,785)	0	0	0	0	0	0	N/A	N/A
Large Power Service TOU	66,309,779	57,243,663	3,034,332	67,544,848	59,042,925	74,032,047	59,042,925	9,521,530	7.71%	6,487,199	5.12%
Industrial Unbilled	-5,000	35,000		Unbilled is included above		0	0	0	N/A	0	N/A
Transmission Service 138kV											
TE-T138kV	0	0	0	0	0	0	0	0	N/A	0	N/A
Lighting											
TE-P41	1,076,513	846,600	(35,111)	1,086,397	801,604	1,132,569	801,604	11,060	0.58%	46,172	2.45%
TE-P47	406,784	319,997	(11,146)	411,640	303,995	429,135	303,995	6,349	0.87%	17,495	2.44%
TE-R51 + TE-R51A	145,242	25,118	(2,571)	145,228	22,560	151,401	22,560	3,602	2.11%	6,173	3.68%
TE-C52 & 52A	1,293,110	184,528	(21,022)	1,290,979	165,636	1,345,956	165,636	33,955	2.30%	54,977	3.77%
TE-P50	364,539	69,816	(7,403)	364,539	62,413	380,032	62,413	8,090	1.86%	15,493	3.63%
Lighting Unbilled	17,000	23,000		Unbilled is included above		0	0	0	N/A	0	N/A

