0000173632

ORIGINAL

Transcript Exhibit(s)

Docket #(s): E-01933A-15-0239

E-01933A-15-0322

Exhibit #: TEP 26-30; IBEW 1-3

Part 3 of 7

For part 1 and 2, see barcodes 0000173630 + 0000173631

For parts 4 through 7, see barcodes 0000173633 through 0000173636

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
SUSAN BITTER SMITH - CHAIRMAN
BOB STUMP
BOB BURNS
DOUG LITTLE
TOM FORESE

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	)))))))))	DOCKET NO. E-01933A-15-______

Direct Testimony of

Carmine A. Tilghman

on Behalf of

Tucson Electric Power Company

November 5, 2015

EXHIBIT
TEP-26
ADMITTED

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

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

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

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

Q. Please describe your background and work experience.

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

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

In 2010, I took over all aspects of renewable energy development for both TEP and UNS Electric. In my current position, I am responsible for the renewable resources and renewable resource programs for the Companies, including compliance with the Arizona Corporation Commission's ("Commission") Renewable Energy Standard and Tariff Rules ("REST Rules") (A.A.C. R14-2-1801 through R14-2-1818)). In 2013, I added oversight of the Wholesale Marketing department to my duties, and in 2014 was promoted to Senior Director.

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

Q. What is the purpose of your Direct Testimony?

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

II. INVESTMENTS AND RENEWABLE GENERATION RESOURCES.

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

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

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

A. Approximately $65 Million.

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

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

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

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

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

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

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

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

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

III. IMPACT OF RENEWABLE ENERGY ON UTILITY OPERATIONS.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

C) While high penetration of DG can help relieve feeder and circuit overload conditions during peaking months, the resulting over-generation and higher exports during the shoulder months often results in reverse power flow and overload conditions.

IV. NET METERING AND THE RENEWABLE CREDIT RATE.

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

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

Q. Please describe the Renewable Credit Rate.

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

---

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

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

Q. Will the Renewable Credit Rate Change?

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

Q. How will the Company purchase the excess energy produced by the Net Metering customer's facility?

A. Net Metering customers would be compensated for any excess energy their DG facility produces and delivers to TEP with a credit on their monthly TEP bill using the Renewable Credit Rate. Net Metering customers could carry over unused bill credits to future months if they exceed the amount of their current bill.

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

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

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

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

Q. Does this conclude your testimony?

A. Yes

Exhibit CAT-1

EXHIBIT CAT-1

TEP
Tucson Electric Power
Building a Bright Tomorrow

Revised 10-06-15 ES

Utility Scale Renewable Portfolio

TEP

Project Name	Project Owner	AKA	Technology	DC MW Capacity	AC MW Capacity	Annual Energy, GWh	COD	Site Location	County	Term	Comments
* Avalon Solar II	Centaurus Renewable Energy	Avalon Phase II	Fixed PV	21.53	17.22	37.71		Sahuarita	Pima County	20	Esimated COD 12/15/2015
* [illegible] Solar 5 MW	TEP		TBD	5.00	4.00	8.76		Tucson, Az	Pima County	Own	Estimated COD 12/13/2016
* Fort Huachuca Phase II	TEP	Fort Huachuca Phase II	Fixed PV	5.00	4.00	8.76		Fort Huachuca, Sierra Vista, AZ	Cochise County	Own	Esimated COD 6/15/2016
Aminox UASTP Solar Power Generation Station	FRB Solar LLC	Amonix	CPV	2.00	1.20	2.63	3/31/2011	UA Tech Park	Pima County	20	
Avalon Solar	Coronal Management, LLC	Avalon Phase I	Fixed PV	35.00	28.34	62.06	12/23/2014	Sahuarita	Pima County	20	
Avra Valley	NRG Solar Avra Valley LLC	NRG Avra Valley	Fixed PV	34.41	25.00	54.75	12/14/2012	Marana, Az	Pima County	20	
Cogenera	WGL Energy	Cogenra	CPV	1.38	1.10	2.42	7/1/2014	UA Tech Park	Pima County	20	
DeMoss Petrie	Tep	TEP	Fixed	0.22	0.18	0.39	6/6/2001	DeMoss Petrie Sub Station	Pima County	Own	
E.On Tech Park	Tech Park Solar, LLC	E.On UASTP	Single-Axis PV	6.60	4.80	10.51	12/28/2012	UA Tech Park	Pima County	20	
Fort Huachuca Phase I	TEP	Fort Huachuca Phase I	Fixed PV	17.20	13.60	29.78	12/9/2014	Fort Huachuca, Sierra Vista, AZ	Cochise County	Own	
Gato Montes Solar	Gato Montes Solar, LLC	AstroSol/Astronergy	Fixed PV	6.00	4.92	10.77	12/19/2012	Tech Park	Pima County	20	
Macho Springs	Capital Power	Macho Springs	Wind	[redacted]	50.40	110.38	11/15/2011	Deming, NM	Luna County	20	
Picture Rocks	Picture Rocks Solar, LLC	FRV Marana	Fixed PV	25.00	20.00	43.80	12/5/2012	Marana, Az	Pima County	20	
Red Horse Solar	Red Horse Wind 2, LLC	Red Horse Solar	Solar	51.25	41.00	89.8	08/31/2015	Wilcox, Az	Cochise County	20	
Red Horse Wind	Red Horse Wind 2, LLC	Red Horse Wind	Wind	[redacted]	30.00	65.70	08/31/2015	Wilcox, Az	Cochise County	20	
Solon Prairie Fire	TEP	DM Air Corridor project	Fixed PV	5.00	4.00	8.76	12/28/2012	Old Vail & Valencia	Pima County	Own	
Springerville .81 expansion	TEP	Springerville	Fixed PV	0.81	0.65	1.42	12/30/2010	Springerville, Az	Apache County	Own	
Springerville 1.0 expansion	TEP	Springerville	Fixed PV	1.00	0.80	1.75	12/30/2010	Springerville, Az	Apache County	Own	
Springerville 4.6	TEP	Springerville	Fixed PV	4.60	3.68	8.06	6/6/2004	Springerville, Az	Apache County	Own	
Sundt - Los Reales	TEP	Sundt - Los Reales	Biogas	[redacted]	4.00	8.76	1/20/1998	Los Reales Landfill	Pima County	Through 2017	These resources provide augmentation only and do not increase the generating capacity rating of the unit.
Sundt Augmentation	TEP	Areva Solar Thermal	Thermal		5.00	10.95	12/30/2014	Sundt #4	Pima County	Own	These resources provide augmentation only and do not increase the generating capacity rating of the unit.
SunPower HQ	TEP	Rooftop	Fixed PV	0.05	0.04	0.088	6/7/2012	HQ	Pima County	Own	DG on company owned buildings
SunPower OH	TEP	Rooftop	Fixed PV	0.50	0.40	0.88	6/6/2012	OH	Pima County	Own	DG on company owned buildings
UASTP I	TEP	UASTP 1.6 Solon	Single-Axis PV	1.60	1.28	2.80	12/31/2010	UA Tech Park	Pima County	Own	
UASTP II	TEP	Solon 5 UASTP TEP Owned	Fixed PV	5.00	4.00	8.76	12/29/2011	UA Tech Park	Pima County	Own	
Valencia Solar	Valencia Solar, LLC	E. On Valencia	Single-Axis PV	13.20	10.00	21.90	6/28/2013	Valencia & I-10	Pima County	20	
White Mountain Solar	TEP	Springerville 10 - SunPower	Fixed / LCPV	10.00	8.25	18.07	12/12/2014	Springerville	Apache County	Own	

	DC MW Capacity	AC MW Capacity	Annual Energy, GWh
Totals	252.35	287.86	630.41

* Projects still under construction/in development

Exhibit CAT-2

Exhibit CAT-2

2015

STATUS	APPROVED

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

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
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

REBUTTAL TESTIMONY OF CARMINE A. TILGHMAN

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

EXHIBIT
TEP-27
ADMITTED

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

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

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

A. My Rebuttal Testimony is filed on behalf of Tucson Electric Power Company ("TEP").

Q. Did you file Direct Testimony in this proceeding?

A. Yes, I did.

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

A. I will primarily be addressing comments made by RUCO witness Huber, Solon witness Seibel, and Vote Solar witness Kobor.

To the extent I have not addressed other positions taken by Intervenors in their testimonies, it should not be taken as agreeing with or supporting these positions, and I reserve the right to discuss those issues as they arise during the course of this proceeding.

II. REBUTTAL TO RUCO WITNESS HUBER.

Q. What issues does the Company have with Mr. Huber's testimony regarding the proposed renewable credit rate?

A. Mr. Huber's proposals would not result in the most cost-effective solutions for TEP ratepayers. He argues that our customers will not be able to understand basic import/export concepts, but offers only speculation to support his thesis. Additionally, while Mr. Huber believes the Company's proposal is too complicated, he then proposes multiple rate design structures that are far more complicated than the methodology the Company has proposed.

While Mr. Huber believes our customers cannot grasp the concept that "any exported energy will be paid at a different price", he proposes to use crediting mechanisms such as three part rates with on and off peak volumetric energy rates and monthly net metering; a buy all/sell all option where the credit rate adjusts annually; and two part rate structures with on and off peak volumetric rates, monthly net metering, and hourly export fees.

It appears from Mr. Huber's testimony that he believes the Company should not utilize all available alternatives for procuring the most cost-effective renewable resources. Whether or not the Company receives a Power Purchase Agreement ("PPA") that is subsidized by the developer, or adds-on to an existing array, is irrelevant. The point is that TEP's residential customers – the group that RUCO represents – should benefit from TEP using the most cost-effective resources available. The Company fails to see how non-DG residential customers benefit if DG customers are compensated at a rate above that of the most cost-effective available resource.

Q. Would implementing Mr. Huber's options be expensive?

A. Yes it would. It is my understanding that implementing all four of them would likely involve significant expense and some substantial changes to TEP's billing system.

Q. Mr. Huber suggests that the export rate TEP is proposing (the renewable credit rider) would be "ever-changing", which would make it difficult for customers to understand. What is your response?

A. I believe our RCR proposal would be less difficult to understand than RUCO's four different net metering options – one of which includes multiple levels of tranches that customers would presumably have to keep track of to know what their export rate would be at a particular time. However, as was the case in the UNS Electric rate case, we are willing to consider more stable options. For example, the export cost could be fixed for a set period of time at the RCR rate for the year the solar system is installed. The key point is that our non-DG customers should not be forced to pay the current high rate, when much less expensive wholesale solar options exist. Further, selling power to a utility is a wholesale transaction, and should be made at wholesale rate.

Q. Do you agree with Mr. Huber's calculations in his Direct Testimony?

A. No. I would like to focus on Mr. Huber's overstated capacity value in his value of DG calculation. While I appreciate his effort to calculate a "capacity value" for distributed generation, Mr. Huber attempts to justify an overstated grid value for DG. Any valid analysis of a generating resource, particularly DG, must acknowledge the operational differences between a unit's ability to provide operational capacity (direct response, reserves, etc.) and its Effective Load Carrying Capability ("ELCC"), which is the approximate or average percentage of the systems' nameplate capacity that can be expected during peak. For example, a 100 MW solar facility may provide an average of 30 MW during the system's peak hour, resulting in an ELCC of 30%. However, this is NOT the same as a conventional 100 MW generator providing 30 MW. The conventional generator can receive system control signals, provide regulation up and down, frequency response, volt/VAR support, and respond to system disturbances. In my experience, the differences between a generators' capacity value and its ELCC are often confused by analysts who lack practical operational knowledge of grid management and operations. This results in an overstated value for a capacity savings based on the inaccurate assumption that the installation of an intermittent resource is the equivalent of a firm generating resource. Mr. Huber and certain other Intervenors continue to claim that DG systems will provide future grid management benefits without fully understanding grid operations and grid management.

In short, Mr. Huber's own arguments are contradictory in pursuit of a higher DG payment value when RUCO knows that TEP can procure renewable energy from a utility scale facility tied to our distribution system for far less. Even if the Company agreed with Mr. Huber's assessment of all of the supposed forward benefits (which the Company does not), how does it benefit residential customers to pay a higher amount for solar energy from a rooftop DG system than the cost of solar energy TEP can procure through a large scale PPA tied to its distribution system?

Q. What is the problem with valuing intermittent resources the way RUCO and Mr. Huber suggest?

A. While it can be argued that intermittent resources provide some level of ELCC on a short term operational basis, this comparison must include the acknowledgement that a presumed capacity value through a planning process DOES NOT provide operational capacity at the time the load is actually served. More to the point, to meet its obligation to serve, a utility does not and cannot: (1) assume that solar will always provide 30% of its rated capacity during peak; (2) assume that solar will provide necessary ancillary services; and (3) equate intermittent resources with a firm, controllable and available resource, when the utility has no direct control over the intermittent resource.

III. <u>REBUTTAL TO SOLON WITNESS SEIBEL.</u>

Q. What issues do you have with Solon witness Seibel's testimony?

A. First and foremost, I disagree with Mr. Seibel's characterization of the June 1, 2015 proposal for net metering changes as being retroactive. As with all industry participants whose business model relies on significant subsidies that burden non-participating utility customers, Solon is simply attempting to protect its own business interests at the expense of TEP's non-DG customers. Even given sufficient notice in early March of 2015 that the Company would be proposing these specific changes, and having approximately 2 ½ months to make even a modest attempt to restructure their development model, Solon has chosen to simply demand that the Commission view the proposal as "retroactive." Mr. Seibel attempts to equate the Company's voluntary proposal to withdraw the original net metering application and include it in the rate case with a hard and fast rule that it must no longer be considered. In fact, the Company's filing stated that TEP would withdraw its application and specifically include the same provisions in its rate case application.

Q. Is the proposed grandfathering date of June 1, 2015, equivalent to retroactive ratemaking?

A. No it is not. That date only identifies which customers would go onto the new R-15 rider *as of the date TEP's rates would go into effect.* TEP is not seeking to reach back to put non-grandfathered DG customers on a new tariff as though it had been effective June 1, 2015 and true-up the difference. Rather, that date gives customers notice as to which DG customers would be subject to the new rider after new rates go into effect – versus which DG customers would have the luxury of staying on the current R-4 Rider through May 31, 2035. Grandfathering is the exception, not the rule. Typically, all customers would go onto the new rider upon Commission approval.

Q. Does Mr. Seibel agree that the grandfathering date and the effective date are different?

A. Yes. In response to TEP data request 2.10, he agreed that "there is a difference between the grandfathering date (which determines which customers are exempt from a tariff) and the effective date of the tariff."

Q. Was Mr. Seibel able to provide any evidence that TEP proposed June 1, 2015 as the effective date?

A. In response to TEP data request 2.11, Mr. Seibel cited page 8, lines 13-17 of the Direct Testimony of Dallas Dukes, which refers to "Rider R-15 (NM-PRS), Post June 1, 2015". This is simply the name of the proposed tariff. The reference to "Post June 1, 2015" is a reference to the grandfathering date. TEP has <u>never</u> advocated for a 2015 effective date for this tariff. The new tariff will apply to non-grandfathered customers on the same date that all other rates from this case take effect. Mr. Seibel's inflammatory rhetoric about "retroactive rates" has no basis in fact.

Q. Have customers been notified that if they apply for DG after the June 1 cutoff date, they may be subject to a new net metering tariff rider?

A. Yes. TEP provided notice to customers of the proposed changes and cutoff date, and the customer has acknowledged the possibility that they may be subject to rate design changes, so that potential DG customers had the requisite information to make a decision at the time they choose to go ahead with installing DG, contrary to what Mr. Seibel implies on page 12 of his Direct Testimony.

Q. Does Attachment A to Mr. Seibel's testimony (TEP's DG interconnection application) "threaten" customers as he describes it on page 13 of his direct testimony?

A. No, it does not. While Mr. Seibel's characterization of providing our customers' with truthful and accurate information as a threat is consistent with the rhetoric and tone throughout his testimony, it is inaccurate. As we have repeatedly explained, we are not "taking net metering away". We are simply adjusting the value of the export rate to be consistent with alternative options. But notifying customers is not a threat, and requiring customers to sign an acknowledgement is also exactly what the Commission and its Staff expected from us to do, so that customer and Company are on the same page as to the customer being informed of this potential change.

Specifically, while Mr. Seibel states, on page 14 of his Direct Testimony, that *"it is deeply disturbing for a regulated utility to distribute, and require a customer to sign, a disclaimer acknowledging the possibility of retroactive rates or other unexplained changes*", he fails to mention that the Company has been has been issuing and requiring these documents in some form since February 2014, at the request of the Commission and Staff following a similar order to Arizona Public Service Company (APS). Moreover, the Company was ordered by the Commission in August 2015 to modify the existing disclaimer and that disclaimer was supported by Staff, Vote Solar, RUCO, ASDA and ARiSEIA.[1]

Q. Are you trying to usurp the Commission's authority, Mr. Tilghman, as Mr. Seibel implies TEP is doing on page 18 of his Direct Testimony?

A. No, that is another misstatement by Mr. Seibel. If the Commission approves a grandfathering date different than what the Company proposes, we will honor that. TEP, however, believes that the June 1, 2015, is reasonable, fair and amply supported in the record. Additionally, since this case will likely not be resolved until the end of 2016 at the earliest, TEP has given customers' well-over-one-year's notice that net metering

[1] *See* Decision No. 75224 (August 26, 2015), Findings of Fact 14-25.

changes could occur. So TEP has, in fact, done exactly what Mr. Seibel recommends the Commission order TEP to do on page 18 of his Direct Testimony.

Q. What other concerns do you have with Mr. Seibel's testimony?

A. Contrary to Mr. Seibel's implication at page 10, the idea that net metering changes were and are needed is not new, and has been a topic of discussion for some time. While Mr. Seibel boasts of a long record of "financial analytics" and "solar production modeling", at the same time he would have the Commission believe that Solon is incapable of performing anything more complicated than a standard "net zero" performance calculation. In actuality, traditional analytics for solar production and financial modeling under an annual net metering policy is the equivalent of a high school math exercise. It is puzzling that solar industry participants such as Solon, who claim to be industry experts in performing financial analytics and solar production modeling, are unable to provide a customer with a more accurate representation of their energy savings.

Q. How do you respond to Mr. Seibel's assertion that solar interconnection applications "came to a screeching halt" as he states on page 13 of his Direct Testimony?

Mr. Seibel's claim is simply wrong. As the Company has provided through numerous data requests in various proceedings, TEP continued to receive applications at a steady rate after June 1, 2015. Indeed, the application rate now exceeds the application rate prior to the Company's March 25, 2015 original proposal to modify changes to net metering.[2]

[2] On March 25, 2015, TEP filed an application with the Commission (Docket No. E-01933A-15-0100) requesting changes to its net metering tariff. TEP subsequently withdrew its application on June 19, 2015 with the intent of seeking net metering modifications in this rate case docket.

IV. REBUTTAL TO VOTE SOLAR WITNESS KOBOR.

Q. What issues does the Company have with Vote Solar witness Kobor's testimony?

A. While the Company has many issues with witness Kobor's testimony, I will focus my comments on her testimony regarding the impacts of DG on the Company's system and associated compensation under the proposed Renewable Credit Rate. I reserve the right to further elaborate on any disagreements regarding Ms. Kobor's testimony through direct examination on the witness stand.

Q. Specifically what does the Company take issue with regarding Ms. Kobor's testimony on DG system impacts and the Renewable Credit Rate?

A. Ms. Kobor indicates that her "analysis" does not show that TEP has established that DG causes significant grid impacts, and therefore no changes to DG compensation or NEM is justified. However, while the Company is unsure what Ms. Kobor would consider a "significant grid impact", the Company—and the utility and electrical industry at large—has shown that there are definitive operational detriments to the integration of variable generation on the grid, including (but not limited to) distributed generation. Ms. Kobor's statement that the Company relies on national and regional studies rather than specific TEP system studies demonstrates her lack of operational understanding of grid operations and the need to perform "repetitive" studies. For the record, TEP has performed certain individual system studies, and continues to perform studies on specific circuits. Most notably, the Company's Los Reales Feeder circuit study has shown significant phase imbalance and backflow due to distributed generation resources on the circuit. Results of these studies confirm what the regional and national studies have previously concluded.

In addition to Ms. Kobor's comments regarding the impacts of DG on TEP's system, Ms. Kobor continues to attempt to disassociate DG solar and its purported "value" from the lower cost that a utility can realize through procurement of a nearly identical resource, namely a utility scale solar facility. Ms. Kobor would have the Commission - and the communities that TEP serves - believe that the purported benefits of a DG system should be priced higher and valued separately, than a community based, utility scale facility that provides solar energy to a broader base of customers at a lower cost. The Company disagrees with Ms. Kobor and Vote Solar's opinion that TEP ratepayers should be forced to pay a higher rate for the benefits of renewable energy than what is available to the Company through larger utility scale facilities.

Q. Do you agree with Ms. Kobor's argument, specifically on page 22 of her direct testimony, that the problem is not large enough to warrant any changes to address the cost-shift due to DG systems?

A. No. Ms. Kobor simply points to a snapshot in time to justify her position. But the fact is that the cost-shift due to DG is a growing problem. Assuming that her conclusion is true (and we are not conceding that at this time) she ignores the fact that the increasing number of DG installations will result in a decline in retail sales in excess of 6%. The Commission has already found that a cost shift exists with non-DG customers subsidizing DG customers. Vote Solar and other parties stated that the rate case is the appropriate forum to address this problem; so now is the time to address this problem while it is at a manageable level. I do not believe it is appropriate to wait until there is a certain level of DG penetration in the market before the Commission addresses an acknowledged problem.

Q. Ms. Kobor insinuates that TEP's argument is based on "hypothetical NEM customers who size their system to offset 100% of annual load." What is your response?

A. This is not a hypothetical situation. We know from actual experience that DG customers have systems designed to offset nearly 100% of annual load. Indeed, the Commission's net metering rules provide for customers sizing their systems up to 125% of total connected load. The solar industry utilizes these rules to their fullest advantage to design systems to provide as close to an annual net-zero effect as possible, and that is reflected in the applications we are seeing and the impacts TEP is experiencing on its system.

Q. Ms. Kobor dismisses the cost shift as "an inherent side effect of rate design." Does that mean we should simply ignore the problem?

A. No. Although there are policy reasons to justify certain cost shifts that occur, such as when low-income customers are subsidized, rate design should be fixed if there are inequitable impacts on customers such as those caused by DG. Differential rate treatment is justified here; it is not unduly discriminatory to reflect that DG customers have essentially become partial-requirements customers.

Q. Is there anything in the net metering rules that prohibits the Company's proposal?

A. No. Changes to the net metering tariff are fully within the Commission's purview, and to the extent TEP needs a waiver from the rules to implement its proposal, it is seeking such a waiver – and is doing so within a full rate case, exactly as we were advised to do. Further, the solar industry appears to be under the misconception that exported excess energy *must* be credited at the retail rate to be net metering. That is not accurate.

The Arizona Administrative Code, under Title 14, Chapter 2, Article 23 under R14-2-2303 defines Net Metering as *"service to an Electric Utility Customer under which electric energy generated by or on behalf of that Electric Utility Customer from a Net Metering Facility and delivered to the Utility's local distribution facilities may be used to offset electric energy provided by the Electric Utility to the Electric Utility Customer* *during the applicable billing period."* While the definition of net metering clearly allows for the use of a full retail credit for energy, the words *"may be used to offset electric energy"* also would apply to a credit paid for exported DG energy. It could just as easily be argued that the offset to *"electric energy"* is the energy only component of the utility's rate, or an equivalent solar energy rate.

The Company's proposal does not eliminate net metering; it simply values excess energy at an export rate more reflective of actual avoided cost. But it is still a credit that offsets DG customer bills. Further, DG customers receive the full retail rate offset for energy that they consume onsite from their PV facilities. Ms. Kobor's implication that the Company's proposal violates net metering is not accurate.

Q. Please address Ms. Kobor's comments that a utility-scale facility is not a fair proxy for distributed generation, specifically on pages 27-28 of her Direct Testimony.

A. First, Ms. Kobor acknowledges that utility-scale resources are essentially less expensive than DG. But then she offers a convoluted argument about conflating the issue of utility-scale pricing versus distributed-scale pricing from a utility perspective. She is basically asking the Commission to ignore the elephant in the room: that a utility like TEP could acquire renewable energy from utility-scale resources at a lower price than from DG. Further, she adds that the "non-participating ratepayer will be generally indifferent to and unaware of" where the electrons come from. While the non-participating ratepayer may be indifferent to where the electrons come from, they are NOT indifferent about having to pay 2-3 times more for energy from a distributed generation resource being paid under net metering.

TEP must consider cost impacts to its customers and typically must seek to acquire power at the most cost-effective level. While the Commission may decide certain societal policies justify the use of a more expensive resource, they should do so with the complete knowledge of lower cost alternatives and the impacts to the ratepayers.

Q. **Ms. Kobor states that TEP is ignoring many key benefits provided by DG that are not provided by utility-scale renewables, such as higher generation capacity and potentially greater avoided distributed costs and grid services. Do you agree?**

A. Ms. Kobor again ignores the unplanned nature of how DG is deployed throughout TEP's service territory. Just because DG is "geographically diverse" does not mean it is going to provide these purported benefits that equate to higher capacity value and potentially greater avoided distribution costs. Also, she ignores the infrastructure improvements TEP must make to accommodate the unplanned nature of DG installations.

As I have stated and based on my experience observing how the growth of DG impacts TEP's grid, the random way by which DG systems are added onto TEP's system will necessitate measures and improvements to address the stability issues caused by DG proliferation. These measures and improvements have a cost. If renewable energy systems were placed strategically throughout TEP's service territory, the need for additional improvements of this type could perhaps be reduced somewhat. But that is not the case with DG and the positions perpetuated by Vote Solar and others. Moreover, the need for ancillary services (such as voltage or frequency control) will increase with increased DG and intermittent resource installations.

In contrast, alternative renewable resources strategically placed would lessen such adverse impacts. Utility-scale renewables, for example, are planned and therefore provide TEP with the opportunity to strategize where they might optimally provide value to it and its system. Ms. Kobor fails to recognize the undisputable advantage of a larger scale facility interconnected to the utility's three-phase system (through a detailed interconnection study) versus the randomly-sited DG system that creates phase imbalances and reverse flows.

Q. Ms. Kobor, on page 32 of her direct testimony, indicates three problems with TEP's proposed renewable credit rate. How do you respond?

A. I have already discussed how the Renewable Credit Rate does not violate Commission rules, especially since the Company is seeking the appropriate waiver in the full rate case. Further, Ms. Kobor assumes that the Commission would have no authority over the RCR once established. TEP would work closely with Utilities Division Staff to demonstrate that any future change in the RCR is appropriate and justified. That leaves Ms. Kobor's first argument – that the RCR does not approximate the value of DG. As I have stated and demonstrated before, utility-scale solar and other renewables provide equivalent benefits as DG, with the added benefit of being planned. Ms. Kobor rests her opinions on abstract study work from other jurisdictions that make generous assumptions about the value of DG. We base our conclusions on actual experience.

The solar industry advocates, such as Ms. Kobor and Vote Solar, have consistently failed throughout this year's various Commission proceedings (UNS Electric rate case, Cost and Value of Distributed Solar hearings, and now the TEP rate case) to explain why a utility's ratepayers should be required to pay 2-3 times for renewable energy than what is available to them form a utility scale facility.

V. <u>RESPONSE TO REQUEST FOR REST PLAN OF ADMINISTRATION.</u>

Q. Are there any other issues that you would like to address in this testimony?

A. Yes. The Direct Rate Design Testimony of Eric Van Epps recommends that the Company file a Plan of Administration ("POA") for its REST adjustor consistent with the POA filed for UNS Electric and that the POA "incorporate all existing pertinent Commission decisions." The Company will provide a POA prior to the hearing in this matter.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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-1933A-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

REBUTTAL TESTIMONY OF H. EDWIN OVERCAST

ON BEHALF OF

OF TUCSON ELECTRIC POWER COMPANY

JULY 25, 2016

EXHIBIT
TEP-28
ADMITTED

TABLE OF CONTENTS

I. Introduction.

Q. Please state your name and business address.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

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

A. I am a Director, Black & Veatch Management Consulting, LLC.

Q. Please describe your educational background and business experience.

A. A detailed summary of my educational and professional experience is provided in Appendix A to this testimony. I have a B. A. degree in economics from King College and a Ph.D. degree in economics from Virginia Polytechnic Institute and State University. My fields of study include microeconomic theory, industrial organization and public finance. I have been employed in the energy industry for more than 40 years in various rate, regulatory and planning positions. My industry employers included the Tennessee Valley Authority, Northeast Utilities (an electric and gas holding company) and AGL Resources (a gas holding company). I have been employed as a utility consultant since 1998 providing rate, regulatory, strategic and other consulting services to utility clients. In my various positions, I have testified before state and federal regulatory bodies, Canadian provincial regulatory bodies, state and federal legislative bodies and in various courts. I have previously testified before the Federal Energy Regulatory Commission ("FERC") on a number of electric, gas pipeline and oil pipeline issues.

Q. On whose behalf are you submitting this testimony?

A. I am testifying on behalf of Tucson Electric Power Company (TEP or the Company).

Q. Have you previously testified before the Arizona Corporation Commission (ACC or the Commission)?

A. Yes. I have testified in the UNS Electric Inc. rate case and in the Commission's Investigation of Value and Cost of Distributed Generation.

Q. Please provide a list of state and Canadian jurisdictions in which you have testified.

A. In addition to Arizona, I have testified in Connecticut, Massachusetts, Georgia, Tennessee, Montana, Missouri, New York, Ohio, Michigan, Arkansas, New Jersey, Oklahoma, Kansas and Maryland. In Canada, I have testified before the Ontario Energy Board, the Alberta Energy and Utilities Board, the New Brunswick Energy and Utilities Board and the British Columbia Utilities Commission. My testimony has been related to issues such as cost of service, rate design, prudence, rate of return, regulatory risk, performance based regulation, competition and unbundling.

Q. During your career have you made presentations to energy related training and other programs?

A. Yes. I have been an instructor for the Edison Electric Institute's Rate Fundamentals and Advanced Rate School related to cost of service. I have been an instructor in both the American Gas Association's Rate Fundamentals and Advanced Rate courses. I have been an instructor for the Southern Gas Association's Intermediate Rate Course and for the RMEL I have provided training related to regulation. I have made numerous presentations to trade association meetings including the EEI Rate Committee, the AGA Rate Committee, the AEIC Load Research Committee, SURFA and other industry sponsored programs. I have made presentations to NARUC events and events sponsored by academic institutions. I have also written broadly on various subjects related to utility regulation, including issues related to the integration of distributed generation into a utility system and the design of rates for the 21st century.

Q. Have you provided expert testimony on cost of service and rate design related to net metering, rates for distributed generation (DG) customers and development of rates for purchase of energy from dg customers?

A. Yes. My testimony in Maryland and Arizona addressed these issues and more related to cost of service, rate design, net metering impacts and the impact of purchasing excess generation at the full retail rate. In that testimony, I developed specific measures of the level of subsidy created by net metering and demonstrated that the Commission's net metering rule resulted in undue discrimination based on the factual circumstances for the utilities.

Q. What is the purpose of your rebuttal testimony in this proceeding?

A. My rebuttal testimony addresses a number of areas related to the economics of DG from the perspective of the utility, its customers and economic efficiency. Specifically, I respond to issues raised by the Commission Staff, Vote Solar (VS), the Energy Freedom Coalition of America (EFCA), Residential Utility Consumer Office (RUCO), Southwest Energy Efficiency Project (SWEEP) and Western Resource Advocates (WRA), Arizona Community Action Association (ACAA), Mr. Kevin Koch and the Solon Corporation (Solon). I address the following issues as discussed by some or all of these parties:

- The cost basis for a customer charge and numerous fallacies associated with opposition to the charge and its calculation;
- The reason partial requirements customers and full requirements customers have different costs;

- The subsidies being provided to DG customers under the current rate design and net metering tariff with banking;
- The cost to serve solar DG customers based on three different cost studies: the base study that merely separates solar DG customers from the residential class, the counterfactual study that measures the cost to serve the solar DG customers as if the customer never adopted solar DG and the solar class study that allocates cost to these customers based on their own unique load characteristics;
- The nature of the undue discrimination among customers with the same cost of service;
- The economic and regulatory rationale for a separate rate for a DG customer that requires different treatment than a standard customer until such time as utility rates are fully unbundled and customers are classed based on the cost causing characteristics of their service;
- The economic and regulatory basis for multi-part rates including customer charges, demand charges and time differentiated energy charges;
- The efficacy and efficiency of demand based rates for all customer classes and how such rates will impact customers;
- The ability of customers to respond to more complex price signals,
- The role of fairness, efficiency and gradualism in developing and implementing new mandatory rate designs; mitigation of adverse impacts during the rate design transition;
- The reason all customers should be on the same rates with any special considerations (Lifeline customers for example) should have considerations outside of the rate structure per se;
- The customers who choose to use the utility system in ways that result in high unit costs (low load factor customers or large on-peak users for example) should pay the

full costs imposed on the system under the cost causation principle and the matching principle of rates; and

- The importance of multi-step transition plans to assure timely and efficient implementation of the best rate design for all customer classes in an expeditious manner.

Finally, I recommend transition steps necessary to rates that match costs and revenues and to minimize the impact of changes over time. I also note that the Commission has a duty to eliminate the undue discrimination that exists in the current rates as it relates to the comparable service between solar DG customers and full requirements customers. Although these issues as they relate to net metering, three part rates and the inefficiency and intraclass subsidy from inverted block rates are all closely intertwined as is evident in the various sections, I have discussed the topics in separate sections to identify the focus on a particular issue.

Q. How is your rebuttal testimony organized?

A. My testimony is organized in sections beginning with this introduction that includes a summary of my recommendations and the individual sections as follows:

II. Customer Cost Analysis and Customer Charges

III. Economics of Serving Full and Partial Requirements Service Customers

IV. Cost of Service Study Results

IV. Separate Rate Treatment for DG Customers

V. The Economic Rationale for Multi-Part Rates

VI. Customer Response to More Complex Price Signals

VII. The Concepts of Fairness, Efficiency and Gradualism

VIII. Customer Response to More Complex Price Signals

IX. Miscellaneous Issues

X. Conclusions

Q. Please briefly summarize your conclusions and recommendations.

A. Based on my testimony I conclude the following:

1. The minimum system for classifying distribution costs in accounts 364-368 as proposed by TEP is a necessary condition for reflecting cost causation on the TEP system. That conclusion is supported by rigorous econometric analysis, public utility accounting, the NARUC Manual, numerous academic and industry literature written by scholars and rate practitioners over more than 100 years and analysis of TEP's own data. The only option offered to the minimum system does not result in an allocation of costs that reflects the real physical assets that underlie service to customers and thereby fails the test of cost causation. The Commission should affirm the use of the minimum system classification in the TEP cost study going forward.
2. Increasing customer charges as proposed by TEP is solidly grounded in cost causation, economic efficiency and results in rates that are just and reasonable and not unduly discriminatory. The Commission should approve the TEP customer charges as filed even if they do not grant the full revenue requirement increase.
3. The rates resulting from net metering with banking are decidedly not just and reasonable and rise to the level of undue discrimination. The Commission has an obligation to cure undue discrimination and should adopt the TEP proposal for modifying net metering by placing customers on a separate rate schedule designed specifically for partial requirements customers including solar DG customers. The rate should be based on the treatment of solar DG customers as a separate class of customers in the TEP cost study.
4. The elimination of the top two tiers of the TEP residential rate is a necessary step to begin the transition to more cost-based and efficient rate designs that comply with the

just and reasonable standard for rates. Just and reasonable rates ultimately require a multi-part rate with customer, demand and energy charges.

5. The Lifeline rates should be consolidated as part of a plan to serve all full requirements residential customers under a single rate with customer, demand and TOU energy charges.
6. Customers can and will respond to the more efficient rates and that response will vary broadly among customers based on their own choices designed to optimize their individual satisfaction and valuation of electric service.
7. No TEP proposals constitute retroactive ratemaking.
8. The three cost studies filed in my testimony provide a clear picture of the cost of service benefits DG customers receive and show that despite those benefits, the treatment of DG customers on the current two part rate result in significant negative earned returns for DG customers

II. <u>Customer Cost Analysis and Customer Charges.</u>

Q. Please summarize the positions of the parties that you will be responding to in this section.

A. Many of the parties filing testimony related to cost of service and rate design oppose the development and implementation of a higher customer charge based on a variety of arguments. These arguments range from using a customer cost estimate that only reflects a portion of actual customer costs to misapplied policy arguments and also in a number of cases represent a classic example of rent-seeking as noted by Alfred Kahn in his monograph "Letting Go: Deregulating the Process of Deregulation" published by The Institute of Public Utilities and Network Industries at Michigan State University in 1998. Rent-seeking is defined as "the activity of a person or firm that tries to obtain benefits for themselves through the political arena"- the Commission in this case. Typically the benefit consists of a subsidy for their product or service including favorable tax treatment and measures that inhibit competitors such as inefficient regulated rates. The subsidy supporting parties distort facts, rely on fallacious arguments, make economically inefficient arguments and misuse data and analysis all of which lead to higher subsidies for solar DG and conservation.

The benefit sought by the subsidy proponents in this case is energy charges for residential rates that exceed marginal cost by an even greater amount than current rates and continue to overcharge high load factor customers whose energy consumption is billed in the highest tiers of the current rates. This is contrary to both economic efficiency and cost based rates and results in rates that are unduly discriminatory by allowing solar DG customers pay far less than comparable full requirements customers for the same service.

Q. How should regulators respond to this type of rent seeking activity?

A. It is not the purpose of regulation to create an economic environment that results in inefficient competitors who have higher costs than both the utility and more efficient competitors having special preferences and protections that result from subsidies and from restraining efficient responses from the utility. The proposals made by DG advocates, and in particular rooftop solar DG, in response to more efficient and equitable rates proposed by TEP represent the worst type of rent-seeking whereby they seek to perpetuate their profitability at the expense of captive consumers and low income customers. Dr. Kahn described this mixed monopoly and competition model as it relates to the local distribution network for electric utilities and noted the following with respect to the role of regulation:

> It is clearly not possible to totally eliminate direct regulation of what we have traditionally considered to be the authentic public utilities. The reason, of course, has been the persistence of monopoly, particularly in the local distribution

networks and also in electric transmission, which has required continuing regulation for two closely related reasons:

- To protect captive, principally residential and small business, customers;
- To ensure fair and efficient competition between the integrated utility companies and the challengers dependent upon their access to their monopolized or partially-monopolized facilities, including safe guarding against cross-subsidization of that competition by the incumbent utilities at the expense of their monopoly customers.[1]

These two reasons represent the fundamental obligation of regulation in the mixed monopoly and competition model. The monopoly aspects of the public utility, in particular the facilities associated with service delivery, must be the focus of the evaluation of evidence in a rate case. There is no question that the issue of customer cost and the appropriate customer charge become a first step in setting rates that protect captive customers from subsidizing the purveyors of rooftop solar DG. However, the customer charge is not solely a mechanism related to a DG subsidy, it is also a cost based, unbundles charge that is needed for all customers to reflect the principles of cost causation and matching principles of rates. The magnitude of this subsidy is quite large as I will demonstrate based on cost of service studies and by illustrating the undue discrimination resulting from net metering and banking. The subsidy is also far greater than the avoided cost that PURPA and FERC regulations implementing Section 210 of PURPA set as a cap on payments for energy from QFs. The first step for regulation is needed to protect the captive residential customers who cannot (or choose not to) avail themselves of DG or net metering, recognizing that the vast majority of residential customers are not DG customers, and that at least a plurality and more than likely a majority of the residential class will never be DG customers. Second, Dr. Kahn notes that competition should be fair and

[1] "Letting Go: Deregulating the Process of Deregulation", Alfred E. Kahn, 1998, MSU Public Utility Papers, p. 17.

efficient. As I will explain later in this testimony the implications of net metering are such that the competition for the end use loads served by DG is neither fair nor efficient under the net metering, banking and volumetric rates commonly used for residential service. Third, and more importantly, I will show that net metering creates cross-subsidization, not by the incumbent utility, but by the rent-seeking behavior of the solar DG advocates that occurs at the expense of customers who remain monopoly customers. This cross subsidization rises to the level of undue discrimination for solar DG customers that is required to be cured.

Typically, the argument for this rent seeking behavior is that it will have a small dollar impact on customers providing the subsidy. This argument can be found in the testimony of Vote Solar[2], Solon[3] and EFCA[4]. Others argue for low fixed costs based on social policy issues that include low income impacts, conservation impacts, and inequities among customers in the residential class. None of these arguments is well founded when viewed in the light of economic theory, sound social policy and cost causation in spite of claims to the contrary.

Q. What are the essential elements for the regulated delivery component to avoid creating cross-subsidy from the monopoly component of the market to solar DG customers who have chosen competitive alternatives?

A. Under regulation, artificial subsidies may be sustained for a period of time but must be addressed ultimately if utility service is to be sustainable. Waiting to address these subsidies when the solar DG market is much larger is far more disruptive to public policy and private investments at that time then it is to address this issue now when only a fraction of existing customers are impacted. Where certain projects or services are

---

[2] Direct Testimony and Exhibits of Briana Kobor on Behalf of Vote Solar, See sections 4, 5 and 7.
[3] Direct Testimony of Brian A. Seibel for Solon Corporation, p. 66-70
[4] Direct Testimony of Mark E. Garrett, EFCA, p. 33-42 and in particular the recommendation to maintain the status quo level at line 7, p. 42

subsidized through regulation, the result is that there is excess and inefficient investment in the favored services such as rooftop solar DG in this case. The result will not be consistent with least cost planning or even efficient operation of the utility. Ultimately, regulated rates must ensure that the monopoly segment of the market must establish fully unbundled rates so that when a customer uses a monopoly service the customer pays for the costs that the customers' use imposes on the monopoly. To establish unbundled rates the cost of service must be unbundled for the services provided. Rates must be developed that signal the factors that cause cost by customer groups that have homogeneous characteristics that cause the cost and match those costs in rates in the prospective period. When rates reflect class cost of service on an unbundled basis and the underlying cost of service reflects the principles of cost causation and matching, subsidies will be eliminated; the price signal in the rates will incent efficient use of resources as required under the purposes of PURPA for net metering; rates will be just and reasonable; rates will not be unduly discriminatory; and investment in DG will be consistent with least cost planning and efficient competitors will earn the required market return for the associated risk they take. In summary the following elements must exist for long term stability and sustainability of the mixed market model:

1. Cost of service reflects cost causation for each class of customer and each service provided including access, capacity and kWhs.
2. Rates match cost in the rate effective period.
3. Rates are fully unbundled such that all energy related costs are recovered in energy charges (preferably seasonal and time differentiated based on marginal cost differences), fixed capacity costs are recovered in demand charges and access costs in customer charges that may not be the same for all customers in a class when the services they select differ.
4. Price signals should reflect marginal cost to the extent practical while still matching costs and revenues.

5. Costs not included in test year revenue requirements such as the present value of future avoided costs or the levelized cost of future avoided energy should not be part of rates or part of valuation of assets that have no long-term, enforceable, contractual obligation for service and even with a long-term power purchase contract energy should be valued at the market as the market changes through time to protect the interests of customers in reasonable rates.

6. There is no reason to believe that investment in rooftop solar DG is entitled to a fixed energy price over the life of the asset since other behind the meter investments by customers such as EE or other DER investments and even competitive merchant power plants are not afforded fixed prices that guarantee the economics of an investment. Further, such a guarantee is not even permitted for as available resources under the FERC regulations applicable to power purchases from QFs.

A. Minimum System to Define the Customer Charge

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

A. Yes. A number of witnesses recommend the concept of the basic customer method for allocating customer costs in the cost study and determining the customer charge[5]. There are two issues with the basic customer method that must be addressed separately. The first is the use of this method in cost allocation and the second is whether this method is valid for determining the customer charge. I will discuss both these issues.

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

---

[5] The list includes Kobor of Vote Solar, Huber of RUCO, Garrett of EFCA,

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

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

A. In classifying all of the distribution plant in Accounts 364 through 368 to demand and allocating those plant costs on non-coincident peak (NCP), these positions do not fairly allocate plant to customer classes for a variety of reasons. As Dr. James Suelflow writes in his treatise Public Utility Accounting: Theory and Practice published by the Institute of Public Utilities at Michigan State University: "... distribution transformers and primary and secondary lines including conductors and devices (account 365 "Distribution Plant") and poles and towers (account 364 "Distribution"), all contain capacity and customer costs."[6] Dr. Suelflow recognizes that costs are more closely related to customers the closer one approaches the ultimate customer.

In other words, assets that are in closer proximity to the load served reflect less diversity and the classification of the costs associated with those assets should recognize this point. The recommendations advanced by these advocates of the basic customer method fail to recognize that class NCP is more appropriately used in circumstances where there is far more diversity in load (e. g., at the substation). Class NCP alone is inappropriate for local facilities that are closer in proximity to customers they serve.

Diversity can be seen by the fact that distribution substation transformer capacity is more than transmission transformer capacity measured in MVA. Typically, distribution transformer capacity is greater than substation capacity and that excludes all customer

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

owned transformers that would increase the difference. These statistics further indicate the way diversity impacts loads as you move closer to customers. For that reason alone, those parties that support the basic customer method and class NCP demand allocation of accounts 364-368 are misguided because that allocation cannot be used as it does not reflect cost causation and cannot be relied upon as a basis for revenue allocation or for rate design.

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

There is no question that the NARUC Manual states that the distribution plant costs in Accounts 364-368 have both a demand and a customer component. The NARUC Manual states "When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, *the utility must classify distribution plant data separately into demand- and customer- related costs.*"[7] (Emphasis added.)

This is not a new concept. In 1963 Constantine Bary published his treatise Operational Economics of Electrical Utilities. This rigorous study of utility costs and how loads cause those costs provides a summary chart of cost causation that is attached as Exhibit HEO- 1. This exhibit shows that a portion of the distribution plant beginning with primary lines is customer related. In the parlance of uniform system of accounts this is accounts 364-368. I should note that support for both the minimum system concept and for customer charges to reflect these costs is not new or novel. Writing in 1900 Henry L. Doherty formulated a three part rate consisting of a customer charge, demand charge and energy charge.[8] In the

---

[7] Electric Utility Cost Allocation Manual, National Association of Regulatory Utility Commissioners, February 1991, p.95

[8] See for example Bonbright 1988 Edition p. 401 for reference to Dohery.

original paper "Equitable, Uniform and Competitive Rates" Doherty defined the minimum costs associated with "readiness to serve" and specifically included not only the components of the basic customer costs but the costs of poles, lines and conductors with 50% classified to the customer component and 50% to the demand component. His analysis also included overhead loaders in the cost per customer.[9] Writing in 1956, Russel Caywood describes customer costs as "Varies with the number of customers served and includes investment charges and expenses relative to a *portion of the general distribution system,* service drop or other local connection facilities, metering equipment, meter reading, billing and accounting."[10] Further, H. E. Eisenmenger has written an extensive analysis of electric utility costs in 1919 and includes in the customer cost component the minimum size of poles and conductors. He states "Up to a certain size of consumer this investment will be practically constant per consumer and above that size we can regard it as composed of two parts: A constant part (cost of average length of service connection, if constructed with minimum size of poles and minimum thickness of service wires: also cost of minimum size of meter, etc.) and another part proportional to the maximum demand of the consumer."[11]

The above citations demonstrate a number of conclusions. First, the minimum system concept for calculating customer costs is neither new nor novel. Despite the protests of the parties opposing the use of the minimum system concept, its pedigree has been established for over 100 years by a variety of disciplines and industry participants including engineers, entrepreneur utility owners, rate experts and others. For example, Henry L. Doherty, was the founder and owner of Cities Service Company (later CITGO), which served as a

---

[9] A reprint of the 1900 article may be found in The Development of Scientific Rates for Electricity Supply, Printed for Private Circulation Only by The Edison Illuminating Company of Detroit, 1915, pp.53-78 (Available from GOOGLE Books)

[10] Electric Utility Rate Economics, Russell E. Caywood, Sixth Printing, 1972, Sponsored and Distributed by Electrical World and Russell E, Caywood, p. 26

[11] "Central-Station Rates in Theory and Practice, Seventh Article—The Consumer Cost, What It Includes and How It Varies—Determining the Numerical Values of the Three Elements of Cost—Analytical Valuation of Costs", Electrical Review, Volume 75, No. 8, 1919, p. 304 (Available from GOOGLE Books)

holding company for the utility firms in all three energy sources available at the time—petroleum, natural gas, and electricity. The arguments related to the basic customer method for reflecting cost causation are flawed when considering the depth of study and analysis that supported these early industry pioneers in determining the customer cost component. Essentially the basic customer method is devoid of the kind of reasoned analysis and strong empirical support that exists for developing customer costs using the minimum system.