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5000	TE-R-01	**Residential Service**				
		Basic Service Charge Single Phase Per Mo.	$10.00	$10.00	$0.00	0%
		Basic Service Charge Three Phase Per Mo.	$15.00	$15.00	$0.00	0%
		Sum First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Sum 501-1,000 kWh	$0.067200	$0.070807	$0.003607	5%
		Sum 1,001-3,500 kWh	$0.079800	$0.084084	$0.004284	5%
		Sum>3,500 kWh	$0.088200	$0.084084	-$0.004116	-5%
		Win First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Win 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win 1,001-3,500 kWh	$0.078100	$0.082292	$0.004192	5%
		Win>3,500 kWh	$0.087100	$0.082292	-$0.004808	-6%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[(1)]	$0.006820	0.00%	N/M	N/M
		Solar Block Rate for Residential Electric Service Rate R-01	$0.053463	$0.055785	$0.002322	4%
XXXX	TE-RXXX	**Residential Service Demand**				
		Basic Service Charge Per Month	N/M	$20.00	N/M	N/M
		Demand 0-7 kW	N/M	$7.40	N/M	N/M
		Demand > 7 kW	N/M	$11.90	N/M	N/M
		Sum kWh	N/M	$0.025000	N/M	N/M
		Win kWh	N/M	$0.025000	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[(1)]	N/M	0.00%	N/M	N/M
5004	TE-201A	**Special Residential Electric Service**				
		Basic Service Charge	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.050600	$0.053316	$0.002716	5%
		Sum 501-1,000 kWh	$0.060500	$0.063748	$0.003248	5%
		Sum 1,001-3,500 kWh	$0.071800	$0.075654	$0.003854	5%
		Sum>3,500 kWh	$0.079400	$0.075654	-$0.003746	-5%
		Win First 500 kWh	$0.050600	$0.053316	$0.002716	5%
		Win 501-1,000 kWh	$0.058700	$0.061851	$0.003151	5%
		Win 1,001-3,500 kWh	$0.070300	$0.074074	$0.003774	5%
		Win>3,500 kWh	$0.078400	$0.074074	-$0.004326	-6%
		Base Power Summer kWh	$0.035111	$0.031726	-$0.003385	-10%
		Base Power Winter kWh	$0.031532	$0.028731	-$0.002801	-9%
		PPFAC Charge[(1)]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5005	TE-201B	**Special Residential Electric Service Time of Use**				
		Basic Service Charge	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak 501-1,000 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak1,001-3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak >3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum Off-peak First 500 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak 501-1,000 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak1,001-3,500 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak >3,500 kWh	$0.044000	$0.046362	$0.002362	5%
		Win On-peak First 500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak 501-1,000 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak1,001-3,500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak >3,500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win Off-peak First 500 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak 501-1,000 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak1,001-3,500 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak >3,500 kWh	$0.035500	$0.037406	$0.001906	5%
		Base Power Summer On-Peak kWh	$0.050669	$0.051680	$0.001011	2%
		Base Power Summer Off-Peak kWh	$0.026679	$0.021845	-$0.004834	-18%
		Base Power Winter On-peak kWh	$0.032893	$0.047600	$0.014707	45%
		Base Power Winter Off-peak kWh	$0.027092	$0.018785	-$0.008307	-31%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5040	TE-R80	**Residential Time of Use**				
		Basic Service Charge	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak 501-1,000 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak1,001-3,500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak >3,500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum Off-peak First 500 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak 501-1,000 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak1,001-3,500 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak >3,500 kWh	$0.051800	$0.054581	$0.002781	5%
		Win On-peak First 500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak 501-1,000 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak1,001-3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak >3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win Off-peak First 500 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak 501-1,000 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak1,001-3,500 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak >3,500 kWh	$0.041800	$0.044044	$0.002244	5%
		Base Power Summer On-Peak kWh	$0.050669	$0.060800	$0.010131	20%
		Base Power Summer Off-Peak kWh	$0.026679	$0.025700	-$0.000979	-4%
		Base Power Winter On-peak kWh	$0.032893	$0.056000	$0.023107	70%
		Base Power Winter Off-peak kWh	$0.027092	$0.022100	-$0.004992	-18%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
XXXX	TE-RXXX	**Residential Demand Time of Use**				
		Basic Service Charge Per Month	N/M	$20.00	N/M	N/M
		Demand 0-7 kW	N/M	$7.40	N/M	N/M
		Demand > 7 kW	N/M	$11.90	N/M	N/M
		Sum On-peak kWh	N/M	$0.025000	N/M	N/M
		Sum Off-peak kWh	N/M	$0.025000	N/M	N/M
		Win On-peak kWh	N/M	$0.025000	N/M	N/M
		Win Off-peak kWh	N/M	$0.025000	N/M	N/M
		Base Power Summer On-Peak kWh	N/M	$0.060800	N/M	N/M
		Base Power Summer Off-Peak kWh	N/M	$0.025700	N/M	N/M
		Base Power Winter On-peak kWh	N/M	$0.056000	N/M	N/M
		Base Power Winter Off-peak kWh	N/M	$0.022100	N/M	N/M
		PPFAC Charge(1)	N/M	0.00%	N/M	N/M
5042	TE-R8	**Residential Time of Use Super Peak**				
		Basic Service Charge	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.097100	$0.102312	$0.005212	5%
		Sum On-peak 501-1,000 kWh	$0.097100	$0.102312	$0.005212	5%
		Sum On-peak1,001-3,500 kWh	$0.120100	$0.126547	$0.006447	5%
		Sum On-peak >3,500 kWh	$0.120100	$0.126547	$0.006447	5%
		Sum Off-peak First 500 kWh	$0.048500	$0.051103	$0.002603	5%
		Sum Off-peak 501-1,000 kWh	$0.048500	$0.051103	$0.002603	5%
		Sum Off-peak1,001-3,500 kWh	$0.071500	$0.075338	$0.003838	5%
		Sum Off-peak >3,500 kWh	$0.071500	$0.075338	$0.003838	5%
		Win On-peak First 500 kWh	$0.089100	$0.093883	$0.004783	5%
		Win On-peak 501-1,000 kWh	$0.089100	$0.093883	$0.004783	5%
		Win On-peak1,001-3,500 kWh	$0.112100	$0.118118	$0.006018	5%
		Win On-peak >3,500 kWh	$0.112100	$0.118118	$0.006018	5%
		Win Off-peak First 500 kWh	$0.038500	$0.040567	$0.002067	5%
		Win Off-peak 501-1,000 kWh	$0.038500	$0.040567	$0.002067	5%
		Win Off-peak1,001-3,500 kWh	$0.061500	$0.064801	$0.003301	5%
		Win Off-peak >3,500 kWh	$0.061500	$0.064801	$0.003301	5%
		Base Power Summer On-Peak kWh	$0.080100	$0.082900	$0.002800	3%
		Base Power Summer Off-Peak kWh	$0.022200	$0.027700	$0.005500	25%
		Base Power Winter On-peak kWh	$0.040200	$0.082900	$0.042700	106%
		Base Power Winter Off-peak kWh	$0.020500	$0.024100	$0.003600	18%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5060	TE-R01BC	**Residential Service R-01 Bright Community Solar**				
		Basic Service Charge Single Phase	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Sum 501-1,000 kWh	$0.067200	$0.070807	$0.003607	5%
		Sum 1,001-3,500 kWh	$0.079800	$0.084084	$0.004284	5%
		Sum>3,500 kWh	$0.088200	$0.084084	-$0.004116	-5%
		Win First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Win 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win 1,001-3,500 kWh	$0.078100	$0.082292	$0.004192	5%
		Win>3,500 kWh	$0.087100	$0.082292	-$0.004808	-6%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5002	TE4-01	**Lifeline Residential Service Standard (Frozen 1996 - R-04-01F Senior % Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5008	TE4-21	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
		Basic Service Charge Per Month	$8.86	$8.86	$0.00	0%
		Sum On-Peak First 500 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak 501-1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak >1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum Off-Peak First 500 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak 501-1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak >1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak 501-1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak >1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Base Power Summer On-Peak kWh	$0.053198	$0.060800	$0.007602	14%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5009	TE4-70	**Lifeline Residential Time of Use (Frozen 1996 - Senior % Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Sum On-Peak First 500 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak 501-1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak >1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum Shldr-Peak First 500 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak >1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Off-Peak First 500 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak 501-1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak >1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Win On-Peak First 500 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak 501-1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak >1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win Off-Peak First 500 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak 501-1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak >1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Base Power Summer On-Peak kWh	$0.055698	$0.060800	$0.005102	9%
		Base Power Summer Shoulder kWh	$0.048198	$0.060800	$0.012602	26%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5010	TE5-01	**Lifeline Residential Service Standard (Frozen Lifeline % Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5012	TE5-21	**Residential Time of Use (Frozen Lifeline % Discount)**				
		Basic Service Charge Per Month	$8.86	$8.86	$0.00	0%
		Sum On-Peak First 500 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak 501-1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak >1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum Off-Peak First 500 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak 501-1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak >1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak 501-1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak >1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Base Power Summer On-Peak kWh	$0.053198	$0.060800	$0.007602	14%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5013	TE5-70	**Residential Time of Use (Frozen Lifeline % Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Sum On-Peak First 500 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak 501-1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak >1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum Shldr-Peak First 500 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak >1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Off-Peak First 500 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak 501-1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak >1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Win On-Peak First 500 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak 501-1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak >1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win Off-Peak First 500 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak 501-1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak >1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Base Power Summer On-Peak kWh	$0.055698	$0.060800	$0.005102	9%
		Base Power Summer Shoulder kWh	$0.048198	$0.060800	$0.012602	26%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5016	TE6-01	**Residential Service Standard (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5017	TE6-21	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$8.86	$8.86	$0.00	0%
		Sum On-Peak First 500 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak 501-1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak >1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum Off-Peak First 500 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak 501-1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak >1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak 501-1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak >1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Base Power Summer On-Peak kWh	$0.053198	$0.060800	$0.007602	14%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5022	TE6-70	**Residential Time of Use (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Sum On-Peak First 500 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak 501-1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak >1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum Shldr-Peak First 500 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak >1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Off-Peak First 500 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak 501-1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak >1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Win On-Peak First 500 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak 501-1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak >1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win Off-Peak First 500 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak 501-1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak >1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Base Power Summer On-Peak kWh	$0.055698	$0.060800	$0.005102	9%