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

A. By using class NCP as opposed to classifying these distribution accounts as customer and capacity, the parties incorrectly allocate more costs to larger customers who may not even use any of the facilities allocated to them. A simple example will illustrate this point. Consider a company with one industrial customer who has a 2500 kVa transformer installed. A typical installed cost for this transformer would be about $40,000. Also assume that the system served the same 2500 kVa of residential load using 50 50 kVa underground transformers that serve 400 residential customers. Those transformers typically cost about $4200 per transformer installed or about $210,000. Allocation of these costs on NCP would allocate the industrial customer $125,000[12] of rate base and the same amount to residential customers. Thus the advocates of the basic customer method would allocate less plant to residential customers than they actually use and at a lower cost than those actually caused by residential customers. The minimum system method would classify 70% of transformer cost on customers and the remainder would be allocated on capacity. That allocation results in about $193,000 of transformer costs to the residential class. Thus the minimum system method allocates cost more closely to causation and shares some of the scale economies between the customer classes. This same principle

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

applies for conductor and for poles in the case that overhead transformers are used. Thus the basic customer method is actually more results oriented than based on the principle that those customers who cause the costs should be responsible for the costs.

Q. So the reality of economies of scale points against using the basic customer method?

A. Correct. The fundamental point is that there are substantial economies of scale for all sizes of transformers, overhead and underground conductor and poles. In each case the per kVa cost of industrial transformers is below the cost for every size of residential transformer except for the largest and least used size of residential transformer. Some industrial transformers are even lower cost per kVa than the lowest cost single phase transformers used for residential customers. Using a demand allocation factor alone implicitly makes the incorrect assumption that the cost of transformer capacity is the same for all classes. It is not. This is the type of empirical analysis that is necessary to develop an appropriate determination of the best available method for allocating costs between classes. By classifying plant between customer and demand, the residential class receives a higher weighting of transformer costs consistent with cost causation since the unit costs per kVa for residential transformers is higher and they use many more transformers than other classes of customers. The basic customer charge method cannot recognize this reality. Bonbright recognizes this phenomenon and states that the exclusion of minimum system costs from demand stands on "much firmer ground."[13] This is exactly where the basic customer method places those costs.

By allocating the cost of transformers on NCP only, the parties supporting the basic customer method unfairly and incorrectly allocate all of the economies of scale in transformer costs to the residential class and compounds that error by allocating fewer transformers to the class than residential customers actually use. Any witness advocating

---

[13] Principles of Public Utility Rates, James C. Bonbright, 1961. p. 348

the use of the Basic Customer Method would produce a result that is inconsistent with cost causation as demonstrated above. Essentially, the basic customer method is not a method for calculating the customer component of costs that is based on the gold standard of cost causation because it fails to reflect any costs more than meter, service and direct customer accounting costs such as meter reading and billing in the customer costs. As often applied, it does not even include the full payroll related costs associated with the employees who provide the basic service and it does not include the office space used by these employees. These two flaws are enough to illustrate the arbitrary and incomplete nature of the development of the concept.

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

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

A. Yes. As the cost study filed by the Company illustrates, there are no energy-related costs for any component of the transmission or distribution costs and virtually none for production plant. Despite this fact, the parties who oppose demand charges have assumed that all of the fixed production, transmission and distribution costs should be allocated to the energy component of the rate and would have higher energy charges for all customers. The testimony of these advocates uniformly point to the resulting higher energy charges as a useful feature of lower customer cost allocation and thus lower customer charges.

Q. Does using the basic customer method in these circumstances violate the matching principle?

A. Yes. By collecting costs that are demand related in energy charges the rates that result violate the matching principle, which provides that the rates charged should match the costs for all customers. Recovery of fixed costs in the energy component of the rate cannot match cost causation for demand unless all customers in a class have identical or near identical load factors. (This is the point noted by Caywood above.) That is not the case, particularly for solar DG customers.

Failure to follow the minimum system classification and in addition putting these costs in the energy charge would unfairly cause customers who use more kWh to pay more for the same customer services provided to customers who consume less, and for customers with the same delivery services to pay more than identical customers with lower load factors.

Q. Is there a particular issue with using the basic customer method for solar DG customers?

A. Yes. In the case of net metering, solar DG customers are not paying the actual cost of the facilities they use related to the distribution system as the cost of service studies discussed below proves. I should also note that it is not necessary to provide a separate class cost study for solar DG customers to reach this conclusion. It is as simple as the cost of service study allocates the minimum system costs and the class NCP costs and production demand costs properly to the residential class including the load shape of solar DG customers. In my view, this allocation is conservative because of the different load characteristics of DG solar customers. The problem is not that the cost of service study needs to be changed; it is the rate design that recovers the allocated fixed cost, both customer and demand, on energy. Since over half of the solar DG bills are for zero kWh, and nearly all of the bills do not exceed the first block, the company collects far less than the average class costs for those customers. It is impossible that solar DG produces revenue enough to cover their allocated costs with so few billed kWh.

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

A. I have discussed above that the accepted method for classifying these costs is to classify them as both demand and customer. Parties opposing various aspects of cost allocation use Bonbright to support the basic customer method. In fact, Bonbright states his position regarding customer costs as "operating and capital costs found to vary with the number of customers, regardless, or almost regardless, of power consumption."[14] I also note that Bonbright states that the minimum system costs should not be allocated to the customer component. Bonbright also continues on to say that the exclusion of minimum system costs from demand stands on "much firmer ground."[15] The key point is that customer costs vary with the number of customers. As I have shown above transformer and other distribution costs vary with the number of customers. Further the relationship between customers and cost is an empirical relationship that has been analyzed in depth by economists in regulatory proceedings in many cases and around the world.

[14] Principles of Public Utility Rates, James C. Bonbright, 1961. p. 347
[15] P.348

Q. Please summarize the research showing that distribution costs vary with number of customers.

A. The correlation between customers and distribution costs has been confirmed by academic and regulatory research work related to estimating Total Factor Productivity (TFP) for use in price cap regulation. Under this system, where customers or connections has been an output measure for calculating the X-Factor in the formula $P = I - X$. The formula $P= I - X$ is essentially a formula that relates either price or the functional equivalent revenue requirements to inflation and changes in productivity as measures by the relationship of physical outputs like customers and demand to measures of physical inputs such as meters or transformers. For example, the following statement from an Australian electric distribution TFP study says "The connection component recognises that some distribution outputs are related to the very existence of customers rather than either throughput or system line capacity. This will include customer service functions such as call centres and, more importantly, *connection related capacity (eg having more residential customers requires more small transformers and poles*)." (Emphasis added.) This information is developed specifically for a network electric utility providing delivery services. I would note that the emphasis on connections is the result of the correlation of distribution costs to the number of customers. In a more recent study related to the electric distribution utilities in Ontario, Canada, The Pacific Economics Group (PEG) found that customer number was an empirically significant output measure for determining productivity. In each case the productivity measure is used to determine the expected changes in costs over time. As an aside, the customer component of TFP has the largest cost elasticity weight meaning the customer component is more significant than the other output measures. In addition to Australia and Ontario, other jurisdictions such as Great Britain and the Netherlands also use customer numbers to develop TFP.

Based on this research, it is fair to conclude that the weight of modern empirical evidence is fully supportive of the minimum system use to classify distribution system costs in accounts 364-368 as both customer and demand. I conclude that this empirical evidence, not available in 1961 or even in 1988, would have Bonbright supporting the minimum system because it aligns with his principle definition noted above. The goal in this case, as dictated by not only regulation but affirmed by the courts, is to allocate costs based on the principle of cost causation.

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

A. Yes. Alfred Kahn clearly defines that the parameter of the defect in cost of service is where marginal costs diverge from average costs. That divergence occurs for any utility exhibiting economies of scale. Kahn also states that the full distribution of costs "is in part along the lines that reflect true causal responsibility."[16] He goes further in that same chapter to conclude that "for those segments of demand that do not have the requisite high elasticity—prices based on fully distributed costs have much to recommend them."[17] Kahn concludes by noting "the respective average historic cost responsibilities of the various classes of service plus proportionate contributions to overhead will most likely strike the various rate-payers as equitable and non-discriminatory."[18] There is nothing in Kahn's view that is in any way inconsistent with the Company's cost study. Kahn's views however are inconsistent with the those parties who advocate the basic customer method and inclusion of all costs in energy charges since they do not reflect cost causation as demonstrated by both theory and pragmatic analytics. Further, the potential for loss in social welfare related to efficiency costs as a result of low customer charge and higher

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

kWh charges is quite large particularly when the targeted benefits of Lifeline rates are considered as part of the income redistribution impact. Simply, the parties' proposals to limit the customer charge represent a level of economic inefficiency that will be quite large to the detriment of the customers and economy in the TEP service territory.

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

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

B. The Appropriate Customer Charge

Q. Is the TEP customer charge proposal a reasonable value for the customer charge?

A. Yes. I reach this conclusion based on the discussion below that represents both practical and theoretical considerations.

Q. Please describe the theoretical issues for determining the customer charge.

A. Economists have discussed the theory of price determination under conditions of decreasing costs in detail. The seminal work in the field is an article entitled "The Marginal Cost Controversy" by Ronald Coase[19]. The Coase argument supports multi-part pricing[20] consisting of a variable charge set at marginal cost and fixed charges to recover the total

[19] "The Marginal Cost Controversy", R. H. Coase, Economica, New Series, Vol. 13, No. 51. (Aug., 1946), pp. 169-182.
[20] Ibid. p. 173

cost of service including what is characterized as customer costs and the remainder of past or sunk costs of the system would be included in the customer charge for a two part rate and in the customer and demand components of a multi-part rate. Since this is wholly consistent with the TEP position on the development of the charge, the proposal is theoretically sound. The proponents of the status quo fail to recognize that the current rates are definitely inefficient based on economic theory since there is no rationale for multiple levels of marginal prices that recover far more than marginal cost.

Q. Are there practical reasons for supporting the TEP proposed customer charges?

A. Yes. Increasing the customer charge is critical for rates to be just and reasonable. Just and reasonable rates must reflect cost causation. Since the customer component of cost is the same for all customers in a properly designed rate class, setting the rate below the properly determined customer costs (discussed above including the minimum system classification) means that low use customers are subsidized by high use customers. This creates an inequity that is not justified except for social policy related to certain customers who have incomes that allow them to qualify as recipients of low income, poverty related services. Maintaining low customer charges based on the impact on low use customers assumes incorrectly that there is a correlation between low use and low income customers who qualify as low income customers with poverty status. The low use/poverty argument suffers from a number of defects that have been discussed in academic studies (little or no correlation between low usage and poverty levels) and as well as in rate cases. Importantly, there is no reason to limit the customer charge for <u>all</u> customers for the benefit of eligible low income customers when they represent only 4.23% of bills under 500 kWhs. Further, eligible low income, low use customers (less than 500 kWhs) actually represent less than 44% of all low income bills. This is statistically the same percentage as the non-low income customers under 500 kWhs. Further, there are almost as many bills less than 500 kWhs for solar DG customers (74,000) as there are for low income customers (78,000) with solar DG having only about two-thirds the number of customers. The policy implication of the argument to limit customer charges to protect low income customers is grossly inefficient and should be rejected. In fact, there is no rationale for having Lifeline customers served on a different rate schedule than all other customers. The existing Lifeline customers should have the choice of the residential default rate or the optional rates so that they face the same price signals as all other customers. Qualifying, low income customers should receive bill assistance that is targeted to each customer's circumstance.

Q. What about the argument made by witness Zwick that only a small percentage of low income households are enrolled in Lifeline?

A. This is a common argument made by low income advocates. I have analyzed this argument in a number of gas and electric rate cases over the years and it is flawed. The argument rests on data such as the American Community Survey (ACS) or other Census data. The most important flaw in the analysis is to assume that every low income household is poor and that every household represents an electric customer. Both of these assumptions are incorrect and it is difficult to actually measure the net of low income poverty households who are utility customers and who pay their own electric bills. A simple but realistic example for TEP will illustrate these issues. From the ACS data we know that more than half of the occupied housing units are rented. This is not unusual for an area with a large state university as I have analyzed data for Columbus, Ohio (Ohio State University) using census block group data and GIS meter data in responding to claims about unserved poverty households. It is also not unusual for college students to be low income and qualify as low income households of unrelated individuals when they rent apartments. If they live in dorms each room is a low income housing unit. As a result in both of these cases, on-campus housing and off-campus apartments the students would be below the poverty level for income and many of those will either not have a utility bill or will not pay for electricity from their limited income. The ones who live off-campus will be the only ones with the potential electric bill and they are likely to be very low use customers based on their lifestyle and there are typically multiple low income persons in an apartment. They are not however poor. In addition to the impact of college students there are low income individuals who live in group homes, individuals who do not pay their own electric bill, low income households who are not poor and so forth. Importantly, there is no economic rationale for potentially eligible low income, poverty households to refuse to participate in a program that is widely known and provides a benefit to reduce bill impacts.

Q. Witness Zwick and others discuss the cost differences for multi-family dwellings as a rationale for opposing increased customer charges. Is that analysis correct?

A. No. This is also a common argument but related to the lower use by apartments and the supposed lower costs. It is not correct that urban area utility costs are lower than suburban or even rural areas. The reason is quite simple. Urban area costs are often higher than suburban or rural areas. ConEd serves the most urban service territory in the country with more multi-family dwellings than most utilities and is one of the highest delivery cost utilities. The explanation is really quite simple. It is more costly to provide underground service in an urban area than in suburbs because of the requirements to use conduit, place facilities in the street, use underground transformers and so forth. In suburbs, the transformers are typically pad mount and conductor is direct buried cable and typically in right of way granted by easement that is not in the street. Finally, for rural or suburban installation projects that require long runs of conductor that cannot be paid for with higher use than apartments, line extension polices would require a contribution in aid of construction.

In addition to capital costs, maintenance costs in urban areas are also more expensive because of the underground facilities that share common space with other utilities under the street.

Figure 1 Example of an Urban Street Cut

Figure 1 is a picture of an urban street cut that illustrates the co-location of utility facilities under the street in urban areas. This includes utility service such as natural gas pipe, electric conduit, water and sewer lines, telephone lines and cable service. The co-location of these facilities requires very different levels of security, different access requirements including street cuts and hand digging and other more costly requirements resulting from local regulations. Taken together it is simply not true that urban costs are lower than suburban costs. It is possible that they are actually higher meaning that the cross subsidy would flow from suburban customers to urban apartment dwellers.

Q. Witness Zwick uses Arizona RECS data to compare low income use to poverty usage in the TEP service area. Is this reasonable?

A. No. The TEP data has been filed in this case. It does not represent a sample but the entire population of actual eligible low income families and households served on the Lifeline rates.

Q. Do Lifeline customers have nearly identical kWh usage as regular customers?

A. Yes. In total Lifeline customers have nearly the same bill distribution except for the high use tail of the non-Lifeline customer distribution. If the highest use bills above 2,000 kWhs per month are removed from the distribution (about 5.7% of non-Lifeline bills) the distributions are nearly identical and the lowest usage bills below 200 kWhs per month represent a larger percentage of bills for regular customers than for Lifeline customers with Lifeline customers having over 5 percentage points fewer bills. The point is that low income customers are not necessarily low usage customers; in fact there little correlation between being low income and having low usage.

Q. RUCO witness Huber states that it is a faulty premise that fixed costs should be recovered in fixed charges. Please comment on this assertion.

A. Witness Huber is incorrect as a matter of economic theory of efficient rates and the requirement that rates be just, reasonable and non-discriminatory. As I have discussed above, throughout the history of the electric utility industry rate practitioners have recognized the need to recover fixed customer costs in fixed charges. And even fixed demand costs in kW demand charges. The Doherty rate discussed above is a prime example of the multi-part rate schedule developed by a utility practitioner. Historically, electricity was billed as a fixed sum per customer per billing period but the fixed charge was not the same for all customers. Energy was not even metered as is the practice today for some loads. The other and more common rate option prior to metering energy was the flat demand rate that was fixed based on the capacity of the loads being served. The concept of customer related costs begin in 1891[21] with the discussion of the role of meter rental charges and the development of costs related solely to the customer. Similar cost analysis including customer costs and meter costs was developed in 1896[22]. In both of these articles the key point is that just and equitable rates require small use customers to pay the fixed customer related costs and not be subsidized by larger use or higher load factor customers.

It is only through the use of fixed charges to recover fixed costs that the matching principle of rates is satisfied. This principle is important since it is required to provide a reasonable opportunity to earn the allowed return and is required for reasonable rates that reflect the cost of service principle. This is the practical side of rates for groups that are not perfectly homogeneous. It is well established that the residential class has grown less homogeneous over the last 100 years—a trend that has accelerated in recent years—increasing the practical requirement that just and reasonable rates recover fixed customer costs in the fixed customer charge. In the past, when residential customers had more homogenous usage, the distinction was less important, and volumetric charges could be used to recover fixed costs, because with similar usage those costs would end up being paid relatively uniformly by the customers. That is no longer the case.

Witness Huber's view is also totally inconsistent with the views of economic theory of efficient rates in a declining cost industry such as electric utilities. In that case the fixed charge would be set to recover all of the fixed embedded costs that exceeded marginal cost. Under the economic theory of optimal rates, the customer charge would be higher than the TEP proposed customer charge and higher even than the allocated customer costs because marginal costs are low.

---

[21] Walton Clark, "Meter Rents—A Question of Equity and Policy", American Gas Light Association Proceedings, IX (1891) pp. 686-688

[22] A reprint of the 1896 article of W. J. Greene on cost analysis may be found in The Development of Scientific Rates for Electricity Supply, Printed for Private Circulation Only by The Edison Illuminating Company of Detroit, 1915, pp. 23-29 (Available from GOOGLE Books)

Q. Please provide an example illustrating how kWh charges should not be used to recover fixed costs.

A. The idea that rates can be reasonable and recover all fixed costs in kWh charges or even with limited customer charges is not logical as can be shown by a simple example. The utility consists of two customers who have identical facilities to provide generation, transmission and distribution and thus cause the same fixed costs. If the two customers used the exact same kWh and kW demand rate design would be trivial since any set of fixed and variable charges would recover the cost caused by each customer because the two customers are perfectly homogeneous. As soon as the customers use different kWhs with the same demand the customer with more kWhs pays more than the cost he causes and the lower use customer pays less. This very observation was the basis for the early development of a customer cost component and customer charges and the observation prevails still today over 100 years later only it is much more important because 100 years ago the loads were homogeneous with only the intensity of use varying. Today the loads are not homogeneous so the costs vary for customers with the same kWhs, customers with different demands on different components of the system and different kWhs. The only reasonable option is to do away with compromise, two-part rates and recover fixed costs in fixed charges and variable costs in variable charges while still sending appropriate price signals as may be permitted by revenue requirements.

Q. Witness Huber states that the proposal deviates from "common utility practice", please comment on that conclusion.

A. That conclusion is simply wrong. Customer charges are increasing at literally thousands of utilities around the country. There are approximately 3,300 electric utilities in the United States. Of this total the investor owned utilities represent about 6%. His basis for this conclusion is a sample of 51 "decisions" in a report he did not prepare. First, municipal utilities are typically not regulated by commissions and there are six of the 51 utilities that are municipals. Likewise public utility districts are typically not subject to state commission regulation and three are PUDs. Finally, the Salt River Project is not regulated by the Arizona Corporation Commission. 15 of the cases were settled and the Commissions accepted the settlements. Five decisions were postponed or moved to another docket. This leaves 21 utilities out of 1000s of utilities as the evidentiary support for defining common utility practice. As a practical matter the common utility practice has been to increase customer charges in order to recover fixed costs caused by customers. On that basis alone the common practice that includes IOUs, Cooperatives and Municipal Utilities is to increase customer charges and to reflect customer costs in rates.

Q. Do you have any specific data on how TEP's proposed customer charge compares to other utilities?

A. There are about 1000 electric utilities with residential customer charges equal to or greater than $20 per month[23] as originally proposed by TEP. I understand that TEP is accepting Staff's even lower customer charge of $17.00 as a compromise measure. Because the evidence fully supports a customer charge of at least $20, it certainly supports increasing the customer charge to no less than that proposed by Staff.

Q. Witness Huber provides a list of reasons that customer charges were not approved. Is that applicable in this case?

A. Witness Huber cites six reasons for not increasing the customer charge as given in the report he cites as the basis for his conclusions as follows:

1. Concerns about reduced customer control;
2. Concerns about rate shock;

[23] Utility Rate Database, http://en.openei.org/wiki/Utility_Rate_Database

3. Concerns about inequitable impacts to low usage customers;
4. Concerns about inequitable impacts to low income customers;
5. Concerns about reduced incentives to invest in energy efficiency; and
6. Concerns about inefficient price signals.

Those concerns are not valid in this case. I will address each of these points in turn.

Q. Please address the first point that customers still have significant control over their bill under TEP's proposed customer charge?

A. Yes. The proposed rates still provide the customer control over the bill unless the customer uses zero kWh because the energy charges are still significant. Importantly, the median use customer (regular or low income) uses over 500 kWhs per month and as a result maintains control over the most significant part of the bill. The largest exception to this is for solar DG customers where over half the bills are zero. In that case the higher charge is fully justified on a cost of service basis since these customers make no contribution to delivery service but use more of that service than the typical customer.

Q. Please address Mr. Huber's "rate shock" contention.

A. Rate shock is nothing more than a convenient phrase to use when there is no real rationale for opposing an increase. The term rate shock refers to large over-all utility increases. The term was coined to address the impact of costly baseload nuclear plant additions to rate base that would add billions of dollars to the rate base. There is no connotation in which an increase in rates of $0.33 per day per customer can be considered rate shock. The term is misapplied in this context. Further, customers typically care about their overall bill, not about specific components such as the customer charge. If "rate shock" is to be considered, the proper frame of reference is the overall bill. Looking at one component—here the customer charge—is misleading because it misses the offsetting impact to the volumetric charge.

Q. Please address the impact of the proposed customer charge to low use customers.

A. The issue of low-use customer impacts has been discussed above, but essentially the current rates and low customer charge are inequitable because they do not recover costs caused by low-use customers. Many of the low-use customers are seasonal and DG customers and are receiving large subsidies under the current rate.

Q. Please address the impact of the customer charge to low income customers.

A. I have also discussed the issue of low income customer impacts above. As I have explained, it is incorrect to equate low income and low use customers. As I have explained there is not economic or rate rationale to limit customer charges to address low income bill issues. The optimal policy is to have one rate for all customers and provide low income assistance outside of a rate mechanism because a one size fits all approach results in a program that really does not fit anyone.

Q. What about energy efficiency and price signals?

A. The issue of incentives for conservation and inefficient price signals are the same issue. In this case the efficient price signal would be an energy charge that is much lower than the resulting energy charges after the full customer charge increase. Simply, efficient pricing sets the volumetric price at marginal cost and the remaining revenue requirement in fixed charges. This point has been made in the New York REV proceeding in a report prepared for NYSERDA. The rate recommendation states:

"Q: Why is it important to collect embedded costs with network subscription charges?

A: *Mispriced components lead to inefficient investment and operation decisions by customers*. Without a size-based access charge to recover residual embedded costs, higher volumetric rates are required which charge customers more than the marginal costs for energy consumption. Access charges reduce uneconomic bypass and *lessens social welfare loss*.

An access charge reduces the risks of recovering residual utility embedded costs, provides greater revenue stability on existing assets for utilities, limits uneconomic bypass, and should allow utilities to achieve lower financing costs of the network on behalf of all ratepayers. This strategy could enable the evolution of different utility business models, such as separating the utility into an independent distribution system operator that plans and operates the grid and an asset company that uses asset-backed financing and a fixed revenue stream based on the network subscription charge to finance and maintain the network at a lower cost."[24] (Emphasis added.)

As this statement notes higher energy charges result in uneconomic bypass including DG, DER and energy efficiency. By charging rates that exceed marginal cost even including plausible values for externalities, the RUCO proposal and indeed the proposals of all the opponents of the TEP customer charge increase are supporting a significant loss in social welfare to support their own end-use opportunities.

Q. Have you addressed witness Huber's cost causation argument that concludes the proposed charge is not based on cost causation?

A. Yes. I have demonstrated above that the minimum system concept is a necessary condition for rates to reflect cost causation. The evidence of that requirement is irrefutable.

[24] Full Value Tariff Design and Retail Rate Choices Prepared for: New York State Energy Research and Development Authority and New York State Department of Public Service April 18, 2016, Energy and Environmental Economics, Inc., p. 18

Q. What about the arguments that witness Huber offers against the minimum system use to classify distribution costs as customer related?

A. Witness Huber has claimed that the method is flawed because it "assumes that the configuration of the distribution network is a given."[25] No such assumption is required. The distribution network is always built in a way to provide safe and reliable service. Regardless of the actual amounts of cost or the actual physical configuration of the network a portion based on the smallest size of equipment that is actually installed is classified as customer. As I have discussed above, the method is required to reflect the relative costs and physical amounts of network assets used by each class of customer. No other method of allocating distribution system plant costs can properly reflect the actual physical assets used by each class.

Q. Do you have empirical data to support the conclusion that distribution costs are directly tied to customers?

A. Yes. This point applies to TEP based on several different types of Company specific empirical analysis. Using distribution plant data for the twenty year period from 1995 to 2015 and customer and demand data for the same period, I have tested empirically the cost causation for this asset class. Using gross plant each year as the dependent variable and customers as the independent variable, with the intercept term set to zero, customers explained 95 percent of the variation in the dependent variable distribution plant costs in accounts 364-368. That value increases to 97 percent if we use customers and demand as measured by MVA of substation capacity. In both analyses the F-Statistics and the t-statistics are significant meaning that we can reject the hypothesis that the variables are no different than zero.

---

[25] Huber Direct Testimony at p. 16

Further, TEP provided data on the number of distribution transformers (Account 368) and the number of transformers used by the residential class. Table 1 below has three columns of data: actual transformers, minimum system allocation and NCP demand allocation.

Table 1 Physical Number of Distribution Transformers

	Actual Transformers	Minimum System*	Class NCP*
Total	72,270	Allocation	Allocation
Residential	59,771	60,056	37,414
All Other	12,559	12,214	34,856

*Values developed from TEP base cost of service study allocation factors.

As the table illustrates, the use of the minimum system closely matches the actual mix of class transformers used in the cost of service study. The same conclusion applies to the physical requirements for the other distribution accounts as well. This is consistent with findings in other cost of service studies where this analysis has been conducted to verify the minimum system concept. With the support of empirical evidence, theoretical analysis and econometric analysis of productivity and so forth, there is no valid opposition to the TEP proposed customer charge or its cost causation tracking based on the RUCO evidence provided by witness Huber.

Q. **What about the customer benefits argument that witness Huber asserts as a basis for limiting the customer charge?**

A. The benefits received argument has no basis for setting rates as it essentially penalizes higher load factor customers who cause the same delivery costs as a low load factor customer. The fallacy of this argument was a central element in the rate strategies used to grow electric utilities to take advantage of economies of scale throughout most of the twentieth century. Namely, the elasticity of demand increases at higher usage levels. In addition smaller customers actually cause more costs than larger customers because of economies of scale. The fundamental point is that there is no basis for measuring benefits and theoretically the highest benefits accrue to the least elastic uses because that results in the highest consumer surplus. If a customer benefits from a service at any level, it can be said that that customer causes costs and should pay those costs. In this case that means a customer charge as proposed by TEP. Even at that charge, the rates will not be economically efficient for residential customers as noted above.

Q. Is there a rationale for keeping the customer charge low to protect low income customers as suggested by witness Huber?

A. No. I have discussed this objection in detail above. Again, low usage customers and low income customers are not identical groups. As I have shown, low income customers actually have a fairly normal distribution of usage. Thus, Mr. Huber's argument is flawed and results in large losses in social welfare for a very few customers who are actually poverty level users and use small amounts of electricity. Targeted assistance as I noted is far more efficient and consistent with more economically efficient rates.

Q. Is earnings risk reduced by higher customer charges as claimed by witness Huber?

A. No. Even with the proposed customer charge increase there is also an increase in the average volumetric charge and in the average bill. If the usage pattern changes from the current pattern through DER or through EE, the system earnings will decline more than currently. This decline results whether customers respond to marginal price or to the total bill. It is also critical to understand the risk profile of comparable companies before even attempting to opine on the potential for reduced equity return based on risk. Witness Huber provides no discussion of comparable companies and the revenue mechanisms employed by their regulators. For that reason alone no conclusion regarding the risk impact on earnings is valid.

Q. RUCO witness Huber states that lower users contribute less to overall system costs. Is that statement correct?

A. No. It actually cost more per unit to serve smaller users because per unit cost of capacity for delivery declines as the size of assets serves increasing load. This is because of economies of scale. Also, on a per unit cost basis low use customers have lower load factors than larger users based on TEP load research data.

Q. Please comment on the testimony of witness Baatz for sweep as it relates to customer costs and customer charges.

A. Witness Baatz makes virtually the same arguments as witness Huber as it relates to the level of the customer charge and the minimum system. Essentially the errors discussed above related to witness Huber are also found in witness Baatz testimony. Witness Baatz states the minimum system is improperly defined. On the contrary, determination of the minimum system is not subjective and is based on the actual distribution standards used by TEP. Witness Baatz states the system is hypothetical and that is not true because TEP actually installs minimum sized facilities. Witness Baatz seeks support from Bonbright for his opposition but in fact no such support can be found if the total context of Bonbright is included rather than selectively lifting one sentence from his work as discussed above. Witness Baatz also cites a 2000 report prepared by the Regulatory Assistance Project as support for the opposition to various support for the customer charge. First, that report is dated and did not have the advantage of the latest empirical research as noted above. Second, that report relies on a statement that thirty states use this "general approach".[26] That statement is not supported by any study or by any survey. The simple fact is that each rate case is a new opportunity for regulators to review the evidence in the case and the

[26] Weston, Fredrick. 2000. "Charging for Distribution Utility Services: Issues in Rate Design." Regulatory Assistance Project. http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724, p. 30

evidence in this case proves that the basic customer method cannot reflect cost causation and is therefore unacceptable for use in this case.

Q. Witness Baatz states that the minimum system is a "radical shift away from previously approved cost of service methods". Please comment.

A. Rate cases represent an opportunity to improve cost of service studies to reflect cost causation. The minimum system is one such improvement. It is based on TEP recognizing that prior cost studies did not adequately reflect cost causation and that is the ultimate objective of a cost study. If the old method had continued the residential class would have been allocated only 62.6% of the transformers they actually use and even less costs for those transformers because of the economies of scale in transformer costs reflected in revenue requirements. This is just one example of the improvement in reflecting cost causation and applies to all of the accounts 364-368. The proposal is nothing more than TEP evolving its cost study to reflect cost causation more accurately. That same conclusion applies to rate design as the mixed competitive and monopoly model requires rates to reflect cost causation or the model makes those customers using the full basket of utility services will pay an ever increasing share of utility fixed costs that they do not cause, which will produce rates that are not just and reasonable.

Q. Witness Baatz makes other arguments about cost causation such as costs for apartments or rural area service costs. Please respond.

A. As with other arguments in the testimony, there is nothing new in witness Baatz testimony. The arguments are not sound as I have discussed in detail above.

Q. Is the TEP rate proposal an SFV rate as discussed by witness Baatz?

A. No. Energy charges continue to recover significant amounts fixed costs so the rate is decidedly not a Straight Fixed Variable ("SFV") rate.

Q. Witness Baatz argues that fixed costs recovery in fixed charges has "little precedent in the commercial world". Please comment.

A. This is an extremely old argument that has been rebutted in the literature as early as 1938 in the monograph <u>Service Charges in Gas and Electric Rates</u> by Hubert Frank Havlik who devoted almost three pages to the subject of the commercial precedent and concludes "These instances show that service charges appear in other than utility industries, and that *demand and customer costs* affect the pricing of the service or commodity."[27] This is not the only such discussion as a recent blog post by Severin Borenstein from the Haas School at the University of California Berkeley who states the argument as "No company in a real market would ever price that way." His conclusion is that "In almost every instance, however, the claim is both incorrect and irrelevant."[28] Witness Baatz views are neither credible nor sound as it relates to the nature and recovery of these costs.

Q. Witness Baatz also makes an equity argument in opposition to customer charges by defining equity based on kWh use. Please comment.

A. The concept of equity is not defined on a kWh basis but on a cost causation basis. The logic is simple. If two customers cause the same costs and pay the same rates that would reflect equitable treatment. As I have shown above, customers regardless of kWh use cause the same customer costs for service within a class such as residential customers- either full or partial requirements service. Alfred Kahn also reaches the same conclusion I have

---

[27] <u>Service Charges in Gas and Electric Rates</u>, Hubert Frank Havlik, Columbia University Press, New York, 1938, p.98

[28] "Is Electricity Pricing Different from "Real Markets"? Should It Be?", Posted on June 13, 2016 by Severin Borenstein, Berkeley-Haas Insights, https://energyathaas.wordpress.com/2016/06/13/is-electricity-pricing-different-from-real-... 6/13/2016

reached when he concludes "for those segments of demand that do not have the requisite high elasticity—prices based on fully distributed costs have much to recommend them."[29] Kahn also concludes that customers typically recognize the equity of paying charges based on cost of service.[30] Since customer costs do not vary with kWh consumption, equity actually requires that all customers, regardless of kWh consumption, pay a charge equal to the costs. It is witness Baatz proposal that is inequitable not the TEP proposal that moves in the necessary direction of equity.

Q. Does the customer charge create a higher hurdle for energy efficiency investment for low income customers as claimed by witness Baatz?

A. No. This statement is nonsense. The customer has the same return as everyone else based on a saved kWh in the energy tier where marginal consumption occurs. However, the use of non-cost based inverted rates results in low use customers facing a lower per kWh return on their investment than other companies. True concern for the low income conservation impact of rate design is inconsistent with witness Baatz opposition to eliminating the tiers in rates.

Q. Witness Kobor states "TEP's proposal to double basic service charges for residential and small commercial customers and to reduce the number of residential tiers is not reflective of "modern" rate design. Instead, it reflects regressive actions that will undermine commission policy." Please comment.

A. As I have noted above common utility practice including all electric utilities in the country is to have higher customer charges as about 1000 of the three odd thousand electric utilities are $20 dollars or greater. This is the essence of a fully unbundled rate structure that is a prerequisite for utility operation in a mixed monopoly and competition model. Failure to

[29] Kahn, Op. Cit. p. 158
[30] P. 158

develop reasonable and modern rates results in the majority of customers subsidizing DG customers as the cost studies discussed below prove. In fact, it is the current two part rate that has been a compromise for over a century. As for undermining Commission policy witness Kobor does not really justify how policy is undermined except to say there may be less DER and EE. The important points in rate design are found in PURPA whose purposes are as follows:

1. Conservation of energy supplied by electric utilities,
2. Optimal efficiency of electric utility facilities and resources, and
3. Equitable rates for electric consumers (PURPA section 101).

These three purposes provide Federal guidance for how rates should be designed. The equitable rates purpose is only satisfied by reflecting cost causation in the customer charge and demand and TOU based energy charges as fundamental principles of rate design. The required basis for cost of service under PURPA is that rates reflect cost of service and measure the impact of customers, demand and energy on the determination of costs. TEP performed such a study to inform its rate design. In addition, the costs studies discussed below adhere to that standard as well. Witness Kobor must define conservation as an absolute reduction in electric sales. That is an incorrect definition. If the definition of conservation used by Congress had been intended to be different from the definition "Conservation is the act of preserving, guarding or protecting; wise use" it would have had the opportunity to define the term among other definitions of the standard. Wise use coupled with optimal efficiency of facilities and resources is only achievable when rates reflect cost of service and any artificial subsidies such as those offered to DG under net metering and banking are eliminated. The simple fact is that the value of rooftop solar is at most the price paid for utility scale solar, adjusted for the net effect of rooftop solar DG on distribution system losses, which may be zero. Nothing in the TEP proposals undermines Commission policy. Further adopting the TEP proposals as filed begin to eliminate the undue discrimination in rates as demonstrated above and in the cost of service studies discussed below. The evidence shows that witness Kobor's statement is negative rhetoric designed to achieve the type of rent-seeking that the Commission must not permit.

Q. Witness Kobor also opposes the use of the minimum system method in the cost study. Is the opposition based on sound analysis and evidence?

A. No. I have discussed most of the points made by witness Kobor above and have demonstrated that her arguments cannot be supported by any evidence she has provided. Her conclusions are simply incorrect for all the reasons I have discussed in detail above. The absence of logic is best demonstrated by her conclusion that because the basic customer method produces lower customer charges the customer charges in the cost study "significantly over-allocates costs to the customer function."[31] Aside from the logical flaw that two different methods produce different results proves the higher number is wrong, the argument suffers from another fatal logical error. This conclusion assumes that a method she proposes that is not recognized by NARUC or any of the theoretical treatises on rates such as Caywood, Bary, Suelflow etc. is the correct method. It is not. In addition the evidence above related specifically to TEP proves quantitatively and qualitatively that the basic customer method can never be cost based. The minimum system is cost based.

Q. Please summarize your conclusions related to the cause of customer costs and the level of the customer charge.

A. Customer costs based on cost causation must include the customer component of the distribution system in Accounts 364 – 368. I show conclusively that inclusion of the minimum system is a necessary condition for reflecting cost causation. I have demonstrated that the arguments of the parties who oppose the minimum system all suffer

---

[31] Kobor at p. 72.

from some incorrect analysis and in general are unsupported by their arguments for alternative methods of calculating customer costs. I also show that modern rate design cannot be equitable or efficient absent a customer charge as proposed by TEP. I recommend that the Commission adopt the cost study as proposed and the proposed customer charges in order to have just and reasonable rates that meet the requirement of providing the Company a reasonable opportunity to earn the allowed return.

III. Economics of Serving Full and Partial Requirements Service Customers.

Q. Please define the terms full and partial requirements customers.

A. A full requirements service customer is a customer who elects to use the full bundle of utility services on a continuous basis and acquires no utility related services from another provider. In the case of an electric customer this means that the customer uses the full scope of production, transmission, distribution and customer services from the utility in a seamless package represented by the delivery of capacity and energy to the customer as required by the customer. A partial requirements service customer is a customer who elects to select the particular components of the utility service to be used when the customer elects to use the utility service and to use other non-utility sources for all or a portion of the some of the standard utility services to meet their demand for energy or capacity or some combination of the two requirements. Solar DG customers are one type of partial requirements customer. Partial requirements customers essentially are former full requirements customers who elect to use the utility for services such as back-up/standby service, maintenance service or supplemental service or some combination of all of these services.

Q. Do partial requirements customers differ from each other and from full requirements customers?

A. Yes. Partial requirements customers differ both from full requirements customers and from each other depending on the non-utility services they purchase because the demand and energy load shapes the utility must stand ready to serve differ and in some case differ dramatically. For example, some partial requirements services provide baseload service leaving the utility to provide supplemental peaking services and may be viewed as low load factor customers for the utility. Other partial requirements services are peaking in nature and leave the utility to provide baseload service and may be viewed as high load factor customers for the utility. Each different service has different cost characteristics based on the cost the utility incurs to serve the customer.

Every solar DG customer differs from customers who use cogeneration and cogeneration customers differ based on technology. They also differ based on the underlying total hourly demand for electricity. For example, when a residential customer changes from full requirements to partial requirements, the underlying load characteristics of the dwelling do not change nor do the local facilities installed to serve that customer change. As an example, the utility cannot change the service line or the transformer to serve that customer because those were sized to serve the maximum load of the customer whenever it occurs. The load measured in kWh and kW imposed on the utility does change however. The customer may use less energy but may still require the same or more kW capacity for delivery service and may even require the same capacity for production and transmission depending on a number of factors associated with the customer's non-utility supply source. Since different technologies have different supply characteristics every different source will have a different impact. In some cases, that impact is a function of system characteristics in others it is a function of technology or some of both. If a new customer comes on the system as a partial requirements customer, the utility system planners must still provide for the maximum service that a partial requirements customer may impose when the customer's non-utility source of supply is not available. The important point is that one cannot assume that partial requirements customers cause fewer costs, and in some cases it may even increase. To determine cost causation requires an understanding of the type and timing of the services provided by the utility. Finally, it is critically important to recognize that utility capacity requirements are not the same for each component of utility service. Appendix B to this rebuttal testimony is a copy of my white paper "Smart Rates for Smart Utilities" that provides a detailed discussion of many of the concepts related to unbundled rates and the necessity for each rate component.

Since the issue of capacity savings cannot be determined based solely on one measure of capacity as discussed later in this rebuttal testimony, it is impossible to conclude that there are capacity benefits for each measure of capacity- production, transmission and distribution- for partial requirements service. The capacity obligation associated with the DG customer is typically the same or as demonstrated in the cost studies below greater than the delivery requirements for a full requirements customer and is based on the expected capacity of the distribution system used by the premises which may and usually does occur outside the peak load period.

Q. In the context of a rate case is it possible to determine the change in revenue requirements resulting from a customer shifting to partial requirements service?

A. Yes. I have made just such a determination in the cost studies provided below. The values in a cost study may or may not equal the actual avoided costs that should be the maximum allowable credit for a solar DG customer. The avoided cost to the utility will generally be lower than the embedded cost credit because of the sunk cost and lumpy nature of utility costs results in higher average costs than avoided cost. Given that utilities exhibit economies of scale, this would imply that marginal cost is below average costs. Further, the marginal cost of a load increment differs from the marginal cost of a load decrement (avoided costs) because of the lumpy investments and the sunk costs of a utility. A simple example will illustrate this point. If a new customer is added to the system that requires 8 kW of delivery capacity the utility adds a 10 kVa transformer to serve the load of that customer along with the necessary conductor and feeder capacity as needed. If a few years later that customer reduces its demand by 2 kW the utility does not change out the transformer and ultimately cannot replace that transformer at the end of its useful life with a smaller transformer. This same logic applies in the context of a substation and its transformers. If the total load on a substation transformer is 8 MVA the utility will install a 10 MVA transformer to serve the load. If that load in every hour of the year is reduced by 25% the substation still requires a 10 MVA transformer to serve the peak loads. If the lower load periods are significantly below 5 MVA, energy losses increase as a percent of load and the utility may actually add a 5MVA transformer to the substation to use in low load periods and switching equipment to use the larger transformer when loads are higher. In either case there are no avoided costs as the result of the drop in load. The avoided cost in the first case is zero and in the second case there are added capacity costs reduced by the reduction in lost energy costs for a net of no avoided costs but there is a cost shift in the second case.

Q. Why would a utility need a separate rate for partial requirements customers?

A. A separate rate for partial requirements customers is needed when some customers use the system differently than other customers who have the same end-use loads. Different usage patterns result from how a partial requirements customer uses the system.

Q. Do solar DG customers use the system differently than full requirements customers?

A. Yes. Solar DG customers provide an excellent example of a group of residential customers that use the system very differently from full requirements customers. These customers use the system for much more than the delivery of kWhs they consume when solar DG is not available or inadequate to serve the total hourly load. Some differences include the use of the system for the sale of excess kWhs back to the system. Under net metering with a banking provision solar DG customers use the system for virtual storage just as if they had a very large battery that would allow them to put kWhs in the battery in low load periods and draw them out of storage to offset purchases in high cost periods. This is a service that is free under net metering but is not free from subsidy from other customers who pay for the storage service and the price differential between high load, high cost periods and low load, low cost periods. Other customers also pay for the losses associated with the delivery to storage and the delivery back to the customer under net metering where there is no loss adjustment associated with the transaction.

Q. Please address class NCP for solar DG customers.

A. Solar DG customers also use the distribution system differently. The reason that the distribution system is used differently is that while there is natural diversity in customer loads that produce the class load NCP, there is no natural diversity at the class NCP for solar DG sales of excess generation. The maximum output of all of the solar DG customers occurs at the same time because the DG facilities are all or predominately designed to maximize kWh production and are fixed axis solar DG installations. The peak production occurs on the coolest day in the spring and at mid-day. There is no diversity in the sense that some customers peak later or on a different day because of the inherent technological and operating characteristics of solar DG. In a sense this peak is like the gas system peak that occurs for all heating customers on the same day based on the weather conditions. This means that it is possible that the class NCP for solar DG actually occurs on a day not based on load but based on delivery of power back to the grid. That is the case for TEP where the delivery NCP is greater than the load NCP. The solar class NCP occurs at noon in March or April when almost twice as much power is delivered to the system than the solar class contribution to the load NCP on the hottest day in the summer. Figure 2 below illustrates the nature of the generation delivery to the utility system for three days in April where the highest delivery is 43,429 kW at 13:00 hours using the hour ended concept used by utility dispatch.

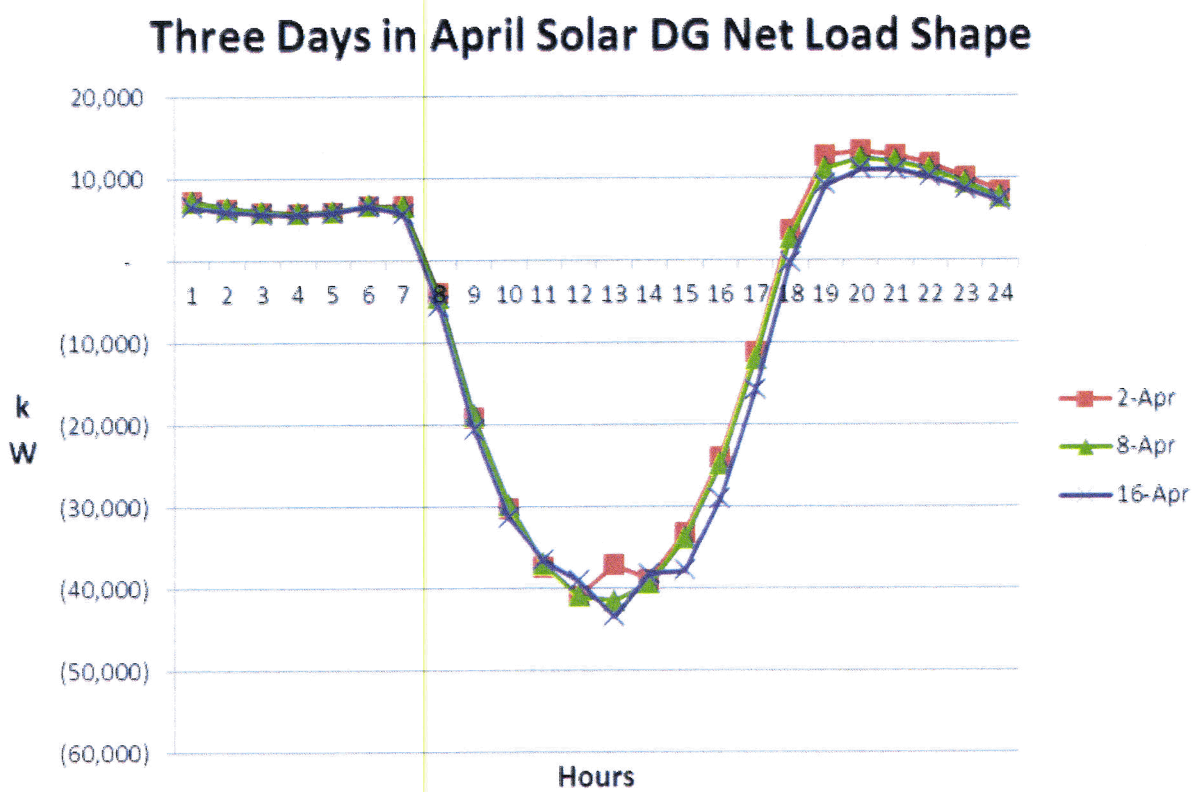


Figure 2 April Solar DG Net Load Shape

The distribution system must be able to accommodate bi-directional delivery service and serve the load at which ever maximum occurs- either load NCP or generation NCP. This high load also raises marginal losses on the local facilities that impact the net delivered power from solar DG for the grid. This is very different from how full requirements customers use the grid.

Q. How should delivery costs be allocated to DG customers?

A. To properly allocate delivery service costs to DG customers it is necessary to recognize the actual class NCP. It also means that for customers who respond to the energy price signal and size their system to minimize the utility bill there are no possible distribution cost savings.

Q. Are there other ways that Solar DG customers are different?

A. Yes. When kWs are sent back to the system in these low load periods the system power factor deteriorates because solar generation produces no vars. In order to resolve the lower power factor associated with solar DG it is inevitable that distribution costs will increase as the utility installs switched capacitors to manage the system power factor. The alternative to the low power factor is to require smart inverters as part of the interconnection standard. This is similar to the provisions in rates for larger customers that either bill customers on a kVa basis or include a power factor adjustment provision that recognizes lower power factor has a cost as in the large customer rates for TEP.

There are other uses that solar customers make of the system such as synchronization of solar generation with the grid, in rush current, supplemental service and backup service. These services all result in differences between the residential solar DG customers and full requirements customers. For example when a full requirements customer uses in rush current to start a motor load there is also kWh use that is billed. For a solar DG customer there is no kWh use when the solar DG is operating and meeting the load but the in rush current is used. The pattern of supplemental service is such that solar DG customers require utility service in some of the highest cost hours based on the limited energy from solar DG in those hours. These are all unbundled services used by solar DG some of which they do not compensate the utility for the costs they cause and others which they pay less than the full costs under the two-part rate.

Q. Is the difference in system use recognized generally by industry observers?

A. Yes. This concept is widely recognized. For example the following quotation from a blog post from the Haas Energy Institute provides one such example:

"The reality is that a customer who consumes 300 kWh in a month is imposing very different costs on the system than a customer who consumes 1500 kWh over some hours and also injects 1200 kWh into the grid during other hours. NEM treats them the same. That may have been a *convenient benign fiction* back when solar PV barely existed. But today *it is a costly distortion that has the potential to create huge economic inefficiencies and unfairly shift billions of dollars in costs among customers*."[32] (Emphasis added.)

Q. Is there a way to illustrate how differently DG customers use the system compared to full requirements customers based on TEP load data?

A. Yes. I have used TEP load research data for the residential class from the cost study and the load shape for TEP solar DG customers developed originally in IN THE MATTER OF THE COMMISSION'S INVESTIGATION OF VALUE AND COST OF DISTRIBUTED GENERATION DOCKET NO. E-00000J-14-0023 and used below in the cost of service studies based on actual TEP billing data and actual customer solar DG capacity and modeled to match actual hourly load profiles for solar DG customers based on residential load research data. Based on that data I have calculated the monthly, class NCP load factors for full requirements residential customers and for solar DG customers.

[32] Blog Post at Energy Institute at Hass Energy "Billing Tweaks Don't Make Net Metering Good Policy" Posted on January 4, 2016 by Severin Borenstein

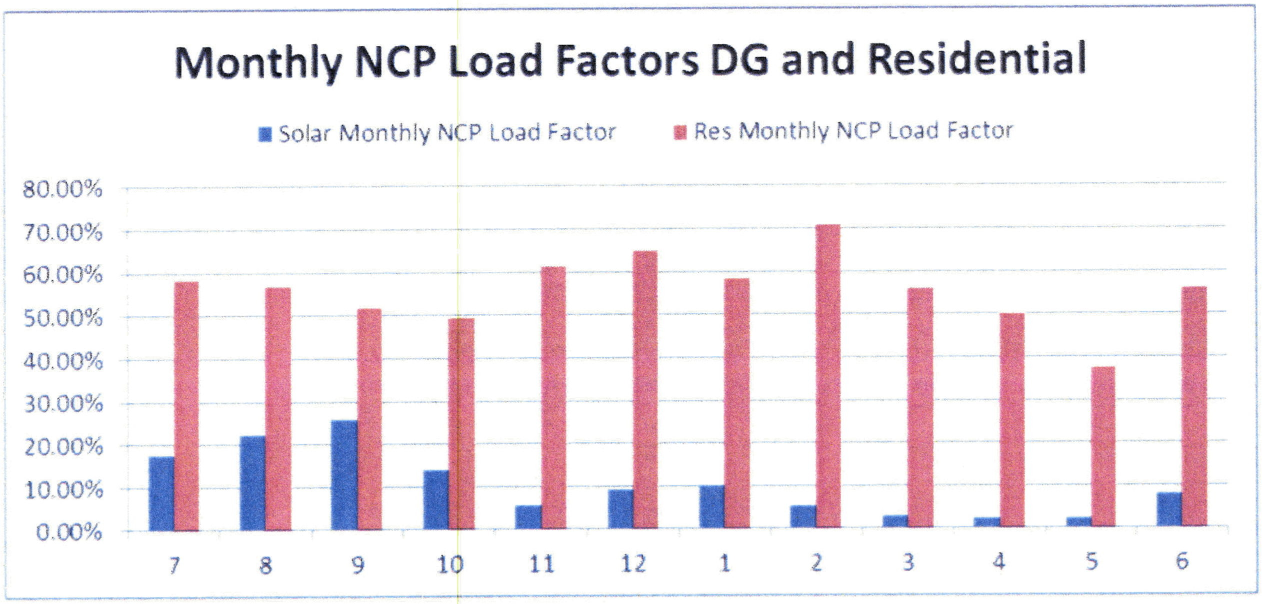


Figure 3 Monthly NCP Load Factors DG and Residential

As Figure 3 illustrates, solar DG customers actually use the system very differently than full requirements customers. In particular, the data shows that DG customers as a class have a lower load factor in every month of the year when compared to full requirements customers. The solar class NCP load factor is consistently less than half of the load factor of full requirements customers and the same result would occur if the data was on an individual customer basis. The second observation is that solar DG customers use more energy in the summer months to supplement their solar DG output as shown by their higher class NCP load factors and the higher system loads. This conclusion is not surprising given the higher summer loads and the reduced DG output associated with ambient temperature. This data contradicts the various claims that TEP has not used their own data to demonstrate how solar DG customers use the system differently than other customers. In addition to this data, the cost of service studies in the next section also demonstrate that TEP based data is used to demonstrate the conclusions related to DG solar proposals.

IV. Cost of Service Study Results.

Q. Please describe the cost of service studies developed in this case.

A. There is no practical way to assess the costs caused or the revenue requirements for full and partial requirements customers without developing a cost of service study that identifies these two classes of residential customers in separate classes for fixed costs and in separate studies for variable energy related costs. In order to respond to he claims made by solar advocates in their direct testimony, I have prepared three different cost studies to allocate the fixed costs of TEP based on the cost study filed in the current TEP rate case. I say fixed costs because the three studies produce results that only allocate costs that are classified as customer or demand costs and do not include any costs classified as energy. I will refer to these three studies collectively as the fixed cost studies. The energy cost studies use hourly costs for full and partial requirement customers to assess the energy related costs and include an analysis of marginal energy costs for each category of residential customers.

Q. Please describe the three fixed cost studies.

A. Based on a decision by the Public Service Commission of Utah in Docket No. 14-035-114 issued November 10, 2015, the Utah PSC adopted a methodology of comparing two cost studies to determine the costs of serving solar customers for ratemaking purposes. The first cost study is the standard cost study with the solar NEM customers' allocated costs just like the residential class based on actual load characteristics of the class. The second study that Utah refers to as counterfactual cost study (CFCOS) assumes that the solar customers did not adopt DG but rather were full requirements customers allocated costs in the same way as the residential class. This study is essentially an embedded cost study that assumes all other things being equal except for the addition of solar PV at the customer premises. By comparing these two studies it is possible to identify the way costs change for both full and partial requirements customers assuming that the load characteristics in terms of both load and delivery capacity requirements are no different. All other things are not equal when viewed from the factors that cause costs. Since we know that the load characteristics are not the same, I recommend a separate class for evaluating the embedded costs of solar DG customers rather than using the counterfactual study alone with its inherently biased assumption about cost causation. That is the third fixed cost study I have included.

For each cost study we use the same fixed costs for the system based on the 2015 rate case costs as filed in the TEP cost study. Those fixed costs are allocated using the same basic methodology of average and excess for production costs and the minimum system customer costs and class NCP for demand related delivery costs. We also use the same customer cost allocations. Using the same customer cost allocations is a conservative approach because TEP has made no effort to account for the higher level of transaction costs for solar DG customers associated with net energy metering storage accounting, billing adjustments and other customer service considerations. The study is also conservative because we have made no attempt to identify any system investments designed to address power factor issues or other distribution related investments. There is also no adjustment for higher losses associated with the power factor issue noted above.

Q. Do the cost studies comply with the principle of cost causation?

A. Yes. The studies follow the standard process of functionalization, classification and allocation for each unbundled component of costs. Costs are functionalized as generation, transmission distribution and customers.

The production function consists of the costs of power generation and purchased power. This includes the cost of generating units and fuel for the units. In addition, any cost of purchased power along with the cost of the delivery of purchased power is also functionalized as production.

The transmission function consists of the assets and expenses associated with the high voltage system used by the power system to interconnect with the grid and to move power from generation to load. In this case, this is allocation of the expense transmission by others.

The distribution function includes the system that connects transmission to loads. Different customers use different components of the distribution system. In recognition of this fact, it is common for the distribution system to be divided into sub-functions such as primary and secondary. In addition, some distribution facilities serve a customer function and are allocated between distribution and customer service accordingly.

The customer service function includes plant and expenses caused by individual customers. Customer service includes meters, service lines, meter reading and billing, for example. It also includes a portion of the distribution system including transformers, conductor and poles.

Q. What is classification?

A. Once costs are functionalized, they must be classified based on the categories customer, demand and energy. The classification step is critical to developing allocation factors that reflect cost causation. In particular, it is imperative to understand not only the accounting basis for costs but the engineering and operational analysis of the system as it is planned, built and operated. This is a particularly important concern when developing costs for customers who use the system differently and who create new costs to accommodate the customers' system impacts.

Q. What are demand costs?

A. Demand costs are those costs that vary with some measure of maximum demand. Measures of maximum demand include coincident peak demand, class non-coincident peak demand and customer non-coincident peak demand.

Q. What are energy costs?

A. Energy costs are those costs that vary directly with the production of energy such as fuel costs, other fuel related expenses or purchased power expense.

Q. What are customer costs?

A. Customer costs are those costs that vary with number of customers such as meters and service lines.

Q. Can costs be classified into more than one category?

A. Yes. For example, some distribution costs may have both a demand and a customer cost component.

Q. What is the allocation process?

A. In this step, costs are allocated to customer classes based on a variety of factors. The purpose of allocation is to assign costs to classes in a manner that reflects the factors that cause the costs to be incurred.

Q. Please explain how you developed allocation factors for the study.

A. To develop the allocation factors for the cost study it was necessary to make a basic assumption that the load shape of residential solar DG customers was on average the same load shape as the residential load shape prior to the installation of solar DG. That is the basic assumption is that the hourly usage pattern for DG customers is no different from the residential class as a whole. The only difference is that solar DG customers provide some of their own energy to satisfy that load shape based on the operation of solar DG.

Using this assumption it is possible to develop a full requirements load shape for solar DG customers using the following data: actual metered kWhs used by solar customers per month, actual excess kWhs delivered to the utility by month, the installed kW capacity of the solar DG, the solar output load shape based on metered data for a fixed axis, south facing solar DG installation, and the load research based residential hourly load shape. With this data the process consisted of a number of logical steps as follows:

1. Using basic number properties of mathematics we calculated the monthly full requirements load for each solar DG customer as the sum of the actual metered kWh plus the monthly solar generation given by the installed capacity times the hourly output load profile less the metered excess energy delivered back to the system. From this calculation we saved both the premises load and the excess energy for use in the various analyses. The value of this calculation cannot produce negative kWh. As a result, we eliminated observations from the data set because the excess kWh sold back to the utility were not possible.
2. Using monthly total energy consumption of the premises and the residential hourly load shape based on the customer's monthly premises use, an hourly load shape of premises use is calculated for each month by taking the ratio of the customer's monthly use to the monthly use of the load shape. In this step we modeled the average solar DG customer as a full requirements customer with the system average load shape.

3. This process was repeated for each residential DG customer and the data aggregated into the DG customers' counter factual load shape for use in the counterfactual cost study.
4. The solar DG class is based on all customers with twelve months of data and a non-zero capacity value. (The Company data set did not have a kW capacity for all of the solar customers and those were excluded from the analysis.)
5. For the counterfactual study the full requirements customer load shape is calculated by subtracting the net load shape of solar DG from the residential load shape used in the base cost study and adding back the full requirements load shape.
6. The solar customer net load shape is the premises hourly load shape minus the generation output shape. The net load shape excluding excess generation is used to develop the solar contribution to the residential load shape for the base fixed cost study.
7. We now have three load profiles for solar DG customers: the counterfactual no solar DG load profile, the generation output profile that allows us to determine distribution system use for exporting power and the solar customer net load profile that allows us to determine distribution system use for system loads.
8. Using this data it is possible to calculate the solar customers demand allocation factors for each fixed cost study and for the energy cost studies.
9. For the counterfactual profile we calculate the residential class Average and Excess Demand (AED) and NCP allocation factors and rerun the cost of service study. We also use the net load profile and calculate the AED and NCP allocation factors using only the net positive energy for AED and the higher of the positive or negative class maximum NCP. The allocation factor for NCP is the absolute value of the class NCP. This is consistent with the maximum requirement for distribution facilities and cost causation.

This data provides a solid, if conservative, basis for assessing the relative revenue requirements differences between the between full and partial requirements customers.

Q. How does one determine the factors that cause costs?

A. In many cases determining cost causation is as simple as asking the question of whether a particular cost changes when some potential allocation factor changes. If a factor causes costs, costs will vary with changes in that factor. For example, if the number of kWhs increases, does the cost of some input such as miles of conductor increase? Since the miles of conductor do not change with kWhs either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that miles of conductor increases for customers added to the periphery of the system, thus customers are a cause of the cost. We also know that the miles of conductor increases with the growth of the peak load on the conductor and that load may be met by paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three-phase conductor. This means that some of the cost of conductors is also caused by the demand on the conductor. In any case, the factors driving the cost of conductors are customers and a measure of non-coincident peak demand. Following this logical process allows one to determine cost causation for each element of the system.

Q. How does the AED method for allocating generation capacity impact solar customers?

A. The AED/4CP method used by TEP in the cost study recognizes that low cost energy results from higher capacity costs. Since solar DG customers use lower cost energy from the utility at night they should also pay for a portion of the fixed capacity costs of baseload units in order to buy the low marginal cost energy. While the AED concept was developed for cost allocation for full requirements customers it results in a more appropriate allocation than would a CP methodology that allocates all capacity costs on a daylight peak hours. Whether the allocation is ultimately reasonable without modification is a fair question for review in rate case proceedings.

Q. Have you used the same data and internal allocation factors as TEP?

A. Generally, the cost studies use the same data for revenue requirements and for allocation factors with the exception of creating a separate column for solar DG customers. We have also changed the use of the minimum system to classify costs. In the base study the solar customers' data and the full requirements customers sum to the same residential allocation factors in the TEP filed study. We have also calculated the rates revenue for each class and those have been included in the study so that the information presented includes the total cost based revenue requirements and the rate of return for each class of service in each study. For the other two studies the total revenue requirements remain the same and only the allocation factors for the solar DG customers have changed. In the counter factual study the customers are allocated the revenue requirement that would result from these customers being full requirements customers. This measures the cost shift between full requirements and partial requirements customers. The counter factual study also shows how the customers shifting to DG contributed to the earned return of the residential class. This recognizes the practical reality of the zero sum nature of the cost study. Increasing the demands of solar DG customers result in lower costs allocated to all the other residential customers.

Q. Please explain the change for the classification of customer costs using the minimum system.

A. In the TEP cost study TEP applied the classification for the minimum system to the costs after using the class NCP to allocate the distribution plant accounts. The use of NCP to allocate distribution plant accounts 364-368 under-allocates distribution plant to residential customers and understates the customer cost component of unbundled rates. After making that methodological change the allocation differs from TEP even though the total revenue requirements remain the same. The result of this change is to allocate more costs to the residential class to reflect the impact of customers on the distribution system costs. It also impacts the unit customer cost component. This adjustment is consistent with the use of the minimum system method as discussed in the NARUC Electric Utility Cost Allocation Manual and the three step cost of service process of functionalization, classification and allocation.

V. Allocation of Fixed Costs – Results of Three Studies.

Q. Please summarize the results of the three fixed cost studies.

A. Table 2 below presents the different revenue requirements for full requirements residential and solar PV residential customers from the cost studies that are attached as Exhibit HEO- 2 Original Base Study, Exhibit HEO- 3 Counterfactual Study, and Exhibit HEO- 4 Solar Class Study. Each Exhibit provides the summary of the allocations, the revenue requirement for each class of service and the earned return by subgroup or class. The base study is identical to the filed TEP study with the exception that solar DG customers are treated as a separate part of the residential class. The counterfactual study assumes that solar DG customers were full requirements customers. The solar class study treats solar DG customers as if they were a separate class with their own allocation factors and not part of the residential allocation factors.

Table 2 Comparative Fixed Cost Revenue Requirements Embedded Cost of Service Studies

Study	Residential Full	Solar DG Partial	Total Company
Base TEP	$490,392,406	$10,454,255	$958,869,144
Counterfactual	$486,024,537	$14,813,313	$958,869,144
Solar Class	$489,506,144	$11,340,517	$958,869,144
Lowest Revenue	$486,024,537	$10,454,255	

The results of these studies are useful in understanding that solar DG causes significant fixed costs. The total residential class fixed cost revenue requirement is the same $500,870,839 for the base, counterfactual and solar as a separate class cost studies. The difference in the studies relates to the intra class allocation.

The current annual rate revenue excluding Power Supply charges (the base revenue) for residential solar DG customers is $3,352,194. The subsidy may be calculated as the difference between the revenue in the base cost of service or $7,034,647. The implicit subsidy for fixed costs is just over $729[33] per customer for the 9,645 solar DG customers on the lowest fixed cost allocation. That number increases to almost $822[34] when the actual solar class fixed costs are used. In addition to this subsidy, DG customers with net metering and banking have an additional subsidy based on energy costs.

Q. Please explain why the three studies are useful.

A. Since cost of service is a zero sum methodology, all costs must go to some class and any change in allocation to one class must be reflected as an opposite change to one or more

[33] Calculated as ($10,386,841 - $3,352,194)/9645= $729
[34] Calculated as ($11,279, 053 - $3,352,194)/9645= $822

of the other classes. In order to understand the costs for residential DG customers, they must be separated from the full class. The portion of the residential class costs allocated to solar DG customers as part of that class are shown in the base study. The counterfactual study shows the amount of costs that would be allocated to full requirements customers prior to customers choosing to install solar DG and capture the benefits of net metering. Even though no changes occurred in the class cost and no changes occurred in the fixed costs[35] for utility service to the solar DG customers the solar DG customers are allocated less plant than would be allocated before they chose DG as shown by the counterfactual study. This result is not surprising since one would expect that these customers were larger on average than the average customer. Finally by treating solar DG customers as a class they still get less costs than when they were full requirements customers but the portion of plant allocated to them recognizes their higher class NCP based on delivering excess generation.

Q. Is it possible to show how costs changed by each unbundled cost category?

A. Yes. Since the cost of service model develops unbundled costs it is possible to show the aggregate revenue requirements by unbundled cost components. Table 3 below provides the revenue requirements for full requirements customers and for Solar DG customers by function excluding energy.

[35] Solar DG customers still have the same distribution facilities and use the same baseload generation to serve night time loads.

Table 3 Unbundled Costs for Each Cost Studies

	Base Study		Counterfactual Study		Solar Class Study	
	Residential	Solar	Residential	Solar	Residential	Solar
Procurement						
Demand	$164,680,215	$3,679,140	$163,218,631	$5,140,724	$164,729,041	$3,630,314
Energy	$121,172,462	$2,475,186	$119,879,015	$3,768,633	$122,301,113	$1,346,536
Customer	$0	$0	$0	$0	$0	$0
Must Run						
Demand	$23,854,022	$522,353	$23,632,537	$743,838	$23,856,361	$520,014
Energy	$0	$0	$0	$0	$0	$0
Customer	$0	$0	$0	$0	$0	$0
Trans						
Demand	$53,881,096	$917,161	$53,133,475	$1,664,782	$52,751,995	$2,046,262
Energy	$0	$0	$0	$0	$0	$0
Customer	$0	$0	$0	$0	$0	$0
Distribution						
Demand	$45,102,958	$767,740	$44,477,137	$1,393,561	$44,157,806	$1,712,891
Energy	$0	$0	$0	$0	$0	$0
Customer	$55,808,488	$1,432,601	$55,808,488	$1,432,601	$55,808,488	$1,432,601
Cust.						
Demand	$0	$0	$0	$0	$0	$0
Energy	$0	$0	$0	$0	$0	$0
Customer	$25,893,165	$660,075	$25,875,254	$669,174	$25,901,339	$651,900
TOTAL						
Demand	$287,518,292	$5,886,394	$284,461,781	$8,942,905	$285,495,204	$7,909,481
Energy	$121,172,462	$2,475,186	$119,879,015	$3,768,633	$122,301,113	$1,346,536
Customer	$81,701,652	$2,092,675	$81,683,741	$2,101,775	$81,709,827	$2,084,500

The table shows the embedded cost allocated to solar DG customers under each cost study. As would be expected the counterfactual cost study allocates more cost to solar DG customers because they are treated as full requirements customers. All of this data is useful because it shows how solar DG customers shift costs to full requirements customers even though in the rate case period there are no changes in fixed costs associated with solar DG and ratemaking is based on cost of service.

Q. Please provide the calculation of the cost shift to full requirements residential customers from solar dg customers on an embedded cost basis.

A. Table 4 below provides the cost shift based on the difference in revenue requirements for the base case and the solar class case from the counter factual cost study.

Table 4 Cost Shifts Resulting From Customers Adding Solar DG- A Comparison of Customers before Solar DG Installed

	Base Case	Solar Class
Procurement		
Demand	$1,461,585	$1,510,410
Energy	$1,293,447	$2,422,097
Customer	$0	$0
Must Run		
Demand	$221,485	$223,824
Energy	$0	$0
Customer	$0	$0
Trans		
Demand	$747,621	-$381,480
Energy	$0	$0
Customer	$0	$0
Distribution		
Demand	$625,821	-$319,331
Energy	$0	$0
Customer	$0	$0
Cust.		
Demand	$0	$0
Energy	$0	$0
Customer	$9,100	$17,275
SUB-TOTAL		
Demand	$3,056,511	$1,033,423
Energy	$1,293,447	$2,422,097
Customer	$9,100	$17,275
TOTAL	$4,359,058	$3,472,796

As would be expected, the AED allocation of production is lower and there is a larger embedded cost savings for solar customers when they are treated as a separate class. The energy cost shift results from the lower use of energy and hence a lower allocation of base costs allocated on energy such as fuel inventory costs. Two important factors should be noted. As expected, treating solar as a separate class properly increases the cost of delivery related services based on the higher class NCPs from delivery of power to the system. There is also a slight increase in must run demand that is attributable to the variable nature of solar DG generation.

Q. Please summarize the residential class returns in each of the costs studies.

A. Table 5 provides the earned return for both the full requirements residential customers and the partial requirements solar DG customers.

Table 5 Earned Returns by Customer Group and Cost Study

	Residential	Solar
Base	0.06%	-17.62%
Counterfactual	-0.32%	-0.41%
Solar Class	0.12%	-17.02%

The magnitude of the negative return for solar DG customers is further evidence of the undue discrimination between full requirements residential customers and the partial requirements solar DG customers who pay much less for comparable service. This is in spite of the fact that solar DG customers have a production capacity credit of $1.5 million dollars for the current year or $24.64 per kW of solar installed capacity. If that value is adjusted for capacity from solar DG in the peak hour of 5 PM, the implied capacity credit is $141.41 per kW[36]. At that level of credit the embedded cost study essentially assumes

[36] Calculated as 17.4% of capacity times 61,277.33 kW solar installed or 10,681 kW CP production divided into $1.5 million dollars.

that the cost is avoided in the current year. Since that is not the case the embedded cost value of the capacity credit actually exceeds avoided costs.

Q. Why does the solar class study allocate more costs to solar customers than the base study?

A. The unbundled cost components are different based on the fact that the AED/4CP cost methodology allocates generation costs using a demand allocation factor made up of weighted average demand and weighted load NCP. The solar class allocation for generation is less than the allocation under the base case. For the demand related portion of the distribution system, the base case under allocates distribution system costs to the solar DG customers because it uses the load demand rather than the actual maximum demand which is based on delivery demand. The different NCP for delivery compared to the residential class coincident NCP for solar DG customers is less than half of the delivery NCP. That difference is based on the difference in the load diversity and the absence of diversity with respect to excess generation. Thus it is the delivery service that establishes the maximum demand on the distribution system. The net result is that the solar class's allocation increases compared to the base case.

Q. Please discuss the cost of service results.

A. Several conclusions are worth noting. First, the total full requirements, residential class, fixed cost of service is higher for the base case and the solar case than if the solar DG customers had not invested in DG. This results from a cost shift within the class to full requirements customers. Second, all three studies produce a customer charge for both full and partial requirements customers of about $18.00 per month. If the company were to analyze the extra costs associated with solar DG associated with record keeping and billing it is likely that the solar DG charge would be above this average level. Third, it is critical to understand cost causation on the distribution system results in higher costs for solar DG even without the consideration of the added costs associated with lower power factor, more frequent voltage control events and other impacts on distribution system costs. Fourth, the evidence is conclusive that there are no avoided distribution costs for TEP and likely none for any utility in Arizona given the solar load shapes. Fifth, the magnitude of the base rate charges for solar customers would be much higher than the energy charges for full requirements customers thus necessitating recovery of the fixed charges in demand charges because the kWh charge under a two-part rate would further distort the solar DG sizing decision. Finally, the large negative return provided conclusive evidence that the solar DG customers are subsidized by other customers at amounts that are significant even compared to the modest return from the residential class.

Q. What conclusions do you reach from the cost of service studies as they relate to solar dg, net metering, banking and rates?

A. The conclusions related to cost of service are as follows:

1. Solar DG customers must be treated as a separate class of service in the cost study.
2. The two-part rate with net metering cannot ever produce equitable treatment of full requirements customers and solar DG customers who have different demand profiles and load factors.
3. Banking adds to the subsidy that result under current rates and a cost study that reflects cost causation.
4. Rate design must be unbundled so that each utility service is priced separately (the ACC has made a good start on unbundled rates by identifying delivery services and power supply charges but more needs to be done in particular removing all fuel and variable generating costs from base rates and recovering those costs on a time of use

basis) and the rate design must be a multi-part rate to meet the principles of cost causation and matching.

5. Solar DG customers should produce at least the residential average return and rates for partial requirements, solar DG customers should be designed to produce the solar class return equal to the residential average from the final decision in this case.

Q. Which cost methodology should be used in future rate cases to promote equitable rates to consumers?

A. Solar DG residential customers have very different usage characteristics as compared to full requirements residential customers. That is the two groups are not homogeneous and thus need to be treated as separate classes in the cost study. Going forward, the solar residential customers should have rates based on the costs they cause. They should also have separate load research for both load and generation to precisely measure the system impacts of both delivery and production. The minimum system method for classifying distribution customer costs should be used to properly reflect costs caused by customers regardless of load. Setting rates based on costs also means that it is important to send these customers a price signal that creates value for smart inverters. Thus, the demand charges for these customers should be based on kVa rather than kW.

VI. <u>Separate Rate Treatment for DG Customers.</u>

Q. What is the rationale for treating partial requirements customers in a separate class from full requirements customers?

A. Under two-part rates the assumption that is required for rates to reflect cost causation is that load characteristics are relatively homogeneous as to cost causation and to load patterns. Relative homogeneity existed when kWh rates were first used for residential customers in the late 19th century because the only electric load was lighting. The demand was a function of the number of fixtures and kWh consumption was a function of average operating hours. Thus a simple two-part rate with a customer or access charge and a flat kWh charge represented a reasonable rate because the cause of cost and the load characteristics of residential customers were the same. Over time, the end use load profiles of residential customers has changed and electric rates evolved to reflect different load characteristics through declining block rates to reflect higher load factors for larger customers and through separate rate classes for different end-use residential loads such as all electric rates or special provisions for specific end-uses such as a water heating block for customers with electric water heating. The trend away from these rate provisions to flat and inverted rate designs and fewer special provisions made rates less cost based as end-use load profiles continued to be more diverse because larger groups of customers were served under rates that were simple but not capable of reflecting the costs caused by less homogeneous subgroups within the class. With the addition of partial requirements customers within a class, customers are no longer homogeneous as the following table illustrates by comparing two identical premises with the same demographic characteristics:

Table 6 Comparison of Full and Partial Requirements Customers

Measures	Full Requirements	Partial Requirements
Customer Maximum Demand	10 kW	10 kW
Annual Energy Consumption	35,040 kWh	35,040 kWh
Annual Billed kWh	35,040 kWh	853 kWh*
Billing Load Factor	40 %	1 %

* Based on 35,040 kWh less the energy produced by a 19 kW Solar PV system operating at a 20.54% annual capacity factor.

From a cost perspective the delivery cost is the same for these two customers. The difference in cost recovery under the current TEP Electric rates is calculated in Table 7 below based on the current full TEP rate.

Table 7 shows that the annual subsidy under current rates is almost $194 per kW of installed solar capacity in this example. This subsidy is based on equal treatment for equal cost causing delivery characteristics and is not tied directly to a measure of the cost subsidy which may be even larger as a result of the higher delivery demand requiring more distribution capacity. On the basis of cost causation there will be subsidy in the generation and transmission portion of the rate simply because the solar PV capacity of 19 kW will not be coincident with the system peak demand.

Table 7 Customer Revenue under Rate Res-01

Billing Determinants	Local Delivery	Full Requirements	Partial Requirements
Customer	12	$120.00	$120.00
0-500 kWh			
Full Requirements	6000	$535.34	
Partial Requirements	853		$77.89
501-1000 kWh	6000	$594.34	
1001-3500 kWh	19548	$2,201.16	
Over 3500	3492	$430.60	
Total Bill		$3,881.44	$197.89
Difference		$3,683.55	
Subsidy Per kW			$193.87
Notes	Assumes saturation of first two blocks in all months		Assumes 853 kWh in summer only
	Assumes 11,000 kWh in summer in third block		

Both Tables 6 and 7 are illustrative of comparing two individual customers- a full requirements customer and a partial requirements solar DG customer. The results of this comparison are consistent with and support the class conclusions in the cost studies.

It should be noted that this result occurs because of the current price signal based on energy that incents the customer to install a system that maximizes energy production without regard to the capacity value of the solar facility[37]. This means that solar panels would face south in the Northern Hemisphere to maximize energy production instead of west to maximize summer peaking capacity contribution.[38] In that event the capacity contribution of solar and the later timing of the solar customers class NCP would result in no distribution cost savings and potentially even higher distribution costs associated with the class NCP for DG customers occurring at a later hour. Under the most favorable circumstances a 5 kW solar facility would reduce the class NCP by about 0.5 kW and that would not be enough to result in smaller distribution facilities such as a transformer or conductor even if all of the customers using the same equipment had installed solar DG.

There is also the issue of a potential subsidy under the energy cost component of the base rate. That subsidy would result from the load pattern of the solar power delivery that does not occur in uniform high cost hours. In fact, solar output is maximized in hours outside the peak period as defined in the residential TOU rate in both the winter and the summer. Since the winter off-peak period represents the majority of operating hours in that season and represents only 33% of the summer peak operating hours it is reasonable to conclude that the solar energy value is less that the base energy charge.

[37] A generation and transmission on-peak demand charge would provide an incentive to consider both the capacity and the energy value when installing solar and also for investments in EE.

[38] See for example "9% of solar homes are doing something utilities love. Will others follow?", OPOWER Blog December 1, 2014.

Q. Is there other evidence that the solar DG customers require their own rate class?

A. Yes. It is instructive to compare the distribution of bills for solar DG customers after installing solar DG to the counterfactual loads before DG. Figure 4 below shows how the bill frequency has changed dramatically from the full requirements monthly kWh billing to the solar DG monthly kWh billing.

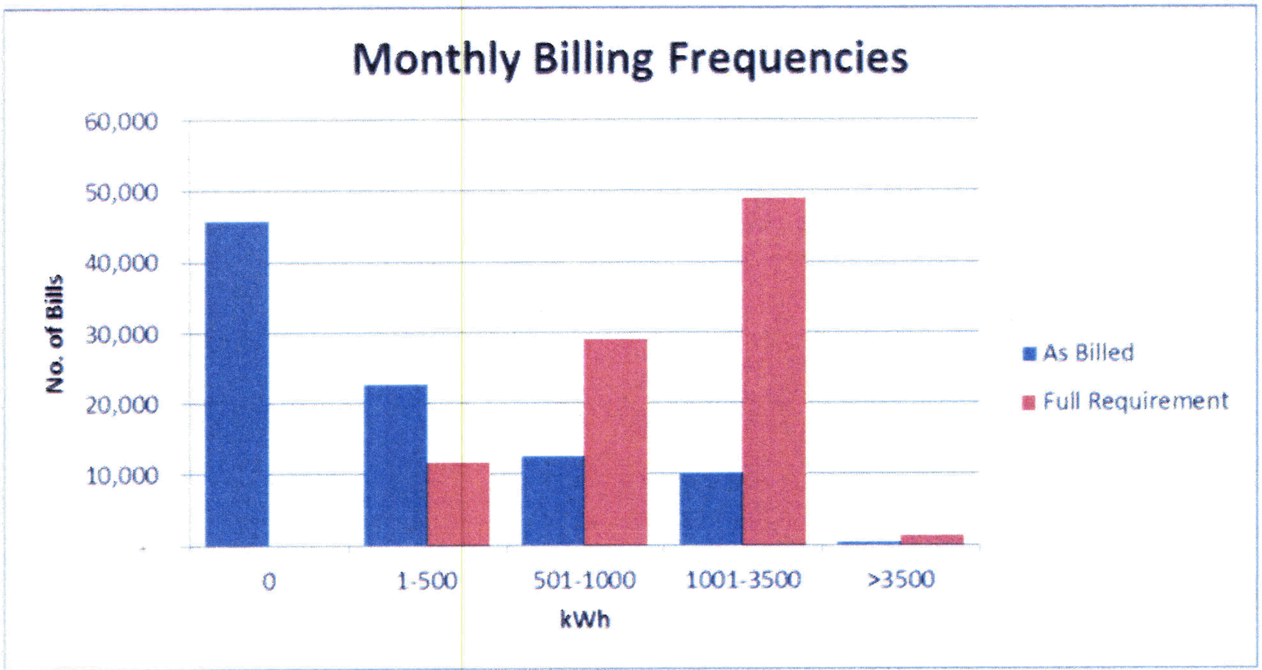


Figure 4 Monthly Billing Frequencies

This figure shows that these customers had more bills in the third tier of the rate as full requirements customers than in any other tier of the rate and these customers had no zero bills as one would expect. This group of customers with DG now has almost the same number of zero bills as they had third tier bills when they were full requirements customers. Given that there delivery cost based revenue requirements have increased there is no way a kWh rate could ever recover these costs equitably from DG customers.

Q. Please summarize why a residential DG customer needs its own rate class.

A. All of this evidence suggests that with a two part rate and net metering with banking can never result in just and reasonable rates for partial requirement DG customers. The only possible alternative to treat partial requirements, DG customers equitably is a separate rate class with a three-part rate. Further, the excess kWhs should not be banked but should be purchased at a market based rate. This solution, as proposed by TEP, is practical immediately and need not wait until there is a general rate redesign for all residential customers. It also illustrates that there is a substantial subsidy inherent in net metering because the use of self-generated kWhs saves the DG customer more than the system saves by an amount that over-values the DG contribution. This is part of the reason that commissions and others are developing Value of Solar (VOS) and a buy all sell all rate as a substitute for net metering.

Q. Please discuss net metering.

A. From an economic perspective solar DG is not a least cost solution for the utility and its customers when community solar and utility scale solar have much lower installed capacity costs because of economies of scale. Furthermore, I disagree with any of the critics of this approach that may suggest that eliminating the banking feature is in effect violating the concept of "netting" which is fundamental to the net metering concept. The fact that the Company is simply crediting back energy produced by DG at a market value different from the total delivered cost of power to the customer does not change the net metering that the customer sees relative to its own use of energy but may change the value of that netting feature as it should to avoid undue discrimination. There are valid cost based reasons including the provision under PURPA that makes adoption of any standard including net metering satisfy the principle of equitable rate treatment for customers.

Q. Are there other issues that make the separate treatment of DG customers necessary in the current proceeding?

A. Yes. The unequal treatment of customers who have the same costs but provide very different levels of revenue to recover those costs is a perfect demonstration of undue discrimination and that the current rates are no longer just and reasonable as the result of a combination of the net metering provisions and the current inverted block two-part rate with a low monthly basic customer charge. Essentially, the recovery of almost all of the fixed cost of service in volumetric charges results in undue discrimination when the customers in a class are no longer homogeneous. Staff witness Solganick reached the same conclusion and states "two customers who require the same equipment might use very different amounts of energy and again would result in one customer being undercharged and the other overcharged."[39] Witness Solganick also notes that "Residential customers are increasingly becoming non-homogenous as they adopt various forms of heat and distributed generation and as their lifestyles, demographics, and work patterns become increasingly more diverse."[40] When the difference in the annual bill of a full requirements customer and a partial requirements customer with identical peak demands is 19 times a partial requirements customer's total bill the subsidy is no longer just and reasonable and constitutes undue discrimination. The only practical solution is to eliminate the net metering provision and recover costs under a separate rate schedule for partial requirements customers as proposed by TEP. Further, it is imperative to immediately flatten the four tiered energy rate to two tiers as proposed by the Company to send a better price signal to other potential DG customers. This is a necessary step as TEP moves over time to TOU based fuel charges and demand based charges for fixed costs. This solution to just, reasonable and non-discriminatory rates has been recognized as the ideal rate since 1900 but could not be implemented because of metering technology

---

[39] Direct Rate Design Testimony of Howard Solganick ("Solganick Rate"), page 6
[40] Ibid. page 9

and costs. Those two constraints no longer apply and reasonable rates can be achieved by the appropriate transition plan.

Q. Is the TEP proposal of a three part rate for new DG and ultimately for all customers consistent with current views on best practices?

A. Yes. In recent years, many industry observers have supported multi-part rates as the best practices approach to designing rates for DG as noted by a number of organizations such as e-Labs of the Rocky Mountain Institute who states "These technologies can provide to or require from the grid energy, capacity, and ancillary services based on individual capabilities. But these characteristics vary along many dimensions that are not reflected in block, volumetric rates. For example, when a customer is exposed to a high marginal price tier in an inclining block rate structure, rates can both reinforce and skew the message that price signals should send. Rooftop PV can look more competitive with retail rates based on the higher credit received for energy production."[41] This is the exact conclusion reached above relative to the inefficient orientation of solar panels relative to actual avoided costs because of the energy only price signal.

A report from the MIT Center for Energy and Environmental Policy Research states the following:

> Allocating network costs primarily on the basis of volumetric energy consumption presents *inefficiencies in distribution systems* evolving to incorporate a growing number of DER and a growing list of new stakeholders. These inefficiencies include: *few price signals to incentivize optimal network utilization; cross-*

[41] "RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE", e-Lab Rocky Mountain Institute, August 2014, p.15 http://www.rmi.org/elab_rate_design

subsidization among network users; and business model arbitrage of rate structures.[42] (Emphasis added.)

That same report supports the use of a customer component of the distribution system and demand charges for customers based on the capacity component of the system.[43]

In a report prepared for EEI titled "Retail Cost Recovery and Rate Design" Kenneth Gordon (the former Chairman of both the Massachusetts Department of Public Utilities and the Maine Public Utilities Commission) and Wayne P. Olson make the following statement:

> To the greatest extent possible, customer- or demand-related fixed costs should not be rolled into energy charges. The end-use customer often sees too high a price for energy and too low a price for demand and customer charges. Hence, the customer never receives the economically efficient price signal for either one.[44]

Each of these references correctly recognizes the role of multi-part rates in addressing the issues of efficient pricing and reflecting cost causation. Current rate designs as recognized by TEP and the Staff correctly conclude that the current two-part rate for residential customers is inefficient and includes subsidies. The important point is that subsidies resulting from averaging costs in class rates are far different than artificial subsidies that reach the level of undue discrimination as they do in the case of net metering with largely volumetric rates. Average cost subsidies are found in items such as using the average service line costs knowing full well that the customer on the same side of the street as the transformer has a shorter service line than the neighbor across the street. Short of designing rates for each customer, a utility and its regulators must accept

---

[42] "A Framework for Redesigning Distribution Network Use of System Charges Under High Penetration of Distributed Energy Resources: New Principles for New Problems" Ignacio Pérez-Arriaga and Ashwini Bharatkumar, October 2014, p.6 https://mitei.mit.edu/system/files/20141028_UOF_DNUoS-FrameworkPaper.pdf

[43] Ibid. p. 16-20

[44] "Retail Cost Recovery and Rate Design" Kenneth Gordon and Wayne P. Olson, Prepared for the Edison Electric Institute, December 2004, p. viii. See also p. 26. http://www.ksg.harvard.edu/hepg/Papers/Gordon.Olson.Retail.Cost.Recovery.pdf

some level of intra class subsidy; however, it is incumbent upon them to address undue subsidies and discrimination. The subsidies under net metering with two part rates create undue discrimination that needs to be addressed in the current case, not postponed and not to wait on implementation of a phased approach to multi-part rates that does little or nothing to address the problem for years to come.

Q. Please discuss the claim that separate rate treatment for DG is discriminatory.

A. This is a common claim made by solar advocates who want to maintain the extremely favorable treatment (and profitable marketing opportunity created by the current combination of net metering and largely kWh recovery of fixed costs) accorded to solar DG. This is a classic example of the rent-seeking identified by Alfred Kahn and discussed above. The best way address this claim is to analyze the meaning of discrimination in the context of regulation. The Merriam-Webster Dictionary defines discrimination as *the practice of unfairly treating a person or group of people differently from other people or groups of people and the ability to understand that one thing is different from another thing.* As applied to solar DG and discussed above customers who become partial requirements customers are clearly different from full requirements customers and in that sense the discrimination is not inconsistent with the basis for designing rates for homogeneous classes of service. While it may be inconvenient for the solar advocates to recognize that solar DG customers differ from full requirements customers the evidence shows that this is precisely the case.

The customers are different based on load characteristics and in terms of cost causation. The cost studies and the results of those studies demonstrate that the solar DG customers are different from the residential class as a whole and are receiving rate treatment that is far more favorable under the current rates than is equitable. The cost results fully demonstrate undue discrimination.

The question becomes: Does singling out these customers for different rate treatment result in those customers being treated unfairly? The simple answer is no. This answer is supported by a review of the evidence as it relates to cost causation and the contribution of these customers to that cost compared to other full requirements customers. This is an empirical question that requires nothing more than the basic analysis of whether the solar DG customers contribute the same revenues toward the costs they cause as other customers who have the same cost causation. Since, the only true avoided costs are related to the marginal energy cost and some potential avoided generation capacity costs at less than one cent per kWh based on the coincident peak demand of less than 24% of the rated capacity depending on the peak load hour. (For this conclusion, the concept of the "Duck Curve" has not been considered because it may well eliminate this avoided cost also.) It is the existence of this undue discrimination that solar advocates seek to maintain to their advantage.

Regulatory policy is not required and in fact is prohibited from picking winners and losers when discrimination becomes undue. The goal of efficient regulatory policy is to develop a system of rates and charges for customers so that as they choose between full requirements service and partial requirements service the utility and its other customers are indifferent between those choices. Such a standard requires that the customers who choose different aspects of utility service pay the full costs of the services they choose to use. It is unreasonable for a customer to use a kilowatt hour of electricity that costs six cents to produce and then pay for that kWh by selling the utility a kWh when the utility value of that kWh is three cents but this is what occurs under the net metering banking provision. It is unreasonable for a customer to use the same distribution services as another customer and pay over far less per year for that delivery service. This later point is also impacted by the fact that the solar DG customer may actually cost more to serve for the same delivery service based on increased day ahead planning reserve requirements and regulation reserve requirements related to generation operation. DG customers also impact the distribution system relative to VAR requirements and reduced life for voltage regulation devices as examples of cost increases. It is reasonable to conclude that the differences between full and partial requirements customers using solar DG are real, empirically verified and thus not discriminatory. It is also reasonable to conclude that separate treatment is a reasonable step to eliminate discrimination between solar DG customers and full requirements customers.

VII. The Economic Rationale for Multi-Part Rates.

Q. What is a multi-part rate?

A. A multi-part rate is an unbundled rate schedule that prices different services at the cost of each service. The TEP proposed three-part rate is an example of a multi-part rate without full unbundling. Ideally, the rate would have seasonal TOU prices for energy and these prices would be the same for each rate schedule except for the adjusting the energy costs for losses at each voltage level of service. No fixed costs would be recovered in the energy charges as is the case today. As I have discussed above there is no rationale for recovery of fixed costs in kWh charges with the exception that the class of service is nearly perfectly homogeneous.

Q. Is TEP's proposed rate structure an ideal rate structure in this sense?

A. No. Under TEP's proposal, a significant amount of fixed costs are still recovered in variable per kWh charges. TEP's proposal can be characterized as a step in the right direction.

Q. Is a two-part TOU rate a substitute for the multi-part rate as some parties have argued?

A. No. Witness Kobor, for example argues that demand charges are a compromise based on an article by Jim Lazar.[45] The statement she cites does not comport with rate history or with the logic of demand charges. Caywood writing in 1956 states "Thus, compromise rates are necessary, with the result that *the demand charge is sometimes included in the energy charge*." (Emphasis added.) This is the exact opposite conclusion from the one cited by witness Kobor. Witness Garrett makes a similar argument that utilities have been content with kWh rates for most of the 20th century. The level of contentment stemmed largely from the inability to justify the much more costly metering to measure demand for small customers and not from any recognition that the kWh rate and in particular inverted block rates were more cost based. All along utility ratemaking has recognized the compromise and has sought to improve cost matching with declining block rates, all electric rates, special rates for electric water heating and so forth. As I have demonstrated above there is no kWh charge that can reflect cost causation and the matching principle in today's modern electric utility where loads even in a class like residential customers are no longer homogeneous. As I have explained, the residential solar DG customers use the system very differently than a typical residential customer. A system that recovers fixed costs from volumetric TOU kWh charges is simply not going fairly recover costs from these solar DG customers.

Q. What about the argument of various parties opposing demand charges that the charges are not cost based?

A. Witness Kobor, witness Baatz, witness Garrett and others oppose the use of demand charges because they are not cost based. Witness Garrett and witness Kobor rely heavily

---

[45] Kobor at p. 54

on the article "Use Great Caution in Design of Residential Demand Charges"[46] to support their conclusions. As the above cost studies illustrate the demand charges as proposed move the rates toward cost of service not away from costs. It should be clear that the end-goal of cost based rates cannot be achieved with a single demand charge because different demands cause different costs—but energy charges can never match demand costs when load factors within a class vary as much as the residential class load factors vary from solar DG load factors. The only cost-based, non-discriminatory solution is to approve the TEP proposal for separate rate class treatment and immediate demand charges in the solar class and eventually demand charges in all rate schedules.

Q. Witness Kobor uses a Table 3 in her testimony that she labels "Garfield and Lovejoy Criteria".[47] Please comment on that table.

A. Since witness Kobor does not cite to the original source (an error in and of itself) she may not realize that she has not cited the actual source of the criteria. While the book by Garfield and Lovejoy does contain a listing of these criteria, Garfield and Lovejoy are not the original source. The original source is Dr. Henry Herz in an article "Impact of Cost Allocation on Gas Pricing," appearing in 58 Public Utilities Fortnightly 685, 692—694 (1956). Second, the Garfield and Lovejoy book makes two statements related to these criteria. "*Standards for testing the reasonableness of methods of allocating demand costs* have been developed by Dr. Henry Herz, consulting economist. These standards are *intended to apply generally, rather than to any one of the public utility industries*. Dr. Herz would judge the reasonableness of an *allocation method* in terms of its capacity to meet the following principles…"[48] (Emphasis added.) These standards are not specific to anything more than the allocation of demand costs in a cost study and they are general and thereby

[46] "Use Great Caution in Design of Residential Demand Charges", Jim Lazar, Natural Gas & Electricity, at 15 (Feb. 2016), available at https://www.raponline.org/document/download/id/7844.
[47] Kobor, p. 57
[48] Garfield and Lovejoy p. 163

cannot address the different capacity cost allocations required in an electric cost of service study. Decidedly, these are not criteria for evaluating rate design as used by witness Kobor. In fact, these standards have nothing to do with rate design and the comments on whether a rate design satisfies these standards do not appear in Garfield and Lovejoy at all. Rather the rate design evaluations are from the Lazar article not the author of the criteria or the authors of the text. The logic of imposing demand cost allocation methods on rate designs does not permit any conclusion about how well a rate design meets these cost allocation criteria because the allocation is only for capacity costs. For example, as noted above, if a class is nearly homogeneous any rate design based on the cost of service study that meets the criteria for capacity cost allocation would also meet the criteria for rate design. For example, the criteria that "The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity" when demand costs are allocated on AED as in the case of TEP higher load factor classes will be allocated more demand costs and as long as the demand charges recover the demand costs the rate design will meet this criterion. If the rate is an energy only rate, the higher load factor customers in the class will pay a disproportionate share of the fixed costs. As a result any energy only rate TOU or tiered cannot meet the requirements of these criteria.

I will not address the cost of service issues associated with these criteria as they do not even recognize that there are different measures of capacity cost causation including CP, class NCP and customer NCP. As for cost causation, the hour's use of capacity does not change the peak responsibility for that cost (the lowest cost capacity available to meet that peak load) and any extra capacity costs as the result of more use may be included in an off-peak demand charge for production capacity. For local delivery capacity the cost is based on the customer's use in the highest billing interval of the year or the contract demand whichever is greater. If the customer operates at a 100% load factor or a 1% load factor the customer only pays for that cost with a maximum demand charge and a 100% ratchet. A time of use energy only rate would meet that requirement if this was the only customer in the class. If there were three other 100% load factor customers but all with different demands the largest demand customer would pay the most for demand even if the actual costs were lower per unit of capacity because of economies of scale. The whole analysis of demand charges and of TOU energy charges is flawed and not reflective of actual results. In fact, any two-part TOU rate essentially consists of a customer charge and energy charges that are differentiated by peak and off-peak periods which may also be seasonally differentiated. This rate means that all fixed costs above those recovered in the customer charge continue to be recovered in kWh charges. It makes the implicit assumptions that patterns of energy consumption correspond with the various demands on capacity and load characteristics are sufficiently homogeneous that such a rate will fairly recover the various demand related costs. Further, energy costs are the most elastic component and recovery of fixed costs in the energy charge cannot ever match costs and revenues for individual customers or even for classes of customers because it is not energy that causes the fixed costs. Rather, it is various measures of demand that cause those fixed costs.