		Base Power Summer Shoulder kWh	$0.048198	$0.060800	$0.012602	26%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5023	TE6-201A	**Special Residential Service (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Mid Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Mid Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Mid Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Remain Sum First 500 kWh	$0.043600	$0.045940	$0.002340	5%
		Remain Sum 501-1,000 kWh	$0.043600	$0.045940	$0.002340	5%
		Remain Sum >1,000 kWh	$0.043600	$0.045940	$0.002340	5%
		Win First 500 kWh	$0.041300	$0.043517	$0.002217	5%
		Win 501-1,000 kWh	$0.041300	$0.043517	$0.002217	5%
		Win >1,000 kWh	$0.041300	$0.043517	$0.002217	5%
		Base Power Mid Summer kWh	$0.033198	$0.031726	-$0.001472	-4%
		Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
		Base Power Winter kWh	$0.027198	$0.028731	$0.001533	6%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5024	TE6-201B	**Special Residential Service Time of Use (Frozen Lifeline Flat Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Mid Sum On-Peak First 500 kWh	$0.136900	$0.144249	$0.007349	5%
		Mid Sum On-Peak 501-1,000 kWh	$0.136900	$0.144249	$0.007349	5%
		Mid Sum On-Peak >1,000 kWh	$0.136900	$0.144249	$0.007349	5%
		Mid Sum Shlder-Peak First 500 kWh	$0.074700	$0.078710	$0.004010	5%
		Mid Sum Shldr-Peak 501-1,000 kWh	$0.074700	$0.078710	$0.004010	5%
		Mid Sum Shldr-Peak >1,000 kWh	$0.074700	$0.078710	$0.004010	5%
		Mid Sum Off-Peak First 500 kWh	$0.038300	$0.040356	$0.002056	5%
		Mid Sum Off-Peak 501-1,000 kWh	$0.038300	$0.040356	$0.002056	5%
		Mid Sum Off-Peak >1,000 kWh	$0.038300	$0.040356	$0.002056	5%
		Remain Sum On-Peak First 500 kWh	$0.099500	$0.104841	$0.005341	5%
		Remain Sum On-Peak 501-1,000 kWh	$0.099500	$0.104841	$0.005341	5%
		Remain Sum On-Peak >1,000 kWh	$0.099500	$0.104841	$0.005341	5%
		Remain Sum Shlder-Peak First 500 kWh	$0.048600	$0.051209	$0.002609	5%
		Remain Sum Shldr-Peak 501-1,000 kWh	$0.048600	$0.051209	$0.002609	5%
		Remain Sum Shldr-Peak >1,000 kWh	$0.048600	$0.051209	$0.002609	5%
		Remain Sum Off-Peak First 500 kWh	$0.025300	$0.026658	$0.001358	5%
		Remain Sum Off-Peak 501-1,000 kWh	$0.025300	$0.026658	$0.001358	5%
		Remain Sum Off-Peak >1,000 kWh	$0.025300	$0.026658	$0.001358	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.015300	$0.016121	$0.000821	5%
		Win Off-Peak 501-1,000 kWh	$0.015300	$0.016121	$0.000821	5%
		Win Off-Peak >1,000 kWh	$0.015300	$0.016121	$0.000821	5%
		Base Power Mid Summer On-Peak kWh	$0.055698	$0.054723	-$0.000975	-2%
		Base Power Mid Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
		Base Power Mid Summer Off-Peak kWh	$0.023198	$0.021845	-$0.001353	-6%
		Base Power Remaining Summer On-Peak kWh	$0.055698	$0.000000	-$0.055698	-100%
		Base Power Remaining Summer Shoulder kWh	$0.048198	$0.000000	-$0.048198	-100%
		Base Power Remaining Summer Off-Peak kWh	$0.023198	$0.000000	-$0.023198	-100%
		Base Power Winter On-Peak kWh	$0.040698	$0.047600	$0.006902	17%
		Base Power Winter Off-Peak kWh	$0.020698	$0.018785	-$0.001913	-9%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5026	TE8-01	**Residential Service Standard (Frozen Lifeline Medical % Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5027	TE8-21	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
		Basic Service Charge Per Month	$8.86	$8.86	$0.00	0%
		Sum On-Peak First 500 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak 501-1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum On-Peak >1,000 kWh	$0.078800	$0.083030	$0.004230	5%
		Sum Off-Peak First 500 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak 501-1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Sum Off-Peak >1,000 kWh	$0.030100	$0.031716	$0.001616	5%
		Win On-Peak First 500 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win On-Peak >1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win Off-Peak First 500 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak 501-1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Win Off-Peak >1,000 kWh	$0.033000	$0.034771	$0.001771	5%
		Base Power Summer On-Peak kWh	$0.053198	$0.060800	$0.007602	14%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5028	TE8-70	**Residential Time of Use (Frozen Lifeline Medical % Discount)**				
		Basic Service Charge Per Month	$8.78	$8.78	$0.00	0%
		Sum On-Peak First 500 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak 501-1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum On-Peak >1,000 kWh	$0.139300	$0.146778	$0.007478	5%
		Sum Shldr-Peak First 500 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak 501-1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Shldr-Peak >1,000 kWh	$0.074000	$0.077972	$0.003972	5%
		Sum Off-Peak First 500 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak 501-1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Sum Off-Peak >1,000 kWh	$0.037900	$0.039934	$0.002034	5%
		Win On-Peak First 500 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak 501-1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win On-Peak >1,000 kWh	$0.092500	$0.097465	$0.004965	5%
		Win Off-Peak First 500 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak 501-1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Win Off-Peak >1,000 kWh	$0.024900	$0.026237	$0.001337	5%
		Base Power Summer On-Peak kWh	$0.055698	$0.060800	$0.005102	9%
		Base Power Summer Shoulder kWh	$0.048198	$0.060800	$0.012602	26%
		Base Power Summer Off-Peak kWh	$0.023198	$0.025700	$0.002502	11%
		Base Power Winter On-peak kWh	$0.040698	$0.056000	$0.015302	38%
		Base Power Winter Off-peak kWh	$0.020698	$0.022100	$0.001402	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5029	TE8-201A	**Special Residential Service (Frozen Lifeline Medical % Discount)**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Mid Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Mid Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Mid Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Remain Sum First 500 kWh	$0.043600	$0.045940	$0.002340	5%
		Remain Sum 501-1,000 kWh	$0.043600	$0.045940	$0.002340	5%
		Remain Sum >1,000 kWh	$0.043600	$0.045940	$0.002340	5%
		Win First 500 kWh	$0.041300	$0.043517	$0.002217	5%
		Win 501-1,000 kWh	$0.041300	$0.043517	$0.002217	5%
		Win >1,000 kWh	$0.041300	$0.043517	$0.002217	5%
		Base Power Mid Summer kWh	$0.033198	$0.031726	-$0.001472	-4%
		Base Power Remaining Summer kWh	$0.033198	$0.000000	-$0.033198	-100%
		Base Power Winter kWh	$0.027198	$0.028731	$0.001533	6%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5032	TE6-01BC	**Residential Service Standard (Frozen Lifeline Flat Discount) Bright Community Solar**				
		Basic Service Charge Per Month	$6.90	$6.90	$0.00	0%
		Sum First 500 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum 501-1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Sum >1,000 kWh	$0.061100	$0.064380	$0.003280	5%
		Win First 500 kWh	$0.057000	$0.060060	$0.003060	5%
		Win 501-1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Win >1,000 kWh	$0.057000	$0.060060	$0.003060	5%
		Base Power Summer kWh	$0.033198	$0.037325	$0.004127	12%
		Base Power Winter kWh	$0.025698	$0.033801	$0.008103	32%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5033	TE-R-01LL	**Residential Service Standard**				
		Basic Service Charge Per Month	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Sum 501-1,000 kWh	$0.067200	$0.070807	$0.003607	5%
		Sum 1,001-3,500 kWh	$0.079800	$0.084084	$0.004284	5%
		Sum>3,500 kWh	$0.088200	$0.092935	$0.004735	5%
		Win First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Win 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win 1,001-3,500 kWh	$0.078100	$0.082292	$0.004192	5%
		Win>3,500 kWh	$0.087100	$0.091776	$0.004676	5%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
5034	TE-R01LB	**Residential Service R-01 Bright Community Solar**				
		Basic Service Charge Per Month	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Sum 501-1,000 kWh	$0.067200	$0.070807	$0.003607	5%
		Sum 1,001-3,500 kWh	$0.079800	$0.084084	$0.004284	5%
		Sum>3,500 kWh	$0.088200	$0.092935	$0.004735	5%
		Win First 500 kWh	$0.056200	$0.059217	$0.003017	5%
		Win 501-1,000 kWh	$0.065200	$0.068700	$0.003500	5%
		Win 1,001-3,500 kWh	$0.078100	$0.082292	$0.004192	5%
		Win>3,500 kWh	$0.087100	$0.091776	$0.004676	5%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5035	TE-201AL	**Special Residential Electric Service**				
		Basic Service Charge Per Month	$10.00	$10.00	$0.00	0%
		Sum First 500 kWh	$0.050600	$0.053316	$0.002716	5%
		Sum 501-1,000 kWh	$0.060500	$0.063748	$0.003248	5%
		Sum 1,001-3,500 kWh	$0.071800	$0.075654	$0.003854	5%
		Sum>3,500 kWh	$0.079400	$0.083662	$0.004262	5%
		Win First 500 kWh	$0.050600	$0.053316	$0.002716	5%
		Win 501-1,000 kWh	$0.058700	$0.061851	$0.003151	5%
		Win 1,001-3,500 kWh	$0.070300	$0.074074	$0.003774	5%
		Win>3,500 kWh	$0.078400	$0.082609	$0.004209	5%
		Base Power Summer kWh	$0.035111	$0.031726	-$0.003385	-10%
		Base Power Winter kWh	$0.031532	$0.028731	-$0.002801	-9%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5036	TE-201BL	**Residential Time of Use**				
		Basic Service Charge Per Month	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak 501-1,000 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak1,001-3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum On-peak >3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Sum Off-peak First 500 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak 501-1,000 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak1,001-3,500 kWh	$0.044000	$0.046362	$0.002362	5%
		Sum Off-peak >3,500 kWh	$0.044000	$0.046362	$0.002362	5%
		Win On-peak First 500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak 501-1,000 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak1,001-3,500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win On-peak >3,500 kWh	$0.048300	$0.050893	$0.002593	5%
		Win Off-peak First 500 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak 501-1,000 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak1,001-3,500 kWh	$0.035500	$0.037406	$0.001906	5%
		Win Off-peak >3,500 kWh	$0.035500	$0.037406	$0.001906	5%
		Base Power Summer On-Peak kWh	$0.050669	$0.051680	$0.001011	2%
		Base Power Summer Off-Peak kWh	$0.026679	$0.021845	-$0.004834	-18%
		Base Power Winter On-peak kWh	$0.032893	$0.047600	$0.014707	45%
		Base Power Winter Off-peak kWh	$0.027092	$0.018785	-$0.008307	-31%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5041	TE-R80LL	**Residential Time of Use**				
		Basic Service Charge Per Month	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak 501-1,000 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak1,001-3,500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum On-peak >3,500 kWh	$0.066800	$0.070386	$0.003586	5%
		Sum Off-peak First 500 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak 501-1,000 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak1,001-3,500 kWh	$0.051800	$0.054581	$0.002781	5%
		Sum Off-peak >3,500 kWh	$0.051800	$0.054581	$0.002781	5%
		Win On-peak First 500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak 501-1,000 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak1,001-3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win On-peak >3,500 kWh	$0.056800	$0.059849	$0.003049	5%
		Win Off-peak First 500 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak 501-1,000 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak1,001-3,500 kWh	$0.041800	$0.044044	$0.002244	5%
		Win Off-peak >3,500 kWh	$0.041800	$0.044044	$0.002244	5%
		Base Power Summer On-Peak kWh	$0.050669	$0.060800	$0.010131	20%
		Base Power Summer Off-Peak kWh	$0.026679	$0.025700	-$0.000979	-4%
		Base Power Winter On-peak kWh	$0.032893	$0.056000	$0.023107	70%
		Base Power Winter Off-peak kWh	$0.027092	$0.022100	-$0.004992	-18%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5043	TE-R8LL	**Residential Time of Use Super Peak Lifeline**				
		Basic Service Charge Per Month	$11.50	$11.50	$0.00	0%
		Sum On-peak First 500 kWh	$0.097100	$0.102312	$0.005212	5%
		Sum On-peak 501-1,000 kWh	$0.097100	$0.102312	$0.005212	5%
		Sum On-peak1,001-3,500 kWh	$0.120100	$0.126547	$0.006447	5%
		Sum On-peak >3,500 kWh	$0.120100	$0.126547	$0.006447	5%
		Sum Off-peak First 500 kWh	$0.048500	$0.051103	$0.002603	5%
		Sum Off-peak 501-1,000 kWh	$0.048500	$0.051103	$0.002603	5%
		Sum Off-peak1,001-3,500 kWh	$0.071500	$0.075338	$0.003838	5%
		Sum Off-peak >3,500 kWh	$0.071500	$0.075338	$0.003838	5%
		Win On-peak First 500 kWh	$0.089100	$0.093883	$0.004783	5%
		Win On-peak 501-1,000 kWh	$0.089100	$0.093883	$0.004783	5%
		Win On-peak1,001-3,500 kWh	$0.112100	$0.118118	$0.006018	5%
		Win On-peak >3,500 kWh	$0.112100	$0.118118	$0.006018	5%
		Win Off-peak First 500 kWh	$0.038500	$0.040567	$0.002067	5%
		Win Off-peak 501-1,000 kWh	$0.038500	$0.040567	$0.002067	5%
		Win Off-peak1,001-3,500 kWh	$0.061500	$0.064801	$0.003301	5%
		Win Off-peak >3,500 kWh	$0.061500	$0.064801	$0.003301	5%
		Base Power Summer On-Peak kWh	$0.080100	$0.082900	$0.002800	3%
		Base Power Summer Off-Peak kWh	$0.022200	$0.027700	$0.005500	25%
		Base Power Winter On-peak kWh	$0.040200	$0.082900	$0.042700	106%
		Base Power Winter Off-peak kWh	$0.020500	$0.024100	$0.003600	18%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