Q. Does the book by Garfield and Lovejoy discuss criteria for electric utility capacity cost allocation? Please explain.

A. Yes. The following page in the text provides "A set of standards for use in selecting a *demand-cost allocation method* for electric utilities has been set forth by a committee of the National Association of Railroad and Utilities Commissioners. Those standards are reviewed below:

1. The method should be based on some basic philosophy.
2. The method should be judged on its recognition of the following three factors: (a) demand in kilowatts; (b) use in kilowatt-hours; and (c) time of use of energy.
3. The method should recognize the characteristics of various loads.

4. The method should result in a relatively stable cost assignment which would not change radically with a shift in loads.
5. The method should require a minimum of measurements before and after allocation.
6. The method should permit allocation to a load which is completely under utility control, such as off-peak water heating.
7. The method should permit an estimate of the capacity cost that would be assigned to prospective loads.
8. The method should establish a minimum demand-cost allocation to off-peak customers.
9. The method should not be dependent upon judgments introduced in the allocation process."[49]

The TEP cost allocation meets these criteria. In either case these criteria apply to cost allocation not rate design and provide no basis for evaluating the rate designs proposed by TEP because they are silent about customer charges which Garfield and Lovejoy define as "The total of customer costs varies directly with the number of customers served. Customer costs include the expenses of meter reading, billing, collecting, and accounting. Also included are the expenses associated with the capital investment in metering equipment, customers' service connections, and *part of the investment in the general distribution system*. If administrative and general expenses are spread on the basis of investment, part of that expense total may be included in customer costs."[50] (Emphasis added.) Further, as I have demonstrated it is impossible for an energy only rate to match cost recovery of fixed costs in the current market environment.

[49] Garfield and Lovejoy, p. 164
[50] Garfield and Lovejoy p. 158

VIII. The Concepts of Fairness, Efficiency and Gradualism.

Q. A number of witnesses turn to Bonbright's principles as the basis for supporting their preferred rates. Please discuss Bonbright's principles in light of the TEP proposed rates.

A. Bonbright discusses ten principles of rate design that he identifies in three sub-headings of: Revenue-related Attributes; Cost-related Attributes; and Practical-related attributes. Of these ten principles Bonbright himself finds that these ten are "unqualified to serve as a base on which to build these principles because of their ambiguities ..., their overlapping character, their inconsistencies and their failure to offer any basis for establishing priorities in the event of conflict."[51] Bonbright then reduces his list to three criteria as follows: Criterion 1 – Capital Attraction; Criterion 2 – Consumer Rationing; and Criterion 3 – Fairness to Ratepayers[52]. After a discussion of these three principles, Bonbright discusses cost of service as a basic standard and states "Without a doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service."[53] Bonbright does not conclude that that cost of service can be implemented without complications and those complications are addressed in the text. These objections range from theoretical to practical. In part, some objections relate to limitations on technology that existed at the time Bonbright, et. al. wrote the book. Others fail to recognize that rate design and cost of service require a level of pragmatism that is based on the informed judgement of those most familiar with the utility and its customers. Where parties promote their individual interests (rent-seeking) and regulators are charged with balancing those interests while still dealing with the elements of the regulatory compact, inevitable conflict arises. Net metering is an example of the balancing of interests that "may have been a

[51] Bonbright, op. cit. p. 384
[52] Ibid. p. 385
[53] Ibid. p. 389

convenient benign fiction back when solar PV barely existed."[54] Yet now, rent-seeking seeks to perpetuate a rate design that no reasonable utility or even parties without a vested interest should be able to see as enriching solar interests at the expense of more costly options for consumers and loss of social welfare. Net metering does not meet any of Bonbright's three criteria for ratemaking and actively works against all three.

Q. Turning to Bonbright's first principle, Capital Attraction, how does net metering work against capital attraction when it is promoting private investment in rooftop solar DG?

A. New net metering has the impact of directly reducing the earnings of the utility by every dollar saved by new net metering customers between rate cases not recovered in the LFCR and the solar advocates as well as others oppose the LFCR actually recovering all of the lost fixed costs as proposed by the Company. Earnings below the allowed return make it more difficult for the utility to attract capital and increase the risk for investors as net metering increases rates for customers overall since the cost of rooftop solar is much higher than larger scale installations that produce the same renewable power benefits at a lower cost. Sound utility regulation would not allow this type of investment in a utilities rate base because it does not represent the least cost capacity option or the ability of a utility to lock-in a levelized energy cost for a utility plant. Under a least cost plan, rooftop solar would not be an option for efficient, least-cost RPS energy.

Q. As to Bonbright's second principle, how does net metering work against consumer rationing?

A. Consumer rationing means that approved rates should discourage wasteful use of utility services and promote all use that is economically justified through application of

[54] Blog Post at Energy Institute at Hass Energy "Billing Tweaks Don't Make Net Metering Good Policy" Posted on January 4, 2016 by Severin Borenstein

economically sound rate designs. Net metering is promoted by charging marginal prices that far exceed marginal cost and in purchasing excess energy at far higher rates than costs avoided by that energy. That impact promotes investment in solar DG facilities that are not cost effective absent that subsidy. As a result customers choose an option that is not economically efficient and make investments that result in wasteful use of the delivery system and investments to accommodate solar DG on the grid and with a new mix of capacity to meet the intermittent nature of the generation and the absence of any diversity in output. The resulting cost shifts from net metering raise non-participants rates even further above marginal cost and prevent the optimum use of utility facilities.

Q. As to Bonbright's third principle, how does net metering work against fairness to consumers?

A. The simplest impact of net metering is the level of undue discrimination between DG and non-DG customers who cause the same costs. Undue discrimination is an anathema to fairness among consumers to such an extent that it is typically singled out as a requirement for rates that must not occur for rates to be just and reasonable. Based on the results of the cost studies above and the examples of rate comparisons there is no question that net metering results in rates that are not fair, just or reasonable. This level of subsidy is far greater than the inevitable class subsidies resulting from averaging costs with in a class as I have shown by comparing solar DG in the counterfactual study to solar DG as a separate class of service.

Q. Why is gradualism an issue in this case?

A. TEP has proposed a gradual process to address issues with net metering. They have done so by proposing grandfathering of existing DG customers and only changing the payment made to cashout excess generation. Even that proposed payment is above the avoided cost that an as available QF is entitled to for payment. This is recognition on the part of TEP that gradualism for rectifying net metering is an important first step. Gradualism is also reflected in the proposal to not eliminate the tiers in the inverted rates but to reduce the rate tiers to two and increase the customer charge as the first step toward rationalization of residential rates. TEP has also chosen to not propose the multi-part rate for non-DG customers that is so necessary for equitable rates and the matching principle, choosing instead to move gradually for non-DG customers on two-part rates.

IX. <u>Serving All Customers in a Class under the Same Rate Schedule.</u>

Q. Why should TEP rates serve residential customers under the same rate schedule?

A. This is an important question given the proliferation of rates that are available for residential customers. TEP rates are likely to be far more confusing as they stand today with different marginal cost blocks for different customers and different marginal costs for the same customer based on seasons and blocks plus the added confusion of optional rates. Simplifying the number of tiers and eliminating all of the special rates will make rates more understandable for customers even if they include demand charges. Current rates include TOU features that are based on different on-peak hours and have different price signals for those different hours. From a cost perspective, there is only one set of hours that represent the peak period and those hours are not based on load for a class or even load for the system. Basing TOU rates on seasonal and diurnal costs is fundamental to having effective and efficient TOU rates. All TOU customers should face the same price signals adjusted for losses associated with delivery. If a customer has load in an hour that load causes the costs in that hour the same as every other customer taking service in that hour. The purpose of rate design is not to cause changes in the customers' use of service. Rather, the purpose is to send a price signal as to the cost of that service so the customer can make a decision that it values service at that time more or less than the cost. Customers who value that service more than the price will continue using the service. Customers who value the service less will not use the service either as a result of DER or EE or by shifting that use to a period where the value of the service is more than the price. Failure to send good price signals distorts the customers' choices and results in inefficient customer decisions. Good price signals must include maximum demand charges, peak demand charges, customer charges and TOU cost based energy charges. Rates will not be as simple as the compromise rates used today but they will be actionable by all customers even if the action is inaction.

Q. What do you conclude about the opposition to the TEP rate simplification proposals?

A. Witness Radigan opposes the simplification but that opposition is misplaced. Simplifying rates is part of the first step to having a single rate for all full requirements residential customers. Instead of making the transition more gradual and less costly, it is incumbent on all parties who have an interest to help smooth the transition not attempt to block a move that is ultimately in the interest of all consumers. In that regard, witness Zwick at least suggests an alternative to the current Lifeline morass of rates and special conditions. It makes no since to serve 20 customers on a specific rate that is not cost based but still may be ineffective in addressing the particular needs of the customers served.

X. Customer Response to More Complex Price Signals.

Q. Are customers able to respond to more complex price signals?

A. Yes. In terms of complex price signals the proposals in this case are comparable to rates in other parts of the world. For many years electric utilities have had more complex rate schedules for customers. The first marginal cost based TOU rates were introduced for large customers in the 1950s. It is common to see separate supply and delivery charges with supply charges consisting of multiple blocks or TOU periods. Some rates have a customer charge that is tied to the maximum capacity that can be served by the utility. Under this arrangement the maximum delivery capacity is limited. This is a rate equivalent to a customer charge and a demand rate. In Italy, residential demand rates have been used for many years. Italy is an example of a demand charge that is based on maximum delivery capacity.

Australia is addressing the issue of residential demand charges to address both the issue of cost recovery for solar DG and added loads from air-conditioning in the residential class. The important point is that there is broad recognition of demand charges as a means to fairly recover distribution related costs based on maximum customer demand whenever it occurs. Production and transmission demand charges are partially related to system peak hours as discussed above.

Q. Are demand charges being adopted in the United States?

A. Yes. Municipal and cooperative utilities have adopted demand charge rates. In Florida where the Commission approves municipal rates Lakeland Electric has adopted a demand rate applicable to new solar DG customers and after 2025 for all solar DG customers. Cobb EMC in Georgia has adopted a demand rate for all new residential customers and the rate is mandatory for solar DG customers. Butler Rural Electric Cooperative has had a demand rate applicable to all residential customers since 2009. Customers adapt to rate schedules in different ways but they do adapt.

Q. Is there empirical evidence that customers do not respond to marginal price signals as much as to the total bill?

A. Yes. In a 2012 paper by Koichiro Ito of Stanford University found that customers respond to the total bill rather than marginal energy prices. This means that the non-linear energy prices under the inverted block rates are not useful as a tool to promote energy conservation. This is further evidence that the insistence of RUCO and others related to the tier consolidation of the TEP inverted rates does not promote conservation and the introduction of more efficient demand rates will not only promote just and reasonable rates, eliminate undue discrimination but will also be consistent with conservation. The findings in this article are not new and have been replicated over the years in various studies. This is further evidence that there is no requirement that residential customers fully understand the individual components of the rates to promote sound decisions related to a more complex rate design.

XI. Miscellaneous Issues.

Q. Witness Higgins states that TEP does not use the correct peak for calculating the load factor weights in the AED/4CP cost study.[55] Please comment on this issue.

A. In the traditional AED allocation system excess is based on a single peak and that peak is indeed used to calculate the system load factor as it should be. When the peak measurement is altered to other than a single peak as it is in this case- 4CP, the load factor weight applied to the average demand component is calculated on the basis of the peak used to determine excess just as it is in the traditional AED with a single peak. Thus the statement that the method is AED/4CP means that 4CP is the peak for determining excess demand and the peak for determining the relative weights for average which is the 4CP

[55] Higgins Direct Testimony at p. 13

load factor and the excess demand which is 1 minus the 4CP load factor. I understand why witness Higgins prefers the single peak load factor because it results in a lower weight for the average component and reduces costs allocated to high load factor customers because of their higher average demand as a class. In any event TEP has calculated the AED/4CP methodology in a logically consistent manner.

Q. Witness Seibel of the Solon Corporation expresses frequent and serious concern over proposals that he concludes are retroactive ratemaking. Please comment.

A. There are no proposals in the TEP filing that result in retroactive ratemaking. Witness Siebel is confusing the concept of setting a new, prospective rate schedule- the TEP proposal for new solar DG customers- as retroactive ratemaking. Retroactive ratemaking would occur if TEP proposed and the Commission approved a rate that allowed TEP to go back in time and bill customers on a different rate than they were billed on historically and collect additional revenues from those customers for that historic period. In this case, customers taking service after a certain date will be placed on a different rate after rates are approved and will be billed on that rate prospectively. This would be the equivalent of a now frozen rate being eliminated and replace by a new rate for example. The new rate would be effective prospectively. It is also the same as a case where the Commission makes a new rate design mandatory for some existing class of customers that fundamentally changes the rate design. It is certainly the Commission's prerogative to change a rate design or to replace a frozen rate with a new rate and those actions are not retroactive. This type of change in rate design has occurred as result of the PURPA standards on declining block rates and time of use rates. In both cases, Commissions that adopted these standards switched customer to a new rate regardless of when they begin service on the rates that were replaced. In these cases there was often no grandfathering as has been proposed in this case for solar DG customers who connected to the system before TEP gave notice of an upcoming proposed change in rates.

XII. Conclusions.

Q. Please summarize your conclusions and recommendations in this case.

A. I conclude that the minimum system for classifying distribution costs in accounts 364-368 as proposed by TEP is a necessary condition for reflecting cost causation on the TEP system. That conclusion is supported by rigorous econometric analysis, public utility accounting, the NARUC Manual, numerous academic and industry literature written by scholars and rate practitioners over more than 100 years and analysis of TEP's own data. The only option offered as an option to the minimum system does not result in an allocation of costs that reflects the real physical assets that underlie service to customers and thereby fails the test of cost causation. The Commission should affirm the use of the minimum system classification in the TEP cost study going forward.

Second, I conclude that increasing customer charges as proposed by TEP is solidly grounded in cost causation, economic efficiency and results in rates that are just and reasonable. The Commission should approve the TEP customer charges as filed even if they do not grant the full revenue requirement increase.

Third, I conclude that the rates resulting from net metering with banking are decidedly not just and reasonable and rise to the level of undue discrimination. The Commission has an obligation to cure undue discrimination and should adopt the TEP proposal for modifying net metering by placing customers on a separate rate schedule designed specifically for partial requirements customers including solar DG customers. The rate should be based on the treatment of solar DG customers as a separate class of customers in the TEP cost study.

I conclude that the elimination of the top tiers of the TEP rates is a necessary step to begin the transition to more cost-based and efficient rate designs that comply with the just and reasonable standard for rates. Just and reasonable rates require a multi-part rate with customer, demand and energy charges.

I conclude that the Lifeline rates should be consolidated as part of a plan to serve all full requirements residential customers under a single rate with customer demand and TOU energy charges.

I conclude that customers can and will respond to the more efficient rates and that response will vary broadly among customers based on their own choices designed to optimize their individual satisfaction and valuation of electric service.

Q. Does this complete your testimony?

A. Yes.

Appendix A

DR. H. EDWIN OVERCAST

Educational Background and Professional Experience

Dr. Overcast graduated cum laude from King College with a Bachelor of Arts Degree in Economics. He received the Doctor of Philosophy Degree in Economics from Virginia Polytechnic Institute and State University. His principal fields of study included Economic Theory, Public Finance and Industrial Organization, with supporting fields of study in Econometrics and Statistics. He has taught courses at both the graduate and undergraduate level in Microeconomic Theory, Managerial Economics and Public Finance. In addition, he has taught courses in Mathematical Economics, Economics of Regulation and Money and Banking. While a faculty member at East Tennessee State University, he was appointed to the Graduate Faculty and subsequently directed thesis programs for graduate students.

In 1975, he joined the Tennessee Valley Authority (TVA) as an Economist in the Distributor Marketing Branch. He held successively higher positions as an Economist in the Rate Research Section of the Rate Branch and was ultimately Supervisor of the Economic Staff of the Rate Branch.

In May of 1978, he joined Northeast Utilities as a Rate Economist in the Rate Research Department and was promoted to Manager of Rate Research in November 1979. In that position, he was responsible for the rate activities of each of the operating companies of Northeast Utilities: Western Massachusetts Electric Company, Holyoke

Water Power Company, Holyoke Power and Electric Company, The Connecticut Light and Power Company, and the Hartford Electric Light Company.

In March 1983, Dr. Overcast became Director of the Rates and Load Research Department of the Consumer Economics Division of Northeast Utilities. In this position, Dr. Overcast directed the planning of analyses and implementation of system-wide pricing and costs for regulated and unregulated products and services of Northeast Utilities. As part of that responsibility, Dr. Overcast represented the system companies before state and federal regulators, legislative bodies and other public and private forums on matters pertaining to rate and cost-of-service issues.

Dr. Overcast represented Northeast Utilities as a member of the Edison Electric Institute (E.E.I.) Rate Committee and the American Gas Association (A.G.A.) Rate Committee. While serving on those committees, he was the Rate Training Subcommittee Chairman of the A.G.A. Rate Committee. He has been an instructor on cost-of-service and federal regulatory issues for the E.E.I. Rate Fundamentals Course and the E.E.I. Advanced Rate Course. Dr. Overcast also represented Northeast Utilities as a member of the Load Research Committee of the Association of Edison Illuminating Companies.

In March 1989, he joined Atlanta Gas Light Company as Director - Rates and was promoted to Vice President - Rates in February 1994. In November 1994 he became Vice President - Corporate Planning and Rates and was subsequently elected Vice President - Strategy, Planning and Business Development for AGL Resources, Inc., the parent company of Atlanta Gas Light Company. His responsibilities in the various rate positions included: designing an administering the Company's tariffs, including rates, rules and regulations and terms of service. He represented the Company before regulatory commissions on rate and regulatory matters and oversaw the preparation of the Company's forecast of natural gas demand. He was responsible for planning activities relating to the regulated businesses of the Company. He developed strategy for both regulated and unregulated business units, monitored markets for new products and services and identified potential new business opportunities for the Company.

Dr. Overcast has previously testified in rate cases and other proceedings before the Connecticut Department of Public Utility Control, the Massachusetts Department of Public Utilities, the Georgia Public Service Commission, the Montana Public Service Commission, the Missouri Public Service Commission, the Kansas Corporation Commission, the Arkansas Public Service Commission, the Corporation Commission of Oklahoma, the Ohio Public Utilities Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, the Michigan Public Service Commission, the Public Service Commission of Maryland and the Tennessee Regulatory Authority and the Federal Energy Regulatory Commission. In Canada, he has testified before the Ontario Energy Board, the British Columbia Utilities Commission, the New Brunswick Energy and Utilities Board and the Alberta Energy and Utilities Board. He has also testified before the subcommittee on Energy and Power of the U.S. House of Representatives and various committees of the Georgia General

Assembly.

Dr. Overcast joined R. J. Rudden Associates, Inc. as Vice President in September 1999. R. J. Rudden Associates became a unit of Black and Veatch in January of 2005. At that time he became a Principal of the EMS Division, he is currently a Director of Black and Veatch Management Consulting, LLC.

Appendix B

SMART RATES FOR SMART UTILITIES

Creating a New Customer Paradigm with Enhanced Pricing of Utility Services

H. Edwin Overcast

BLACK & VEATCH
Building a world of difference.®

Table of Contents

Introduction

The U.S. electric utility industry is in the midst of rapid technological change and a transformation of the customer service paradigm. Much of the debate surrounding the changing industry centers on the implementation of more sustainable practices, such as energy efficiency and distributed energy resources, and compliance with more stringent environmental regulations. Notably, the debates continue to focus on technological and operational solutions. However, developing a 21st century rate design, or Smart Rates, can help facilitate solutions to today's industry challenges and provide customers with better price signals to assess competitive service offerings.

Smart Rates recognize that utilities provide a variety of services to customers and that the costs of these services are not always caused by the amount of energy the customer consumes. From a rate design perspective, Smart Rates fully unbundle[1] each component of utility costs and bill those components on the appropriate customer billing determinants consistent with the concept of cost causation. The unbundling of costs changes virtually all of the current rate traditions because it no longer rolls all utility costs into a single kilowatt-hour (kWh) charge or single kilowatt (kW) charge as if those costs are caused only by the single measure of customer energy consumption. Cost unbundling is critical for accommodating competition from on-site generation and allowing customers to choose which services they need from the utility.

This paper sets forth the theory and practice of 21st century rate designs through full rate unbundling of utility services and provides a framework for "Smart Rates" that enable customers to purchase – and pay an equitable and supportable price for – the services they want and need, regardless of their energy consumption levels. Through the use of Smart Rates, a utility can send customers a proper price signal associated with each service and improve the efficiency of all its services to customers.

Many aspects of the electric utility industry have changed dramatically since its founding, yet rate structures have significantly lagged these advancements. In order to best represent today's electric services and meet the needs of today's electric consumers, modern rate designs are essential. Smart Rates enable customers to use electricity and electric services more efficiently and provide utilities with revenue stability that enable the offering of more responsive services to accommodate customers' specific demands.

[1] Rate unbundling in this context is simply pricing each utility provided service separately so that customers pay only for the services they use, rather than paying a single charge that includes all services and assumes that all customers within a class have homogenous service requirements.

The Challenge with Current Utility Rate Designs

Current utility rate designs have their foundation in rates developed in the 19th century. The most common rates in use today are based on the watt-hour meter and consist of a fixed customer charge and some form of volumetric charge per kWh. As a practical matter, the choice of rate designs for various customer classes has depended specifically on the cost of metering relative to the total cost of service to the customer. For larger customers, most utilities use one of the following rate forms, both developed in the 19th century, or a combination of the two forms:

- **Hopkinson Demand Rate:** The most common method of pricing electricity for customers served with demand meters, such as large industrial customers. The Hopkinson Demand Rate consists of an energy charge for total kWh consumption in addition to a demand charge based on the facility's maximum energy use during any short time period (quarter-hour, half-hour or one-hour) in the month.
- **Wright Hours Use of Demand:** This rate form is also used for demand metered customers and bills those customers using kWh charges for different levels of hours use of demand. The Wright Hours Use of Demand consists of a customer charge and kWh charge blocks based on the number of hours that the customer's maximum monthly demand is used. Hours use is calculated by dividing the monthly kWhs by the measured maximum demand. The price of energy declines as the hours use increases recognizing both the customer's increased load factor and the increasing use of off-peak energy.

Even today, not all electric service applications are metered and the rate design used for such services are the same flat rate service used by the industry when it first started delivering electric power to customers in the 1880s.

Unless the rate design reflects cost causation for the services provided, customers who elect to buy particular service components will not pay for all the services they consume. This creates market instabilities as the result of cross-subsidies embedded in the utility's rates. Such cross-subsidies cannot withstand today's market pressures and will result in skewed prices and service levels for all market participants.

UNDERSTANDING COST DRIVERS

As noted, modern regulatory requirements for demand-side management (DSM) and energy efficiency, as well as customer demands for distributed generation (DG), do not align with current utility rate structures. The reason for this is that current rate structures incorrectly assume that energy, or measured kWh use, causes the utility to incur nearly all costs except for the costs that are reflected in a modest customer charge. For larger customers, the use of both a demand component and an energy component assume that a single measure of kW demand coupled with a unit kWh charge cause all of the fixed costs of utility service. In reality, utility services and the costs associated with each are caused by fixed and variable cost drivers. Both the fixed and variable cost drivers differ for different cost components and for different seasonal and diurnal periods.

Fixed costs do not change with energy use but can vary as a result of other cost drivers, such as customers or demand. Because these costs are fixed, they do not change with any hourly pattern of energy use, even though some time interval is used to measure demand (e.g., highest 15, 30 or 60 minutes). *Appendix A* provides a brief description of the determination of demand for billing capacity-related costs to customers. Examples of utility fixed costs include:

- The investment in the fleet of plants generating electric power.
- The integrated transmission network investment that moves power from generators to the distribution system.
- The distribution system that provides power to homes and businesses.

Variable costs, on the other hand, can vary by season of the year, time of use, and/or environmental conditions such as forced outages or partial unit deratings that change the marginal source of energy for a particular time period. Examples of variable costs include:

- Fuel and fuel handling costs.
- Purchased power.
- Volumetric charges from regional transmission organizations (RTOs) or independent system operators (ISOs).
- Chemical costs.
- Energy-related operations and maintenance costs.
- Other environmental costs.

A Utility's Cost Causative Factors

Whether fixed or variable, costs are generally caused by one or a combination of three general factors:

- **Customer:** In general, if a cost varies as a result of customer count, then this is a customer-caused cost and can include customer service expenses (e.g., billing and meter reading), and facilities or assets located on the customer premise, such as the meter and service line, and even portions of the distribution system that serve to connect customers to the grid.
- **Energy:** These are the costs that vary directly with the number of kWhs produced, with the cost of fuel being the largest component.
- **Demand:** Demand related costs are those costs caused by the largest load in kW imposed on various parts of the utility's transmission or distribution systems.

  NOTE: *The demand factor that causes costs differs for different types of cost elements. For example, some form of coincident demand is the cause of both utility production and transmission costs. This peak hour or other measure of demand drives the required capacity along with a level of reserves and it is this measure of demand that should be the basis for the charges to recover that unbundled cost.*

Understanding the nature of different utility costs, the types of costs, and what causes costs to be incurred enables utilities to use specific pricing mechanisms that align with cost factors (Table 1).

Table 1 - Unbundled Costs by Type and Causal Factors

COST FUNCTION	COST TYPE	CAUSAL FACTOR(S)	PRICING
Generation Plant	Fixed	Demand	kW Charge
Transmission Plant	Fixed	Demand	kW Charge
Distribution Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
General Plant	Fixed	Demand, Customers	kW Charge and Customer Charge
Generation O&M	Fixed, Variable	Demand, Energy	kW Charge and kWh Charge
Transmission O&M	Fixed	Demand	kW Charge
Distribution O&M	Fixed	Demand, Customers	kW Charge and Customer Charge
Administrative & General costs	Fixed	Demand, Customers	kW Charge and Customer Charge

This table shows the appropriate type of charge to recover the categorized costs in order to match cost causation with pricing without a detailed specification of the particular charge.

UNDERSTANDING UTILITY SERVICES

Unbundling of rates requires an understanding of all services a utility provides, and the cost drivers for each service. Most stakeholders generally understand that a utility provides safe and reliable electric service to its customers. However, most characterize this service as simply providing the energy product, which is one reason why the kWh-based rate structure continues to prevail today. In reality, utilities provide numerous services, including:

- Generation service
- Transmission and distribution services
- Customer service
- A variety of services that provide safe and reliable operation of the electric system as well as the facilities that use the electricity behind the meter, such as voltage regulation, in-rush current for starting electric motors and other ancillary services.

Each of the listed major functions of the utility can provide multiple specific services for a variety of customers. Furthermore, each service also includes a quality of service component, generally defined as firm or non-firm. Firm quality means that the utility provides service continuously without interruption except those related to unavoidable system outages (e.g. outages caused by severe weather). Non-firm quality means that the customer has agreed with the utility to permit its service to be interrupted at times the utility chooses. Table 2 demonstrates the multiple services provided under the generation functional umbrella, and how those services have different patterns of cost based on the quality of service.

Table 2. Potential generation services

SERVICE	QUALITY
Full Requirements	Firm
Full Requirements	Non-Firm
Partial Requirements- Supplemental	Firm/ Non-Firm
Partial Requirements- Supplemental Baseload	Firm/ Non-Firm
Partial Requirements- Supplemental Peaking	Firm/ Non-Firm
Partial Requirements- Standby/Backup	Firm/ Non-Firm
Partial Requirements- Maintenance Service	Firm/ Non-Firm
Partial Requirements- Scheduled Maintenance Service	Firm/ Non-Firm
Partial Requirements- Unscheduled Maintenance Service	Firm/ Non-Firm
System Related Services- Black Start, Area Protection, Frequency, Transmission Support	Firm

As Table 2 illustrates, there are many potential services (the list is not intended to be comprehensive) provided by the generation assets. Each service has different cost characteristics as well as quality differences. The result is that rates for unbundled generation may differ based on the type of service required. A similar set of requirements relate to transmission and even to some distribution services, although the closer the service is to the customer the less costs and quality of service provided vary. For example, if the provision of energy is non-firm, that service does not change the cost of the distribution facilities for serving the customer because the utility must still be able to meet the customer's maximum requirements when there is no interruption of service.

MODERN CHALLENGES TO TRADITIONAL RATES

Net Metering Policies

The fallacy of applying 19th century rate structures to the types of 21st century electric utility services required by customers is made clear by the economic effects of DSM programs, and the growing adoption of DG assets (e.g., rooftop solar) among customers who seek the economic benefit net metering policies provide. While these customers are using less energy, and some may even be net-producers of energy, they are still using utility services. However, because current rate structures assume that the level of kWh consumed by the customer causes the utility's costs; discontinuities in billing and cost recovery among customers are created. According to the Edison Electric Institute (EEI):

While net metering policies vary by state, customers with rooftop solar or other distributed generation systems usually are credited at the full retail electricity rate for any electricity they sell to electric companies via the grid. The full retail electricity rate includes, not only the cost of power but also all of the fixed costs ... that makes the electric grid safe, reliable, and able to accommodate solar panels or other distributed generation systems. Through the credit, net-metered customers effectively are avoiding paying these costs for the grid.[2]

Net metering is the practice of allowing on-site generation to reduce the kWh portion of the residential customer's bill (netting generation against load) on a unit kWh generated basis. Recognizing that under a utility's traditional rate design the kWh charge for these customers recovers most of the fixed costs and the variable costs of energy on an average basis, the compensation for the customer's level of self-generation essentially assumes that all of the costs not recovered under net metering can be saved by the utility. That is simply not the case.

Consider, for example, the utility that peaks after sunset in every month of the year. Solar PV makes zero contribution to reducing the fixed costs for that utility. Importantly, the only cost savings are the avoided energy costs - and that would not even be valued at the utility's highest energy cost hours. In this case, net metering forces all non-solar PV customers to bear the costs of production, transmission and distribution capacity costs that are caused by the solar PV customer. While this is an extreme case to illustrate this deficiency in net metering, there are many utilities where the peak loads occur when solar PV is not generating its maximum output. This means that the avoided costs of the utility will not be as large as the credit provided under net metering, and that a cross subsidy will be created which allows solar PV customers to avoid paying for the fixed costs they cause the utility to incur.

Demand-Side Management Issues

With respect to DSM, issues similar to those under net metering arise when DSM programs save energy, but not capacity. A simple example illustrates this point:

A recreational facility owner invests in skylights to save energy during the day. The skylight salesman calculated his expected savings by dividing the total utility bill by the monthly kWh and providing a unit kWh savings. However, the facility was billed on a commercial rate that included a demand charge. Needless to say, the savings did not materialize because the facility's peak demand occurred at night due to its heavy lighting load. The skylights created no demand savings - only daytime energy savings. Based on the actual savings, the skylights were not economic and the owner made a poor decision to invest his limited capital on an inefficient solution to reduce energy-related costs.

By unbundling rates, the utility recovers all of its costs from each customer regardless of the amount of energy (kWh) used by the customer, or when the energy was used. Such a pricing structure will create rates that fairly portray the value of the service in the market and will eliminate the inherent

[2] "Straight Talk About Net Metering." Edison Electric Institute (http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Straight%20Talk%20About%20Net%20Metering.pdf). September 2013.

intra-class cost subsidies in current utility rates, creating benefits for all segments of the energy industry.

21st Century Rate Design

A 21st century rate design fully unbundles each component of cost and bills those components to customers based on the appropriate billing determinants (customer, kW, kWh) consistent with cost causation. The unbundling of costs and the implementation of modern rate designs appropriately change virtually all of the current rate traditions perpetuated over the years. Different rate components are billed separately and each customer will only pay for the services they use. This section focuses on the components of an unbundled rate design.

Unbundled rates consist of the basic customer, demand and energy charges. Under full unbundling, these basic rate components are translated into:

- Customer charge
- Production demand charge
- Transmission demand charge
- Distribution demand charge
  - Distribution substation service
  - Distribution primary service
  - Secondary distribution demand
- Energy charge
  - Energy service at transmission voltage
  - Energy service at substation delivery
  - Energy service at primary delivery with and without transformation
  - Energy service at secondary voltage.

Obviously, not every utility will require all of these distinct charges based on their existing service arrangements and the customers' available service options. Further, there may well be subcomponents of various costs associated with services such as back-up, standby, maintenance and supplemental power as each relate to generation, transmission, distribution and energy services. In some markets, unbundled services, such as meter reading and billing, may not be provided by the utility. In that case, the customer charge component needs to reflect the exclusion of the costs of these services.

A customer's rates may also differ based on geographic segments of the utility's system because costs may differ at different load nodes (this consideration is particularly important for systems with wide geographic reach that include different load nodes and/or climatic considerations.)

UNBUNDLED RATE COMPONENTS

Derivation of the Customer Charge

The derivation of a fully unbundled rate design begins with the customer cost component. While customer costs will always be a subject of debate among a utility's stakeholders, the logic supporting this concept is quite simple: If a cost varies based on customer count, then the cost is customer-related. This includes a utility's customer service functions and its assets located on the customer premise.

Another element of customer costs are those portions of the utility's minimum distribution system required to serve even the smallest customer. Minimum distribution system requirements include transformers, secondary conductors, poles and/or underground facilities.

To derive its fixed customer charge, a utility uses a detailed cost of service study that unbundles costs into various components. These unbundled costs form the basis for setting the rates for each component of service. For example, if the cost of service study calculates the customer component to be $300 per year, that amount would be the basis for a $25 per month customer charge. The annual cost derived from the utility's cost of service study would include the annualized cost to support the investment in a meter, service line, transformers, secondary conductors and poles, Operation & Maintenance (O&M) expenses related to the customer's plant, general plant, and any other assets required to provide the service, and customer service expenses (e.g., billing, meter reading, customer accounts and collections).

Derivation of the Production Demand Charge

Not all electric utilities will have production demand charges. This discussion focuses on the need for such charges for a vertically integrated utility. In that case, the production demand charge includes the fixed costs of generation and the transmission lines and related facilities that interconnect the utility's generation to its bulk transmission system. Ideally, these costs would be collected through two separate demand charges. This is the preferred rate structure because the typical electric utility experiences distinct differences between the marginal costs of production for serving peak loads compared to the costs for serving loads occurring other than during the peak period (i.e., base load production). At the same time, with the expected increase in the penetration of distributed energy resources (DER) on utility systems, this rate structure will properly value the benefits of DER to the customer based on the times when such self-generation actually is operating.

In general terms, the first demand charge (known as the Production Peak Demand Charge) recognizes the capacity costs associated with the utility's peak demand period, while the second demand charge recognizes the higher capacity costs of base load units that provide substantially lower energy costs. These costs are recovered based on the maximum demand in the peak demand period subject to a one hundred percent ratchet.

The carrying cost of the utility's least-cost production resource (nominally a gas turbine) and the associated transmission costs would be collected as a demand charge based on a demand measure during the highest load hours, where load is defined as: *The sum of customer load, forced outage load, scheduled outage load and generator deratings.*

This demand charge reflects the unbundled costs of required capacity with a level of reserves. The result is that certain charges may be incurred by the customer based on specific time periods that may differ from on-peak hours for energy, in general, and may differ for generation and transmission. For example, if the reserve requirements are calculated by an RTO or ISO based on a specific set of critical hours, those critical hours may be appropriate for determining the billable production demand associated with peaking facilities. If these hours are very short periods, such as the maximum demand hour in the summer months of June, July and August, it is not feasible to know in advance when those peak hours may occur and the peak hours used to measure the hours when the demand charge is applied may change from year-to-year and month-to-month.

It is important to note that deriving the Production Peak Demand Charge based on a short demand period runs the risk of shifting load out of that period. In addition, this also creates risk for increasing load after the peak demand period, causing the peak to occur in different hours because shifting load out of a short period may reduce natural diversity. It is critical that the shifting peak concept be fully assessed because there is a possibility that the loss of natural diversity in loads may cause other capacity-related costs to increase - such as for the utility's distribution and transmission facilities.

By establishing a longer fixed period for deriving the Production Peak Demand Charge, the shifting demand peak creates no issue for creating a new production demand peak outside of the demand hours. This is done by taking advantage of the natural diversity that occurs between loads.

It is also critical to understand that the need for capacity is based on more than just the customer load on the utility's system. Simply, the total maximum load on the system is the sum of customer loads, scheduled outage loads, unscheduled outage loads and unit derating loads. The latter two components change for every time interval just like customer loads. In some cases, the seasonal derating is known in advance based on the generation technology or a condition such as lower water flows that occur naturally.

Other factors may also derate the capacity of a unit without forcing the unit out of service (e.g., tube leaks). Since these types of occurrences reduce available capacity, they must be treated as load for purposes of determining the peak hours that matter for cost causation purposes. It has been said that if load factor on the generation system increases beyond a certain point, it will be necessary to build reserves just to schedule maintenance activities. Thus, it is important to understand the full demand on generation resources for purposes of establishing the demand period for production. Shifting load to off-peak periods does not always result in the full expected savings and could with some technologies create a new peak period in the former off-peak hours.

The second demand charge (known as the Production Base Load Demand Charge) is designed to recover that portion of the utility's revenue requirement associated with production not recovered through the Production Peak Demand Charge. The value of this charge may be zero in some circumstances. Where there are additional costs, the Production Base Load Demand Charge will be based on the highest monthly demand outside the peak demand period, without any ratchet provision. Thus, customers who benefit from lower cost energy will contribute to the additional capacity costs that produce those savings.

In the alternative, where utilities operate in restructured markets, the Production Peak Demand Charge of RTO or ISO participants could be based on the capacity responsibility determined by the operational control entity. This charge would be subject to a 100 percent ratchet on an annual basis. The remainder of the capacity costs not covered by the Production Peak Demand Charge would be recovered in a second demand charge applicable to the highest monthly load occurring in the month, without a ratchet.

Derivation of the Transmission Demand Charge

For transmission, the analysis of peak loads need not be the same as for generation. On integrated utility systems, native load may be only one component of the peak load. Understanding how the system is loaded on an hourly basis is a necessary element for the determination of transmission system peak periods. It is possible that the demand allocation for the generation function will differ from the allocation that is appropriate for the transmission function. This is particularly true where transmission for others across the utility system results in higher loading at times other than the native load system peak.

Transmission system loading on integrated utility systems is not solely a function of customer load on the system because of congestion management and centralized dispatch. For example, if load flows across the individual utility system because of lower cost generation, a transmission system may be fully loaded many more hours than retail customers' own load alone would indicate. Determination of the expected loading may also change because of events unrelated to the transmission facility owner, such as unit forced outages, changes in relative fuel costs, must-run generation and other factors that alter grid dispatch. The result of these factors is to change the allocation and cost responsibility for transmission in a way that impacts the appropriate demand period determination. To do this, it is important to understand the components of the transmission system and the cost drivers for each:

- **Generation laterals**: costs driven by connecting generation to the system and should be included in the generation/production demand costs.
- **Load laterals:** Costs driven by the loads on the lateral and may differ from the system or the transmission peak. Costs for load laterals are recovered through the distribution facilities demand charge.
- **Bulk transmission system**: Costs driven by loading of the bulk system and are recovered based on the load characteristics of the system. Options include:
  - Maximum load occurs in each month of the year: The demand charge is based on the peak period demand within every month and is the basis for the transmission demand charge.
  - Maximum load occurs in summer: If system is loaded only during four summer months, then the costs would be based on demand that occurs during the peak demand time period, even though the charges are billed over all 12 months. In essence, the non-seasonal demand would be equal to the average of the four critical peak demand periods.

Derivation of the Distribution Demand Charge

Distribution demand costs are driven by the customer peak load whenever it occurs. These costs are not identifiable on a time-of-use basis and the individual customer's maximum demand or contract demand (the maximum obligation of the utility to provide the local distribution service) is the appropriate demand measure to use to recover such costs. Any distribution costs not recovered in the customer cost category and the portion of transmission costs for load laterals are recovered in the distribution demand charge. The distribution demand charge would include a 100 percent demand ratchet based on either the customer's contract or actual demand.

As a general rule, the distribution system components peak at times that may not be coincident with the generation or transmission peak load. In planning and designing the distribution system, an important design element is natural load diversity that occurs based on the electricity use of the premise (businesses and residences have differing time patterns of load).

Certain activities, such as storage may alter the natural diversity of loads. For example, controlling electric water heaters by shutting them off for extended peak periods results in much higher coincident peak demands on delivery facilities because the natural load diversity is disrupted by the added control. The result is both higher distribution costs and higher peak demands for customers subject to control. Based on experience with time-of-use rates, there is potential for a similar impact on the distribution peaks and the cost of delivery service.

The recovery of distribution-related costs based on maximum demand whenever it occurs is fundamental to cost-based rates.

The three components of the distribution demand charge are recognized in the cost allocation process and relate to substation costs, primary facilities and secondary facilities not recovered in the customer charge. Conceptually, in a modern electric system all secondary costs should be customer-related. The allocation process recognizes that diversity increases as the load is measured further from the customer's individual load. To the extent that loads are homogeneous, a single distribution demand charge would be adequate. If there is little homogeneity, then the costs may need to be broken out separately but billed under the same 100 percent ratchet provision.

The customer and ratcheted demand charges would be based on an annual cost payable in 12 equal amounts. These annual charges would be premise-based so that a new customer occupying the premise would have his bills initially based on the premise's measures of demand. In addition, if a customer has service turned off at the premise and subsequently turns service back on, the customer would be responsible for the payment of fixed charges for the period where service was not taken as part of the cost of establishing service. Non-ratcheted demand charges would be based on the actual monthly use of demand.

Derivation of the Energy Charge

The final component of the unbundled rate design is the energy charge. The energy charge recovers all of the variable costs associated with the production or purchase of power. Further, the energy charge is not part of the utility's base rate. Rather, it is reflected in a full tracking fuel clause that recovers not only fuel and purchased power, but also variable production costs, environmental costs (e.g., scrubber chemicals), variable charges from the RTO or ISO, and any other costs that change with the consumption of energy.

The energy charge is subject to regular adjustments, like a fuel clause, and includes a deferral account that matches these costs dollar for dollar. The energy charges under this charge are differentiated based on cost causation by season, by time of use, by voltage level of service and, where applicable, by critical periods above and beyond the time of use periods. The adjustments to this charge are always seasonal-based adjustments in the sense that over or under recoveries of cost in a season are subsequently recovered in that season.

Energy charges may not require the inclusion of all of the cost components described above. For example, some utilities may not have distinct seasons. Others may have diurnal cost differences that are so small that there is no reason to separately bill for those differences. Some utilities with little diurnal difference may instead have critical peak periods when, for a few hours per month or for a few hours per season, they may experience costs far in excess of typical average or marginal cost levels. For example, the average cost might be approximate $35 per MWh for 97 percent of the time, but could easily exceed $100 per MWh in the remaining hours. In this case, the ability to provide proper price signals to customers would be important as would rate provisions designed to match costs and revenues under the critical peak period.

ILLUSTRATIVE RATE STRUCTURES

Using the concept of fully unbundled rates means that a utility's traditional rate class definitions are no longer as important. Cost-based rates enable the use of a less homogeneous class of customers, (e.g., there is no need to have one or more residential classes of service). There will no longer be a need for separate rate classes for certain end-uses, such as churches or schools, to reflect their different load characteristics compared to those of other general service customers. The ability to recover costs based on individual load characteristics then allows for rates based on other relevant conditions of service that have specific cost implications, such as voltage level of service or transformer or substation ownership.

Thinking about the factors that impact cost must begin with the customer component of costs including meter and service investment. This classification should also recognize that voltage level of service is of particular importance. In that context, it is possible to define a Small General Service Secondary Voltage Class. This class would consist of all customers who have essentially the same types of meter installations and service lines (e.g., residential, residential space heating, small commercial, small commercial all electric, etc.). Differences in other characteristics of utility service, such as demand coincidence factors and individual maximum demands, would not matter since the costs that are caused by these demand measures are already unbundled. The important point is to derive each component of the rate structure to reflect the actual cost of service.

Other classes would include General Service Primary Voltage, General Service Primary Voltage Transformer Ownership, Large General Service Substation, Large General Service Transmission, Non-Firm Service Rates and Back-Up and Standby Service Rates. These rates would reflect the different costs associated with each service and, as appropriate, seasonal, time of use and critical peak pricing-type considerations based on service level requirements and associated costs.

Customers who require unique service arrangements would have those costs recovered in a separate monthly fixed charge for directly-assigned facilities. For example, an industrial customer may take service at the substation, but require one or more dedicated lines to connect the substation to its facility. In that instance, the dedicated lines would be a directly-assigned cost and recovered under a separate charge unrelated to the customer's actual load.

To illustrate these concepts, the following tables outline the rate forms for General Service Secondary Voltage Class and General Service Primary Voltage Class customers.

Rates for the General Service Secondary Voltage Class assume the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the secondary level.
- All primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 3 - Rate structure for General Service Secondary Voltage Class customers (i.e., residential)

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Customer Charge $300.00/year or $25.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Distribution Demand Charge $3.00/kilowatt of billed demand	Fixed	Charges resulting from the demand-related portions of the distribution system. This charge can be based on the greater of the current month's maximum demand, or the maximum demand occurring in any of the preceding 11 months.
Transmission Demand Charge $12.00/kilowatt year or $1.00/month	Fixed	This charge is for services provided by the bulk transmission system. It should be based on the rolling average of the maximum on-peak demand for the system
Production Demand Charge $96.00/kilowatt year or $8.00/month	Fixed	Includes the fixed costs of generation and the infrastructure that connects generation to the bulk transmission system.
Energy Charge Charges would vary based on time of use, such as $0.058/kWh for summer on-peak and $0.038/kWh for winter off-peak	Variable	Recovers all of the variable costs associated with the production or purchase of power, most notably fuel and environmental costs.

Charges based on a hypothetical vertically integrated electric utility providing a bundled service.

The rate components of a General Service Primary Voltage Class are outlined below assuming the following operating conditions:

- All customers have the same meter costs and the average cost of secondary service lines consistent with the applicable line extension policy (customer's requiring a greater level of service investment make an appropriate contribution for the excess investment).
- Customer costs include a minimum system component for local distribution facilities at the primary level.

- Remaining primary related costs are included in the distribution demand charge.
- The utility is strongly summer-peaking for the 4 months, June through September.
- Partial requirements customers take service under this rate and the applicable back-up and standby service rate.
- Customers who require unique service arrangements either make a contribution in aid of construction for excess facilities or they pay a separate fixed charge.

Table 4 - Rate structure for General Service Primary Voltage Class

RATE STRUCTURE (Billed amount)	TYPE OF CHARGE	DESCRIPTION OF CHARGE
Annual Customer Charge $600.00/year or $50.00/month	Fixed	Charges that support the customer service functions of a utility (e.g., billing, meter reading, distribution connection)
Primary Distribution Facilities Demand Charge $24.00/year or $2.00/kilowatt of billed demand	Fixed	Charge based on the greater of the current month's maximum demand or the maximum demand occurring in any of the preceding 11 months payable in monthly installments.
Transmission System Demand Charge $11.75/kW-year or $0.98/month	Fixed	Charge based on the rolling average of the maximum on-peak demand occurring in the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments
Production Peak Demand Charge $94.00/kW-year or $7.84/month	Fixed	Charge based on the rolling average of the maximum peak demand occurring during the hours of 12 noon through 9 pm weekdays in the months of June through September payable in twelve monthly installments.
Production Base Load Demand Charge $6.86/kW per month	Fixed	Charge based on the actual maximum demand occurring monthly regardless of the time the demand occurred.
Energy Charges Variable	Variable	The energy charges hereunder shall be determined from time to time to recover the total variable costs associated with the production, purchase and delivery of energy to the Company's transmission system including any volumetric charges imposed under an RTO/ISO Tariff. The summer season is defined as the months of June through September. The charges effective for the twelve months commencing June 1, 2014 are as follows: • Summer On-Peak (Hours 10 AM to 11 PM weekdays excluding holidays) $0.568 per kWh • Summer Off-Peak (All other hours in the season) $0.0441 per kWh • Winter On-Peak (Hours 6 AM to 10 AM and 5 PM to 9 PM weekdays excluding holidays) $0.0451 per kWh • Winter Off-Peak (All other hours in the season) $0.0372 per kWh

As these two rate structures illustrate, many of the unit charges for primary customers are lower because generation and transmission capacity related costs reflect lower primary voltage losses. For primary distribution costs, the lower charge represents the exclusion of secondary facilities from the cost of service at the distribution level. The lower energy-related charges are also the result of lower losses. The higher customer charge reflects higher metering and service costs, including using primary minimum system costs for service at this level. This general pattern will be repeated for each additional rate schedule with charges declining as the result of fewer facilities and lower losses. In addition, charges such as the residual generation costs or transmission costs will differ based on class load characteristics.

ROLE OF ADVANCED TECHNOLOGIES

Perhaps the primary reason rate structures have not changed significantly during the past century was due to a lack of technology to measure and appropriately charge for a variety of utility services. Until recently, utilities did not possess the technology and capability for measuring and recording data for each of its individual cost drivers.

Today's smart meters and advanced metering infrastructure (AMI) enable utilities to measure more than monthly kWh consumption. The technologies and back office software programs enable utilities to produce dynamic pricing information for customers and measure, record, bill and credit based on the usage levels of each service. Examples of additional services advanced technologies can track include:

- Time differentiated energy costs including critical peak prices;
- Demands by time of use and by maximum demand regardless of time; and
- Power factor measurement.

Smart meters permit a wider variety and type of price signals that can remove rate subsidies and send better, more cost-effective price signals to customers. With smart meters, each different rate component may be billed separately, enabling customers to pay for only the services they use.

OTHER CONSIDERATIONS

In addition to the various unbundled charges described above, it will be important to overlay seasonal and diurnal cost characteristics, critical peak pricing and time-of-use pricing, load control credits and other yet to be developed programs that reduce loads and create cost savings that would not be reflected in rates. Thus, we would expect to see energy prices that vary by season and by time of day based on time periods defined by cost differences, where appropriate. It will be important to develop seasonal and diurnal periods based on the underlying marginal costs recognizing that for some utilities those periods may vary in different parts of their systems. This would be the case where a portion of the utility delivery system is served off an electrically isolated load node of the transmission system. Where the system receives service from isolated facilities, the cost of these facilities and service should be borne only by the customers using these services. If the system is fully integrated, the costs of different nodes should be averaged across those nodes.

It is also important to remember that because unbundled rates eliminate intra-class subsidies that are included in many of today's traditional rate structures, certain policy goals could no longer be viably reflected as part of the rate. As such, programs such as low income bill assistance would need to be addressed indirectly through fixed bill credits funded by a separate rate component.

Ultimately these unbundled rates will be designed to recover the utility's class-related revenue requirements. The resulting price signals will be significantly more efficient from an economic perspective resulting in less resource waste and more economically efficient power systems. A key element of the successful implementation of unbundled rates will be to educate customers on how the rates reflect the underlying costs of particular utility services and how the customer can manage electricity use to reduce those costs. Overall, such rates are expected to generate efficiency gains for both customers and the utility.

The benefits of unbundled Smart Rates will accrue to every stakeholder group even though some members will pay more for the services they buy and others will pay less. Customers who pay more benefit from receiving the correct price signal and understand the benefits of alternative choices related to DSM and DG investments. For the utility, unbundled rates will not change the utility's revenue requirement in total, but will impact the stability of revenues favorably and will cause the utility to be more proactive in its marketing of unbundled services to customers. It will likely take substantial effort on the part of the utility to educate stakeholders of these benefits in a rising cost environment. It is the Smart Rates that will allow customers to use electricity more efficiently and allow the utility to recover its costs from customers who cause those costs to be incurred. While the utility will be economically indifferent as rate designs change, it will also benefit from better price signals as consumers adapt to the cost causative factors that form the basis for unbundled rates. Changing rate design will also impact customers who have made investments based on the economic signals of the 19th Century rates and some of those investments will no longer be cost effective. The issue of customer stranded costs will be a difficult element of the transition, but is inevitable because of technological advances in metering and in utility operations.

The end result of unbundled rates will be a more cost effective and better integrated utility system to the benefit of economic growth and new investments that enhance the efficiency of the utility grid. This new customer paradigm is a prerequisite for improving the safety and reliability of the utility system.

Appendix A

As electric rates become unbundled, it is important to understand the concept of demand billing. The concept of demand billing is one of measuring the maximum capacity of the electric utility's system used in any particular period of measurement. Load varies from moment to moment based on the actual use of electric appliances including motor loads such as compressors in HVAC systems or refrigerators and freezers. Lighting load varies even from minute to minute as lights are turned on and off. Some loads run continuously while other loads operate infrequently. The net result is that any particular customer can have a different load shape on a daily basis.

Figure A-1 Daily Residential Hourly Load Shape

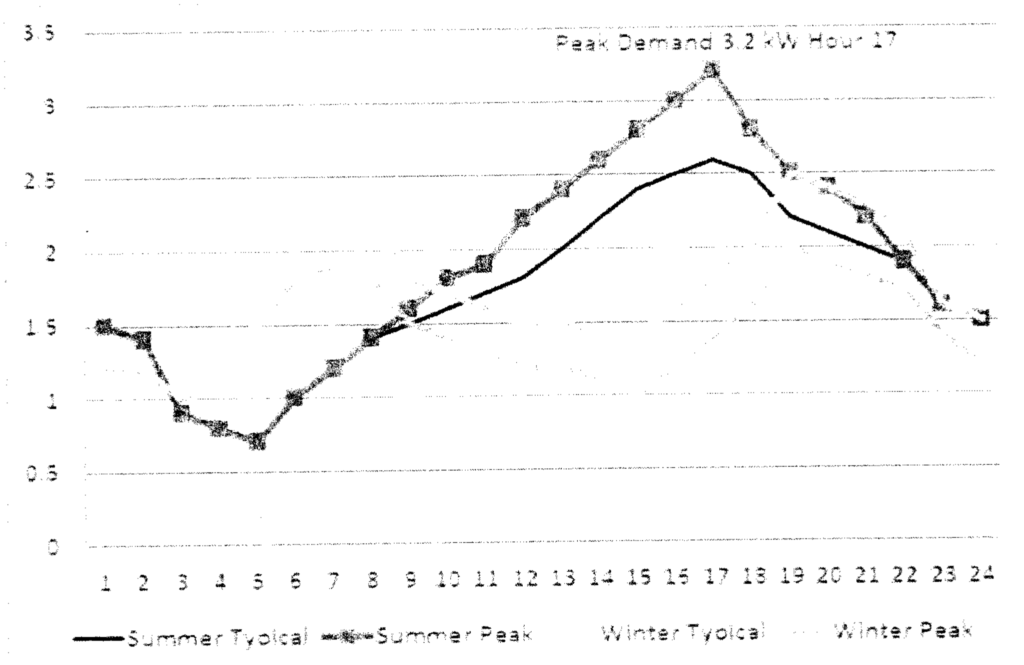


Figure A-1 shows a typical day summer and winter load shape and the peak day for both seasons. The peak hour demand for this customer occurs in the summer and is 3.2 kW. This is the customer's non-coincident peak demand based on an hourly measure. Hourly demand averages the kWh usage over the underlying measurement interval. For example, this demand may be average over four-15 minute intervals as illustrated in Figure A-2.

Figure A-2 Summer Peak Hour kW per Interval

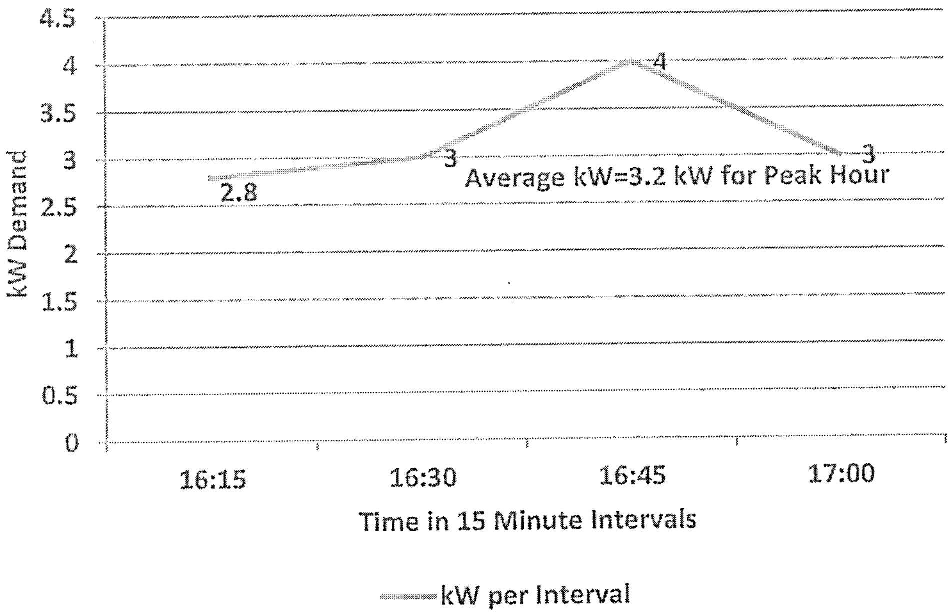


Figure A-2 illustrates the averaging of four-15 minute intervals to derive the customer's maximum demand. Maximum demand is also measured using shorter intervals. Table A-1 provides the demand in kW for each of the three possible measurement intervals.

INTERVAL	kW DEMAND
15 Minutes	4 kW
30 Minutes	3.5 kW
60 Minutes	3.2 kW

Since the kW measure of capacity required to meet the customer's load is the maximum demand on the utility system, the 15-minute interval is more representative of the required capacity for the utility's local distribution facilities. In any event, the choice of the measurement interval has little impact on customers' bills except for customers with highly variable loads. The reason for this is the costs are fixed and the higher measure of demand results in a lower unit charge for the customer.

As discussed earlier, there are many different billing demands that are relevant for cost recovery purposes. The same method of calculation is used in each instance although the hour or hours of measurement may differ. That is, some measures of demand might be defined as occurring within a specific range of hours. For example, the demand may be defined as occurring between the hours of 1 p.m. and -4 p.m. Since our data is reported on an hour-ended basis, the peak demand would be measured as the maximum demand occurring during the hours of 14 through 16 above. In that case, the demand would be 3 kW occurring at hour 16.

Exhibit HEO – R – 1

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

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

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

Exhibit HEO – R – 2

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Intangible Plant	301-303	160,246,771	92,889,664	2,051,982	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
Subtotal - INTANGIBLE PLANT	301-303	160,246,771	92,889,664	2,051,982	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
B. PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
Land & Land Rights	310	6,057,619	3,119,315	69,694	1,391,363	740,686	532,776	203,784	0
StructuresImprovements	311	195,860,951	100,856,786	2,253,420	44,986,944	23,948,596	17,226,257	6,588,948	0
Boiler Plant Equipment	312	1,000,007,373	514,944,551	11,505,288	229,689,865	122,274,363	87,952,109	33,641,196	0
Reactor Plant Equipment	322	0	0	0	0	0	0	0	0
Turbogenerator Units	314	294,774,517	151,791,412	3,391,441	67,706,220	36,043,100	25,925,849	9,916,494	0
Accessory Electric Equipment	315	134,465,967	69,242,007	1,547,058	30,885,242	16,441,619	11,826,478	4,523,563	0
Miscellaneous Power Plant Equipment	316	25,580,106	13,172,239	294,304	5,875,448	3,127,768	2,249,808	860,539	0
Sundt/SPV/SGS1 Acquisition Adjustment	114	-31,854,390	-16,403,124	-366,491	-7,316,577	-3,894,947	-2,801,640	-1,071,612	0
Electric Plant Purchased or Sold	102	15,029	7,739	173	3,452	1,838	1,322	506	0
OTHER PRODUCTION PLANT									
Land and Land Rights	340	1,873,363	964,671	21,553	430,289	229,063	164,765	63,022	0
Structures and Improvements	341	21,065,337	10,847,400	242,361	4,838,459	2,575,732	1,852,727	708,658	0
Boiler Plant Equipment	342	17,936,074	9,236,015	206,358	4,119,704	2,193,106	1,577,504	603,387	0
Reactor Plant Equipment	343	181,875,041	93,654,871	2,092,509	41,774,546	22,238,491	15,996,175	6,118,449	0
Engines and Generators	344	244,472,493	125,888,850	2,812,706	56,152,440	29,892,498	21,501,713	8,224,286	0
Turbogenerator Units	345	12,398,839	6,384,667	142,651	2,847,867	1,516,049	1,090,496	417,109	0
Accessory Electric Equipment	346&347	13,743,196	7,076,932	158,118	3,156,650	1,680,428	1,208,734	462,334	0
Misc. Power Plant Equipment	114	-37,278,677	-19,196,310	-428,899	-8,562,471	-4,558,193	-3,278,714	-1,254,090	0
Subtotal - PRODUCTION PLANT	304-346	2,080,992,837	1,071,588,022	23,942,246	477,979,440	254,450,197	183,026,359	70,006,572	0
C. TRANSMISSION PLANT									
Land and Land Rights	350	0	0	0	0	0	0	0	0
Structures and Improvements	352	0	0	0	0	0	0	0	0
Station Equipment	353	0	0	0	0	0	0	0	0
Towers and Fixtures	354	0	0	0	0	0	0	0	0
Poles and Fixtures	355	0	0	0	0	0	0	0	0
Overhead Conductors and Devices	356	0	0	0	0	0	0	0	0
Underground Conduit	357	0	0	0	0	0	0	0	0
Underground Conductors and Devices	358	0	0	0	0	0	0	0	0
Roads and Trails	359	0	0	0	0	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	0	0	0	0	0	0	0	0

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. DISTRIBUTION PLANT									
Land and Land Rights	360	11,605,107	6,204,731	105,617	2,761,319	1,415,243	1,109,368	0	8,830
Structures and Improvements	361	11,835,474	6,327,898	107,713	2,816,132	1,443,336	1,131,389	0	9,005
Station Equipment	362	161,677,439	86,441,690	1,471,406	38,469,527	19,716,560	15,455,241	0	123,017
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	233,534,842	171,792,005	4,017,278	33,123,849	10,603,690	8,123,174	0	5,874,847
Overhead Conductors and Devices	365	183,006,168	109,553,312	2,137,495	37,945,458	17,858,051	13,951,321	0	1,560,531
Underground Conduit	366	61,247,158	52,086,600	1,337,060	5,324,180	102,415	2,495	0	2,394,407
Underground Conductors and Devices	367	304,496,075	202,069,335	4,354,196	53,672,692	22,175,997	17,225,188	0	4,998,668
Line Transformers	368	281,381,714	174,269,453	3,484,997	56,998,305	26,189,309	20,439,489	160	0
Services	369	134,848,680	114,679,759	2,943,823	11,722,318	225,488	5,494	0	5,271,798
Meters	370	46,154,903	33,856,083	869,084	10,524,428	0	893,157	12,152	0
Installed on Cust Premise PR_L	371	0	0	0	0	0	0	0	0
Other Property on Customers Premise	372	0	0	0	0	0	0	0	0
Street Lighting and Signals	373	11,995,791	0	0	0	0	0	0	11,995,791
Subtotal - DISTRIBUTION PLANT	374-387	1,441,783,351	957,280,867	20,828,668	253,358,208	99,730,087	78,336,315	12,311	32,236,894
E. GENERAL PLANT									
General Plant	389-399	314,077,737	180,937,543	3,992,924	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
Subtotal - GENERAL PLANT	389-399	314,077,737	180,937,543	3,992,924	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
TOTAL PLANT IN SERVICE	101	3,997,100,696	2,302,696,096	50,815,820	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252
ADDITIONS TO UTILITY PLANT									
Energy Conservation Programs	182.3	0	0	0	0	0	0	0	0
Property Held for Future Use	105	0	0	0	0	0	0	0	0
Construction Work in Progress	107	0	0	0	0	0	0	0	0
Nuclear Plant Costs - Calvert Cliffs	182.3	0	0	0	0	0	0	0	0
Total Additions to Utility Plant		0	0	0	0	0	0	0	0
TOTAL UTILITY PLANT		3,997,100,696	2,302,696,096	50,815,820	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION RESERVE									
Intangible	301-303	-119,977,698	-69,118,143	-1,525,297	-24,899,170	-12,062,678	-8,900,072	-2,384,665	-1,087,674
Production	304-359	-796,297,495	-410,046,033	-9,161,565	-182,900,116	-97,366,051	-70,035,528	-26,788,203	0
Transmission	350-359	0	0	0	0	0	0	0	0
Land and Land Rights	360	-3,862,742	-2,065,235	-35,154	-919,101	-471,061	-369,251	0	-2,939
Structures and Improvements	361	-3,279,743	-1,753,532	-29,849	-780,382	-399,965	-313,521	0	-2,495
Station Equipment	362	-54,387,561	-29,078,594	-494,974	-12,940,975	-6,632,562	-5,199,073	0	-41,382
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	-87,160,606	-64,116,751	-1,499,341	-12,362,587	-3,957,542	-3,031,756	0	-2,192,629
Overhead Conductors and Devices	365	-71,943,372	-43,571,875	-853,237	-14,968,663	-7,021,347	-5,484,567	-34	-43,650
Underground Conduit	366	-27,348,184	-23,257,796	-597,026	-2,377,362	-45,730	-1,114	0	-1,069,155
Underground Conductors and Devices	367	-141,085,166	-93,626,775	-2,017,472	-24,868,697	-10,275,023	-7,981,116	0	-2,316,082
Line Transformers	368	-135,774,711	-82,958,836	-1,652,574	-27,387,686	-12,634,865	-9,862,583	0	-1,278,167
Services	369	-52,591,903	-44,725,886	-1,148,111	-4,571,784	-87,942	-2,143	0	-2,056,037
Meters	370	4,020,491	2,949,157	75,705	916,769	0	77,802	1,059	0
Street Lighting and Signals	373	-5,781,491	0	0	0	0	0	0	-5,781,491
General	389-398	-86,548,234	-49,859,710	-1,100,302	-17,961,498	-8,701,646	-6,420,239	-1,720,224	-784,615
Subtotal-DEPRECIATION RESERVE		-1,582,018,414	-911,230,009	-20,039,198	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
Dep. Res.- adjust for 13 month avg.	108.9	0	0	0	0	0	0	0	0
TOTAL RESERVE FOR DEPRECIATION	108	-1,582,018,414	-911,230,009	-20,039,198	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
III. OTHER RATE BASE ITEMS									
Cash Working Capital	n/a	-10,528,676	-6,065,482	-133,853	-2,185,033	-1,058,564	-781,028	-209,267	-95,449
Fuel Inventory	151, 152	25,107,584	12,928,918	288,868	5,766,915	3,069,991	2,208,249	844,643	0
Materials & Supplies	154, 163	77,125,097	44,431,120	980,504	16,005,899	7,754,235	5,721,221	1,532,931	699,188
Prepayments	165	9,439,165	4,552,174	94,946	1,980,218	1,258,831	1,086,594	419,119	47,283
Customer Advances for Construction	252	-11,046,099	-5,906,989	-100,548	-2,628,814	-1,347,330	-1,056,133	0	-6,284
Customer Deposits	235	-19,400,461	-10,374,551	-176,595	-4,617,032	-2,366,340	-1,854,906	0	-11,036
Deferred Credits - Asset Retirement - tax cr	230&253	-2,630,793	-1,515,578	-33,446	-545,973	-264,503	-195,155	-52,289	-23,850
Plant Held for Future Use - Transmission Pl	105	0	0	0	0	0	0	0	0
Regulatory Assets	182	0	0	0	0	0	0	0	0
Regulatory Liabilities	254	25,112,104	14,466,872	319,254	5,211,556	2,524,796	1,862,842	499,126	227,657
ADIT	190	0	0	0	0	0	0	0	0
ADIT - Other Property	283	-403,582,512	-232,500,491	-5,130,813	-83,756,146	-40,576,591	-29,938,174	-8,021,566	-3,658,731
Total - OTHER RATE BASE ITEMS	131-283	-310,404,592	-179,984,007	-3,891,682	-64,768,410	-31,005,474	-22,946,491	-4,987,304	-2,821,223
TOTAL RATE BASE		2,104,677,691	1,211,482,080	26,884,939	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. OPERATING AND MAINTENANCE EXPE									
A. PRODUCTION EXPENSES									
Operation Supervision & Engineering	500	9,802,746	5,047,833	112,783	2,251,575	1,198,616	862,166	329,774	0
PPFAC - FUEL	501	303,925,690	121,073,677	2,473,168	62,245,531	50,002,169	47,317,185	19,496,303	1,317,657
Steam Expenses	502	21,363,731	11,001,056	245,794	4,906,996	2,612,217	1,878,971	718,696	0
Electric Expenses	505	2,800,879	1,442,287	32,225	643,329	342,473	246,341	94,224	0
Miscellaneous Steam Power Expenses	506	4,495,150	2,314,736	51,718	1,032,483	549,638	395,355	151,221	0
Rents	507	14,157,699	7,290,376	162,887	3,251,856	1,731,111	1,245,190	476,278	0
Maintenance Supervision & Engineering	510	4,146,264	2,135,080	47,704	952,348	506,978	364,670	139,484	0
Maintenance of Structures	511	3,573,450	1,840,115	41,113	820,779	436,938	314,290	120,214	0
Maintenance of Boiler Plant	512	30,090,681	15,494,918	346,199	6,911,474	3,679,292	2,646,519	1,012,279	0
Maintenance of Electric Plant	513	5,140,971	2,647,296	59,148	1,180,820	628,604	452,156	172,947	0
Maintenance Miscellaneous Steam Plant	514	6,697,663	3,448,900	77,058	1,538,374	818,946	589,069	225,316	0
FAS 143 Accretion Expense	411	0	0	0	0	0	0	0	0
Loss from Disposition of Utility Plant	412	0	0	0	0	0	0	0	0
Subtotal - Other Production	500-554	406,194,926	173,736,275	3,649,796	85,735,565	62,506,983	56,311,913	22,936,737	1,317,657
Operation Supervision & Engineering	546	7,586,523	3,906,610	87,284	1,742,535	927,630	667,246	255,218	0
PPFAC - Fuel	547	0	0	0	0	0	0	0	0
Generation Exp & Misc Other Power Gener	548 & 549	1,498,181	771,474	17,237	344,114	183,188	131,767	50,400	0
Rents	550	10,337	5,323	119	2,374	1,264	909	348	0
Maintenance Supervision & Engineering	551	2,193	1,129	25	504	268	193	74	0
Maintenance Structures, Generating, Other	552-554	5,740,669	2,956,105	66,048	1,318,564	701,932	504,900	193,122	0
Other Expenses	557	645,356	332,320	7,425	148,231	78,910	56,760	21,710	0
Subtotal	556-557	15,483,258	7,972,961	178,138	3,556,321	1,893,192	1,361,775	520,871	0
TOTAL PRODUCTION EXPENSE	500-557	421,678,184	181,709,235	3,827,935	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
B. TRANSMISSION EXPENSE									
Supervision and Engineering	560	0	0	0	0	0	0	0	0
Load Dispatching	561	0	0	0	0	0	0	0	0
Station Expenses	562	0	0	0	0	0	0	0	0
Overhead Line Expenses	563	0	0	0	0	0	0	0	0
Underground Lines Expenses	564	0	0	0	0	0	0	0	0
Transmission by Others	565	95,464,952	49,405,132	840,971	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Miscellaneous Expenses	566	0	0	0	0	0	0	0	0
Rents	567	0	0	0	0	0	0	0	0
Supervision and Engineering	568	0	0	0	0	0	0	0	0
Maintenance of Structures	569	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	570	0	0	0	0	0	0	0	0
Maintenance of Overhead Lines	571	0	0	0	0	0	0	0	0
Maintenance of Underground Lines	572	0	0	0	0	0	0	0	0
Misc Maintenance - Credits	573	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION EXPENSES	560-573	95,464,952	49,405,132	840,971	21,986,984	11,268,859	8,833,333	3,059,365	70,310

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
C. DISTRIBUTION EXPENSE									
Operation Supervision & Engineering	580	719,344	460,973	9,828	142,377	53,179	43,452	27	9,508
Load Dispatching	581	701,361	375,058	6,384	166,914	85,547	67,058	0	399
Station Expenses	582	263,040	140,663	2,394	62,600	32,084	25,150	0	150
Overhead Line Expenses	583	831,367	497,683	9,710	172,380	81,126	63,379	0	7,089
Underground Line Expenses	584	247,581	164,300	3,540	43,640	18,031	14,006	0	4,064
Street Light and Signal Systems	585	219,325	0	0	0	0	0	0	219,325
Meter Expenses	586	2,764,693	2,027,990	52,058	630,416	0	53,500	728	0
Customer Installation Expenses	587	59,339	43,527	1,117	13,531	0	1,148	16	0
Misc. Distribution Expenses	588	11,306,668	7,511,624	163,457	1,984,910	782,122	614,015	92	250,448
Rents	589	834,309	554,276	12,061	146,465	57,712	45,308	7	18,480
Maint Supervision & Engineering	590	1,054,638	675,838	14,409	208,741	77,966	63,705	40	13,939
Maint of Structures	591	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	592	1,385,470	740,749	12,609	329,659	168,958	132,441	0	1,054
Maintenance of Overhead Lines	593	2,298,053	1,375,687	26,841	476,490	224,248	175,190	0	19,596
Maintenance of Underground Lines	594	132,130	87,684	1,889	23,290	9,623	7,475	0	2,169
Maintenance of Line Transformers	595	155,703	96,432	1,928	31,540	14,492	11,310	0	0
Maintenance of Street Lights	596	0	0	0	0	0	0	0	0
Maintenance of Meters	597	127,603	93,601	2,403	29,097	0	2,469	34	0
Maintenance of Misc. Plant	598	576,162	382,775	8,329	101,146	39,855	31,289	5	12,762
Regulatory Asset Amortization	407	408,531	271,409	5,906	71,718	28,260	22,186	3	9,049
Subtotal - DISTRIBUTION EXPENSES	580-599	24,085,317	15,500,269	334,867	4,634,914	1,673,202	1,373,080	951	568,033
Total - OPER. AND MAINT. EXPENSE	500-599	541,228,453	246,614,635	5,003,773	115,913,784	77,342,236	67,880,101	26,517,924	1,956,000

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. CUSTOMER ACCOUNTS AND SERVIC									
Supervision	901	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,538,844	1,358,784	34,880	138,892	2,672	3,255	362	0
Customer Records & Collection Expense	903	18,299,064	15,527,614	398,593	1,587,199	30,531	37,194	4,133	713,800
Uncollectible Accounts	904	1,723,975	876,942	17,913	604,683	224,436	0	0	0
Misc Customer Accounts Expenses	905	0	0	0	0	0	0	0	0
Subtotal - Customer Accounts Expense	901-905	21,561,883	17,763,340	451,386	2,330,775	257,639	40,448	4,494	713,800
Customer Assistance Exp Electric	(907, 908)	0	0	0	0	0	0	0	0
Supervision	909	202,797	168,941	4,337	17,269	332	405	3,747	7,766
Customer Assistance Expenses	910	109,873	93,439	2,399	9,551	184	4	0	4,295
Information, Instructional Advertising	911	0	0	0	0	0	0	0	0
Misc Customer Serv & Inform Expen	912	0	0	0	0	0	0	0	0
Rents	913	0	0	0	0	0	0	0	0
Subtotal - Customer Service & Info.	909-913	312,669	262,380	6,735	26,820	516	409	3,747	12,062
Supervision	915	0	0	0	0	0	0	0	0
Demonstrating & Selling Expenses	916	0	0	0	0	0	0	0	0
Advertising Expenses	917	0	0	0	0	0	0	0	0
Miscellaneous Sales Expenses	918	0	0	0	0	0	0	0	0
Subtotal - Sales Expense	915-919	0	0	0	0	0	0	0	0
Total - CUST ACCTS, SERVS, & SALES E)	901-919	21,874,552	18,025,721	458,121	2,357,595	258,155	40,858	8,241	725,862

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
E. ADMINISTRATIVE AND GENERAL									
LABOR RELATED EXPENSES									
Administrative & General Salaries	920	29,996,909	17,204,454	381,861	6,238,598	3,008,207	2,225,437	737,737	200,614
Office Supplies & Expenses	921	11,749,828	6,739,007	149,575	2,443,667	1,178,319	871,707	288,973	78,581
Admin Expenses Transferred-Credit	922	-9,762,376	-5,599,122	-124,275	-2,030,327	-979,009	-724,260	-240,094	-65,289
Outside Services Employed	923	11,102,007	6,367,455	141,329	2,308,937	1,113,353	823,645	273,040	74,248
Employee Pensions and Benefits	926	21,312,336	12,223,496	271,306	4,432,427	2,137,284	1,581,138	524,151	142,533
Subtotal - O & M Accounts 920-923,926	920-926	64,398,703	36,935,290	819,796	13,393,301	6,458,154	4,777,668	1,583,807	430,688
PLANT RELATED EXPENSES									
Property Insurance	924	2,403,431	1,384,596	30,555	498,788	241,643	178,289	47,770	21,789
Injuries and Damages	925	2,054,306	1,183,469	26,117	426,334	206,542	152,391	40,831	18,624
Maintenance of General Plant (also acct 93	935	26,768	15,421	340	5,555	2,691	1,986	532	243
Subtotal - O & M Accounts 924-925	924,925,935	4,484,505	2,583,486	57,012	930,677	450,877	332,665	89,134	40,655
OTHER A&G EXPENSES									
Franchise Requirements	927	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	1,326,223	760,864	16,881	275,783	133,021	98,390	32,209	9,075
Duplicate Charges-Credit	929	-375,164	-215,234	-4,775	-78,014	-37,629	-27,833	-9,111	-2,567
General Advertising Expenses	930	5,093,710	2,922,297	64,837	1,059,216	510,902	377,894	123,709	34,854
Miscellaneous General Expenses	930	107,111	61,450	1,363	22,273	10,743	7,946	2,601	733
Rents	931	687,396	394,364	8,750	142,941	68,946	50,997	16,695	4,704
Misc Expenses - Credit	932	0	0	0	0	0	0	0	0
Subtotal	927-932	6,839,276	3,923,740	87,056	1,422,199	685,984	507,395	166,103	46,799
TOTAL A&G EXPENSES	920-932	75,722,484	43,442,516	963,864	15,746,177	7,595,014	5,617,728	1,839,044	518,141
TOTAL OPERATING EXPENSES		638,825,490	308,082,872	6,425,759	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION EXPENSE									
Intangible	301-303	13,277,153	7,648,856	168,795	2,755,430	1,334,898	984,913	263,895	120,366
Production - Steam	500-511	60,024,743	30,452,455	669,780	13,630,703	7,517,151	5,585,177	2,166,051	3,426
Production - Other	546-557	12,557,762	6,466,503	144,480	2,884,369	1,535,481	1,104,474	422,455	0
Transmission	565	0	0	0	0	0	0	0	0
Land & Rights	360	86,658	46,332	789	20,619	10,568	8,284	0	66
Structures & Improvements	361	185,998	99,445	1,693	44,256	22,682	17,780	0	142
Station Equipment	362	2,445,508	1,307,504	22,256	581,884	298,230	233,774	0	1,861
Poles, Towers, & Fixtures	364	3,451,385	2,538,894	59,371	489,534	156,711	120,051	0	86,824
Overhead Conductors & Devices	365	2,779,481	1,683,369	32,964	578,304	271,265	211,892	1	1,686
Underground Conduit	366	750,665	638,390	16,387	65,255	1,255	31	0	29,347
Underground Conductors & Devices	367	4,999,675	3,317,878	71,494	881,279	364,119	282,829	0	82,076
Line Transformers	368	4,903,883	2,996,290	59,687	989,183	456,343	356,215	0	46,165
Services	369	1,916,596	1,629,936	41,840	166,609	3,205	78	0	74,928
Meters	370	2,037,023	1,494,221	38,357	464,490	0	39,419	536	0
Street Lighting & Signal Systems	373	194,790	59,508	1,057	26,492	13,651	10,574	3,713	79,796
Distribution Plant Net Salvage	403	5,407,146	3,115,011	68,742	1,122,154	543,640	401,108	107,472	49,019
General	EDST	14,684,437	8,459,581	186,686	3,047,485	1,476,388	1,089,307	291,866	133,124
TOTAL DEPRECIATION EXPENSES		129,702,903	71,954,174	1,584,377	27,748,046	14,005,587	10,445,904	3,255,991	708,823
III. TAXES									
A. GENERAL TAXES									
Payroll Taxes	408	5,290,439	3,073,455	70,133	1,084,749	518,177	379,593	124,806	39,526
PropertyTaxes - Production	408	14,193,015	7,308,562	163,294	3,259,968	1,735,429	1,248,296	477,466	0
PropertyTaxes - Transmission	408	0	0	0	0	0	0	0	0
PropertyTaxes - Distribution	408	18,111,409	12,032,377	261,831	3,179,496	1,252,830	983,551	148	401,176
PropertyTaxes - General	408	3,070,559	1,768,923	39,037	637,238	308,717	227,777	61,030	27,837
Business Activity Tax - Generation	408	0	0	0	0	0	0	0	0
Business Activity Tax - Transmission	408	69,718	36,081	614	16,057	8,230	6,451	2,234	51
Subtotal - General Taxes		40,735,140	24,219,397	534,908	8,177,508	3,823,383	2,845,668	665,685	468,590
B. FRANCHISE AND REVENUE TAXES									
Franchise Tax T&D	408.11	0	0	0	0	0	0	0	0
PSC Assessment	408.12	0	0	0	0	0	0	0	0
Franchise Tax Prod	408	0	0	0	0	0	0	0	0
Franchise	408.13	0	0	0	0	0	0	0	0
Retail Sales & Other	408.14	0	0	0	0	0	0	0	0
Subtotal - Franchise & Gross Receipts		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
TOTAL TAXES		74,090,738	43,435,277	958,964	15,099,851	7,176,988	5,320,021	1,328,658	770,980
TOTAL EXPENSES		842,619,131	423,472,323	8,969,099	176,865,453	106,377,980	89,304,612	32,949,858	4,679,806

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
IV. OPERATING REVENUES									
Revenues	440-446	927,140,267	407,674,736	3,983,681	263,174,018	111,490,378	99,967,027	36,194,919	4,655,508
Production Other Rev	440-446	0	0	0	0	0	0	0	0
Delayed Payment Charges	440-446	0	0	0	0	0	0	0	0
Reconnect Charges-Missouri	440-446	0	0	0	0	0	0	0	0
Ot Elec Rev-Off-Sys	440-446	0	0	0	0	0	0	0	0
Rent From Elec Property-Mo	440-446	0	0	0	0	0	0	0	0
Miscellaneous Service Revenues Retail	451	6,461,516	5,495,074	141,058	561,695	10,805	263	15	252,607
Scrap Sales Revenues	456	0	0	0	0	0	0	0	0
Other Electric Revenues	447.5, 456.1	25,267,361	11,110,363	108,567	7,172,283	3,038,448	2,724,402	986,420	126,877
Other Electric Revenues - Misc Transmissic	456	0	0	0	0	0	0	0	0
Other Electric - Ancillary	147.4, 449.1, 456.	0	0	0	0	0	0	0	0
Excess Fac Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	424,280,172	4,233,306	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
Gains/Losses from Energy Purchases		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
V. NET INCOME		116,218,762	784,921	-4,736,382	94,035,416	8,161,651	13,386,475	4,231,495	355,186
Rate of Return		5.52%	0.06%	-17.62%	21.43%	3.86%	8.58%	9.71%	2.12%

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
SUMMARY REPORT									
OPERATING REVENUES									
Utility Sales Revenues	440-446	933,601,783	413,169,810	4,124,739	263,735,713	111,501,183	99,967,290	36,194,933	4,908,115
Interdepartmental Revenues	448	0	0	0	0	0	0	0	0
Other Operating Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	424,280,172	4,233,306	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
OPERATING EXPENSES									
Production	500-555	421,678,184	181,709,235	3,827,935	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
Transmission	560-573	95,464,952	49,405,132	840,971	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Distribution	580-599	24,085,317	15,500,269	334,867	4,634,914	1,673,202	1,373,080	951	568,033
Customer Acctg & Service	901-919	21,874,552	18,025,721	458,121	2,357,595	258,155	40,858	8,241	725,862
Admin & General	920-932	75,722,484	43,442,516	963,864	15,746,177	7,595,014	5,617,728	1,839,044	518,141
Total Operating Expenses		638,825,490	308,082,872	6,425,759	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSES	403	129,702,903	71,954,174	1,584,377	27,748,046	14,005,587	10,445,904	3,255,991	708,823
TAXES OTHER THAN INCOME TAX	408	40,735,140	24,219,397	534,908	8,177,508	3,823,383	2,845,668	665,685	468,590
INCOME BEFORE INCOME TAXES		149,605,611	20,023,730	-4,311,738	100,964,886	11,515,256	15,861,434	4,894,468	657,575
INCOME TAXES		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
OPERATING INCOME		116,250,012	807,850	-4,735,793	94,042,544	8,161,651	13,387,080	4,231,495	355,186
Gains/Losses		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
NET INCOME		116,218,762	784,921	-4,736,382	94,035,416	8,161,651	13,386,475	4,231,495	355,186
RATE BASE		2,104,677,691	1,211,482,080	26,884,939	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714
RETURN ON RATE BASE		5.52%	0.06%	-17.62%	21.43%	3.86%	8.58%	9.71%	2.12%
Unitized Rate of Return		1.00	0.01	-3.19	3.88	0.70	1.55	1.76	0.38

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
REVENUE REQUIREMENTS									
RATE OF RETURN		5.22%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%
Using Target for System									
RATE BASE		2,104,677,691	1,211,482,080	26,884,939	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714
OPERATING EXPENSES		638,825,490	308,082,872	6,425,759	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSE		129,702,903	71,954,174	1,584,377	27,748,046	14,005,587	10,445,904	3,255,991	708,823
GENERAL TAXES		40,735,140	24,219,397	534,908	8,177,508	3,823,383	2,845,668	665,685	468,590
Other costs (benefits), net of taxes		31,250	22,929	589	7,128	0	605	0	0
Subtotal- Operating Costs to recover		809,294,783	404,279,372	8,545,633	169,950,238	103,024,375	86,830,864	32,286,886	4,377,416
Target Return on Rate Base- After taxes		116,218,763	66,897,154	1,484,567	24,226,640	11,662,896	8,616,386	2,405,716	925,404
Actual Historic FIT		33,355,599	19,215,880	424,055	6,922,343	3,353,605	2,474,353	662,973	302,390
Incremental Tax Due to Target ROR		0	0	0	0	0	0	0	0
Subtotal- Rev Req before Uncollectible Adj.		958,869,144	490,392,406	10,454,255	201,099,220	118,040,876	97,921,603	35,355,574	5,605,210
Proforma Incr for Uncollect. Calc		0	0	0	0	0	0	0	0
ECCR & Prop Tax Surcharge		0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT		958,869,144	490,392,406	10,454,255	201,099,220	118,040,876	97,921,603	35,355,574	5,605,210

Exhibit HEO – R – 3

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Intangible Plant	301-303	160,246,771	92,183,862	2,757,785	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
Subtotal - INTANGIBLE PLANT	301-303	160,246,771	92,183,862	2,757,785	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
B. PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
Land & Land Rights	310	6,057,619	3,091,635	97,374	1,391,363	740,686	532,776	203,784	0
StructuresImprovements	311	195,860,951	99,961,810	3,148,396	44,986,944	23,948,596	17,226,257	6,588,948	0
Boiler Plant Equipment	312	1,000,007,373	510,375,071	16,074,769	229,689,865	122,274,363	87,952,109	33,641,196	0
Reactor Plant Equipment	322	0	0	0	0	0	0	0	0
Turbogenerator Units	314	294,774,517	150,444,456	4,738,397	67,706,220	36,043,100	25,925,849	9,916,494	0
Accessory Electric Equipment	315	134,465,967	68,627,571	2,161,493	30,885,242	16,441,619	11,826,478	4,523,563	0
Miscellaneous Power Plant Equipment	316	25,580,106	13,055,352	411,191	5,875,448	3,127,768	2,249,808	860,539	0
Sundt/SPV/SGS1 Acquisition Adjustment	114	-31,854,390	-16,257,567	-512,048	-7,316,577	-3,894,947	-2,801,640	-1,071,612	0
Electric Plant Purchased or Sold	102	15,029	7,671	242	3,452	1,838	1,322	506	0
OTHER PRODUCTION PLANT									
Land and Land Rights	340	1,873,363	956,111	30,114	430,289	229,063	164,765	63,022	0
Structures and Improvements	341	21,065,337	10,751,144	338,618	4,838,459	2,575,732	1,852,727	708,658	0
Boiler Plant Equipment	342	17,936,074	9,154,057	288,316	4,119,704	2,193,106	1,577,504	603,387	0
Reactor Plant Equipment	343	181,875,041	92,823,802	2,923,578	41,774,546	22,238,491	15,996,175	6,118,449	0
Engines and Generators	344	244,472,493	124,771,746	3,929,810	56,152,440	29,892,498	21,501,713	8,224,286	0
Turbogenerator Units	345	12,398,839	6,328,012	199,307	2,847,867	1,516,049	1,090,496	417,109	0
Accessory Electric Equipment	346&347	13,743,196	7,014,133	220,917	3,156,650	1,680,428	1,208,734	462,334	0
Misc. Power Plant Equipment	114	-37,278,677	-19,025,967	-599,242	-8,562,471	-4,558,193	-3,278,714	-1,254,090	0
Subtotal - PRODUCTION PLANT	304-346	2,080,992,837	1,062,079,036	33,451,232	477,979,440	254,450,197	183,026,359	70,006,572	0
C. TRANSMISSION PLANT									
Land and Land Rights	350	0	0	0	0	0	0	0	0
Structures and Improvements	352	0	0	0	0	0	0	0	0
Station Equipment	353	0	0	0	0	0	0	0	0
Towers and Fixtures	354	0	0	0	0	0	0	0	0
Poles and Fixtures	355	0	0	0	0	0	0	0	0
Overhead Conductors and Devices	356	0	0	0	0	0	0	0	0
Underground Conduit	357	0	0	0	0	0	0	0	0
Underground Conductors and Devices	358	0	0	0	0	0	0	0	0
Roads and Trails	359	0	0	0	0	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	0	0	0	0	0	0	0	0

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. DISTRIBUTION PLANT									
Land and Land Rights	360	11,605,107	6,118,638	191,710	2,761,319	1,415,243	1,109,368	0	8,830
Structures and Improvements	361	11,835,474	6,240,096	195,515	2,816,132	1,443,336	1,131,389	0	9,005
Station Equipment	362	161,677,439	85,242,279	2,670,817	38,469,527	19,716,560	15,455,241	0	123,017
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	233,534,842	171,162,072	4,647,211	33,123,849	10,603,690	8,123,174	0	5,874,847
Overhead Conductors and Devices	365	183,006,168	108,470,730	3,220,077	37,945,458	17,858,051	13,951,321	0	1,560,531
Underground Conduit	366	61,247,158	52,086,600	1,337,060	5,324,180	102,415	2,495	0	2,394,407
Underground Conductors and Devices	367	304,496,075	200,732,959	5,690,572	53,672,692	22,175,997	17,225,188	0	4,998,668
Line Transformers	368	281,381,714	172,683,460	5,070,991	56,998,305	26,189,309	20,439,489	160	0
Services	369	134,848,680	114,679,759	2,943,823	11,722,318	225,488	5,494	0	5,271,798
Meters	370	46,154,903	33,856,083	869,084	10,524,428	0	893,157	12,152	0
Installed on Cust Premise PR_L	371	0	0	0	0	0	0	0	0
Other Property on Customers Premise	372	0	0	0	0	0	0	0	0
Street Lighting and Signals	373	11,995,791	0	0	0	0	0	0	11,995,791
Subtotal - DISTRIBUTION PLANT	374-387	1,441,783,351	951,272,677	26,836,858	253,358,208	99,730,087	78,336,315	12,311	32,236,894
E. GENERAL PLANT									
General Plant	389-399	314,077,737	179,554,093	5,376,373	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
Subtotal - GENERAL PLANT	389-399	314,077,737	179,554,093	5,376,373	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
TOTAL PLANT IN SERVICE	101	3,997,100,696	2,285,089,668	68,422,248	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252
ADDITIONS TO UTILITY PLANT									
Energy Conservation Programs	182.3	0	0	0	0	0	0	0	0
Property Held for Future Use	105	0	0	0	0	0	0	0	0
Construction Work in Progress	107	0	0	0	0	0	0	0	0
Nuclear Plant Costs - Calvert Cliffs	182.3	0	0	0	0	0	0	0	0
Total Additions to Utility Plant		0	0	0	0	0	0	0	0
TOTAL UTILITY PLANT		3,997,100,696	2,285,089,668	68,422,248	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION RESERVE									
Intangible	301-303	-119,977,698	-68,589,665	-2,053,775	-24,899,170	-12,062,678	-8,900,072	-2,384,665	-1,087,674
Production	304-359	-796,297,495	-406,407,394	-12,800,204	-182,900,116	-97,366,051	-70,035,528	-26,788,203	0
Transmission	350-359	0	0	0	0	0	0	0	0
Land and Land Rights	360	-3,862,742	-2,036,579	-63,810	-919,101	-471,061	-369,251	0	-2,939
Structures and Improvements	361	-3,279,743	-1,729,201	-54,179	-780,382	-399,965	-313,521	0	-2,495
Station Equipment	362	-54,387,561	-28,675,118	-898,451	-12,940,975	-6,632,562	-5,199,073	0	-41,382
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	-87,160,606	-63,881,645	-1,734,446	-12,362,587	-3,957,542	-3,031,756	0	-2,192,629
Overhead Conductors and Devices	365	-71,943,372	-43,146,290	-1,278,821	-14,968,663	-7,021,347	-5,484,567	-34	-43,650
Underground Conduit	366	-27,348,184	-23,257,796	-597,026	-2,377,362	-45,730	-1,114	0	-1,069,155
Underground Conductors and Devices	367	-141,085,166	-93,007,579	-2,636,669	-24,868,697	-10,275,023	-7,981,116	0	-2,316,082
Line Transformers	368	-135,774,711	-82,193,549	-2,417,861	-27,387,686	-12,634,865	-9,862,583	0	-1,278,167
Services	369	-52,591,903	-44,725,886	-1,148,111	-4,571,784	-87,942	-2,143	0	-2,056,037
Meters	370	4,020,491	2,949,157	75,705	916,769	0	77,802	1,059	0
Street Lighting and Signals	373	-5,781,491	0	0	0	0	0	0	-5,781,491
General	389-398	-86,548,234	-49,478,482	-1,481,530	-17,961,498	-8,701,646	-6,420,239	-1,720,224	-784,615
Subtotal-DEPRECIATION RESERVE		-1,582,018,414	-904,180,028	-27,089,179	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
Dep. Res.- adjust for 13 month avg.	108.9	0	0	0	0	0	0	0	0
TOTAL RESERVE FOR DEPRECIATION	108	-1,582,018,414	-904,180,028	-27,089,179	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
III. OTHER RATE BASE ITEMS									
Cash Working Capital	n/a	-10,528,676	-6,019,105	-180,230	-2,185,033	-1,058,564	-781,028	-209,267	-95,449
Fuel Inventory	151, 152	25,107,584	12,814,190	403,596	5,766,915	3,069,991	2,208,249	844,643	0
Materials & Supplies	154, 163	77,125,097	44,091,399	1,320,225	16,005,899	7,754,235	5,721,221	1,532,931	699,188
Prepayments	165	9,439,165	4,508,403	138,588	1,980,313	1,258,866	1,086,594	419,119	47,283
Customer Advances for Construction	252	-11,046,099	-5,825,028	-182,510	-2,628,814	-1,347,330	-1,056,133	0	-6,284
Customer Deposits	235	-19,400,461	-10,230,600	-320,546	-4,617,032	-2,366,340	-1,854,906	0	-11,036
Deferred Credits - Asset Retirement - tax cr	230&253	-2,630,793	-1,503,990	-45,034	-545,973	-264,503	-195,155	-52,289	-23,850
Plant Held for Future Use - Transmission Pl	105	0	0	0	0	0	0	0	0
Regulatory Assets	182	0	0	0	0	0	0	0	0
Regulatory Liabilities	254	25,112,104	14,356,258	429,868	5,211,556	2,524,796	1,862,842	499,126	227,657
ADIT	190	0	0	0	0	0	0	0	0
ADIT - Other Property	283	-403,582,512	-230,722,791	-6,908,513	-83,756,146	-40,576,591	-29,938,174	-8,021,566	-3,658,731
Total - OTHER RATE BASE ITEMS	131-283	-310,404,592	-178,531,264	-5,344,556	-64,768,315	-31,005,439	-22,946,491	-4,987,304	-2,821,223
TOTAL RATE BASE		2,104,677,691	1,202,378,376	35,988,513	438,735,350	211,210,661	156,039,474	43,566,603	16,758,714