RUCO Schedule H-3

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
XXXX	TE-PESXX	**Prepay Electric Service**				
		Basic Service Charge Per Day	N/M	$0.84	N/M	N/M
		Sum First 20 kWh Per Day	N/M	$0.064000	N/M	N/M
		Sum >20 kWh Per Day	N/M	$0.079000	N/M	N/M
		Win First 20 kWh Per Day	N/M	$0.064000	N/M	N/M
		Win >20 kWh Per Day	N/M	$0.079000	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
5200	TE-GS10	**Small General Service**				
		Basic Service Charge Single Phase Per Mo.	$15.50	$15.50	$0.00	0%
		Basic Service Charge Three Phase Per Mo.	$20.50	$20.50	$0.00	0%
		Sum First 500 kWh	$0.077000	$0.094095	$0.017095	22%
		Sum >500 kWh	$0.097800	$0.119550	$0.021750	22%
		Win First 500 kWh	$0.057000	$0.069747	$0.012747	22%
		Win >500 kWh	$0.079000	$0.096676	$0.017676	22%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
XXXX	TE-GSXX	**Small General Service Demand**				
		Basic Service Charge Per Month	N/M	$30.00	N/M	N/M
		Demand 0-7 kW	N/M	$9.95	N/M	N/M
		Demand > 7 kW	N/M	$13.90	N/M	N/M
		Sum kWh	N/M	$0.057500	N/M	N/M
		Win kWh	N/M	$0.047500	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
5201	TE-GS11	**Mobile Home Park Service (FROZEN)**				
		Basic Service Charge Single Phase Per Mo.	$15.50	$15.50	$0.00	0%
		Basic Service Charge Three Phase Per Mo.	$20.50	$20.50	$0.00	0%
		Sum kWh	$0.082000	$0.100389	$0.018389	22%
		Win kWh	$0.062000	$0.075904	$0.013904	22%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5213	TE-GS76	**Small General Service Time of Use**				
		Basic Service Charge	$17.50	$15.50	-$2.00	-11%
		Sum On-peak First 500 kWh	$0.099100	$0.094095	-$0.005005	-5%
		Sum On-peak >500 kWh	$0.099100	$0.119550	$0.020450	21%
		Sum Off-peak First 500 kWh	$0.084900	$0.094095	$0.009195	11%
		Sum Off-peak >500 kWh	$0.084900	$0.119550	$0.034650	41%
		Winter On-peak First 500 kWh	$0.081400	$0.069747	-$0.011653	-14%
		Winter On-peak >500 kWh	$0.081400	$0.096676	$0.015276	19%
		Winter Off-Peak First 500 kWh	$0.064900	$0.069747	$0.004847	7%
		Winter Off-Peak >500 kWh	$0.064900	$0.096676	$0.031776	49%
		Base Power Summer On-Peak kWh	$0.050669	$0.060800	$0.010131	20%
		Base Power Summer Off-Peak kWh	$0.026679	$0.025700	-$0.000979	-4%
		Base Power Winter On-peak kWh	$0.032893	$0.056000	$0.023107	70%
		Base Power Winter Off-peak kWh	$0.027092	$0.022100	-$0.004992	-18%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
		Solar Block Rate for Small General Service Rate GS-10	$0.053274	$0.055557	$0.002283	4%
XXXX	TE-GSXXX	**Small General Service Demand Time of Use**				
		Basic Service Charge Per Month	N/M	$30.00	N/M	N/M
		Demand 0-7 kW	N/M	$9.95	N/M	N/M
		Demand > 7 kW	N/M	$13.90	N/M	N/M
		Sum On-peak kWh	N/M	$0.057500	N/M	N/M
		Sum Off-peak kWh	N/M	$0.057500	N/M	N/M
		Win On-peak kWh	N/M	$0.047500	N/M	N/M
		Win Off-peak kWh	N/M	$0.047500	N/M	N/M
		Base Power Summer On-Peak kWh	N/M	$0.060800	N/M	N/M
		Base Power Summer Off-Peak kWh	N/M	$0.025700	N/M	N/M
		Base Power Winter On-peak kWh	N/M	$0.056000	N/M	N/M
		Base Power Winter Off-peak kWh	N/M	$0.022100	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
5225	TE-G10BC	**General Service Bright Community Solar**				
		Basic Service Charge Single Phase Per Month	$15.50	$15.50	$0.00	0%
		Basic Service Charge Three Phase Per Month	$20.50	$20.50	$0.00	0%
		Sum First 500 kWh	$0.077000	$0.094095	$0.017095	22%
		Sum>500 kWh	$0.097800	$0.119550	$0.021750	22%
		Winter First 500 kWh 0568	$0.057000	$0.069747	$0.012747	22%
		Winter >500 kWh 0788	$0.079000	$0.096676	$0.017676	22%
		Winter First 500 kWh 0570	$0.057000	$0.000000	-$0.057000	-100%
		Winter >500 kWh 0790	$0.079000	$0.000000	-$0.079000	-100%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		Solar Blocks kWh_2011	$0.028475	$0.028475	$0.000000	0%
		Solar Blocks kWh_2013	$0.033274	$0.033274	$0.000000	0%
		Solar Blocks kWh_20xx	$0.028475	$0.028475	$0.000000	0%
		Credited Solar Blocks kWh_2011	-$0.028475	-$0.028475	$0.000000	0%
		Credited Solar Blocks kWh_2013	-$0.033274	-$0.033274	$0.000000	0%
		Credited Solar Blocks kWh_20xx	-$0.028475	-$0.028475	$0.000000	0%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5230	TE-GSM10	**Small General Service (Municipal Transitional Adjustment)**				
		Basic Service Charge Single Phase Per Month	$15.50	$15.50	$0.00	0%
		Basic Service Charge Three Phase Per Month	$20.50	$20.50	$0.00	0%
		Sum First 500 kWh	$0.077000	$0.094095	$0.017095	22%
		Sum>500 kWh	$0.097800	$0.119550	$0.021750	22%
		Win First 500 kWh	$0.057000	$0.069747	$0.012747	22%
		Win>500 kWh	$0.079000	$0.096676	$0.017676	22%
		Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5231	TE-G10MBC	**General Service (Municipal Transitional Adjustment) Bright Community Solar**				
		Basic Service Charge Three Phase Per Month	$20.50	$15.50	-$5.00	-24%
		Sum First 500 kWh	$0.077000	$0.094095	$0.017095	22%
		Sum>500 kWh	$0.097800	$0.119550	$0.021750	22%
		Win First 500 kWh	$0.057000	$0.069747	$0.012747	22%
		Win>500 kWh	$0.079000	$0.096676	$0.017676	22%
		Transitional Adjustment	16.50%	0.00%	-$0.165000	-100%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
		RT 43 Water Pumping				
5240	TE-GS36	GS-36 (43) Water Pumping-Firm Service				
		Basic Service Charge Per Mo.	$15.50	$15.50	$0.00	0%
		Sum kWh	$0.068000	$0.083249	$0.015249	22%
		Win kWh	$0.048000	$0.058764	$0.010764	22%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5240	TE-GS37	GS-37 Com Water Pumping-Firm w/ Primary Voltage Discount				
		Basic Service Charge Per Mo.	$15.50	$15.50	$0.00	0%
		Sum kWh	$0.064600	$0.079087	$0.014487	22%
		Win kWh	$0.045600	$0.055826	$0.010226	22%
		Base Power Summer kWh	$0.033355	$0.035459	$0.002103	6%
		Base Power Winter kWh	$0.029955	$0.032111	$0.002156	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5240	TE-GS38	GS-38 (43) Water Pumping-Interruptible Serv				
		Basic Service Charge Per Mo.	$15.50	$15.50	$0.00	0%
		Sum kWh	$0.042000	$0.057200	$0.015200	36%
		Win kWh	$0.027000	$0.037800	$0.010800	40%
		Base Power Summer kWh	$0.031310	$0.033500	$0.002190	7%
		Base Power Winter kWh	$0.028420	$0.030700	$0.002280	8%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5240	TE-GS39	GS-39 (43) Water Pumping-Interupt w/Primary Voltage Discount				
		Basic Service Charge Per Mo.	$15.50	$15.50	$0.00	0%
		Sum kWh	$0.039900	$0.054300	$0.014400	36%
		Win kWh	$0.025650	$0.035900	$0.010250	40%
		Base Power Summer kWh	$0.029745	$0.031825	$0.002081	7%
		Base Power Winter kWh	$0.026999	$0.029165	$0.002166	8%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
XXXX	TE-MGS	**Medium General Service**				
		Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
		Summer Demand Charge Per kW	N/M	$8.00	N/M	N/M
		Winter Demand Charge Per kW	N/M	$6.00	N/M	N/M
		Summer kWh	N/M	$0.083249	N/M	N/M
		Winter kWh	N/M	$0.058764	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
		Solar Block Rate for Medium General Service Rate MGS	$0.053227	0.055539		
XXXX	TE-MGSTOU	**Medium General Service TOU**				
		Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
		Demand Summer On-Peak per kW	N/M	$8.00	N/M	N/M
		Demand Summer Off-Peak Excess Per kW	N/M	$4.76	N/M	N/M
		Demand Winter On-Peak Per kW	N/M	$4.00	N/M	N/M
		Demand Winter Off-Peak Excess Per kW	N/M	$3.50	N/M	N/M
		Summer On-Peak kWh	N/M	$0.115800	N/M	N/M
		Summer Off-Peak kWh	N/M	$0.073100	N/M	N/M
		Winter On-Peak kWh	N/M	$0.115800	N/M	N/M
		Winter Off-Peak kWh	N/M	$0.073100	N/M	N/M
		Base Power Summer On-Peak kWh	N/M	$0.060800	N/M	N/M
		Base Power Summer Off-Peak kWh	N/M	$0.025700	N/M	N/M
		Base Power Winter On-peak kWh	N/M	$0.056000	N/M	N/M
		Base Power Winter Off-peak kWh	N/M	$0.022100	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M
XXXX	TE-MGSBC	**Medium General Service Bright Community solar**				
		Basic Service Charge Per Month	N/M	$40.00	N/M	N/M
		Summer Demand Charge Per kW	N/M	$8.00	N/M	N/M
		Winter Demand Charge Per kW	N/M	$6.00	N/M	N/M
		Summer kWh	N/M	$0.083249	N/M	N/M
		Winter kWh	N/M	$0.058764	N/M	N/M
		Base Power Summer kWh	N/M	$0.037325	N/M	N/M
		Base Power Winter kWh	N/M	$0.033801	N/M	N/M
		PPFAC Charge[1]	N/M	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5300	TE-LGS13	**Large General Service**				
		Basic Service Charge Per Month	$775.00	$775.00	$0.00	0%
		Demand Charge Per kW	$15.25	$10.43	-$4.83	-32%
		Summer kWh	$0.0192	$0.0192	$0.000000	0%
		Winter kWh	$0.0134	$0.0134	$0.000000	0%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5305	TE-LG85	**Large General Service TOU**				
		Basic Service Charge Per Month	$950.00	$950.00	$0.00	0%
		Demand Summer On-Peak per kW	$14.55	$10.43	-$4.13	-28%
		Demand Summer Off-Peak Per kW	$10.92	$10.43	-$0.49	-5%
		Demand Winter On-Peak Per kW	$11.59	$11.59	$0.00	0%
		Demand Winter Off-Peak Per kW	$9.10	$9.10	$0.00	0%
		Summer On-Peak kWh	$0.008600	$0.008600	$0.000000	0%
		Summer Off-Peak kWh	$0.006000	$0.016900	$0.010900	182%
		Winter On-Peak kWh	$0.003000	$0.008600	$0.005600	187%
		Winter Off-Peak kWh	$0.000500	$0.016900	$0.016400	3280%
		Base Power Summer On-Peak kWh	$0.050669	$0.060800	$0.010131	20%
		Base Power Summer Off-Peak kWh	$0.026679	$0.025700	-$0.000979	-4%
		Base Power Winter On-peak kWh	$0.032893	$0.056000	$0.023107	70%
		Base Power Winter Off-peak kWh	$0.027092	$0.022100	-$0.004992	-18%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5322	TE-L13BC	**Large General Service Brigh Community Solar**				
		Basic Service Charge Per Month	$775.00	$775.00	$0.00	0%
		Demand Charge Per kW	$15.25	$10.43	-$4.83	-32%
		Summer kWh	$0.0192	$0.0192	$0.000000	0%
		Winter kWh	$0.0134	$0.0134	$0.000000	0%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		Solar_Blocks_kWh_053227_2P	$0.033227	$0.033227	$0.000000	0%
		Solar_Blocks_kWh_039371_1_1P	$0.029371	$0.029371	$0.000000	0%
		Credited_Blocks_kWh_039371_1_1P	-$0.029371	-$0.029371	$0.000000	0%
		Solar_Blocks_kWh_039371_2_1P	$0.029371	$0.029371	$0.000000	0%
		Credited_Blocks_kWh_039371_2_1P	-$0.029371	-$0.029371	$0.000000	0%
		PPFAC Charge[1]	$0.006820	0.00%	N/M	N/M
5301	TE-LLP14	**Large Light & Power**		$0.00	$0.00	
		Basic Service Charge	$1,800.00	N/M	N/M	N/M
		Demand Charge	21.98	N/M	N/M	N/M
		Summer kWh	0.0032	N/M	N/M	N/M
		Winter kWh	0.0021	N/M	N/M	N/M
		Base Power Summer kWh	0.031611	N/M	N/M	N/M
		Base Power Winter kWh	0.028388	N/M	N/M	N/M
		PPFAC Charge[1]	$0.006820	N/M	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5309	TE-LLP90	Large Power Service Time of Use				
		Basic Service Charge Per Month	$2,000.00	$2,000.00	$0.00	0%
		Demand Summer On-Peak per kW	$20.49	$25.11	$4.62	23%
		Demand Summer Off-Peak Excess Per kW	$12.49	$12.49	$0.00	0%
		Demand Winter On-Peak Per kW	$15.49	$12.56	-$2.94	-19%
		Demand Winter Off-Peak Excess Per kW	$9.99	$9.99	$0.00	0%
		Summer On-Peak kWh	$0.006900	$0.006900	$0.000000	0%
		Summer Off-Peak kWh	$0.006500	$0.006500	$0.000000	0%
		Winter On-Peak kWh	$0.007500	$0.007500	$0.000000	0%
		Winter Off-Peak kWh	$0.007100	$0.007100	$0.000000	0%
		Base Power Summer On-Peak kWh	$0.045568	$0.057760	$0.012192	27%
		Base Power Summer Off-Peak kWh	$0.023985	$0.024415	$0.000430	2%
		Base Power Winter On-peak kWh	$0.029581	$0.053200	$0.023619	80%
		Base Power Winter Off-peak kWh	$0.024352	$0.020995	-$0.003357	-14%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M
XXXX	TE-138	Transmission Service Rate 138kV				
		Basic Service Charge Per Month	N/M	$3,000.00	N/M	N/M
		Demand Summer On-Peak per kW	N/M	$17.15	N/M	N/M
		Demand Summer Off-Peak Excess Per kW	N/M	$12.49	N/M	N/M
		Demand Winter On-Peak Per kW	N/M	$14.15	N/M	N/M
		Demand Winter Off-Peak Excess Per kW	N/M	$9.99	N/M	N/M
		Summer On-Peak kWh	N/M	$0.006900	N/M	N/M
		Summer Off-Peak kWh	N/M	$0.006500	N/M	N/M
		Winter On-Peak kWh	N/M	$0.007500	N/M	N/M
		Winter Off-Peak kWh	N/M	$0.007100	N/M	N/M
		Base Power Summer On-Peak kWh	N/M	$0.056544	N/M	N/M
		Base Power Summer Off-Peak kWh	N/M	$0.023901	N/M	N/M
		Base Power Winter On-peak kWh	N/M	$0.052080	N/M	N/M
		Base Power Winter Off-peak kWh	N/M	$0.020553	N/M	N/M
		PPFAC Charge(1)	N/M	0.00%	N/M	N/M
5400	TE-P41&P47	P41 Traffic Signal & Street Lighting				
		Basic Service Charge Per Month	$0.00	$0.00	$0.00	0%
		All Delivery kWh	$0.047600	$0.049623	$0.002023	4%
		Base Power Summer kWh	$0.035111	$0.037325	$0.002214	6%
		Base Power Winter kWh	$0.031532	$0.033801	$0.002269	7%
		PPFAC Charge(1)	$0.006820	0.00%	N/M	N/M