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. OPERATING AND MAINTENANCE EXPE									
A. PRODUCTION EXPENSES									
Operation Supervision & Engineering	500	9,802,746	5,003,040	157,576	2,251,575	1,198,616	862,166	329,774	0
PPFAC - FUEL	501	303,925,690	119,781,285	3,765,561	62,245,531	50,002,169	47,317,185	19,496,303	1,317,657
Steam Expenses	502	21,363,731	10,903,435	343,415	4,906,996	2,612,217	1,878,971	718,696	0
Electric Expenses	505	2,800,879	1,429,488	45,023	643,329	342,473	246,341	94,224	0
Miscellaneous Steam Power Expenses	506	4,495,150	2,294,196	72,258	1,032,483	549,638	395,355	151,221	0
Rents	507	14,157,699	7,225,683	227,580	3,251,856	1,731,111	1,245,190	476,278	0
Maintenance Supervision & Engineering	510	4,146,264	2,116,134	66,650	952,348	506,978	364,670	139,484	0
Maintenance of Structures	511	3,573,450	1,823,787	57,442	820,779	436,938	314,290	120,214	0
Maintenance of Boiler Plant	512	30,090,681	15,357,420	483,697	6,911,474	3,679,292	2,646,519	1,012,279	0
Maintenance of Electric Plant	513	5,140,971	2,623,804	82,639	1,180,820	628,604	452,156	172,947	0
Maintenance Miscellaneous Steam Plant	514	6,697,663	3,418,295	107,663	1,538,374	818,946	589,069	225,316	0
FAS 143 Accretion Expense	411	0	0	0	0	0	0	0	0
Loss from Disposition of Utility Plant	412	0	0	0	0	0	0	0	0
Subtotal - Other Production	500-554	406,194,926	171,976,568	5,409,503	85,735,565	62,506,983	56,311,913	22,936,737	1,317,657
Operation Supervision & Engineering	546	7,586,523	3,871,944	121,951	1,742,535	927,630	667,246	255,218	0
PPFAC - Fuel	547	0	0	0	0	0	0	0	0
Generation Exp & Misc Other Power Gener	548 & 549	1,498,181	764,629	24,083	344,114	183,188	131,767	50,400	0
Rents	550	10,337	5,276	166	2,374	1,264	909	348	0
Maintenance Supervision & Engineering	551	2,193	1,119	35	504	268	193	74	0
Maintenance Structures, Generating, Other	552-554	5,740,669	2,929,873	92,279	1,318,564	701,932	504,900	193,122	0
Other Expenses	557	645,356	329,371	10,374	148,231	78,910	56,760	21,710	0
Subtotal	556-557	15,483,258	7,902,211	248,888	3,556,321	1,893,192	1,361,775	520,871	0
TOTAL PRODUCTION EXPENSE	500-557	421,678,184	179,878,779	5,658,391	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
B. TRANSMISSION EXPENSE									
Supervision and Engineering	560	0	0	0	0	0	0	0	0
Load Dispatching	561	0	0	0	0	0	0	0	0
Station Expenses	562	0	0	0	0	0	0	0	0
Overhead Line Expenses	563	0	0	0	0	0	0	0	0
Underground Lines Expenses	564	0	0	0	0	0	0	0	0
Transmission by Others	565	95,464,952	48,719,616	1,526,486	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Miscellaneous Expenses	566	0	0	0	0	0	0	0	0
Rents	567	0	0	0	0	0	0	0	0
Supervision and Engineering	568	0	0	0	0	0	0	0	0
Maintenance of Structures	569	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	570	0	0	0	0	0	0	0	0
Maintenance of Overhead Lines	571	0	0	0	0	0	0	0	0
Maintenance of Underground Lines	572	0	0	0	0	0	0	0	0
Misc Maintenance - Credits	573	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION EXPENSES	560-573	95,464,952	48,719,616	1,526,486	21,986,984	11,268,859	8,833,333	3,059,365	70,310

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
C. DISTRIBUTION EXPENSE									
Operation Supervision & Engineering	580	719,344	457,756	13,045	142,377	53,179	43,452	27	9,508
Load Dispatching	581	701,361	369,854	11,588	166,914	85,547	67,058	0	399
Station Expenses	582	263,040	138,711	4,346	62,600	32,084	25,150	0	150
Overhead Line Expenses	583	831,367	492,765	14,628	172,380	81,126	63,379	0	7,089
Underground Line Expenses	584	247,581	163,213	4,627	43,640	18,031	14,006	0	4,064
Street Light and Signal Systems	585	219,325	0	0	0	0	0	0	219,325
Meter Expenses	586	2,764,693	2,027,990	52,058	630,416	0	53,500	728	0
Customer Installation Expenses	587	59,339	43,527	1,117	13,531	0	1,148	16	0
Misc. Distribution Expenses	588	11,306,668	7,464,507	210,574	1,984,910	782,122	614,015	92	250,448
Rents	589	834,309	550,799	15,538	146,465	57,712	45,308	7	18,480
Maint Supervision & Engineering	590	1,054,638	671,122	19,125	208,741	77,966	63,705	40	13,939
Maint of Structures	591	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	592	1,385,470	730,470	22,887	329,659	168,958	132,441	0	1,054
Maintenance of Overhead Lines	593	2,298,053	1,362,093	40,435	476,490	224,248	175,190	0	19,596
Maintenance of Underground Lines	594	132,130	87,104	2,469	23,290	9,623	7,475	0	2,169
Maintenance of Line Transformers	595	155,703	95,555	2,806	31,540	14,492	11,310	0	0
Maintenance of Street Lights	596	0	0	0	0	0	0	0	0
Maintenance of Meters	597	127,603	93,601	2,403	29,097	0	2,469	34	0
Maintenance of Misc. Plant	598	576,162	380,374	10,730	101,146	39,855	31,289	5	12,762
Regulatory Asset Amortization	407	408,531	269,707	7,608	71,718	28,260	22,186	3	9,049
Subtotal - DISTRIBUTION EXPENSES	580-599	24,085,317	15,399,149	435,987	4,634,914	1,673,202	1,373,080	951	568,033
Total - OPER. AND MAINT. EXPENSE	500-599	541,228,453	243,997,544	7,620,864	115,913,784	77,342,236	67,880,101	26,517,924	1,956,000

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. CUSTOMER ACCOUNTS AND SERVIC									
Supervision	901	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,538,844	1,358,784	34,880	138,892	2,672	3,255	362	0
Customer Records & Collection Expense	903	18,299,064	15,527,614	398,593	1,587,199	30,531	37,194	4,133	713,800
Uncollectible Accounts	904	1,723,975	859,046	27,006	611,104	226,819	0	0	0
Misc Customer Accounts Expenses	905	0	0	0	0	0	0	0	0
Subtotal - Customer Accounts Expense	901-905	21,561,883	17,745,444	460,479	2,337,195	260,022	40,448	4,494	713,800
Customer Assistance Exp Electric	(907, 908)	0	0	0	0	0	0	0	0
Supervision	909	202,797	168,941	4,337	17,269	332	405	3,747	7,766
Customer Assistance Expenses	910	109,873	93,439	2,399	9,551	184	4	0	4,295
Information, Instructional Advertising	911	0	0	0	0	0	0	0	0
Misc Customer Serv & Inform Expen	912	0	0	0	0	0	0	0	0
Rents	913	0	0	0	0	0	0	0	0
Subtotal - Customer Service & Info.	909-913	312,669	262,380	6,735	26,820	516	409	3,747	12,062
Supervision	915	0	0	0	0	0	0	0	0
Demonstrating & Selling Expenses	916	0	0	0	0	0	0	0	0
Advertising Expenses	917	0	0	0	0	0	0	0	0
Miscellaneous Sales Expenses	918	0	0	0	0	0	0	0	0
Subtotal - Sales Expense	915-919	0	0	0	0	0	0	0	0
Total - CUST ACCTS, SERVS, & SALES E:	901-919	21,874,552	18,007,824	467,214	2,364,015	260,538	40,858	8,241	725,862

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
E. ADMINISTRATIVE AND GENERAL									
LABOR RELATED EXPENSES									
Administrative & General Salaries	920	29,996,909	17,074,919	511,395	6,238,598	3,008,207	2,225,437	737,737	200,614
Office Supplies & Expenses	921	11,749,828	6,688,268	200,314	2,443,667	1,178,319	871,707	288,973	78,581
Admin Expenses Transferred-Credit	922	-9,762,376	-5,556,966	-166,432	-2,030,327	-979,009	-724,260	-240,094	-65,289
Outside Services Employed	923	11,102,007	6,319,514	189,270	2,308,937	1,113,353	823,645	273,040	74,248
Employee Pensions and Benefits	926	21,312,336	12,131,464	363,338	4,432,427	2,137,284	1,581,138	524,151	142,533
Subtotal - O & M Accounts 920-923,926	920-926	64,398,703	36,657,200	1,097,886	13,393,301	6,458,154	4,777,668	1,583,807	430,688
PLANT RELATED EXPENSES									
Property Insurance	924	2,403,431	1,374,010	41,142	498,788	241,643	178,289	47,770	21,789
Injuries and Damages	925	2,054,306	1,174,420	35,166	426,334	206,542	152,391	40,831	18,624
Maintenance of General Plant (also acct 93	935	26,768	15,303	458	5,555	2,691	1,986	532	243
Subtotal - O & M Accounts 924-925	924,925,935	4,484,505	2,563,732	76,766	930,677	450,877	332,665	89,134	40,655
OTHER A&G EXPENSES									
Franchise Requirements	927	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	1,326,223	755,129	22,616	275,783	133,021	98,390	32,209	9,075
Duplicate Charges-Credit	929	-375,164	-213,612	-6,398	-78,014	-37,629	-27,833	-9,111	-2,567
General Advertising Expenses	930	5,093,710	2,900,272	86,862	1,059,216	510,902	377,894	123,709	34,854
Miscellaneous General Expenses	930	107,111	60,987	1,827	22,273	10,743	7,946	2,601	733
Rents	931	687,396	391,392	11,722	142,941	68,946	50,997	16,695	4,704
Misc Expenses - Credit	932	0	0	0	0	0	0	0	0
Subtotal	927-932	6,839,276	3,894,168	116,629	1,422,199	685,984	507,395	166,103	46,799
TOTAL A&G EXPENSES	920-932	75,722,484	43,115,100	1,291,280	15,746,177	7,595,014	5,617,728	1,839,044	518,141
TOTAL OPERATING EXPENSES		638,825,490	305,120,469	9,379,358	134,023,977	85,197,788	73,538,686	28,365,210	3,200,003

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION EXPENSE									
Intangible	301-303	13,277,153	7,590,373	227,278	2,755,430	1,334,898	984,913	263,895	120,366
Production - Steam	500-511	60,024,743	30,172,417	949,818	13,630,703	7,517,151	5,585,177	2,166,051	3,426
Production - Other	546-557	12,557,762	6,409,121	201,862	2,884,369	1,535,481	1,104,474	422,455	0
Transmission	565	0	0	0	0	0	0	0	0
Land & Rights	360	86,658	45,689	1,432	20,619	10,568	8,284	0	66
Structures & Improvements	361	185,998	98,065	3,073	44,256	22,682	17,780	0	142
Station Equipment	362	2,445,508	1,289,362	40,398	581,884	298,230	233,774	0	1,861
Poles, Towers, & Fixtures	364	3,451,385	2,529,585	68,681	489,534	156,711	120,051	0	86,824
Overhead Conductors & Devices	365	2,779,481	1,666,926	49,406	578,304	271,265	211,892	1	1,686
Underground Conduit	366	750,665	638,390	16,387	65,255	1,255	31	0	29,347
Underground Conductors & Devices	367	4,999,675	3,295,936	93,436	881,279	364,119	282,829	0	82,076
Line Transformers	368	4,903,883	2,968,650	87,328	989,183	456,343	356,215	0	46,165
Services	369	1,916,596	1,629,936	41,840	166,609	3,205	78	0	74,928
Meters	370	2,037,023	1,494,221	38,357	464,490	0	39,419	536	0
Street Lighting & Signal Systems	373	194,790	58,724	1,841	26,492	13,651	10,574	3,713	79,796
Distribution Plant Net Salvage	403	5,407,146	3,091,194	92,559	1,122,154	543,640	401,108	107,472	49,019
General	EDST	14,684,437	8,394,899	251,368	3,047,485	1,476,388	1,089,307	291,866	133,124
TOTAL DEPRECIATION EXPENSES		129,702,903	71,373,488	2,165,064	27,748,046	14,005,587	10,445,904	3,255,991	708,823
III. TAXES									
A. GENERAL TAXES									
Payroll Taxes	408	5,290,439	3,052,653	90,935	1,084,749	518,177	379,593	124,806	39,526
PropertyTaxes - Production	408	14,193,015	7,243,707	228,148	3,259,968	1,735,429	1,248,296	477,466	0
PropertyTaxes - Transmission	408	0	0	0	0	0	0	0	0
PropertyTaxes - Distribution	408	18,111,409	11,956,904	337,304	3,179,496	1,252,830	983,551	148	401,176
PropertyTaxes - General	408	3,070,559	1,755,398	52,562	637,238	308,717	227,777	61,030	27,837
Business Activity Tax - Generation	408	0	0	0	0	0	0	0	0
Business Activity Tax - Transmission	408	69,718	35,580	1,115	16,057	8,230	6,451	2,234	51
Subtotal - General Taxes		40,735,140	24,044,242	710,063	8,177,508	3,823,383	2,845,668	665,685	468,590
B. FRANCHISE AND REVENUE TAXES									
Franchise Tax T&D	408.11	0	0	0	0	0	0	0	0
PSC Assessment	408.12	0	0	0	0	0	0	0	0
Franchise Tax Prod	408	0	0	0	0	0	0	0	0
Franchise	408.13	0	0	0	0	0	0	0	0
Retail Sales & Other	408.14	0	0	0	0	0	0	0	0
Subtotal - Franchise & Gross Receipts		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
TOTAL TAXES		74,090,738	43,113,197	1,281,043	15,099,851	7,176,988	5,320,021	1,328,658	770,980
TOTAL EXPENSES		842,619,131	419,607,154	12,825,465	176,871,873	106,380,363	89,304,612	32,949,858	4,679,806

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
IV. OPERATING REVENUES									
Revenues	440-446	927,140,267	399,453,333	12,205,084	263,174,018	111,490,378	99,967,027	36,194,919	4,655,508
Production Other Rev	440-446	0	0	0	0	0	0	0	0
Delayed Payment Charges	440-446	0	0	0	0	0	0	0	0
Reconnect Charges-Missouri	440-446	0	0	0	0	0	0	0	0
Ot Elec Rev-Off-Sys	440-446	0	0	0	0	0	0	0	0
Rent From Elec Property-Mo	440-446	0	0	0	0	0	0	0	0
Miscellaneous Service Revenues Retail	451	6,461,516	5,495,074	141,058	561,695	10,805	263	15	252,607
Scrap Sales Revenues	456	0	0	0	0	0	0	0	0
Other Electric Revenues	447.5, 456.1	25,267,361	10,886,305	332,625	7,172,283	3,038,448	2,724,402	986,420	126,877
Other Electric Revenues - Misc Transmissic	456	0	0	0	0	0	0	0	0
Other Electric - Ancillary	147.4, 449.1, 456.	0	0	0	0	0	0	0	0
Excess Fac Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	415,834,712	12,678,767	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
Gains/Losses from Energy Purchases		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
V. NET INCOME		116,218,762	-3,795,371	-147,286	94,028,996	8,159,268	13,386,475	4,231,495	355,186
Rate of Return		5.52%	-0.32%	-0.41%	21.43%	3.86%	8.58%	9.71%	2.12%

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
SUMMARY REPORT									
OPERATING REVENUES									
Utility Sales Revenues	440-446	933,601,783	404,948,407	12,346,142	263,735,713	111,501,183	99,967,290	36,194,933	4,908,115
Interdepartmental Revenues	448	0	0	0	0	0	0	0	0
Other Operating Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	415,834,712	12,678,767	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
OPERATING EXPENSES									
Production	500-555	421,678,184	179,878,779	5,658,391	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
Transmission	560-573	95,464,952	48,719,616	1,526,486	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Distribution	580-599	24,085,317	15,399,149	435,987	4,634,914	1,673,202	1,373,080	951	568,033
Customer Acctg & Service	901-919	21,874,552	18,007,824	467,214	2,364,015	260,538	40,858	8,241	725,862
Admin & General	920-932	75,722,484	43,115,100	1,291,280	15,746,177	7,595,014	5,617,728	1,839,044	518,141
Total Operating Expenses		638,825,490	305,120,469	9,379,358	134,023,977	85,197,788	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSES	403	129,702,903	71,373,488	2,165,064	27,748,046	14,005,587	10,445,904	3,255,991	708,823
TAXES OTHER THAN INCOME TAX	408	40,735,140	24,044,242	710,063	8,177,508	3,823,383	2,845,668	665,685	468,590
INCOME BEFORE INCOME TAXES		149,605,611	15,296,513	424,282	100,958,466	11,512,873	15,861,434	4,894,468	657,575
INCOME TAXES		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
OPERATING INCOME		116,250,012	-3,772,442	-146,698	94,036,123	8,159,268	13,387,080	4,231,495	355,186
Gains/Losses		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
NET INCOME		116,218,762	-3,795,371	-147,286	94,028,996	8,159,268	13,386,475	4,231,495	355,186
RATE BASE		2,104,677,691	1,202,378,376	35,988,513	438,735,350	211,210,661	156,039,474	43,566,603	16,758,714
RETURN ON RATE BASE		5.52%	-0.32%	-0.41%	21.43%	3.86%	8.58%	9.71%	2.12%
Unitized Rate of Return		1.00	-0.06	-0.07	3.88	0.70	1.55	1.76	0.38

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
REVENUE REQUIREMENTS									
RATE OF RETURN		5.22%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%
Using Target for System									
RATE BASE		2,104,677,691	1,202,378,376	35,988,513	438,735,350	211,210,661	156,039,474	43,566,603	16,758,714
OPERATING EXPENSES		638,825,490	305,120,469	9,379,358	134,023,977	85,197,788	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSE		129,702,903	71,373,488	2,165,064	27,748,046	14,005,587	10,445,904	3,255,991	708,823
GENERAL TAXES		40,735,140	24,044,242	710,063	8,177,508	3,823,383	2,845,668	665,685	468,590
Other costs (benefits), net of taxes		31,250	22,929	589	7,128	0	605	0	0
Subtotal- Operating Costs to recover		809,294,783	400,561,128	12,255,073	169,956,658	103,026,758	86,830,864	32,286,886	4,377,416
Target Return on Rate Base- After taxes		116,218,763	66,394,454	1,987,259	24,226,645	11,662,898	8,616,386	2,405,716	925,404
Actual Historic FIT		33,355,599	19,068,955	570,980	6,922,343	3,353,605	2,474,353	662,973	302,390
Incremental Tax Due to Target ROR		0	0	0	0	0	0	0	0
Subtotal- Rev Req before Uncollectible Adj.		958,869,144	486,024,537	14,813,313	201,105,646	118,043,261	97,921,603	35,355,574	5,605,210
Proforma Incr for Uncollect. Calc		0	0	0	0	0	0	0	0
ECCR & Prop Tax Surcharge		0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT		958,869,144	486,024,537	14,813,313	201,105,646	118,043,261	97,921,603	35,355,574	5,605,210

Exhibit HEO – R – 4

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. ELECTRIC PLANT IN SERVICE									
A. INTANGIBLE PLANT									
Intangible Plant	301-303	160,246,771	92,491,760	2,449,886	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
Subtotal - INTANGIBLE PLANT	301-303	160,246,771	92,491,760	2,449,886	33,006,195	16,114,538	11,847,834	3,184,513	1,152,044
B. PRODUCTION PLANT									
STEAM PRODUCTION PLANT									
Land & Land Rights	310	6,057,619	3,120,260	68,749	1,391,363	740,686	532,776	203,784	0
StructuresImprovements	311	195,860,951	100,887,356	2,222,850	44,986,944	23,948,596	17,226,257	6,588,948	0
Boiler Plant Equipment	312	1,000,007,373	515,100,632	11,349,208	229,689,865	122,274,363	87,952,109	33,641,196	0
Reactor Plant Equipment	322	0	0	0	0	0	0	0	0
Turbogenerator Units	314	294,774,517	151,837,420	3,345,433	67,706,220	36,043,100	25,925,849	9,916,494	0
Accessory Electric Equipment	315	134,465,967	69,262,994	1,526,071	30,885,242	16,441,619	11,826,478	4,523,563	0
Miscellaneous Power Plant Equipment	316	25,580,106	13,176,232	290,312	5,875,448	3,127,768	2,249,808	860,539	0
Sundt/SPV/SGS1 Acquisition Adjustment	114	-31,854,390	-16,408,096	-361,519	-7,316,577	-3,894,947	-2,801,640	-1,071,612	0
Electric Plant Purchased or Sold	102	15,029	7,742	171	3,452	1,838	1,322	506	0
OTHER PRODUCTION PLANT									
Land and Land Rights	340	1,873,363	964,963	21,261	430,289	229,063	164,765	63,022	0
Structures and Improvements	341	21,065,337	10,850,688	239,073	4,838,459	2,575,732	1,852,727	708,658	0
Boiler Plant Equipment	342	17,936,074	9,238,815	203,559	4,119,704	2,193,106	1,577,504	603,387	0
Reactor Plant Equipment	343	181,875,041	93,683,258	2,064,122	41,774,546	22,238,491	15,996,175	6,118,449	0
Engines and Generators	344	244,472,493	125,927,007	2,774,549	56,152,440	29,892,498	21,501,713	8,224,286	0
Turbogenerator Units	345	12,398,839	6,386,603	140,716	2,847,867	1,516,049	1,090,496	417,109	0
Accessory Electric Equipment	346&347	13,743,196	7,079,077	155,973	3,156,650	1,680,428	1,208,734	462,334	0
Misc. Power Plant Equipment	114	-37,278,677	-19,202,128	-423,080	-8,562,471	-4,558,193	-3,278,714	-1,254,090	0
Subtotal - PRODUCTION PLANT	304-346	2,080,992,837	1,071,912,822	23,617,446	477,979,440	254,450,197	183,026,359	70,006,572	0
C. TRANSMISSION PLANT									
Land and Land Rights	350	0	0	0	0	0	0	0	0
Structures and Improvements	352	0	0	0	0	0	0	0	0
Station Equipment	353	0	0	0	0	0	0	0	0
Towers and Fixtures	354	0	0	0	0	0	0	0	0
Poles and Fixtures	355	0	0	0	0	0	0	0	0
Overhead Conductors and Devices	356	0	0	0	0	0	0	0	0
Underground Conduit	357	0	0	0	0	0	0	0	0
Underground Conductors and Devices	358	0	0	0	0	0	0	0	0
Roads and Trails	359	0	0	0	0	0	0	0	0
Subtotal - TRANSMISSION PLANT	350-359	0	0	0	0	0	0	0	0

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. DISTRIBUTION PLANT									
Land and Land Rights	360	11,605,107	6,074,709	235,639	2,761,319	1,415,243	1,109,368	0	8,830
Structures and Improvements	361	11,835,474	6,195,294	240,317	2,816,132	1,443,336	1,131,389	0	9,005
Station Equipment	362	161,677,439	84,630,268	3,282,827	38,469,527	19,716,560	15,455,241	0	123,017
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	233,534,842	170,840,643	4,968,640	33,123,849	10,603,690	8,123,174	0	5,874,847
Overhead Conductors and Devices	365	183,006,168	107,918,333	3,772,474	37,945,458	17,858,051	13,951,321	0	1,560,531
Underground Conduit	366	61,247,158	52,086,600	1,337,060	5,324,180	102,415	2,495	0	2,394,407
Underground Conductors and Devices	367	304,496,075	200,051,062	6,372,470	53,672,692	22,175,997	17,225,188	0	4,998,668
Line Transformers	368	281,381,714	171,874,192	5,880,258	56,998,305	26,189,309	20,439,489	160	0
Services	369	134,848,680	114,679,759	2,943,823	11,722,318	225,488	5,494	0	5,271,798
Meters	370	46,154,903	33,856,083	869,084	10,524,428	0	893,157	12,152	0
Installed on Cust Premise PR_L	371	0	0	0	0	0	0	0	0
Other Property on Customers Premise	372	0	0	0	0	0	0	0	0
Street Lighting and Signals	373	11,995,791	0	0	0	0	0	0	11,995,791
Subtotal - DISTRIBUTION PLANT	374-387	1,441,783,351	948,206,943	29,902,592	253,358,208	99,730,087	78,336,315	12,311	32,236,894
E. GENERAL PLANT									
General Plant	389-399	314,077,737	180,157,510	4,772,956	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
Subtotal - GENERAL PLANT	389-399	314,077,737	180,157,510	4,772,956	65,181,072	31,577,691	23,298,616	6,242,578	2,847,314
TOTAL PLANT IN SERVICE	101	3,997,100,696	2,292,769,036	60,742,880	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252
ADDITIONS TO UTILITY PLANT									
Energy Conservation Programs	182.3	0	0	0	0	0	0	0	0
Property Held for Future Use	105	0	0	0	0	0	0	0	0
Construction Work in Progress	107	0	0	0	0	0	0	0	0
Nuclear Plant Costs - Calvert Cliffs	182.3	0	0	0	0	0	0	0	0
Total Additions to Utility Plant		0	0	0	0	0	0	0	0
TOTAL UTILITY PLANT		3,997,100,696	2,292,769,036	60,742,880	829,524,916	401,872,513	296,509,125	79,445,974	36,236,252

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION RESERVE									
Intangible	301-303	-119,977,698	-68,820,170	-1,823,269	-24,899,170	-12,062,678	-8,900,072	-2,384,665	-1,087,674
Production	304-359	-796,297,495	-410,170,319	-9,037,279	-182,900,116	-97,366,051	-70,035,528	-26,788,203	0
Transmission	350-359	0	0	0	0	0	0	0	0
Land and Land Rights	360	-3,862,742	-2,021,957	-78,432	-919,101	-471,061	-369,251	0	-2,939
Structures and Improvements	361	-3,279,743	-1,716,786	-66,595	-780,382	-399,965	-313,521	0	-2,495
Station Equipment	362	-54,387,561	-28,469,240	-1,104,328	-12,940,975	-6,632,562	-5,199,073	0	-41,382
Compressor Station Equipment	363	0	0	0	0	0	0	0	0
Poles, Towers and Fixtures	364	-87,160,606	-63,761,680	-1,854,411	-12,362,587	-3,957,542	-3,031,756	0	-2,192,629
Overhead Conductors and Devices	365	-71,943,372	-42,929,132	-1,495,980	-14,968,663	-7,021,347	-5,484,567	-34	-43,650
Underground Conduit	366	-27,348,184	-23,257,796	-597,026	-2,377,362	-45,730	-1,114	0	-1,069,155
Underground Conductors and Devices	367	-141,085,166	-92,691,629	-2,952,619	-24,868,697	-10,275,023	-7,981,116	0	-2,316,082
Line Transformers	368	-135,774,711	-81,803,054	-2,808,356	-27,387,686	-12,634,865	-9,862,583	0	-1,278,167
Services	369	-52,591,903	-44,725,886	-1,148,111	-4,571,784	-87,942	-2,143	0	-2,056,037
Meters	370	4,020,491	2,949,157	75,705	916,769	0	77,802	1,059	0
Street Lighting and Signals	373	-5,781,491	0	0	0	0	0	0	-5,781,491
General	389-398	-86,548,234	-49,644,762	-1,315,251	-17,961,498	-8,701,646	-6,420,239	-1,720,224	-784,615
Subtotal-DEPRECIATION RESERVE		-1,582,018,414	-907,063,255	-24,205,953	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
Dep. Res.- adjust for 13 month avg.	108.9	0	0	0	0	0	0	0	0
TOTAL RESERVE FOR DEPRECIATION	108	-1,582,018,414	-907,063,255	-24,205,953	-326,021,251	-159,656,413	-117,523,160	-30,892,067	-16,656,315
III. OTHER RATE BASE ITEMS									
Cash Working Capital	n/a	-10,528,676	-6,039,333	-160,001	-2,185,033	-1,058,564	-781,028	-209,267	-95,449
Fuel Inventory	151, 152	25,107,584	12,932,837	284,949	5,766,915	3,069,991	2,208,249	844,643	0
Materials & Supplies	154, 163	77,125,097	44,239,574	1,172,050	16,005,899	7,754,235	5,721,221	1,532,931	699,188
Prepayments	165	9,439,165	4,549,218	97,902	1,980,218	1,258,831	1,086,594	419,119	47,283
Customer Advances for Construction	252	-11,046,099	-5,783,206	-224,332	-2,628,814	-1,347,330	-1,056,133	0	-6,284
Customer Deposits	235	-19,400,461	-10,157,148	-393,998	-4,617,032	-2,366,340	-1,854,906	0	-11,036
Deferred Credits - Asset Retirement - tax cr	230&253	-2,630,793	-1,509,044	-39,979	-545,973	-264,503	-195,155	-52,289	-23,850
Plant Held for Future Use - Transmission Pl	105	0	0	0	0	0	0	0	0
Regulatory Assets	182	0	0	0	0	0	0	0	0
Regulatory Liabilities	254	25,112,104	14,404,504	381,622	5,211,556	2,524,796	1,862,842	499,126	227,657
ADIT	190	0	0	0	0	0	0	0	0
ADIT - Other Property	283	-403,582,512	-231,498,168	-6,133,137	-83,756,146	-40,576,591	-29,938,174	-8,021,566	-3,658,731
Total - OTHER RATE BASE ITEMS	131-283	-310,404,592	-178,860,765	-5,014,925	-64,768,410	-31,005,474	-22,946,491	-4,987,304	-2,821,223
TOTAL RATE BASE		2,104,677,691	1,206,845,016	31,522,003	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
I. OPERATING AND MAINTENANCE EXPI									
A. PRODUCTION EXPENSES									
Operation Supervision & Engineering	500	9,802,746	5,049,363	111,253	2,251,575	1,198,616	862,166	329,774	0
PPFAC - FUEL	501	303,925,690	122,201,407	1,345,438	62,245,531	50,002,169	47,317,185	19,496,303	1,317,657
Steam Expenses	502	21,363,731	11,004,390	242,460	4,906,996	2,612,217	1,878,971	718,696	0
Electric Expenses	505	2,800,879	1,442,724	31,788	643,329	342,473	246,341	94,224	0
Miscellaneous Steam Power Expenses	506	4,495,150	2,315,438	51,016	1,032,483	549,638	395,355	151,221	0
Rents	507	14,157,699	7,292,586	160,677	3,251,856	1,731,111	1,245,190	476,278	0
Maintenance Supervision & Engineering	510	4,146,264	2,135,727	47,056	952,348	506,978	364,670	139,484	0
Maintenance of Structures	511	3,573,450	1,840,673	40,556	820,779	436,938	314,290	120,214	0
Maintenance of Boiler Plant	512	30,090,681	15,499,615	341,503	6,911,474	3,679,292	2,646,519	1,012,279	0
Maintenance of Electric Plant	513	5,140,971	2,648,098	58,346	1,180,820	628,604	452,156	172,947	0
Maintenance Miscellaneous Steam Plant	514	6,697,663	3,449,945	76,013	1,538,374	818,946	589,069	225,316	0
FAS 143 Accretion Expense	411	0	0	0	0	0	0	0	0
Loss from Disposition of Utility Plant	412	0	0	0	0	0	0	0	0
Subtotal - Other Production	500-554	406,194,926	174,879,967	2,506,104	85,735,565	62,506,983	56,311,913	22,936,737	1,317,657
Operation Supervision & Engineering	546	7,586,523	3,907,794	86,100	1,742,535	927,630	667,246	255,218	0
PPFAC - Fuel	547	0	0	0	0	0	0	0	0
Generation Exp & Misc Other Power Gener	548 & 549	1,498,181	771,708	17,003	344,114	183,188	131,767	50,400	0
Rents	550	10,337	5,324	117	2,374	1,264	909	348	0
Maintenance Supervision & Engineering	551	2,193	1,129	25	504	268	193	74	0
Maintenance Structures, Generating, Other	552-554	5,740,669	2,957,001	65,152	1,318,564	701,932	504,900	193,122	0
Other Expenses	557	645,356	332,421	7,324	148,231	78,910	56,760	21,710	0
Subtotal	556-557	15,483,258	7,975,377	175,721	3,556,321	1,893,192	1,361,775	520,871	0
TOTAL PRODUCTION EXPENSE	500-557	421,678,184	182,855,344	2,681,825	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
B. TRANSMISSION EXPENSE									
Supervision and Engineering	560	0	0	0	0	0	0	0	0
Load Dispatching	561	0	0	0	0	0	0	0	0
Station Expenses	562	0	0	0	0	0	0	0	0
Overhead Line Expenses	563	0	0	0	0	0	0	0	0
Underground Lines Expenses	564	0	0	0	0	0	0	0	0
Transmission by Others	565	95,464,952	48,369,826	1,876,277	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Miscellaneous Expenses	566	0	0	0	0	0	0	0	0
Rents	567	0	0	0	0	0	0	0	0
Supervision and Engineering	568	0	0	0	0	0	0	0	0
Maintenance of Structures	569	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	570	0	0	0	0	0	0	0	0
Maintenance of Overhead Lines	571	0	0	0	0	0	0	0	0
Maintenance of Underground Lines	572	0	0	0	0	0	0	0	0
Misc Maintenance - Credits	573	0	0	0	0	0	0	0	0
TOTAL TRANSMISSION EXPENSES	560-573	95,464,952	48,369,826	1,876,277	21,986,984	11,268,859	8,833,333	3,059,365	70,310

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
C. DISTRIBUTION EXPENSE									
Operation Supervision & Engineering	580	719,344	456,115	14,686	142,377	53,179	43,452	27	9,508
Load Dispatching	581	701,361	367,199	14,244	166,914	85,547	67,058	0	399
Station Expenses	582	263,040	137,715	5,342	62,600	32,084	25,150	0	150
Overhead Line Expenses	583	831,367	490,255	17,138	172,380	81,126	63,379	0	7,089
Underground Line Expenses	584	247,581	162,659	5,181	43,640	18,031	14,006	0	4,064
Street Light and Signal Systems	585	219,325	0	0	0	0	0	0	219,325
Meter Expenses	586	2,764,693	2,027,990	52,058	630,416	0	53,500	728	0
Customer Installation Expenses	587	59,339	43,527	1,117	13,531	0	1,148	16	0
Misc. Distribution Expenses	588	11,306,668	7,440,466	234,615	1,984,910	782,122	614,015	92	250,448
Rents	589	834,309	549,025	17,312	146,465	57,712	45,308	7	18,480
Maint Supervision & Engineering	590	1,054,638	668,716	21,532	208,741	77,966	63,705	40	13,939
Maint of Structures	591	0	0	0	0	0	0	0	0
Maintenance of Station Equipment	592	1,385,470	725,226	28,132	329,659	168,958	132,441	0	1,054
Maintenance of Overhead Lines	593	2,298,053	1,355,157	47,372	476,490	224,248	175,190	0	19,596
Maintenance of Underground Lines	594	132,130	86,808	2,765	23,290	9,623	7,475	0	2,169
Maintenance of Line Transformers	595	155,703	95,107	3,254	31,540	14,492	11,310	0	0
Maintenance of Street Lights	596	0	0	0	0	0	0	0	0
Maintenance of Meters	597	127,603	93,601	2,403	29,097	0	2,469	34	0
Maintenance of Misc. Plant	598	576,162	379,149	11,955	101,146	39,855	31,289	5	12,762
Regulatory Asset Amortization	407	408,531	268,838	8,477	71,718	28,260	22,186	3	9,049
Subtotal - DISTRIBUTION EXPENSES	580-599	24,085,317	15,347,552	487,584	4,634,914	1,673,202	1,373,080	951	568,033
Total - OPER. AND MAINT. EXPENSE	500-599	541,228,453	246,572,722	5,045,686	115,913,784	77,342,236	67,880,101	26,517,924	1,956,000

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
D. CUSTOMER ACCOUNTS AND SERVIC									
Supervision	901	0	0	0	0	0	0	0	0
Meter Reading Expenses	902	1,538,844	1,358,784	34,880	138,892	2,672	3,255	362	0
Customer Records & Collection Expense	903	18,299,064	15,527,614	398,593	1,587,199	30,531	37,194	4,133	713,800
Uncollectible Accounts	904	1,723,975	885,110	9,745	604,683	224,436	0	0	0
Misc Customer Accounts Expenses	905	0	0	0	0	0	0	0	0
Subtotal - Customer Accounts Expense	901-905	21,561,883	17,771,509	443,218	2,330,775	257,639	40,448	4,494	713,800
Customer Assistance Exp Electric	(907, 908)	0	0	0	0	0	0	0	0
Supervision	909	202,797	168,941	4,337	17,269	332	405	3,747	7,766
Customer Assistance Expenses	910	109,873	93,439	2,399	9,551	184	4	0	4,295
Information, Instructional Advertising	911	0	0	0	0	0	0	0	0
Misc Customer Serv & Inform Expen	912	0	0	0	0	0	0	0	0
Rents	913	0	0	0	0	0	0	0	0
Subtotal - Customer Service & Info.	909-913	312,669	262,380	6,735	26,820	516	409	3,747	12,062
Supervision	915	0	0	0	0	0	0	0	0
Demonstrating & Selling Expenses	916	0	0	0	0	0	0	0	0
Advertising Expenses	917	0	0	0	0	0	0	0	0
Miscellaneous Sales Expenses	918	0	0	0	0	0	0	0	0
Subtotal - Sales Expense	915-919	0	0	0	0	0	0	0	0
Total - CUST ACCTS, SERVS, & SALES E:	901-919	21,874,552	18,033,889	449,953	2,357,595	258,155	40,858	8,241	725,862

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
E. ADMINISTRATIVE AND GENERAL									
LABOR RELATED EXPENSES									
Administrative & General Salaries	920	29,996,909	17,139,168	447,146	6,238,598	3,008,207	2,225,437	737,737	200,614
Office Supplies & Expenses	921	11,749,828	6,713,434	175,148	2,443,667	1,178,319	871,707	288,973	78,581
Admin Expenses Transferred-Credit	922	-9,762,376	-5,577,875	-145,522	-2,030,327	-979,009	-724,260	-240,094	-65,289
Outside Services Employed	923	11,102,007	6,343,292	165,491	2,308,937	1,113,353	823,645	273,040	74,248
Employee Pensions and Benefits	926	21,312,336	12,177,112	317,691	4,432,427	2,137,284	1,581,138	524,151	142,533
Subtotal - O & M Accounts 920-923,926	920-926	64,398,703	36,795,131	959,954	13,393,301	6,458,154	4,777,668	1,583,807	430,688
PLANT RELATED EXPENSES									
Property Insurance	924	2,403,431	1,378,627	36,524	498,788	241,643	178,289	47,770	21,789
Injuries and Damages	925	2,054,306	1,178,366	31,219	426,334	206,542	152,391	40,831	18,624
Maintenance of General Plant (also acct 93	935	26,768	15,354	407	5,555	2,691	1,986	532	243
Subtotal - O & M Accounts 924-925	924,925,935	4,484,505	2,572,348	68,150	930,677	450,877	332,665	89,134	40,655
OTHER A&G EXPENSES									
Franchise Requirements	927	0	0	0	0	0	0	0	0
Regulatory Commission Expenses	928	1,326,223	757,951	19,794	275,783	133,021	98,390	32,209	9,075
Duplicate Charges-Credit	929	-375,164	-214,410	-5,599	-78,014	-37,629	-27,833	-9,111	-2,567
General Advertising Expenses	930	5,093,710	2,911,109	76,025	1,059,216	510,902	377,894	123,709	34,854
Miscellaneous General Expenses	930	107,111	61,215	1,599	22,273	10,743	7,946	2,601	733
Rents	931	687,396	392,854	10,260	142,941	68,946	50,997	16,695	4,704
Misc Expenses - Credit	932	0	0	0	0	0	0	0	0
Subtotal	927-932	6,839,276	3,908,718	102,078	1,422,199	685,984	507,395	166,103	46,799
TOTAL A&G EXPENSES	920-932	75,722,484	43,276,198	1,130,182	15,746,177	7,595,014	5,617,728	1,839,044	518,141
TOTAL OPERATING EXPENSES		638,825,490	307,882,809	6,625,821	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
II. DEPRECIATION EXPENSE									
Intangible	301-303	13,277,153	7,615,882	201,769	2,755,430	1,334,898	984,913	263,895	120,366
Production - Steam	500-511	60,024,743	30,456,794	665,441	13,630,703	7,517,151	5,585,177	2,166,051	3,426
Production - Other	546-557	12,557,762	6,468,463	142,520	2,884,369	1,535,481	1,104,474	422,455	0
Transmission	565	0	0	0	0	0	0	0	0
Land & Rights	360	86,658	45,361	1,760	20,619	10,568	8,284	0	66
Structures & Improvements	361	185,998	97,361	3,777	44,256	22,682	17,780	0	142
Station Equipment	362	2,445,508	1,280,105	49,656	581,884	298,230	233,774	0	1,861
Poles, Towers, & Fixtures	364	3,451,385	2,524,834	73,431	489,534	156,711	120,051	0	86,824
Overhead Conductors & Devices	365	2,779,481	1,658,537	57,796	578,304	271,265	211,892	1	1,686
Underground Conduit	366	750,665	638,390	16,387	65,255	1,255	31	0	29,347
Underground Conductors & Devices	367	4,999,675	3,284,739	104,633	881,279	364,119	282,829	0	82,076
Line Transformers	368	4,903,883	2,954,546	101,432	989,183	456,343	356,215	0	46,165
Services	369	1,916,596	1,629,936	41,840	166,609	3,205	78	0	74,928
Meters	370	2,037,023	1,494,221	38,357	464,490	0	39,419	536	0
Street Lighting & Signal Systems	373	194,790	58,437	2,128	26,492	13,651	10,574	3,713	79,796
Distribution Plant Net Salvage	403	5,407,146	3,101,582	82,171	1,122,154	543,640	401,108	107,472	49,019
General	EDST	14,684,437	8,423,111	223,155	3,047,485	1,476,388	1,089,307	291,866	133,124
TOTAL DEPRECIATION EXPENSES		129,702,903	71,732,300	1,806,252	27,748,046	14,005,587	10,445,904	3,255,991	708,823
III. TAXES									
A. GENERAL TAXES									
Payroll Taxes	408	5,290,439	3,068,177	75,411	1,084,749	518,177	379,593	124,806	39,526
PropertyTaxes - Production	408	14,193,015	7,310,777	161,078	3,259,968	1,735,429	1,248,296	477,466	0
PropertyTaxes - Transmission	408	0	0	0	0	0	0	0	0
PropertyTaxes - Distribution	408	18,111,409	11,918,393	375,815	3,179,496	1,252,830	983,551	148	401,176
PropertyTaxes - General	408	3,070,559	1,761,297	46,662	637,238	308,717	227,777	61,030	27,837
Business Activity Tax - Generation	408	0	0	0	0	0	0	0	0
Business Activity Tax - Transmission	408	69,718	35,325	1,370	16,057	8,230	6,451	2,234	51
Subtotal - General Taxes		40,735,140	24,093,968	660,337	8,177,508	3,823,383	2,845,668	665,685	468,590
B. FRANCHISE AND REVENUE TAXES									
Franchise Tax T&D	408.11	0	0	0	0	0	0	0	0
PSC Assessment	408.12	0	0	0	0	0	0	0	0
Franchise Tax Prod	408	0	0	0	0	0	0	0	0
Franchise	408.13	0	0	0	0	0	0	0	0
Retail Sales & Other	408.14	0	0	0	0	0	0	0	0
Subtotal - Franchise & Gross Receipts		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
TOTAL TAXES		74,090,738	43,227,007	1,167,233	15,099,851	7,176,988	5,320,021	1,328,658	770,980
TOTAL EXPENSES		842,619,131	422,842,116	9,599,307	176,865,453	106,377,980	89,304,612	32,949,858	4,679,806

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
IV. OPERATING REVENUES									
Revenues	440-446	927,140,267	407,674,736	3,983,681	263,174,018	111,490,378	99,967,027	36,194,919	4,655,508
Production Other Rev	440-446	0	0	0	0	0	0	0	0
Delayed Payment Charges	440-446	0	0	0	0	0	0	0	0
Reconnect Charges-Missouri	440-446	0	0	0	0	0	0	0	0
Ot Elec Rev-Off-Sys	440-446	0	0	0	0	0	0	0	0
Rent From Elec Property-Mo	440-446	0	0	0	0	0	0	0	0
Miscellaneous Service Revenues Retail	451	6,461,516	5,495,074	141,058	561,695	10,805	263	15	252,607
Scrap Sales Revenues	456	0	0	0	0	0	0	0	0
Other Electric Revenues	447.5, 456.1	25,267,361	11,110,363	108,567	7,172,283	3,038,448	2,724,402	986,420	126,877
Other Electric Revenues - Misc Transmissic	456	0	0	0	0	0	0	0	0
Other Electric - Ancillary	147.4, 449.1, 456.	0	0	0	0	0	0	0	0
Excess Fac Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	424,280,172	4,233,306	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
Gains/Losses from Energy Purchases		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
V. NET INCOME		116,218,762	1,415,128	-5,366,589	94,035,416	8,161,651	13,386,475	4,231,495	355,186
Rate of Return		5.52%	0.12%	-17.02%	21.43%	3.86%	8.58%	9.71%	2.12%

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
SUMMARY REPORT									
OPERATING REVENUES									
Utility Sales Revenues	440-446	933,601,783	413,169,810	4,124,739	263,735,713	111,501,183	99,967,290	36,194,933	4,908,115
Interdepartmental Revenues	448	0	0	0	0	0	0	0	0
Other Operating Revenues	450-456	0	0	0	0	0	0	0	0
Total Operating Revenues		958,869,144	424,280,172	4,233,306	270,907,996	114,539,631	102,691,692	37,181,354	5,034,992
OPERATING EXPENSES									
Production	500-555	421,678,184	182,855,344	2,681,825	89,291,886	64,400,174	57,673,688	23,457,608	1,317,657
Transmission	560-573	95,464,952	48,369,826	1,876,277	21,986,984	11,268,859	8,833,333	3,059,365	70,310
Distribution	580-599	24,085,317	15,347,552	487,584	4,634,914	1,673,202	1,373,080	951	568,033
Customer Acctg & Service	901-919	21,874,552	18,033,889	449,953	2,357,595	258,155	40,858	8,241	725,862
Admin & General	920-932	75,722,484	43,276,198	1,130,182	15,746,177	7,595,014	5,617,728	1,839,044	518,141
Total Operating Expenses		638,825,490	307,882,809	6,625,821	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSES	403	129,702,903	71,732,300	1,806,252	27,748,046	14,005,587	10,445,904	3,255,991	708,823
TAXES OTHER THAN INCOME TAX	408	40,735,140	24,093,968	660,337	8,177,508	3,823,383	2,845,668	665,685	468,590
INCOME BEFORE INCOME TAXES		149,605,611	20,571,096	-4,859,104	100,964,886	11,515,256	15,861,434	4,894,468	657,575
INCOME TAXES		0	0	0	0	0	0	0	0
Income Taxes - Current		33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
Subtotal - Federal Income Taxes	409-411	33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
OPERATING INCOME		116,250,012	1,438,057	-5,366,000	94,042,544	8,161,651	13,387,080	4,231,495	355,186
Gains/Losses		0	0	0	0	0	0	0	0
Allowance for Funds During Construction		0	0	0	0	0	0	0	0
Interest on Customer Deposits		-31,250	-22,929	-589	-7,128	0	-605	0	0
NET INCOME		116,218,762	1,415,128	-5,366,589	94,035,416	8,161,651	13,386,475	4,231,495	355,186
RATE BASE		2,104,677,691	1,206,845,016	31,522,003	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714
RETURN ON RATE BASE		5.52%	0.12%	-17.02%	21.43%	3.86%	8.58%	9.71%	2.12%
Unitized Rate of Return		1.00	0.02	-3.08	3.88	0.70	1.55	1.76	0.38

TUCSON ELECTRIC POWER COMPANY
TEST PERIOD ENDING JUNE 30, 2015
2016 Rate Case Base Electric COSS
Allocation Phase

Account Description	Account Code	Total Allocated Dollars	Residential RES	Solar SOLAR	TOTAL General Service GS	Large Gen. Service GSL	Large Power Service LPS	138 kV MINING	Lighting LIGHTING
REVENUE REQUIREMENTS									
RATE OF RETURN		5.22%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%	5.52%
Using Target for System									
RATE BASE		2,104,677,691	1,206,845,016	31,522,003	438,735,255	211,210,626	156,039,474	43,566,603	16,758,714
OPERATING EXPENSES		638,825,490	307,882,809	6,625,821	134,017,556	85,195,405	73,538,686	28,365,210	3,200,003
DEPRECIATION EXPENSE		129,702,903	71,732,300	1,806,252	27,748,046	14,005,587	10,445,904	3,255,991	708,823
GENERAL TAXES		40,735,140	24,093,968	660,337	8,177,508	3,823,383	2,845,668	665,685	468,590
Other costs (benefits), net of taxes		31,250	22,929	589	7,128	0	605	0	0
Subtotal- Operating Costs to recover		809,294,783	403,732,006	9,092,999	169,950,238	103,024,375	86,830,864	32,286,886	4,377,416
Target Return on Rate Base- After taxes		116,218,763	66,641,099	1,740,622	24,226,640	11,662,896	8,616,386	2,405,716	925,404
Actual Historic FIT		33,355,599	19,133,039	506,896	6,922,343	3,353,605	2,474,353	662,973	302,390
Incremental Tax Due to Target ROR		0	0	0	0	0	0	0	0
Subtotal- Rev Req before Uncollectible Adj.		958,869,144	489,506,144	11,340,517	201,099,220	118,040,876	97,921,603	35,355,574	5,605,210
Proforma Incr for Uncollect. Calc		0	0	0	0	0	0	0	0
ECCR & Prop Tax Surcharge		0	0	0	0	0	0	0	0
TOTAL REVENUE REQUIREMENT		958,869,144	489,506,144	11,340,517	201,099,220	118,040,876	97,921,603	35,355,574	5,605,210

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

Rejoinder Testimony of

H. Edwin Overcast

on Behalf of

Tucson Electric Power Company

September 1, 2016

EXHIBIT
TEP-29
ADMITTED

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. H. Edwin Overcast. My business address is P. O. Box 2946, McDonough, Georgia 30253.

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

A. Yes. I filed Rebuttal Testimony in this proceeding.

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

A. I will respond to the testimony of witness Kobor of Vote Solar, witness Huber of the Residential Utility Consumer Office (RUCO), witness Zwick of the Arizona Community Action Association (ACCA), witness Higgins of Freeport Minerals Corporation, Arizonans for Electric Choice & Competition and Noble Americas Energy Solutions LLC, and witness Baatz of the Southwest Energy Efficiency Project (SWEEP) and Western Resource Advocates (WRA). Since several of these witnesses cover the same issues, at some points I will refer to them collectively for ease of discussion.

Q. How is your testimony organized?

A. My testimony addresses the use of the minimum system for classifying costs associated with distribution system costs in FERC accounts 364-368 between a customer and a demand component. The parties who oppose this cost classification have chosen to either ignore the evidence related to cost causation for these accounts or have made fatal errors in their analysis of the evidence before the Arizona Corporation Commission (Commission) that provides the factual basis for use of the minimum system. Opposition to the use of the minimum system is simply not consistent with the principle of cost causation as my Rebuttal Testimony has shown. I also discuss why it is both necessary and appropriate to raise the monthly customer charge for rates to be efficient, cost-based and just and reasonable. Cost-based rates, as a matter of principle, is a requirement for rates that satisfies the U.S. Supreme Court mandate that rates provide the utility a reasonable opportunity to earn its allowed rate of return.

I will also address issues related to energy price signals and conservation that have been the subject of the surrebuttal testimony of several witnesses. The claim that raising the utility's monthly customer charge will result in decreased energy conservation is not credible unless the only definition of conservation is reduced use, and that is not the definition of conservation. As I discussed in my rebuttal testimony the actual definition of conservation follows: "Conservation is the act of preserving, guarding or protecting; wise use."

II. COMMENTS ON WITNESS HUBER'S SURREBUTTAL TESTIMONY.

Q. Witness Huber asserts that you are incorrect when you state that the basic customer method is inconsistent with the NARUC Electric Cost Allocation Manual (NARUC Manual). Please comment on that assertion.

A. Witness Huber's assertion is completely contrary to the contents of the NARUC Manual for a number of reasons. For example, the basic customer method is not even discussed in the NARUC Manual. In fact, the NARUC Manual states the following related to the classification of distribution system costs between customer and demand.

> Distribution plant Accounts 364 through 370 involves demand and customer costs. The customer component of distribution facilities is that portion of the costs which varies with the number of customers. Thus, the number of poles, conductors, transformers, services and meters are

directly related to the number of customers on the utility's system.[1] (Emphasis added.)

There is no ambiguity in this statement and it is certainly evidence that the NARUC Manual does not support the use of services and meters as the only customer-related plant costs. Thus my conclusion relative to the basic customer method is completely accurate. More importantly, my Rebuttal Testimony has provided the critical lynchpin between customer and demand costs by empirical analysis that shows the equipment in Accounts 364 through 368 are directly related to the number of customers served by the utility. That conclusion is not based solely on my own evidence, but it is also supported by empirical analyses conducted for estimating total factor productivity in utility rate cases.

Q. Does witness Huber find fault with your empirical analysis?

A. Yes. Witness Huber claims that neither analysis "succeeds in proving cost causality." The basis for his conclusions related to cost causality in the regression analysis I presented is the concept of "omitted variable bias". Essentially, this is an argument that the independent variables specified in the regression analysis omitted a critical model variable and thereby produce a result that is biased. However, the discussion of this potential problem ignores the conditions necessary to reach the conclusion that a critical variable has been omitted. Two conditions must hold true for omitted-variable bias to exist in a linear regression: 1) the omitted variable must be a determinant of the dependent variable (i.e., its true regression coefficient is not zero); and 2) the omitted variable must be correlated with one or more of the included independent variables (i.e. cov(z,x) is not equal to zero). Witness Huber does not agree that his list of other variables meets either of these two tests. There is also a variable omitted in the model specification. For example, witness Huber postulates that kWhs are relevant and should

[1] NARUC Electric Utility Cost Allocation Manual, p. 95.

have been included in the analysis. However, there is no possible basis for inclusion of kWhs in a properly specified model of cost causation. KWhs cannot cause distribution investment since a causal variable must precede the dependent variable and kWhs are not known until after the delivery facilities are installed. That installation is based on two independent measures- the existence of the customer on the utility's distribution grid and the maximum demand of that customer. There are no other variables omitted from the model since these are in fact the independent variables used to develop the utility's delivery system. Thus there is no evidence of omitted variable bias. The model is properly specified and meets all the required statistical tests to demonstrate that both demand and customers cause the investment in FERC accounts 364 through 368. The first analysis I presented is conclusive as to cost causation.

Q. Please comment on the analysis used by witness Huber to dismiss the transformer analysis used in your Rebuttal Testimony to demonstrate that only with the minimum system analysis can delivery costs allocated among the customer classes reflects cost causation.

A. Witness Huber makes two arguments he claims prevent the use of this analysis. First, he argues incorrectly that the physical count of transformers used by the residential class may not reflect the total cost of those transformers. For purposes of demonstrating the physical allocation of transformer assets, the cost is not particularly relevant to the argument that Non-Coincident Peak (NCP) under allocates the number of transformers to residential customers. The cost becomes important when developing the class revenue requirements and the residential class receives a pro-rata share of the total costs. This means that the allocated share of transformer costs for the residential class is actually lower than the cost of the physical transformers simply because of economies of scale that result in a higher cost per kVa of transformer capacity for smaller, single phase transformers used by residential customers. This is not a flaw in the analysis but a benefit that results from average costing in the utility's cost of service study. His argument makes the results of the minimum system conservative relative to actual costs, and therefore must be rejected as an argument against the minimum system cost classification.

The second argument against the analysis is that transformers may be used by more than one class. There are two problems with this statement. First, nearly all residential transformers are single phase and step down to secondary voltage. Thus most transformers are uniquely serving the residential class alone. Where the transformers serve small commercial customers also, the transformer is considered residential only if more than half of the load is residential. Thus, the estimate of the physical number of transformers serving residential customers is based on actually serving residential load. Use of the basic customer charge method allocates these costs predominantly to larger customer classes who account for more NCP demand but do not even cause the costs for single phase secondary transformers. Witness Huber is incorrect in his criticism and hence has not shown by evidence that customers are not the cause of these delivery costs. The only remaining conclusion is that it is the so called basic customer method that cannot and does not reflect cost causation and therefore must be rejected as a measure of the allocated customer costs for the utility's delivery system.

Q. Witness Huber states that RUCO's position is that any cost that is shared between customers should not be included in fixed charges. Please comment on this position.

A. There is no basis for this position other than an opinion consistent with the basic customer method that is unsupported by any evidence of cost causation or even support from any rigorous analysis of cost of service and rate design. The fact that fixed charges are calculated including shared cost is sufficient to demonstrate that equitable rates require fixed cost recovery in fixed charges in order for rates to be just, reasonable, not unduly discriminatory and to fairly recover the apportioned costs. The argument that fixed charges must be used to recover fixed costs is firmly established for numerous reasons as I have explained in my Rebuttal Testimony and in the paper provided as Appendix B to that Rebuttal Testimony. The average customer cost from the utility's cost of service study is based on a mix of shared and dedicated facilities and represents the average customer cost across the class of service.

Q. Witness Huber discusses the matching principle and claims that among other things it is not related to rate design and the minimum system violates the matching principle. Please comment on these claims.

A. Witness Huber cites to an American Public Power Association (APPA) report that no rate design will result in a perfect matching of rates and costs. That conclusion is wholly consistent with my views on the matching principle and has no role in determining the conclusions I have drawn about the matching principle as it relates to rate design. As I have pointed out, each customer has a different actual cost by virtue of such factors such as the side of the street the customer is served on or the age of the facilities that serve the customer. There are other factors discussed in my Rebuttal Testimony such as urban and rural costs, overhead and underground costs and so forth. The matching principle is not based on perfection for each customer simply because rates are based on average costs for a class - not the actual costs for each customer. Matching is however an important ratemaking principle for both revenue requirements in the rate effective period and the design of rates necessary to provide the utility with a reasonable opportunity to recover revenue requirements from customers in a way that provides the utility with a reasonable opportunity to recover costs from those customers who cause the costs. Without matching, no rate design can meet the requirement that the utility has a reasonable opportunity to earn the allowed rate of return and that an individual customer pays the average cost imposed on the utility's delivery system. Both of these concepts are not addressed by witness Huber in his rate design proposals so it is not surprising that he would find this principle problematic.

Q. How does witness Huber ignore these principles in rate design?

A. Witness Huber ignores both of the cost causation and the matching principles by supporting rates that recover nearly all fixed costs in ever increasing kWh charges or non-cost based TOU price signals coupled with as low a customer charge as his basic customer method will support. A two-part rate cannot track costs unless a customer class is homogeneous. Residential customers are no longer homogeneous or even close to that standard with the introduction of distributed energy resources. Currently customers have load factors as low as zero and as high as above 40 percent. It is impossible for any two part rate- TOU or otherwise- to match costs and revenues during a rate effective period for customers who have this large a variance in consumption patterns. For example, no two customers have the same on-peak kWh use. Under witness Huber's proposed rates, the on-peak hours recover a significant portion of the utilities fixed costs that do not vary with kWh use. Thus if kWh use drops in response to a high on-peak price signal, the utility is deprived of any opportunity to earn the allowed rate of return since its change in revenue under witness Huber's rate design declines by much more than the actual decline in costs. That equals lost return for each cent that costs decline by less than the revenue. The problem is also exacerbated by the differences in customer load factor because the incentive for high load factor customers is to use less energy resulting in a less efficient use of productive resources. That outcome is also inconsistent with the rate design provisions under the Public Utility Regulatory Policies Act (PURPA) where the proposed rates totally fail to meet two of the three purposes of PURPA: the optimization of the efficiency of use of facilities and resources by electric utilities and equitable rates for electric consumers.

Q. Witness Huber claims that your hypothetical example of the failure of two-part rates to track costs when customers are not homogeneous is so flawed that it proves nothing. Please comment.

A. His observations about my simple example are simply wrong. To start, witness Huber states a premise for the example that I have assumed all fixed costs are customer-related and then proceeds to demonstrate that the hypothetical with his modification produces an unacceptable result. In fact, there is no assumption that costs are customer- related since the assumption is that the customers have identical demands that cause all non-customer or energy-related costs to be the same. By adding a third customer as suggested by witness Huber that has the same demand and different energy characteristics, the example still holds that customers with less than the average energy level for the class will pay less for demand-related costs and be subsidized by the higher than average energy user. I might add that one reaches that same conclusion even if the energy rates are time-differentiated. Using energy charges to recover fixed costs (customer or demand) always creates an intra-class subsidy. That conclusion is unavoidable unless the customer in that class all has equivalent load factors and common peak demands.

Q. Witness Huber argues that competitive businesses with high fixed costs recover those costs volumetrically and hence there is no basis for fixed charges. Please comment.

A. As I discussed in detail in my Rebuttal Testimony, this is a common argument made by opponents of fixed charges. The argument has been shown to be false repeatedly beginning as early as the 1930s and as recent as June of this year. I will not repeat the discussion from my Rebuttal Testimony here except to say that witness Huber continues to make an argument that is not supported by utility ratemaking principles.

Q. Witness Huber argues that fixed charges are inefficient. Please comment.

A. The basic economic proposition for efficient pricing is that per unit price equals short-run marginal costs. There is no dispute in economic theory about this conclusion. I have discussed the economics of efficient pricing in detail in my Rebuttal Testimony in a discussion of the seminal work of Ronald Coase in laying out the principles for efficient pricing. The argument is simple and basic. Set the marginal price at marginal cost (the short-run value is the efficient price) and recover the remaining revenue requirement in a fixed charge. The fixed charge is a residual value and is efficient under two conditions: the marginal price equals marginal cost and the total revenue requirement of the utility is recovered. Witness Huber is correct in this case just not for the reason he states. He is correct because the marginal price signal far exceeds marginal cost and Tucson Electric Power Company (TEP or the Company) does not recover its revenue requirements. In essence, an efficient customer charge would need to be higher not lower since the marginal price exceeds marginal costs.

Q. Witness Huber makes a number of observations related to the use of the OpenEI Utility Rate Database. Please comment.

A. First, as with any database one must use the data carefully. While the data base does contain much more than just residential rates, it is relatively easy to sort out residential rates from all of the other utility rates. My report used only current residential rates as reported in the database. Further, I have collected similar data on my own from current rate schedules for other utilities over the years, by state, and am able to confirm the conclusions independently for utilities in a number of the states. The criticisms of witness Huber are incorrect because the data represents current residential rates for the utilities used in the analysis. The data shows that higher monthly customer charges are much more common than witness Huber and others in this case want to believe thus destroying the fundamental narrative that higher fixed charges are inappropriate. They are not.

III. COMMENTS ON WITNESS BAATZ'S SURREBUTTAL TESTIMONY.

Q. Please comment on the testimony of Witness Baatz of SWEEP and WRA. Are the utility regulatory commission citations he provides in support of moderating the Company's proposed customer charge level relevant?

A. Absolutely not. The decisions he cites are from proceedings in which the fact bases are entirely different or difficult to compare with the Company's facts in this proceeding; in some cases these decisions are based on erroneous interpretation of NARUC guidance; or are simply policy level decisions to which the Commission has to obligation to adhere. Witness Baatz merely selects a handful of decisions that appear to endorse ameliorating of proposed customer charge increases for specific facts and policy level considerations relevant to that proceeding/jurisdiction and suggest they represent a body of evidence as to a far reaching national precedent that should somehow apply to the facts in this case before the ACC.

Q. Please explain.

A. Consider the cite from the Michigan Public Service Commission (MPSC) in the DTE Electric Company proceeding: "In addition, as the Staff observed, the NARUC Manual likewise supports using only the marginal costs of customer attachment in developing a customer charge." There is no language in the NARUC Manual that could reasonably be interpreted as direction from NARUC requiring utilities to use the marginal costs of attachments alone to compute a customer charge. The NARUC Manual states that this is one of two options for analysts and that the other includes the minimum distribution system. In this particular order, the MPSC relied on an incorrect interpretation of the

NARUC Manual as part of its support in its decision. It further ignored the preamble to the chapter on marginal transmission, distribution and customer costs that includes the following statement: "'… the determination of marginal costs for these functions and especially for distribution and customer costs, is much more difficult and less precise than for power supply, and it is not clear that the benefits are sufficient to justify the effort.'" The decision of the MPSC was purely a policy level decision guided in part by choosing one potential view of NARUC guidance on the matter of the proper determination of customer costs. The Commission is under no obligation to adhere to policy decision by the MPSC and should ignore this decision.

Q. **Please comment on the relevance of the decision issued by the Minnesota Public Utilities Commission (re: Northern States Power Company) contained in Witness Baatz's Rebuttal Testimony.**

A. As is the case for all of the decisions cited by Witness Baatz regarding the customer charge topic, this is based upon a particular set of facts that differ from those of the Company in this proceeding. Consider the passage in his cite: "This is particularly true where the Commission has approved a revenue decoupling mechanism that will largely eliminate the relationship between Xcel's sales and the revenues it earns. As several parties have argued, decoupling removes the need to increase customer charges to ensure revenue stability." Although Witness Baatz chose not to emphasize this sentence in this cite, I believe this passage highlights the key reason this decision is not applicable in this proceeding. That is, according to this cite, one of the key considerations of the MPSC in reaching its decision to not increase the customer charge in this particular proceeding was that Northern States Power Company had an approved revenue decoupling mechanism. This is not the case with the Company – although the Company has an LFCR in place – the revenue recovery potential is limited as compared to the one described in this decision. Again, this key difference highlights the problem with hand-picking a few orders from proceedings with different facts and suggesting they represent a broad policy consensus. In fact, nearly all the states from which Witness Baatz provides regulatory decisions that support limited to no customer charge increases are from jurisdictions with revenue decoupling in place. On this basis alone, they should all be ignored.

Q. Please comment on the 2007 order issued by the Illinois Commerce Commission (Commonwealth Edison Company) that Witness Baatz cites in his rebuttal testimony.

A. Witness Baatz cites an order that appears to reject the use of the Minimum Distribution System as the basis for supporting a certain customer charge level. What is interesting however to note, is that since 2011 Commonwealth Edison Company has been setting rates under a Formula Rate Plan (FRP) approach; this approach is essentially an annual rate setting process that allow for rate recognition for certain company investments; a formula set by legislation for determining annual ROE; certain reconciliation adjustments to account for differences in revenue requirement based on timing of data availability in any given year; and other features. The approach is a dramatic departure from the former traditional test year approach (used in 2007) in which revenue requirement is set on a specific test year and rate recovery is achieved only after an extended rate proceeding. In effect, although the FRP is different than a revenue decoupling approach, there are features to the plan that reduce the risks of fixed cost recovery for a large portion of capital investments ($1.3 billion over 10 years). The regulatory construct for Commonwealth Edison has changed dramatically since 2007. This fact alone disqualifies this order from having any relevance to the question of the proper customer charge level for the Company in this proceeding or in the state of Illinois at this time for that matter. However, even if the Commission chooses to consider this data point, it should recognize that the introduction of the FRP relieves some of the need of a higher fixed customer charge to address fixed cost recovery.

Q. What is the relevance of all of these decisions in this case?

A. These decisions provide nothing more than a variety of views on the issues in this case. They set no precedent for the Commission simply because it is the evidence in this particular case that must form the basis of the decision. With respect to the minimum system and the residential customer charge, that evidence proves conclusively that the use of the minimum system is a necessary condition for reflecting cost causation both within and between classes of service. The evidence also fully supports the customer charge supported by Staff and the Company.

Q. Please comment on Mr. Baatz's claim at page 14 of his Surrebuttal Testimony that, "State commissions nationwide are rejecting utility proposals to increase fixed charges as bad public policy."

A. Mr. Baatz's claim is simply misleading and one-sided since it is not indicative of the nationwide trends I have observed related to the regulatory treatment of the monthly customer charges proposed by electric utilities applicable to residential customers. In support of his claim, Mr. Baatz has provided highlights of four (4) rate case decisions in the states of Michigan, Washington, Minnesota, and Illinois in which the regulator in each state has decided to moderate the increase in the monthly customer charges proposed by the electric utility. Unfortunately, these select regulatory decisions fail to provide a fair representation of the very different conclusions in this matter reached by utility regulators in other states.

In a number of states, regulators have determined the importance of increasing monthly customer charges to reflect the fixed cost nature of the electric distribution business in an effort to establish just and reasonable rates for the utility customers. For example, in a recent rate case of Madison Gas and Electric Corporation ("MGE"), the Public Service Commission of Wisconsin approved an increase in the electric utility's residential customer charge from $10.44 to $19.00 per month. The Commission based its rate design decision on the following considerations:

- "Where a particular rate design collects a significant portion of the utility's fixed costs through the variable energy charge, this results in higher-use customers subsidizing lower-use customers regardless of the reasons those customers may have lower use. To the extent a customer reduces usage via energy efficiency, conservation or renewable generation, the customer reduces his or her contribution to the utility's fixed costs and these costs must be picked up from other customers."[2]
- "In this case, the Commission agrees with MGE that an appropriate fixed charge should better align the charge with the fixed costs of providing service, regardless of the amount of energy used or demand placed on the system by the customer. The regulated utility ratemaking process is intended to simulate a free market for monopoly utilities. When rates are properly designed, the rate structure signals to customers the actual cost of providing both backup service and electricity to each class. If the fixed charge is too low, the customer will receive an incorrect price signal that the cost to provide access to the electric system is lower than it actually is to the utility. They will also receive an incorrect signal that the variable cost to provide energy is higher than it actually is to the utility. Setting price signals correctly is important because those signals influence customer behavior, which in turn influences how the utility incurs costs."
- "MGE provides a compelling case that its fixed charges are insufficient to recover its fixed costs. As a result, the variable energy charge is correspondingly too high. The result is a price signal that tells customers that the economic benefit of conservation is higher than it actually is."[3]

---

[2] Public Service Commission of Wisconsin, Docket No. 3270-UR-120, Final Decision, dated December 23, 2014, pages 38-39.
[3] Ibid, p. 39.

- "More importantly, however, the purpose of rate design is not to subsidize the payback of energy efficiency measures or renewable energy. The purpose of rate design is, fundamentally, to connect the rates that customers pay to the costs the utility incurs. Such an approach appropriately encourages efficient utility scale planning."[4]
- "This Commission continues to support customers who want to own their own generation; however, the Commission also has an obligation to those customers who do not want, or who cannot afford, to own generation to make sure these customers are not subsidizing the costs for those who choose to do so."[5]
- "To the extent fixed costs are recovered through the variable energy charge, more fixed costs are paid by higher energy users within a class. The Commission finds that the most equitable result is to better align fixed charges with the fixed costs to serve a customer so that, as best as can be determined in a reasonable regulatory environment, members in a class pay for their fair share of the cost of service."[6]

I should point out that the Commission reached a very similar conclusion on rate design in the rate case filed around the same time by Wisconsin Public Service Corporation.[7] The Commission increased the utility's residential customer charge from $10.40 to $19.00 per month.

In a recent rate case of Sierra Pacific Power Company (d/b/a NV Energy), the Public Utilities Commission of Nevada approved an increase in the utility's residential customer charge from $9.25 to $15.00 per month.[8] The Commission based its rate design decision on the following considerations:

---

[4] Ibid, p. 40-41.
[5] Ibid, p. 41.
[6] Ibid, p. 43.
[7] See the Final Decision dated December 18, 2014 in Docket No. 6690-UR-123 (Wisconsin Public Service Corporation).
[8] Public Service Commission of Nevada, Docket Nos. 13-06002, 13-06003 and 13-06004.

- “The Commission continues to support movement toward cost-based rates and the elimination of intra-class subsidies. If costs that do not vary with energy usage are recovered in the energy rate component, cost recovery is inequitably shifted away from customers whose energy usage is lower than average within their class, to customers whose energy usage is higher than average within that class. This is not just and reasonable. It is appropriate to move the BSCs [Basic Service Charges] closer to their corresponding cost bases in order to establish appropriate price signals and avoid intra-class subsidies.
- While the increase in BSCs will have a corresponding decrease in the energy component of rates, this decrease is not enough to discourage conservation. The residential and small commercial customer classes will continue to control a significant portion of their bills by engaging in activities to reduce their electric consumption while the overall billing is better aligned with the costs SPPC incurs to provide service. As the BSCs for residential and small commercial customers continue to move toward cost-based rates, these customers will have more accurate price signals to inform their conservation activities.”[9]

Finally, the Public Utilities Commission of Ohio (the “Commission”) recently conducted a three-year long proceeding related to aligning electric distribution utility rate structures with the state’s public policies to promote competition, energy efficiency, and distributed generation.[10] The regulator reached the following conclusions on rate design:

- “Initially, the Commission notes the importance of aligning cost causation with cost recovery in order to further Ohio's policy goals of competition, increased energy efficiency, and encouraging distributed generation pursuant to Section 4928.02, Revised Code. The Commission believes that, given the comments filed in this proceeding, as well as recent experience by the natural gas utilities, the rate

[9] Ibid, Modified Final Order, dated January 29, 2014, pages 183-184.
[10] The Public Utilities Commission of Ohio, Case No. 10-3126-EL-UNC.

structure that may best accomplish these policy goals is the SFV rate design (emphasis added).

- Based on findings the Commission made in previous rate cases in which it approved an SFV rate design for all gas distribution utilities on Ohio, "the Commission found that the SFV rate design would produce more stable bills for customers, that bills would be easier to understand and would produce a more accurate price signal, and that the SFV rate design would assure a more equitable allocation of distribution system costs to cost-causers. The Commission believes that these same characteristics could be applicable to an SFV rate design for electric utilities."[11]

Contrary to Mr. Baatz's claimed portrayal, the regulatory decisions across the U.S. associated with increases to the monthly customer charges for electric utilities are much more balanced and reflective of the costing and pricing considerations deemed to be most important by the Company.

Q. Witness Baatz concludes that the Company's proposed customer charge increases are not cost-based. Please comment.

A. As I have shown in detail in my Rebuttal Testimony and above relative to the basic customer method, it is witness Baatz who fails to provide evidence that supports this conclusion. I have shown that the method used to determine customer costs is both sound and accurate. The evidence supports the minimum system method based on theory, good utility practice, engineering, operations, over 100 years of detailed cost analysis from the best minds in the industry including early pioneers in developing the business, empirical analysis and the evidence for the Company in this case. There is no evidence offered by any of the opponents of the cost allocation or rate design that proves there is a better or

[11] Ibid, Modified Final Order, dated January 29, 2014, pages 183-184.

more appropriate cost analysis. In fact, at its core, witness Baatz and others ultimately rely on their preferred results as the basis for opposing the increase. Those preferred results include higher kWh charges even though the charges exceed marginal cost and lower customer charges designed to continue intraclass subsidies from large use customers to small customers on some definition of fair rates. There is no basis for accepting these misplaced arguments that perpetuate inequitable rates for all customers in a class of service.

Q. Witness Baatz makes the claim that increasing fixed charges "violates the primary ratemaking principle of designing rates to discourage wasteful use of public utility services." Please comment on this claim.

A. First, witness Baatz has misstated the Bonbright principle. Correctly stated, the principle is the "Consumer Rationing" principle that states "rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationship between the private and social costs incurred and benefits received." Second, this principle is an economic principle that is founded in marginal cost pricing. It is wasteful use of public utility services if and only if the marginal cost of an additional service is more than the price. Witness Baatz has not even recognized the fundamental meaning of this principle and no evidence has been provided to even show that the marginal cost of additional service is greater than the current price of service, much less the proposed price of service. The facts are quite different. Third, the price exceeds marginal cost by a substantial amount since the savings for the utility from energy efficiency are less in every case than the lost revenue. If the opposite were true, energy efficiency would result in increased earnings for the utility because costs would decline by more than revenue. Fourth, the requirement is symmetrical to promote all use that is economically justified. Current and more importantly proposed rates exceed marginal cost and thus discourage use that is economically justified. Fifth, as noted above, this view, that is pervasive among those who oppose the customer charge increase, violates two of the three purposes of PURPA as they relate to rate design standards. As such, this type of unsupported statement is not evidence, but rather is ill-informed opinion inconsistent with the basic principles of utility ratemaking.

Q. Does witness Baatz make the same argument about fixed charges not being used in competitive markets as discussed above related to witness Huber?

A. Yes. As I note above this argument is both false and irrelevant. I will not repeat my Rebuttal Testimony here and the discussion above except to say that it seems opponents of customer charges that recover the fixed costs of delivery service follow the dictum that if they make the argument often enough it will somehow become true. It will not.

Q. Please comment on witness Baatz's view that recovering fixed customer costs in a fixed charge "collects distribution plant costs evenly for all residential customers without consideration of the differences in costs to serve those customers."

A. Witness Baatz is correct with respect to distribution costs classified to customers, but not with respect to all distribution plant costs. The fundamental cost concept in ratemaking is the recovery of class average costs. As I have discussed in detail, no rates track fixed costs precisely, but an average cost applied to all customers is just and reasonable and not unduly discriminatory. In fact, every customer has a different actual cost for both the customer and the demand components of distribution costs. However, in making his argument, witness Baatz bases his costs on unsupported statements about subgroups of customers within the class. For example he incorrectly assumes that urban customers are less costly to serve than rural customers but provides no evidence to support that assumption. As I show in my Rebuttal Testimony, that is clearly not the case. He assumes that apartment dwellers are less costly to serve than single family customers. He offers no evidence for the validity of this assumption for the simple reason that there is no evidence that demonstrates this is generally true and in fact the opposite may be true in some cases if one actually identifies the factors that cause costs. As a practical matter, there is no attempt to define costs down to individual or subgroup levels simply because using average costs is a reasonable and universally accepted basis for designing a utility's rates.

Q. Witness Baatz claims that TEP's customer charge proposal violates the Bonbright principle of gradualism. Please comment on that claim.

A. As in other rate cases, witnesses quickly choose to quote Bonbright without an understanding of the full context of his principles. Bonbright specifically recognizes that all of his principles cannot be implemented in the real world at the same time because they conflict with one another and gradualism is an excellent example of a principle that causes regulatory conflict. A simple example illustrates this point. Gradualism, as defined by Bonbright does not even state that principle is absolute because he refers to a "minimum of unexpected changes". A minimum is far different from none as proposed by witness Baatz. The principle also conflicts with cost fairness and equity as demonstrated conclusively in this case. The principle also conflicts with compensatory rates that are subsidy free simply because the current customer charge causes low use customers to be subsidized by high use customers. Finally, the concept of gradualism is not fairly measured by a percentage increase as noted by witness Baatz. I have discussed this concept in my Rebuttal Testimony and I will not repeat that discussion here.

Q. Is witness Baatz correct in his conclusion that a high customer charge is antithetical to energy efficiency and conservation?

A. No. As I show above the opposite is true. It is the low customer charge rate resulting in a marginal price far above TEP's marginal cost that is antithetical to energy efficiency and conservation simply because it induces wasteful investments that provide far less customer benefit than the expected benefits based on rates in excess of marginal costs. Customers, who base their decisions on kWh rates above marginal cost, waste valuable resources. Those same dollars could be used to produce a higher return elsewhere in their household budget.

Q. **Please comment on witness Baatz's claim that TEP's proposed rate design will increase consumption in its service area.**

A. If rates above marginal cost promote increased consumption that would imply that such use is economically justified (part of the Bonbright principle on consumer rationing). In that case, all of TEP's customers benefit since that extra revenue would reduce the frequency of rate cases and reduce rates for customers over time. As for the claim itself, the evidence cited by witness Baatz is not sound. In a 2012 paper by Koichiro Ito of Stanford University he found that customers respond to the total bill rather than marginal energy prices. This means that the non-linear energy prices under the inverted block rates are not useful as a tool to promote energy conservation. This is further evidence that the insistence of witness Baatz and others that the rate design will promote energy use is not possible when bills actually increase. The findings in this article are not new and have been replicated over the years in various studies.

IV. <u>OTHER WITNESSES.</u>

Q. **Witness Kobor opposes any customer charge increase. Please comment on her opposition.**

A. Witness Kobor offers no new evidence in her support of applying all of the increase to the kWh charge. I believe this position is totally self-serving for solar DG advocates. She has not offered any evidence that supports the basic customer method for customer cost allocation purposes and I have addressed the issues of that method in detail above and in my Rebuttal Testimony. I will not repeat that evidence here. I will merely point out that witness Kobor has not provided anything new to support her conclusion and her recommendation of no increase is based solely on a discredited methodology.

Q. Does witness Zwick properly characterize your Rebuttal Testimony?

A. No. Witness Zwick creates an argument that is not in my Rebuttal Testimony and then refutes the argument. In my Rebuttal Testimony, I merely show that the process used by witness Zwick to estimate eligible low income customers for purposes of criticizing the TEP participation rate is flawed. In simplest terms the data used to estimate the eligible population includes low income individuals or households that are not poor. This is a common problem working across databases to estimate electric customers who qualify as poor. Second, I point out that not all poor, low income customers have electric bills. That point has nothing whatsoever to do with master meters. Instead it recognizes group homes and other institutional living arrangements where persons below the poverty level have no electric bill.

Q. Witness Zwick disputes your conclusion that correlation between use and income is weak. Please comment on his position.

A. The concept of weak correlation does not mean there is no correlation between income and use. It simply means that the distribution of regular bills and low income bills demonstrate that there are small differences between the two groups. Using that weak correlation as a basis for public policy related to electric bill assistance, represents a policy that is ineffective and costly compared to a more targeted approach. It is easy to see that conclusion by looking at the number of eligible low income customers whose bills are among the highest bills for the Company as a whole.

Q. Witness Higgins claims that TEP erred in calculating the load factor for the 4CP/AED cost allocation methodology because TEP did not calculate the load factor based on a single peak. Please comment on that assertion.

A. Witness Higgins is incorrect in his assertion. The system load factor that is properly used is defined by the peak – 4CP in this case. In referencing the NARUC Manual calculation as the basis for his conclusion that AED allocation is based on a single peak. If multiple peaks are used as in this case the weighting for average demand is based on the load factor consistent with the identified peaks. Thus the system load factor would be determined in this case based on the 4CP demand. In part, that is why the methodology is identified as 4CP. The logic used by TEP is sound for using the same measure to determine both load factor and excess demand and the weights for each component. If the total demand on the system is relative uniform AED would be based on 12CP and the load factor would be the 12CP load factor and so forth. By using a single peak to calculate the weight of the average demand component and calculating the average demand on a single CP there is a logical inconsistency between the measure of the average and excess components for the system and the weighting applied to those components. The TEP calculation method properly matches the measures of average demand and the weight used for that measure. Witness Higgins failed to understand the significance of the 4CP component in the development of the allocation factors under 4CP/AED. His assertion should be rejected.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF TUCSON ELECTRIC POWER COMPANY DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA, AND FOR RELATED APPROVALS.	))))))))))	DOCKET NO. E-01933A-15-____

Direct Testimony of

Craig A. Jones

on Behalf of

Tucson Electric Power Company

November 5, 2015

EXHIBIT
TEP-30
~~ADMITTED~~

TABLE OF CONTENTS

Exhibits

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Craig A. Jones. My business address is 88 East Broadway Blvd., Tucson, Arizona 85701.

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

A. I am employed by Tucson Electric Power Company ("TEP" or the "Company"), a wholly-owned subsidiary of UNS Energy Corporation ("UNS Energy") as the Director of Pricing. As the Director of Pricing, I am responsible for various rate-related matters including monitoring and coordinating the determination of customer pricing options with any necessary support to justify the creation of the various rate structures for all the regulated subsidiaries of UNS Energy, including TEP, UNS Electric, Inc. ("UNS Electric") and UNS Gas, Inc. ("UNS Gas"). This includes overseeing the development of the cost-of-service analysis and rate design in general rate cases.

Q. Please describe your educational background.

A. I graduated from the University of Missouri Columbia in December 1980 with a Bachelor of Science Degree in Agricultural Engineering. In May 1981, I received a Bachelor of Science Degree in Agricultural Mechanization. I have completed much of the course work required for a Master's Degree in Agricultural Engineering at the University of Missouri Columbia. I am qualified as an Engineer-in-Training under the laws of the State of Missouri.

Q. Please describe your professional background and experience.

A. In February 1983, I joined the Staff of the Missouri Public Service Commission as a Rate Engineer. My responsibilities included analyzing and making recommendations relating to purchased gas adjustment filings, actual cost adjustment filings, rate cases, certificate of service applications, intrastate pipeline applications and applications to establish new local distribution systems. I left the Missouri Public Service Commission in December 1994 to take a position with the New York State Electric and Gas Corporation ("NYSEG"). My responsibilities at NYSEG included establishing prices to be used in "repackaged" contract offerings, training co-workers and end-users with respect to the application of new rates and service concepts, and complying with regulatory filing requirements, including the calculation and filing of the monthly gas cost adjustment filings with the New York Public Service Commission.

I left NYSEG in April 1998 to take a position as Rates Manager with Citizens Energy Group (formerly Citizens Gas & Coke Utility) ("Citizens") in Indianapolis, Indiana. In March 2004, I was promoted to Manager Rates and Regulatory Affairs. I was responsible for various rate-related matters associated with both the natural gas and steam utilities operated by Citizens, including the annual filings for approval of a fuel cost adjustment for the steam utility and the development of the monthly gas cost adjustment filings, various miscellaneous tariff filings, special contracts, and numerous other rate-related activities for the gas and steam utilities, including cost of service and rate design in general rate cases.

In November 2009, I left my position at Citizens and joined TEP as the Manager of Pricing. I was promoted to Director of Pricing in September 2015. Since joining TEP, I have provided pre-filed direct testimony and live testimony in the UNS Gas 2011 general rate case (Docket No. G-04204A-11-0158, Decision No. 73142), and pre-filed testimony in TEP's last general rate case (Docket No. E-01933A-12-0291) and UNS Electric's 2012 and 2015 general rate cases (Docket Nos. E-04204A-12-0504, Decision No. 74235 and E-04204A-15-0142). I have actively participated in the Arizona Corporation Commission's

("Commission") Decoupling Workshops, Line Extension reviews and the filing of TEP's Community Solar tariff and other Pricing and Regulatory activities.

Q Have you previously testified before any other regulatory agencies?

A. Yes. I testified before Indiana Public Service Commission on numerous occasions, including in Cause Nos. 41969-FAC01-FAC15, 41969-FAC03(S1), 41969-FAC06(S1), 41605, 41824, 42578, 42726, 42767, 43025, 43463 37399-GCA68, 37399-GCA68(S1), 37399-GCA69, and 37399-GCA77. I also testified before the Missouri Public Service Commission on several occasions regarding rates, tariffs, and certificate applications.

Q. Are you sponsoring any schedules?

A. I am sponsoring the "G" and "H" Schedules, which summarize the class cost-of-service study ("CCOSS"), rate design, and proof of revenue in this proceeding.

Q. Could you please summarize your Direct Testimony?

A. First, I detail TEP's CCOSS. This study is necessary in order to determine an appropriate total cost to serve each class. The goal of the CCOSS is to determine fair cost allocation and rate design among the customer classes based on the principle of cost causation and the principle of matching costs and revenues. Establishing which classes are responsible for which costs is the bedrock of designing rates. The Company's objective, by undertaking a CCOSS, is to confirm that proposed rates generate revenue that recover costs and provide an opportunity for the Company to earn a reasonable return on investment per customer class.

As part of TEP's CCOSS, I directed the development of an embedded cost study and a marginal customer cost study for the Company. Both studies are useful in developing rate designs that support and reflect valid price signals. The results of the embedded cost study provide important guidance for the class allocation of revenues; while the embedded cost and marginal cost studies, taken together, help determine the level of specific charges to establish just and reasonable rates. For the embedded cost study, the Company has chosen the Average and Excess method to allocate demand costs, a commonly-accepted methodology used in the industry, including by Arizona Public Service Company ("APS"). By contrast, the Company's marginal cost study is a forward-looking study that focuses on the change in costs associated with a small change in the number of customers added to the system – or the cost to replace the current customer related infrastructure to continue service to an existing customer. As a result, the Company can propose rates designed to encourage efficient use of the TEP system and to establish basic service charges that send the right price signals to customers.

Second, I describe the Company's proposed rate design, including modifying existing rates to move toward parity and recover costs in a more equitable manner from all similarly situated customers – by shifting more of the fixed costs into fixed-rate components and to create rate classes that contain a more similar grouping of customers. I describe how TEP's proposed rate design can better align the Commission's policies and support the Company's need for fixed cost recovery, as well as reduce existing cross-subsidies within and between customer classes. To meet these objectives, and in light of the CCOSS results, my testimony explains how TEP proposes a lower percentage rate increase for classes presently paying significantly more than the system-average return on rate base, and a higher percentage rate increase for classes presently paying significantly less than the system average return on rate base. I also detail additional factors focused on in designing rates – including billing determinants, ratchets and consistency. My testimony also explains that the resulting bill impact is reasonable and consistent with the gradualism principle. Additionally, I set forth the bill impacts of these changes.

My testimony also describes TEP's proposal to increase the monthly basic service charges to levels that better match the minimum cost to serve the customer – including incorporating demand-related costs for those classes without a demand charge. The inclusion of some demand costs in fixed charges is consistent with the rule economists call the inverse elasticity pricing rule. That rule recognizes that efficient prices should be set at marginal cost and any additional revenue requirements should be recovered in the most inelastic portion of the rate schedule - in this case the basic service charge. The proposed rate design changes are needed to send customers more accurate price signals. With better price signals to customers and more appropriate fixed cost recovery for the Company the environment will be much more conducive to the promotion of energy efficiency ("EE") and distributed generation ("DG"), as well as the adoption of new technologies. In addition, these more efficient rates provide TEP a reasonable opportunity to earn its allowed return.

My testimony also addresses other rate design changes including: (1) elimination of the third and fourth rate tiers in the residential Rate R-01 and Rate R-201A; (2) the addition of a second tier to comparable time-of-use ("TOU") rates for both Residential and Small General Service rate classes (incenting customers to move their consumption from on-peak hours to off-peak hours in order to generate savings on their bills instead of being able to save on a per kWh basis by simply using more energy); (3) establishment of a charge for those customers who do not want an automated meter installed; (4) establishment of a new Medium General Service ("MGS") class; (5) changes to the minimums, maximums, power factor calculations and demand charges for certain classes; (6) the elimination of Rate LLP-14; (7) creation of a 138 kV rate that will contain only customers' service points that are taking service at transmission level voltage; and (8) revising the Community Solar rate.

In short, the Company seeks to modernize and update its rate design to address: (1) declining usage per customer; (2) low-use/no-use customers that are not paying an equitable share of the fixed costs to operate and maintain the TEP grid; and (3) lost-fixed cost revenues associated with energy efficiency and distributed generation.

Third, I address Lifeline rates. The Company proposes to simplify and reduce the number of Lifeline rates currently in place by offering two levels of discount to the five primary types of Residential customers. Currently, TEP has 27 Lifeline tariffs which contain multi-leveled percentage discount variations, numerous rate design variations and single monthly discounts (limited to a reduction of the bill to zero). Many of these tariffs have only 10 or less participating customers. The Company proposes to modify the current Lifeline Rates in a manner that allows the grouping of customers in an attempt to minimize the impact to a typical Lifeline customer.

Fourth, I discuss the "buy through" tariff the Company is proposing as required under the UNS Energy and Fortis Inc. ("Fortis") merger Settlement Agreement.[1] The Company does not support it, and in fact, is opposed to the implementation of this tariff. It allows for certain large customers to "cherry pick" currently available capacity resulting from short-term energy market conditions and will ultimately result in costs being shifted to the remaining customers.

Fifth, I provide bill impact comparisons by class by using "typical" usage amounts for each major rate class and applying that usage amount to the other similar sub-classes. This provides a more accurate comparison of current rates to proposed rates beyond what is provided in the "H" schedules, although the proposed "H" schedules are expanded in this

[1] Decision No. 74689 (August 12, 2014)

case to include rate schedules individually, along with additional details. This methodology takes into account the increases associated with the rate design changes, the proposed increase in base rates and updated fuel costs.

Sixth, I address the weather normalization and customer annualization adjustments. Both of these adjustments reflect test year billing determinants under normal weather and year-end customer levels, respectively. This adjustment does not reflect a planned reduction in usage recently announced by the Company's largest customer as of the date of this filing. Once more information becomes available, the Company will propose a post-test year adjustment to reflect any substantial changes. For the weather normalization adjustment, I am proposing to use a more refined method that produces forecasts that are more closely aligned with actual results (what I call the "Average Temperature" method). Regarding the customer annualization adjustment, the Company proposes to use the same method that has been approved by this Commission in prior electric rate cases. I also summarize the Company's proposed transmission expense adjustment, and the adjustments and additions regarding miscellaneous service charges.

Finally, I describe TEP's proposed modifications to the Demand Side Management Surcharge ("DSM"), Environmental Cost Adjustment ("ECA"), the Lost Fixed Cost Recovery mechanism ("LFCR") and a portion of the changes to the Purchased Power and Fuel Adjustment Clause ("PPFAC") to better reflect how the specific costs addressed in each adjustor are identified and recovered. Regarding the PPFAC, the Company is proposing that the PPFAC rate be calculated as a percentage of a customer's base fuel rate, rather than as a single per kilowatt hour (kWh) energy rate that is applied to all customers. This approach will more fairly align the changes in fuel costs with each rate classes' base fuel costs.

For the LFCR, the Company proposes to allow recovery of lost fixed costs attributable to generation (including fixed-must run) and the full recovery of lost demand revenues, in addition to other changes. Generation costs are significant, unavoidable and necessary. Because the calculation of demand-related losses specifically identifies the actual amount of offset to the customer's peak demand, only allowing 50% of lost demand revenues does not reflect the actual value of demand-related losses.

II. COST OF SERVICE ANALYSIS.

Q. What is the purpose of performing cost of service studies and how is it beneficial to customers?

A. The cost of service study is the core foundation in developing just and reasonable rates. Once the Company's revenue requirement is calculated, the next step is determining how and from whom it should be recovered.

A properly performed CCOSS analyzes all costs and services provided to each of the primary rate classes. The CCOSS also provides a guide as to how those costs should be recovered from each rate class. As I will discuss later in my testimony, there are multiple ways of determining how costs should be functionalized, classified and allocated. While each party representing a specific group of customers may have an opinion on how those costs should be split between the classes, TEP is focused on allocating the costs as fairly as possible. Fair cost allocation is based on the principle of cost causation. This principle has been referred to as the gold standard of cost of service. Equitably allocating costs between the classes protects all customer classes and creates rates that attempt to assign customers the actual cost of serving them. The Company's goal is to create fair and equitable rates for all customer classes under sound Cost-of-Service and Rate Design principles.

Q. Please discuss the concept of cost of service as a tool for ratemaking.

A. The process of developing rates relies on cost of service for establishing both the revenue level by class and the design of rates. By understanding how costs are caused and establishing rates to reflect cost causation, the important principle of matching costs with revenues under new rates will be satisfied. While the CCOSS is a great tool to use in this process, sometimes technology and available data can constrain the overall outcome of the CCOSS.

Q. How does technology and available data limit the usefulness of the CCOSS?

A. The CCOSS attempts to match costs with cost causation. However, it must be recognized that the best possible matching may be constrained by the ability to measure all of the needed elements of cost causation with the current meter and billing technologies. As technology advances in both the areas of cost causation and metering to track those costs, one must also recognize the temporary nature of that constraint. Thus, it is important to begin to modify rate designs so that there is a reasonable transition to new, more efficient rates that are enabled by new technology.

Q. What is the objective of the CCOSS?

A. Based on allocated costs, the goal is to confirm which present and proposed rates generate revenues that recover appropriate levels of costs per customer class. The term "cost" covers both expenses (including taxes) and the return on the Company's investment. The total cost to serve a particular class varies depending on the customers' individual and combined consumption characteristics, installed facilities, labor, and other capital needed to reliably and safely serve customers in the class.

If the proposed rates produce customer class revenues resulting in each class generating revenues sufficient to earn a return on plant that matches the overall return on invested capital, "parity" has been reached. This is typically characterized by a "return index" (actual return/ required return) of one (100%) for each class. The CCOSS is designed to clearly present the costs and the allocation factors applied to the costs. The cost model also includes sections summarizing costs, a list of the allocation factors, and a revenue requirements summary. The "G" Schedules of the filing are assembled using the results of the CCOSS. Please refer to Schedule G-2 – Summary at Proposed Rates to see the results of the Company's CCOSS calculations.

Although existing circumstances may preclude reaching "parity", the goal should be to use the results of the CCOSS to minimize cross subsidies both between and within customer classes.

Q. Please summarize the types of CCOSS used in allocating revenue and designing electric rates.

A. Cost studies may be based on embedded costs or marginal cost. Embedded cost studies analyze the costs for a test year based on either the book value of accounting costs (a historical period), the estimated book value of costs for a forecasted test year or some combination of actual and forecast costs. The cost of service period is adjusted for known and measurable changes and is normalized and annualized. The cost of service used for the study is also used to determine the revenue requirement and is based on the 12-months ending June 30, 2015 for this filing.

Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions and classes and between customers within a class. In addition to providing information related to the allocation of revenue requirement changes among customers, the CCOSS provides valuable information for rate design. A fully unbundled CCOSS provides the fully allocated costs of a detailed list of various services provided by the Company.

By contrast, marginal cost studies do not reflect actual costs but rely on estimates of the expected changes in cost associated with changes in service. Marginal cost studies are forward looking to the extent permitted by available data. Marginal cost studies are most useful for rate design when it is important to send appropriate price signals associated with demand and energy consumption by customers in a particular class. Marginal cost is also important for determining optimal seasons and time of use periods. In this case, TEP is relying on information from both the embedded and the marginal cost studies for its recommendations related to rate design.

Q. **Have you prepared cost studies for this case?**

A. Yes. The embedded cost study for the test year has been prepared under my supervision and can be found in Schedule G submitted as part of this filing. Also prepared under my supervision is an analysis of the marginal customer costs for residential and small general service customers to support improvements in the efficiency and tracking of costs for the historic two-part rate design consisting of basic service charges and volumetric charges.

Between the marginal cost study and the embedded cost study there is sufficient information to develop a just and reasonable rate design for customers in the classes where we currently bill only a basic service charge and an energy charge. Ultimately, the ideal rate design should include a combination of demand charges, a basic service charge and time differentiated energy charges for all. This will allow the Company to convey accurate price signals to customers about the cost of the individual services they purchase from TEP.

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.

A. Cost of Service and Economic Theory.

Q. Please explain the importance of cost causation in developing a cost of service study.

A. Just and reasonable rates must avoid undue discrimination and must reflect the principle of "user pays," also known as "cost causation," or as I prefer to say, those who cause the costs should pay the costs. Undue discrimination occurs when customers pay significantly different amounts for the same service without good cause.

The development of cost-based rate structures permits regulatory review of the costs that are the same on average for customers in the class. I say "on average" because no two customers are exactly alike. Therefore, we determine costs and set cost-based rates for "typical" customers grouped by similar demand and usage patterns. For example, residential customers may have different service costs just based on the proximity to the distribution transformer. Typically, the customer on the same side of the street as the transformer will have a shorter service line than the customer across the street. As a result, the cost of service differs based on which side of the street the home is located.

In setting rates, we use the average cost of the two services. Once we determine the customer-related costs, those costs should be recovered in the basic service charge. If those costs are not recovered in the basic service charge, then they are recovered in the volumetric charges which results in the customers with higher than average energy consumption subsidizing the customers who use less than average. The cost of service study that unbundles customer costs provides a benchmark to assess the rates to determine if they are just and reasonable and do not discriminate based on the rate design.