Tucson Electric Power Company
Comparison of Revenues by Rate Schedule
Present and Proposed Revenues
Test Year Ended June 30, 2015

Dist. ID	Rate Id	Rate Description	Present Rates	Proposed Rates	Increase $	Increase %
5402	TE-P50	Lighting Service				
5011	TE-R51 + TE-R5:	100OH	$8.19	$8.54	$0.35	4%
5203	TE-C52 & 52A	100UG	$23.72	$24.73	$1.01	4%
		250OH	$12.29	$12.81	$0.52	4%
		250UG	$27.82	$29.00	$1.18	4%
		400OH	$18.70	$19.49	$0.79	4%
		400UG	$34.23	$35.68	$1.45	4%
		55OH	$8.19	$8.54	$0.35	4%
		55P	$8.19	$8.54	$0.35	4%
		55UG	$23.72	$24.73	$1.01	4%
		70UG	$23.72	$24.73	$1.01	4%
		Pole	$2.86	$2.98	$0.12	4%
		Base Power				
		100OH	$1.34	$1.37	$0.03	2%
		100UG	$1.34	$1.37	$0.03	2%
		250OH	$3.36	$3.42	$0.06	2%
		250UG	$3.36	$3.42	$0.06	2%
		400OH	$5.38	$5.30	-$0.08	-1%
		400UG	$5.38	$5.30	-$0.08	-1%
		55OH	$0.85	$0.87	$0.02	2%
		55P	$0.85	$0.87	$0.02	2%
		55UG	$0.85	$0.87	$0.02	2%
		70UG	$0.94	$0.96	$0.02	2%

Note:
(1) The Present Rate for the PPFAC is the Test Year PPFAC. 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. In this proposal the Company has proposed the PPFAC be a 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).

RESIDENTIAL SERVICE RATE R-01

WINTER

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06520	$0.07810	$0.08710	$0.031532	$0.00682	
Small	520	500	20	0	0	$10.00	$28.10	$1.30	$0.00	$0.00	$16.40	$3.55	$59.35
Medium	840	500	340	0	0	$10.00	$28.10	$22.17	$0.00	$0.00	$26.49	$5.73	$92.49
Large	1,250	500	500	250	0	$10.00	$28.10	$32.60	$19.53	$0.00	$39.42	$8.53	$138.18
XLg	1,564	500	500	564	0	$10.00	$28.10	$32.60	$44.05	$0.00	$49.32	$10.67	$174.74
AnnAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78
ResAvg	785	500	285	0	0	$10.00	$28.10	$18.58	$0.00	$0.00	$24.75	$5.35	$86.78

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000			500	1000	>1000						
						$10.00	$0.05910	$0.07910	$0.07910		$0.033801	0.0000%			
Small	520	500	20	0		$10.00	$29.55	$1.58	$0.00		$17.58	$0.00	$58.71	-$0.64	-1.1%
Medium	840	500	340	0		$10.00	$29.55	$26.89	$0.00		$28.39	$0.00	$94.83	$2.34	2.5%
Large	1,250	500	500	250		$10.00	$29.55	$39.55	$19.78		$42.25	$0.00	$141.13	$2.95	2.1%
XLg	1,564	500	500	564		$10.00	$29.55	$39.55	$44.61		$52.86	$0.00	$176.57	$1.83	1.0%
AnnAvg	785	500	285	0		$10.00	$29.55	$22.54	$0.00		$26.53	$0.00	$88.62	$1.84	2.1%
ResAvg	785	500	285	0		$10.00	$29.55	$22.54	$0.00		$26.53	$0.00	$88.62	$1.84	2.1%

Tucson Electric Power Company
Typical Bill Comparison - Present and Proposed Rates
Test Period Ending June 30, 2015

RESIDENTIAL SERVICE RATE R-01

Summer

BILL IMPACTS CURRENT RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill
		500	1000	3500	>3500		500	1000	3500	>3500			
						$10.00	$0.05620	$0.06720	$0.07980	$0.08820	$0.035111	$0.00682	
Small	822	500	322	0	0	$10.00	$28.10	$21.64	$0.00	$0.00	$28.86	$5.61	$94.21
Medium	1,384	500	500	384	0	$10.00	$28.10	$33.60	$30.64	$0.00	$48.59	$9.44	$160.37
Large	1,997	500	500	997	0	$10.00	$28.10	$33.60	$79.56	$0.00	$70.12	$13.62	$235.00
XLg	2,430	500	500	1,430	0	$10.00	$28.10	$33.60	$114.11	$0.00	$85.32	$16.57	$287.70
AnnAvg	785	500	285	0	0	$10.00	$28.10	$19.15	$0.00	$0.00	$27.56	$5.35	$90.16
ResAvg	1,150	500	500	150	0	$10.00	$28.10	$33.60	$11.97	$0.00	$40.38	$7.84	$131.89

BILL IMPACTS PROPOSED RATES

	kWh	Delivery (kWh) TIERS				Basic Service Charge	Delivery				Base Fuel	PPFAC	Net Bill	$ Change	% Change
		500	1000	>1000			500	1000	>1000						
						$10.00	$0.05922	$0.07081	$0.08408		$0.037325	0.0000%			
Small	822	500	322	0		$10.00	$29.61	$22.80	$0.00		$30.68	$0.00	$93.09	-$1.12	-1.2%
Medium	1,384	500	500	384		$10.00	$29.61	$35.40	$32.29		$51.66	$0.00	$158.96	-$1.41	-0.9%
Large	1,997	500	500	997		$10.00	$29.61	$35.40	$83.83		$74.54	$0.00	$233.38	-$1.62	-0.7%
XLg	2,430	500	500	1,430		$10.00	$29.61	$35.40	$120.24		$90.70	$0.00	$285.95	-$1.75	-0.6%
AnnAvg	785	500	285	0		$10.00	$29.61	$20.18	$0.00		$29.30	$0.00	$89.09	-$1.07	-1.2%
ResAvg	1,150	500	500	150		$10.00	$29.61	$35.40	$12.61		$42.92	$0.00	$130.54	-$1.35	-1.0%