I am not alone in expressing this view. For example, the Rocky Mountain Institute has published a report titled "RATE DESIGN FOR THE DISTRIBUTION EDGE: ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE". That report, published in August 2014, recommends full unbundling for efficient integration of distributed resources that include not only DG but conservation and DSM as well. In the executive summary the report states "...bundled, volumetric block rates—provide little or no incentive for the deployment and operation of DERs (Distributed Energy Resources) at the times and places where they can create greatest overall benefit. The perpetuation of these pricing structures in the face of ongoing improvement in DER cost and performance and increased adoption of these technologies will result in *lost opportunities for cost reduction and inefficient utilization of assets on the part of both customers and utilities*." (Emphasis added.)

It is also important to know the marginal cost because the economic concept of "subsidy free rates" means that the rate must be above marginal cost but less than stand-alone costs. In order for rates to be efficient, the concept of customers being charged for the distinct services they use is important because different customers use different services. Further, the costs of those services may be different because of the different load characteristics of customers within the same class. Both cost allocation and rate design are critical in designing efficient rates.

Q. How have you approached the development of the cost studies?

A. A properly developed cost of service study represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. Understanding cost causation requires an in-depth understanding of the planning, engineering, and operations of the utility system, as well as the basic economics of the unbundled components of the electric system. In developing both the embedded cost study and the marginal customer cost study, I have relied on input from planning, engineering and operations within the Company.

Q. Please describe the nature of utility costs.

A. The requirement to develop cost studies results from the nature of utility costs. Utility costs are characterized by the existence of common and joint costs.[2] In addition, utility costs may be fixed or variable.[3] Finally, utility costs exhibit significant economies of scale.[4] These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies requires an understanding of the operating characteristics of the utility system. Further, as noted above, different cost studies provide different contributions to the development of economically efficient rates and the cost causation by customer class.

Utilities are unusual in the relationship between fixed and variable costs. The only variable costs for an electric utility are the costs of fuel, purchased power, fuel handling

---

[2] Common costs occur when the fixed costs of providing service to one or more classes or the cost of providing multiple products to the same class use the same facilities and the use by one class precludes the use by another class. Joint costs occur when two or more products are produced simultaneously by the same facilities in fixed proportions. In either case, the allocation of such costs is arbitrary in a theoretical economic sense.

[3] Fixed costs do not change with the level of output, while variable costs change directly with the utility output. The vast majority of non-fuel related utility costs are fixed and do not vary with changes in load.

[4] Scale economies result in declining average cost as output increases and marginal costs are below average costs.

and some limited amount of variable operating and maintenance expense ("O&M"). All other costs are fixed. The fixed costs for TEP represent the sunk costs of the utility to produce and deliver electricity and provide other services to customers, such as taking energy from customers who self-generate in excess of their own needs and push that excess back onto the distribution system for delivery to other customers. The portion of fixed and variable costs of the total cost of service varies among the customer classes based on the types and quantity of the services used by the customer. Currently, the fixed component of TEP's residential rates (Basic Service Charge) only recovers approximately 17% of the average level of fixed costs approved in the Company's last rate case with the remaining fixed costs being recovered volumetrically through the delivery charge.

As a practical matter, failure to recover fixed costs in fixed charges results in unreasonable outcomes by creating subsidies both between and within the classes. It can also result in the utility recovering either more than or less than the authorized revenue requirement, based on whether consumption is higher or lower, respectively, than the levels used in the determination of base rates.

In today's market, traditional rate classes are no longer homogeneous. In fact the availability of self-generation (particularly solar distributed generation) has created a second class of customers within the typical residential service class. Some customers remain the traditional full requirements customer using all of the bundled services of the utility while a growing number of customers have become partial requirements customers who use the utility's services differently. 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. 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 requirements customer.[5] However, the self-generating customer purchases far fewer kWh and thus avoids paying for fixed distribution costs when rates recover those costs in energy charges. The table below illustrates this problem. The table presents a comparison of two residential customers with identical energy usage and delivery requirements. The customers both use an average of 900 kWh per month. One customer is a full requirements customer taking service on Rate R-01. The other customer is a partial requirements customer and owns a photovoltaic ("PV") DG system that is sized to produce 100% of the energy the customer uses over a year. The partial requirements customer is on a net metering tariff that allows the banking and rollover of excess self-generated energy production.

Residential Customer Comparison	R-01 Full Requirements Customer	R-01 DG Customer with Net Metering
NCP kW Demand	6.3	6.3
Annual Billed kWh	10,800	32
CCOSS Customer Costs ($/customer/year)	$188.00	$188.00
Distribution Demand Cost ($/NCP kW/year)	$44.27	$44.27
Annual Customer & Distribution Costs	$466.19	$466.19
Annual Customer & Distribution Revenue	$437.09	$240.3

As this table illustrates, even though the partial requirements customer requires the same sized equipment and has the same capacity needs (e.g. on cloudy days or at night), they are paying only a little over half as much as the full requirements customer for the fixed costs of electric service. In reality, the partial requirements customer is also likely to require more services than the full requirements customer, even though their demands are the same.

[5] This is because the DG customer may require additional investments in the distribution system to provide frequency control and power factor correction, for example.

The Company is moving to a new rate design model that is designed to better recognize that the distribution system is a critical and regulated or monopoly component of the new market model. While distributed generation, in the form of PV solar, wind and combined heat and power ("CHP"), changes the amount of energy that must be produced by central generation, it continues to be dependent on the distribution system for many critical services.

Q. How is cost causation determined?

A. In many cases determining cost causation is as simple as asking the question of whether a particular cost changes when the service required by a customer changes. If a change in a customer's service causes a change in costs, then the particular service should be considered a cost causer. For example, if the number of kWh increases, does the cost of some input such as miles of conductor increase with more kWh? Since the miles of conductor do not change with kWh either monthly or annually, energy consumption is not a cause of conductor costs. What we do know is that the number of miles of conductor increases when new customers are added to the system, thus the customers are the cause of the cost. We also know that the length of conductor increases with the growth of the peak load on the conductor which may require paralleling the system, looping the system, or networking the system. It may also mean building added capacity through expanding the system to a three phase conductor. This means that some of the cost of conductors is also caused by the demand on the conductor. In any case, the factors driving the cost of conductor are customers and a measure of non-coincident peak demand. Following this logical process allows one to determine cost causation for each element of the system.

Fundamentally, performing cost of service studies is comprised of applying experience and science. The science of the process involves calculations consistent with the methods outlined in the National Association of Regulatory Utility Commissioners Electric Utility

Cost Allocation Manual ("NARUC Manual"). The art of applying experience involves the subjective application of certain methods, in conjunction with consideration of policy objectives, regulatory case law, emerging issues, and other factors, within the framework of the regulatory process. Every utility system is different and those differences impact the choices that the cost analyst makes based on the relevant cost causation factors for each utility system. The art of the cost study is having an understanding of how the unique characteristics of the utility should be combined with the various scientific methodologies.

Q. How do you decide what type of cost you are analyzing?

A. There are three fundamental cost classifications that are the basis for cost causation: customers; demand; and energy. Essentially, all costs incurred by the utility are directly or in some cases indirectly related to one of these three classifications. That is, a utility incurs costs based on: (1) the number, size, geographic location and type of customers; (2) a combination of several measures of customer demand; or (3) a measure of the energy used by customers. Within these three cost classifications there may be different measures of the factor based on how costs are incurred when allocation factors are developed.

The NARUC Manual identifies three fundamental methods for allocation of demand related costs: Coincident Peak ("CP") methods, Non-Coincident Peak ("NCP") methods and Average and Excess Demand ("AED") methods. Within each of these categories, there are numerous specific formulations of the methods. Further, to reflect the cost of an electric system, a complete cost of service study requires application of more than one demand category of these allocation methods. For example, class non-coincident peaks drive the allocation of part of the distribution system capacity while it is some combination of coincident peaks and demand and energy methods that drive the allocation for generation. Within each of these fundamental allocation methods, there may be multiple specific methods. CP allocation category options include a single CP, 4 CP, 12 CP, winter/summer CP and so forth. In addition to the AED allocation method, there are a number of methods that consider both demand and energy such as peak and average, peaker methods and so forth. These methods are all described in the NARUC Manual.

In any event, the choice of allocation methods relies on the concept of cost causation to choose the most appropriate method that best reflects those costs based on the particular utility's system. NCP methods may use a variety of peaks other than the actual system peak based on the peaks of individual service classifications or individual customers. Cost causation requires the determination of the cost to serve each class of customers in a way that recognizes apparent cost responsibility and reflects the engineering and operating characteristics of the utility system. It is not unusual that a cost study includes all of the methods for allocating demand and more than one of the variants of these methods.

Q. **Please explain the classification and allocation of distribution costs.**

A. There is an underlying logic to the choice of the most appropriate demand allocation methodology. The system distribution plant consists of different facilities that have different cost causation factors. The reason for this is threefold. First, load diversity increases as the cost becomes more remote from the individual customer. Second, some facility cost is the direct result of the individual customer and is caused by the customer unrelated to demand. These facilities include the meter and service line. Third, other local facilities have both a customer and a demand component. Transformers are sized to meet the NCP of the customers served from a single transformer but utilities do not install every possible size of transformer. Instead, utilities use a standard set of transformer sizes and one of those is the transformer that represents the minimum size. Transformer costs exhibit significant scale economies. This means that the smallest transformers cost much more per kVa than larger transformers. Given the fact that utilities typically use a minimum size of transformer, the cost of the minimum size is related to a customer since every customer requires transformer capacity.[6] For transformers larger than the minimum size, the remainder of transformer cost is related to demand. The portion related to demand is based on the customers served from each transformer and represents a much smaller share of costs than the customer component. Given the proximity of the customers to transformers, there is limited diversity for transformers that may serve a few customers and no diversity if a transformer serves only one customer. Thus, transformer demand is related to the individual customer NCP. The NCP for the system based on the sum of individual customers is much higher than either the system coincident peak or the sum of the class NCPs. For facilities located close to the customer, such as transformers, secondary conductor, and secondary poles and even single phase primary conductor, both a customer component and the individual NCP allocation factor is the most appropriate. As the cost becomes more remote from the customer, it is the class NCP that drives the costs. This applies to the demand portion of primary poles and primary conductor. The substation related investment is based on the class NCP allocation factor alone. In fact, any number of substations peak at different times and even different seasons from the coincident peak demand of the utility.

Q. Have you considered the customer component in the CCOSS you have developed for the Company in this rate case?

A. Yes. The allocation of certain costs to a mix of "customer" and "demand" is provided in Schedule G, sheet G-7 Allocations.

---

[6] For larger customers, the customer may provide its own transformers or even its own substation in the case of some very large customers. These distinctions are typically reflected either as credits in rates or separate rate schedules for different service classes defined based on use of distribution facilities.

Q. Are all customers allocated some level of distribution costs?

A. Yes, but not always at the same level. Distribution costs differ based on the portion of the system used by different classes of service. In fact, some customers make no use of certain portions of the distribution system at all. As a result, only limited amounts of distribution costs are allocated to customers taking service at 138 kV. Metering related costs, some level of intangible and general plant and a portion of administrative and general ("A&G") costs have been included in the allocation to this class. Where customers own their own substation and connect directly to the transmission system, the customer causes no specific plant related distribution costs to the utility. These customers are typically served either through special contracts or under a transmission voltage service rate schedule. Further, not all customers use the same level of distribution facilities. For example, customers may own their own transformers. Some larger customers may be served at primary voltages only and thus use no secondary facilities. For very large customers, the customer may use only the three-phase primary system operating at the upper end of voltages for the primary system. Where the utility data supports the identification of the facilities at a detailed level, it is possible to reflect the actual facilities used. Distribution costs may differ based on the facilities required to serve some customers. Some loads require extra facilities based on unique load characteristics such as low power factor or frequency regulation for intermittent loads. In that case, the customer may require special rate provisions such as a facilities charge or power factor adjustment to pay for the extra investment. When customers share common load characteristics that are substantially more or less than a comparable standard customer, they may warrant a separate class of service. This is particularly important to recognize for partial requirements customers who would typically require their own class of service because of their unique load characteristics.

For distribution plant costs found in FERC Account Nos. 364 - 374 either all or a portion of the costs are customer related because they are caused by customers. For Account No.

369 - Services, each customer has a service designed to meet that customer's own load characteristics. Services are dedicated to a customer based on their load and each customer causes the cost of its service even if the customer never consumes any energy beyond that required for a single light bulb. If the customer is able to avoid all volumetric electric charges and pays only a nominal, non-compensatory basic service charge, the result is not just and reasonable and causes undue discrimination unless that minimum charge covers not only the service line costs but the component of all of the other distribution costs related to providing the customer access to the electric system. More importantly, there are demand related costs associated with the distribution system that must also be recovered. Partial requirements customers who use little or no net energy must still have a distribution system designed to meet the maximum non-coincident peak of the customer. TEP must have an opportunity to recover these costs as well.

Q. How is the appropriate level of meter and metering related costs determined by customer class?

A. Electricity will not flow into a premise (at least not legally, unless it is an un-metered lighting customer) without an electric meter (Account No. 370). Meters are virtually the same for all small customers. However as the size of the customer increases, the meter installation becomes increasingly complex and the cost of meter sets increases. In addition, Account Nos. 371 – 373 (investments on the customer's premise) represents facilities that are also customer related. In the case of these facilities, the customers who request the extra service provided by these facilities typically pay for these directly as in the case of Account No. 373 related to lighting. In addition to the costs of Account Nos. 369 - 373, a customer cannot be connected to the system (or receive service) without a minimum level of distribution services provided through the assets in Account Nos. 364 - 368. These accounts support the basic distribution facilities that must be extended to connect new customers to the system and to meet the maximum demand of those customers. All existing premises were at one time new customers for whom the system must have been extended. Further, the Company must continually replace aging infrastructure to continue to serve all customers regardless of their annual kWh usage. In the case of these distribution facilities, the minimum size of equipment commonly installed under current policies and procedures represents the costs caused by customers in order to connect the minimum load to the system. The minimum system concept assures that customers who cause the costs of facilities to interconnect to the utility are properly allocated those costs. The current costs for new, minimum sized facilities are a fundamental component for estimating the marginal customer costs for TEP. The demand component of these costs also needs to be recovered to compensate for standby and supplemental services as well as the other services typically provided to support a DG installation.

Q. Are there other costs that are customer related and should be allocated to the basic service charge calculation?

A. Yes. First, a portion of the O&M associated with the distribution plant accounts that are allocated on both customer and demand are appropriately allocated to customer-related costs as well. In addition, where all of an account is allocated as customer-related, all of the O&M should also be allocated to customer costs. Second, customer service related expenses should be fully allocated to customer costs. Third, a portion of general plant costs should be allocated to customer costs to include such items as customer service facilities, the meter shop, stores and tools and equipment. Fourth, a portion of administrative and general expenses should be included in the customer costs as well. Inclusion of general plant and A&G costs is based on the requirement that significant overhead costs are related to direct payroll costs included in the O&M accounts for distribution and customer service expenses. This is the concept of capturing the fully loaded costs of the service provided and includes not only workspace costs but pension and benefits cost and other items related directly to employee costs. These costs are also a proxy for the marginal customer cost study.

Q. Please discuss the classification and allocation of distribution plant.

A. As noted above, distribution plant is classified as demand, demand and customer, or just customer depending on the costs. Each component of the distribution system requires a different allocation factor based on the classification of the costs and the role that customer diversity plays in causing the costs. For plant functionalized as distribution plant and found in accounts related to facilities associated with distribution substations (Account Nos. 360-363), the plant is classified as demand and is allocated on the class NCP. Substations reflect the diversity of the customers served out of a particular substation. Typically, substations have different mixes of customer class and loads. As a result, substations often peak at times different from the system peak loads. Some substations may even have peak loads in a different season of the year than the system. The use of the sum of the class NCPs accounts for the differences that occur in the capacity demand on substations. Diversity of load on the distribution system is greatest at the substation level where multiple feeders serve a variety of customers and loads.

For distribution facilities in the accounts related to the power lines and transformers (Account Nos. 364-368) where power is delivered to the interconnection point with the customer, the costs are classified as both customer and demand. While there are several methods to classify these costs between customer and demand, the minimum system approach is the most consistent with cost causation because it represents the actual cost of connecting a customer to the system to serve the minimum load that meets the parameters of the approved line extension policy. Any investment, greater than the minimum system, must be related to the customers' maximum demands on that portion of the system. Thus, in addition to the customer allocation, the demand allocation is based on the sum of the customers NCPs for each class of service. For the remainder of the distribution accounts (Account Nos. 369-373), the costs are classified as customer and are allocated on a customer basis with as much direct assignment of costs as possible. The final distribution account (Account No. 374) is related to amortization of polychlorinated biphenyl related costs and is allocated based on the transformer investment.

Q. Is there a listing of allocation factors?

A. Yes. Allocation factors are listed in Schedule G-7.

Q. During the rate design process, did you achieve parity as it relates to each classes contribution to the return on plant?

A. No. The Company strives to achieve parity where possible, but due to the principle of gradualism, we made some reasonable adjustments. The impact on customers must be compared to the benefits of moving to fully cost-based rates. This approach moderates what would have been even larger variations in the percentage rate changes some classes would have received. In other words, we balanced the need to move each class towards rates that are more reflective of cost of service while recognizing that such a move must be tempered with other factors like gradualism. Some classes will be affected more than others because their below cost of service rates have been subsidized by other customers for many years. The Company is attempting to move in the general direction of parity between classes, and send customers more accurate price signals, but to truly achieve parity will likely take a few more rate cases.

To better understand how the return on plant varies by rate class based on the different assumptions, the table below reflects the by-class return on plant at the Company's proposed rates under the demand allocation method used in the last rate request and the method the Company is proposing in this rate case. Historically, the Company has used the Peaks and Average method, but in order to address an argument that the Peaks and Average method may have the effect of doubling some portion of demand-related costs that are allocated to certain rate classes, the Company has chosen to move to the Average and Excess method. This is the method used by APS and is a commonly accepted methodology used throughout the utility industry.

CCOSS COMPARISON OF DEMAND ALLOCATIONS

	RESIDENTIAL SERVICE	SMALL/MED GENERAL SERVICE	LARGE GENERAL SERVICE
Current Method: Average & Excess & 4CP			
Demand	1,170,148	510,535	271,781
RETURN AT PRESENT RATES	-1.60%	19.35%	4.61%
RETURN AT PROPOSED RATES	**$17,239,214**	**$78,421,423**	**$52,019,773**
RETURN ON RATE BASE	**1.51%**	**16.13%**	**21.60%**
Method Last Case: Peaks & Average & 4CP			
Demand	1,036,724	482,855	318,777
RETURN AT PROPOSED RATES	**$38,377,205**	**$82,809,951**	**$44,582,737**
RETURN ON RATE BASE	**3.60%**	**17.62%**	**16.66%**

B. Marginal Cost of Service Study.

Q. Please explain why a marginal cost study is of value in this case.

A. There are several reasons why knowing the marginal cost is valuable in designing rates. First, economics tells us that prices set on marginal cost leads to the efficient use of scarce resources. Customers cannot make efficient decisions about how to spend their energy dollars, including capital investment, unless they know how costs will change at the margin. For example, under cost-based rates, if a DG customer and a full requirements customer use exactly the same average distribution system components, the rates charged to both customers for those services should be the same. If the DG customer uses more of some service, such as voltage regulation, because of the intermittent nature of the solar PV system, that extra cost should be borne by the DG customer. If rates do not recover the same or even more costs from the DG customer in this instance, the allocation of energy dollars is economically inefficient because of the resultant subsidy.

The second reason for understanding marginal costs is that if a customer pays less than marginal cost for the service, other customers would be better off if that customer was not served by TEP. This situation is analogous to an extension policy where if the revenues are inadequate to support the investment, the customer makes a contribution to defray the excess costs so that other customers do not have their rates increased to provide a connection subsidy at the margin.

Third, marginal cost provides a guide to rate design. Essentially, the price of any unbundled service should not be less than marginal cost. In the case of the basic service charge, the charge is really more appropriately classified as an access charge. That is, it represents the cost of having access to the unbundled distribution services of the utility. Therefore, the marginal cost study identifies what the floor is for establishing a basic service charge, where the embedded cost study indicates in total the revenue requirement to be recovered from the combination of all charges. This establishes a minimum basic service charge for the class.

Q. Please describe the marginal customer cost study.

A. Studies used to calculate marginal costs are common in rate case filings and use relatively consistent methodologies. Marginal cost studies focus on the change in costs associated with a small change in the number of customers added to the system or the cost to replace the current customer-related infrastructure to continue service to an existing customer.

Marginal costs are forward looking and require making estimates of future costs with an understanding of the elements that drive those future costs. As a practical matter, marginal costs bear no relationship to the mix of actual historical costs that constitute the utility revenue requirement. The reasons that marginal costs do not reflect actual costs used in revenue requirement calculations include the following:

- The relationship between historic and prospective costs reflects changes in technology.
- Sunk costs (the fixed cost of the existing system) do not impact marginal cost but may account for a large portion of the test year revenue requirement, particularly where economies of scale are significant.
- The underlying impacts of inflation on prospective costs cause such costs to differ from past costs.
- Additions to the system are lumpy and as a result, utilities' optimal additions often include more capacity than the marginal change in customer count.

Q. What are the steps involved in estimating marginal cost?

A. To estimate marginal cost, the first step requires determining the change in cost associated with the addition of a new customer on average. I say on average because there are two different types of customers that may be added to the system. The first type of customer is added at a point on the existing system and thus requires a smaller investment than a customer that requires a larger investment such as a line extension. The second type of customer is added at the periphery of the system and requires extra investment to connect the customer to the distribution system. The marginal cost study takes this into account by weighting the proportion of customers that are in each category.

Electric distribution systems (from the customer's meter up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into consideration the density of customers in a particular location and the expected loads of those customers. For example, an area with all-electric homes may have different design standards than an area where the homes are not electrically heated. Distribution facilities for larger commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served ultimately, not specifically on the number of customers or their actual loads at any given moment. The concept of a network cost provides a convenient way to discuss the marginal distribution costs. Network costs represent the cost of the interconnected facilities that serve local loads and include: substations, feeders, transformers, service drops and meters. Feeders may be primary or secondary lines depending on the location of the customer and the design of the system. The customer component of these systems is related to the smallest size of the equipment that is installed to serve customers. If larger equipment, such as that required for all electric homes, is installed the extra costs are demand related. The economies of scale in the distribution system mean that the demand-related cost is much less significant than the customer component.

Q. **Have you provided the marginal customer cost study results?**

A. Yes. The results of the study are attached as **Exhibit CAJ-1** and consist of three schedules. Schedule 1 is a summary of all of the components, the costs and provides the marginal customer cost for residential and small general service customers. Schedule 2 provides the minimum system investment for each component of the customer marginal cost along with the levelized carrying charge rate for each component to produce the revenue requirement for the component. Schedule 3 provides the customer-related expenses based on the embedded cost study that are customer related.

Q. Have you identified the minimum size components used by TEP in the delivery system?

A. Yes. We have worked with the Company's distribution engineering and operations groups to determine the smallest standard size of facilities used and with the accounting function to determine the fully loaded installed costs of these components. Schedule 2 in **Exhibit CAJ-1** provides the cost of the minimum system components. In addition, the schedule provides the economic carrying charge rate and the appropriate weighting for customers requiring a line extension. This schedule produces the marginal revenue requirement for customer-related capital expenditures. The economic carrying charge rate uses the Company's capital structure and the marginal cost of the components of that structure. The forward looking nature of a marginal cost study requires that the capital cost be estimated on an incremental basis, not on embedded costs.

Q. Have you identified the customer related expenses?

A. Yes. The customer related expenses may be found on Schedule 3 in **Exhibit CAJ-1.** These expenses were based on embedded costs as a proxy for long-run marginal costs. In the short-run these costs would be zero because adding one customer does not change most of these costs. However, at some level these costs would increase by an amount related to the average cost when a minimum number of customers have been added. This approach provides a reasonable proxy for the O&M related costs.

Q. Please summarize the results of the customer costs on an embedded and a marginal cost basis.

A. The results are summarized in the table below.

Table 1

Cost Study	Residential	Small General Service
Marginal Customer Cost	$29.49	$219.60
Embedded Customer Cost	$15.67	$45.55

Q. Why are marginal customer costs so much higher than embedded customer costs?

A. There are several reasons marginal costs are much higher than embedded costs. First, as part of the Company's efforts to improve service reliability and have the capability to refine its rates to modern unbundled rate design, the costs reflect a significant change in metering technology. These meters are more costly than the traditional watt hour meters used since the 19th century. Second, the impact of inflation on certain portions of the distribution assets has been significant. For example, since 2005 the cost of electric transformers has increased by over 42% based on the Handy Whitman Index. This means that the depreciated original cost for these assets is far below the replacement cost for these assets. Third, the pattern of infrastructure replacement differs from the installation of all new infrastructures. This timing difference results from the different useful lives of the original infrastructure installed to serve customers. At any point, the average age of assets and the pattern of cost recovery is significantly different resulting in higher marginal costs.

Q. Please explain how the embedded and marginal cost of service studies provide the necessary support for the proposed basic service charge levels.

A. The embedded cost of service study guides the allocation of revenues among the classes of service. Specifically, that study, which includes use of the minimum distribution system approach, clearly identifies the embedded levels of distribution, customer related, and other costs by class of service. In order to fully evaluate the appropriate level of basic service charge, a marginal cost of service is required to support and reflect a valid price signal related to connecting customers. To the extent that the basic service charge is set below the marginal cost level existing customers will be subsidizing the costs of connecting new customers. Together, the embedded and marginal cost studies provide the Commission with the full picture as to how total revenues should be allocated across classes; and in turn, how customer costs and the cost of connecting a customer should be set to send correct price signals to customers and to encourage economic use of the system.

III. RATE DESIGN.

A. Overall Objectives of Updated Rate Design.

Q. What are the Company's objectives in rate design?

A. The Company's primary objective is to modify existing rates to recover costs in a more equitable manner from all similarly situated customers. The Company is proposing to do this by shifting more of the fixed costs into fixed rate components for the more than 95% of the customers who are on a two-part rate and to create rate classes that contain a more appropriate grouping of customers.

To move toward this objective the Company must continually evaluate and adjust rates to evolve with changing cost structures, customer usage patterns, market changes and technology changes. An important first step is to move toward more equitable rate design that will recover more of the system fixed costs, in rate components that better reflect system usage.

Q. Are there other significant rate changes that need to be made to move toward more equitable structures?

A. Yes. The Company is proposing rate class changes to more appropriately group customers by the way these customer groups use the system, including the elimination of Rate LLP-14. A new MGS class will be established that will contain both a minimum and a maximum kW level. This will allow the largest Small General Service ("SGS") customers to move to a more similarly sized, homogeneous rate class that will include a demand charge which will help recover costs in a manner more reflective of the way the costs are incurred. Additionally, the Company is proposing to establish a new 138 kV rate that will be offered to only those customers with the ability to take service at this transmission level voltage or greater. This 138 kV service will only be available for consumption at the meter capable of receiving service at this transmission level voltage, or greater. The Company is proposing the elimination of two rate tiers in the Residential rate class and the addition of a rate tier to each of the rate classes' comparable TOU rates to prevent higher energy usage customers from taking advantage of the TOU rate without having to modify usage habits.

Q. Are there other reasons justifying the need for TEP to update and modernize its rate schedules?

A. Yes. In addition to the reasons outlined above, TEP's proposed rate design has two secondary objectives: (1) to initiate movement to updated industry rate design standards that are more aligned with the Company's need for fixed cost recovery; and (2) to reduce existing cross-subsidies within and between customer classes. To meet these objectives, the Company proposes: a somewhat lower percentage rate increase for classes presently paying more than the system average return on rate base based on the results of the CCOSS; and a higher percentage rate increase for classes presently paying less than the system average return on rate base, where the resulting bill impact is reasonable and consistent with the gradualism principle. **Exhibit CAJ-2**, which I discuss in more detail below, sets forth average annual bill impacts for each of the rate classes based on the Company's proposed rates.

Q. What other considerations were made in developing the Company's rate design proposals?

A. As we analyzed each of the proposed rate design changes and evaluated their potential impacts on customers, we also had to develop a full understanding of how these changes would affect revenues. Our considerations focused on billing determinants,[7] ratchets,[8] and consistency. To best determine the true impact on the customer and the Company revenues, we went to great lengths to determine the appropriate levels of billing determinants. It was essential that we had a complete understanding of the billing determinants as we modified provisions within the tariffs. For the Demand Charge in the new MGS class, we evaluated how the billing determinant changes will impact customers' bills and the Company's revenues as the 75% ratchet is applied to a group of customers that has not historically been billed based on a Demand Charge. Applying a Demand Charge will impact various customers more than others. The Company has attempted to identify groups of these migrating customers that will be falling into different levels of impact. These different levels of impact will be grouped into customers that we anticipate will experience an overall, annual increase at or below the average increase for the class, a group with a moderately larger increase than the class average

---

[7] Billing determinants are number of units on which each of the billing components would apply to generate the Company's Revenue Requirement. By class, this would include the number of bills on which the basic service charge applies, the number of total demand units on which the Demand Charges apply and the number of kWh on which the volumetric charges apply.

[8] A ratchet is a billing provision under which the Demand Charge for each month is based on the highest billed demand over a period of time in the previous year. This mechanism minimizes risk of not recovering fixed costs and properly compensates for the year-round expenses incurred to provide service to a customer. It is also consistent with the fact that the distribution system demand costs are incurred based on the maximum demand of the customer whenever it occurs.

and a group with an increase of a magnitude that will require special consideration to help mitigate if possible. Extra consideration must be made to inform and work with these customers. Numerous methods of communications have been considered, depending on the level of impact and, where warranted, methods of offering temporary billing considerations have been evaluated to allow a customer some time to acclimate to the new rate design.[9] The Company is requesting that as efforts are made to mitigate the bill impact for these customers, a temporary provision be discussed and arranged that will allow the Company to maintain revenue neutrality for the class.

The other demand-related change the Company is proposing in this case is for the current demand charge method used in the current Rate LPS-90 to be applied to the other large customer TOU rate classes as well (the new MGS TOU rate and the current Large General Service ("LGS") TOU rate, Rate LGS-85). Therefore the Company is proposing to use the same method of calculating on-peak and off-peak demand for all three large customer rate classes and the 138 kV rate class. This maintains the same design relating to the demand charges approved for Rate LPS-90 in TEP's last rate case for all other large customer TOU rate classes with a demand rate. This design promotes load shifts from on-peak periods to off-peak periods.

Q. What must be considered with respect to whether the ratchet and billing determinants result in just and reasonable rates?

A. First, in developing these proposed modifications, a thorough analysis must be performed to best ensure that the impacts on the customer are understood and the proposals are fair

---

[9] Since these customers are moving from a non-demand based rate to a demand based rate, low load factor customers, seasonal customers, cyclical use customers, etc. may see unusually high bill impacts. An attempt will be made to mitigate any disproportionally large impacts. Prior to the hearing the Company would like to discuss options with the other parties to arrive at a way to create a revenue neutral way to allow this mitigation of impact to the 50 or so customers the Company believes will be most affected.

and equitable. Second, in the event even one of the design parameters is changed during the rate case process, the billing determinants and ratchets must be re-evaluated to assure the bill impact is acceptable and revenues generated are as expected.

If any change is made to a rate design component, an equivalent review and appropriate change in billing determinants must be made to the revenue proof to assure the revenue proof reflects the appropriate recovery of revenues.

B. Specific Rate Design Changes.

Q. Please provide an overview of the changes that the Company is proposing that are not class specific before moving to the individual rate classes.

A. First, the Company is proposing to increase all monthly basic service charges in a manner consistent with the results of the CCOSS and equitable fixed cost recovery. TEP proposes an increase in monthly basic service charges to levels that better match, but are not equivalent to, the customer-related costs and the minimum cost to serve the customer as indicated by the CCOSS and the marginal cost study which was used as a guide to determine what the minimum cost to serve a customer should be. The majority of TEP's non-fuel costs are fixed in nature because the Company's requirement to ensure that service is available (including having the distribution infrastructure in place) does not change if a customer decides not to use energy on a given day.

Second, the Company is proposing to change the PPFAC charge to a percentage-based rate instead of a per-kWh rate and that it be recalculated monthly based on a 12-month rolling average cost of purchased power and fuel as discussed in more detail in the direct testimony of the Company's witness Michael Sheehan. The Company is also proposing to change the residential DSM and ECA charges to percentage based adjustments. These changes will be discussed more thoroughly later in my testimony.

Third, for TOU customers, the Company is proposing to add a tier to the rates where the non-TOU option contains a tier. In TEP's last rate case, the Company proposed to eliminate the tiers for TOU customers in the hope that the simplified rate would be more appealing to the customers. This inadvertently created a perverse situation where the largest usage customers could benefit from lower average rates and as a result, a lower bill without changing their consumption to off-peak from on-peak times. This unintended consequence can be rectified by adding a tier back to the appropriate TOU rates.

Fourth, for most non-interruptible classes with a Demand Charge, the Company proposes to establish minimum and/or maximum demand amounts (billing demand levels) in order for a customer to become and remain eligible in the individual classes. This should provide for better parity within the classes and thus less intra-class inequity which will make it easier for customers to stay on a particular rate.

Fifth, the Company's current SGS and Large Power Service ("LPS") rates will be redesigned. The Company is proposing to create a new MGS rate that will contain approximately 3,995 former SGS customers and 93 former Large General Service ("LGS") customers, but will be limited to only those customers who the Company has estimated, based on test year data, to use a combined total of 24,000 kWh or more in any two consecutive months or who the Company has calculated will have a minimum demand of greater than 20 kW. Those migrating customers will also be tested to determine if their demand will exceed 250 kW in any month. If so, they will be moved to either the LGS or LGS-TOU rate, as appropriate. Other than the minimum and maximum demand amounts, the design of the new MGS rates (standard and TOU) will be generally the same as the current LGS rates (e.g. 75% ratchet, winter/summer differentiated rates and a single tier rate). The new LGS rate will not undergo a rate design change (e.g. the 75% ratchet will remain), however the billing determinants used to calculate the rates will be recalculated to blend in any migrating customers and the TOU demand calculation will be modeled after the existing Rate LPS-90 method.

The current LPS-TOU customer class (Rate LPS-90) will reflect the current rate design but will see former mining customers blended into the class for purposes of developing the rate. As of the filing of this rate case there is only one customer on the non-TOU LPS rate (Rate LLP-14) and that customer would likely save money if they move to Rate LPS-90. Therefore the Company is eliminating Rate LLP-14 as an option and moving the customer to Rate LPS-90. This is not only beneficial to the impacted customer it is consistent with our general theme of keeping customers on the most cost effective rate classes where possible. Additionally, customers of this size will be more attentive to operating in the most efficient manner if they are on a TOU rate.

Lastly, a 138 kV rate will be established for any customer taking service at a dedicated service point at 138 kV or greater. The general rate design will be similar to the current Rate LPS-90 with the exception that a lower level of losses will be built into the fuel rates because service is being received at the higher transmission level voltage and a portion of the distribution-related costs will be excluded from this rate. All customer related costs and a certain level of distribution level costs will be included in the rate, but some distribution plant will be removed since it is not technically utilized to serve this class. Other system related distribution costs will continue to be assessed to this class since it is still providing benefits to them. This would include A&G, common plant, taxes, overhead costs, etc.

For these firm non-TOU classes the billed demand amount will continue to be based on the greater of: (1) the greatest measured 15-minute interval demand read of the meter during all hours of the billing period; (2) 75% of the greatest demand used for billing purposes in the preceding 11 months; or (3) the contract capacity or the specified minimum demand amount, whichever is greater.

For the firm TOU classes, the billed demand will be based on the method currently in place for Rate LPS –90.

Q. Does the existing rate design, which recovers a significant portion of the fixed costs through volumetric energy charges for most customers, create problems other than revenue instability?

A. Yes. First, the collection of significant fixed costs through energy charges places a disproportionate burden on the customers who are typically using the system the most efficiently. Even though a higher load factor customer is using the system more efficiently (and therefore more cost effectively) than a low load factor customer, having a larger proportion of the fixed costs in the energy rate will result in that higher load factor customer paying a disproportionate amount of the system cost. Shifting revenue collection away from volumetric energy charges reduces the cross-subsidization that occurs when usage within customer classes varies significantly. It also reduces a rate design that promotes the inefficient use of the system.

Second, the existing rate design creates the wrong price signals. Rate design that creates an over-dependence on fixed cost recovery through volumetric energy charges creates an economic disincentive for the Company to promote conservation, EE, and DG. If non-fuel rates are collected primarily through volumetric charges and the recovery of costs is dependent on usage, the associated reduction in sales significantly erodes TEP's ability to earn its Commission-authorized rate of return. This is true even with the LFCR mechanism, as currently designed, since 50% of any demand charge reductions and the entire generation component of retail rates is not currently included in the LFCR.

Q. Can this disparity be resolved solely through modification of the monthly basic service charges?

A. Only partially. The basic customer-related charges are a good starting point to identify what should be included in the monthly basic service charge for each class, but they do not tell the whole story. Historically, basic service charges are limited to metering, meter-reading, service (service drop) to the specific customer, and customer service and billing. While these costs should be included in the basic service charge and may be used as the guide to what the basic service charge should be for classes with Demand Charges, they are not sufficient for classes without a Demand Charge.

Q. Why is it appropriate for a portion of the demand-related costs to be included in monthly basic service charges for classes with rates that do not include a Demand Charge?

A. As discussed earlier in my testimony, the minimum cost of serving a customer includes more than what has historically been seen as customer-related charges. Without some level of demand-related cost being included in the basic service charge for classes without a Demand Charge, a disproportionate amount of the Company's fixed costs must be recovered in volumetric energy charges. Consequently, if customer energy usage falls, the Company will not have a reasonable opportunity to earn its Commission-authorized rate of return. Also, since the current LFCR rate excludes the generation component of retail rates, this will only be exacerbated as the amount of sales erosion from increased levels of EE and DG continues. Modifying the rates to include a higher proportion of fixed costs in the monthly basic service charges will help send customers the right price signals and provide additional support for the Company's efforts to promote EE and DG. Specifically, because the residential and small general service classes currently do not have a Demand Charge, the cost of at least some of the fixed cost items required to serve a customer (such as transformers and distribution conductors) should be included in the monthly basic service charge. It was even acknowledged in the Commission's decoupling workshops that increased fixed charges would help minimize the revenues lost and ultimately recoverable in any decoupling adjustment (including a partial decoupler like the Company's LFCR mechanism.)

Q. Why does TEP prefer increasing the monthly basic service charges over further increasing the energy (per kWh) charges to recover fixed costs?

A. For the smaller rate classes, TEP currently collects the majority of its fixed costs through a volumetric energy charge, which is a conceptually flawed rate design and is made worse by the inverted nature of the charges that cause larger customers to pay well above their actual costs and well above the costs actually saved from conservation. This is because the bulk of a utility's costs are fixed and do not vary with the quantity of energy the customer uses on a given day. The Company is in the business of providing safe and reliable energy service. This means that facilities and personnel must be in place to ensure that customer demand is met – 365 days a year, no matter where or when the service is requested in the Company's service territory. In short, the Company earns a regulated rate of return on the infrastructure necessary to provide electrical service – on demand - to its customers. The obligation to provide safe, adequate, and reliable service does not change, regardless of whether or how much energy TEP's customers consume. This is why the majority of TEP's costs are fixed.

Periodic variation in energy consumption has limited impact on the true, non-fuel cost of serving customers. Most non-fuel costs are fixed and will ultimately produce a mismatch between costs and revenues when a substantial portion of the revenues are recovered through weather-sensitive sales. Increasing basic service charges helps to address this disparity. When basic service charges are increased, energy charges are decreased (holding revenue requirement and other factors constant). Fixed basic service charge revenue stays relatively constant within a given month – despite weather variations, conservation efforts or (in the short run) economic activity. Consequently, basic service charges provide a relatively stable and predictable source for funding fixed costs, which constitute the bulk of a utility's non-fuel revenue requirement.

Q. Will the Company's proposed rate designs guarantee it the ability to earn its authorized rate-of-return?

A. Absolutely not. The Company's rate design hardly guarantees achieving its Commission-authorized rate-of-return ("ROR"). For the majority of TEP's customers, a significant percentage of non-fuel revenue recovery will still be collected through the energy charges (volumetric or per kWh). For example, TEP's residential class (which is responsible for approximately 46% of the Company's non-fuel revenue) is currently collecting approximately 83% of the class' non-fuel revenue through volumetric energy charges. This is similar for the general service class as well, and the general service class accounts for another 30% of the Company's non-fuel revenues. This large allocation of fixed cost to a volumetric energy charge potentially causes large swings in the amount of revenue collected to provide the Company an opportunity to earn its authorized ROR. Warmer than normal summer weather could result in over-recovery and cool summer weather will result in under-recovery of non-fuel revenues. Of course, any conservation effort or decreased use per customer will, by design, result in under earnings for the utility. Further, even with a three-year rate-case cycle, the costs of providing service, including O&M costs, material costs, and plant investments have consistently increased. These factors work against the Company's ability to earn its authorized ROR.

1. **Residential Rates.**

a. **Monthly Charge.**

Q. How do TEP's current residential monthly basic service charges compare to other Arizona electric utilities?

A. The Company's residential basic service charge covers a smaller portion of fixed costs than the residential basic service charges of other electric utilities in Arizona. TEP's residential basic service charge is only $10.00 per month (as low as $6.90 if currently on a Lifeline rate). In contrast, APS, Trico Electric Cooperative, Inc. and Salt River Project ("SRP") have basic service charges ranging from $15.00 to $20.00 per month, with TOU basic service charges in the $18.00 to $36.00 per month range. APS and SRP also have a Demand Charge that applies in addition to the basic service charge in one of its residential rate offerings. 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. While it is imperative to start addressing the issue of moving basic service charges towards reflecting actual fixed costs incurred, the Company realizes the difference cannot be fully addressed in a single rate case. Therefore, TEP is proposing an increase in the monthly basic service charge that makes a step in the right direction, but does not necessarily fully address the issue.

Q. With that background in mind, what increase is TEP proposing to the residential monthly basic service charge?

A. In an effort to move towards more appropriate monthly basic service charges for the residential rate classes, TEP proposes to increase residential basic service charges to $20.00 per month for both the standard and TOU residential customers with some

Lifeline customers paying even less when new rates are implemented. The proposed $20.00 basic service charge is still only approximately 21% of the $93.61 of fixed cost per residential customer quantified in the CCOSS (which is the combined customer service and demand related charges identified by the CCOSS for the residential customer) and is still below monthly basic service charges that this Commission has previously approved for other electric utilities.

Q. Will the increases in the monthly basic service charges also smooth out the amount of revenues that will be recovered through the Company's proposed LFCR mechanism?

A. Yes. Besides reflecting sound rate design principles, increasing these basic service charges will also help to mitigate the amount of lost revenues to be recovered in the LFCR. This is because as the fixed charges are increased, the volumetric charges are proportionally decreased for each rate class. Further, because the energy rate is lower, the total lost margin will be smaller for each kWh lost as the result of Commission approved EE and DG programs.

b. <u>Volumetric Rate.</u>

Q. What volumetric rate is TEP proposing for the residential rate classes?

A. Schedule H-3 shows the various rates and rate components for each of the Company's proposed rates. For the Residential Rate R-01 rate class, TEP proposes an average overall volumetric rate of $0.0688 per kWh (exclusive of purchased power and fuel costs), resulting in a $0.0048 per kWh increase on the average volumetric rate for the Rate R-01 rate. This rate is identified as the "Delivery Services-Energy" charge on the tariffs and is designed to recover the portion of fixed costs not covered by the monthly basic service charge.

Q. Describe the change for Rate R-01.

A. For Rate R-01, which is the residential rate for nearly 80% of our total customers, the Company is proposing only one substantial rate design change other than the increase to the basic service charge. The Company is proposing to eliminate the third and fourth tier in the residential rate class. It adds no cost-based value to the rate class other than exacerbating the issues of fixed cost being inequitably recovered from the higher usage customers. As we move to more cost-based rates, inverted block rates make less sense. As consumption increases, the cost per kWh actually decreases. Therefore, eliminating the upper rate tiers results in a more cost-based rate design. The Company would like to maintain only two rate tiers for the residential classes. However, there is no cost justification for inverted rates and certainly no cost basis for too many tiers in TOU rates. Thus, the tier proposal is an interim step to ultimately eliminate the tiers for more efficient rates.

Q. Describe the changes to the residential TOU rates.

A. Except for the change in the basic service charge described above, the only substantial change that the Company is proposing to make to the residential TOU rates is to add back tiers that align with what is currently in place for the Residential Non-TOU rate and as described earlier in my testimony.

2. <u>Non-Residential Rates.</u>

Q. Describe the changes the Company is proposing for the general service customers and the large power service customers.

A. Much like what the Company is proposing for the residential customers, the changes for general service and large power service customers are designed to more appropriately recover fixed costs in the fixed portion of rates. Basic service charges for the non-residential classes also need to be increased to amounts closer to levels indicated by the CCOSS. The other changes have been described earlier in my testimony, including the establishment of a provision where, if a SGS customer's accumulated consumption in the current billing month and the month preceding meets or exceeds 24,000 kWh, the SGS customer will be moved to the MGS rate. Additionally, both a minimum billing demand and a maximum demand for eligibility in the new MGS rate were created and a new 138 kV rate is being proposed. Demand Charges for all TOU rates will be calculated consistent with the method used in the existing Rate LPS-90 class. Rate LLP-14 will be eliminated.

In TEP's last rate case, the Commission approved a 16.5% transitional credit for municipal customers in order to partially mitigate the significantly discounted rate that was available to municipal customers. Municipal customers enjoyed a substantial subsidy without providing any system benefits that justified the subsidy. The rates approved in the last rate case placed all former municipal customers that were on the former Rate PS-40 on the same rates as a standard general service customer, Rate GS-10, while offering a 16.5% discount to moderate the bill impact. The Company proposes to take the next step towards bringing municipal customers' rates in line with other similarly situated customers and eliminate the discount.

a. Monthly Charges – Basic Service Charge and Demand Charges.

Q. What monthly charge is TEP proposing for non-residential customer classes?

A. For SGS customers, TEP is proposing an increase to the basic service charges for the same reasons as discussed for the residential class, since no Demand Charge is in place for this class of customers. The proposed basic service charge will reflect an increase from the current $15.50 and $17.50 per month to the proposed $30.00 per month for both standard and TOU rate classes. The SGS class will have a provision introduced that a customer will be moved to the new MGS rate in the subsequent month if a SGS customer's two month accumulated consumption in the current billing month and the month preceding meets or exceeds 24,000 kWh.

For the MGS class, the basic service charge will be $40 per month. As set forth in Schedule G-6-1, line 32, the proposed MGS charges are still below the true costs of providing service. Additionally, the MGS class will maintain a minimum billing demand of 20 kW. A new cap of 250 kW will be established such that any customer meeting or exceeding the cap for a billing month will automatically be moved, in the subsequent month, to the LGS rate class. The customer must remain there for at least 12 months without exceeding the 250 kW demand to qualify to move back to MGS.

The LGS class will have a minimum billing demand of 200 kW and the basic service charge will be established at $1,000 per month. The LGS-TOU class will be the same. Even though a MGS customer will be moved to the LGS class if their demand meets or exceeds 250 kW, the minimum billing demand will remain at 200 kW, and the cap on demand for eligibility in the LGS classes (both non-TOU and TOU) will be established at 5,000 kW, at which point they will be moved to the LPS-TOU class. Since Rate LLP-14 is being canceled, once this level is achieved, the customer will only have a TOU rate available.

While there is no distinct rate, the current LPS-90 class contains two types of customers. Service is taken at either less than 138 kV or greater than or equal to 138 kV, with the basic service charge currently established at $2,000 per month. As mentioned earlier, most of the customers in this class receive service at less than 138 kV and will remain in the LPS-TOU rate class and will be served at a basic service charge of $2,000. Aside from updating the rates in this class, no other major changes are being proposed for this class. For the LPS-TOU class, the current minimum billing demand of 3,000 kW will continue to be applied to all customers within the class.

The Company is also proposing a new 138 kV rate. This will only be available to service points where a customer has facilities in place to receive service at 138 kV. The minimum demand billed to any customer receiving service under this new rate schedule will be 10 MW. The basic service charge will be $3,000 per month and will have summer and winter demand charges of $17.15 and $14.15 per kW, respectively, with off-peak excess demand charges similar to the existing Rate LPS-90 class. The volumetric delivery charge will only be $0.0071 per kWh. The customers on this rate will pay slightly lower base power charges than those on LPS-TOU due to this class not being allocated distribution level system losses. The class will be responsible for all of the transmission and generation costs allocated to the Rate LPS-90 class and a slightly reduced level of distribution related costs. While some distribution plant related costs may not be used by this group of customers, they do benefit from the A&G related costs and many of the other miscellaneous plant costs.

Based on the results of the CCOSS, the Company believes these new basic service charges are just and reasonable as they will help levelize the class's contribution to the cost of service while still allowing the Company to recover more of its fixed costs through a fixed charge.

b. **Calculation of Demand Charges.**

Q. How is the Company proposing to calculate demand charges?

A. As discussed above, TEP is proposing to maintain the way it calculates the Demand Charges in those firm non-TOU rate tariffs where a Demand Charge is part of the rate design. This would include the existing LGS-13 rate tariff and the new MGS rate tariff.

The LPS-TOU Rate monthly billing demand will remain unchanged and that demand billing process will be applied to the billing process for the new MGS-TOU class, the LGS-TOU class and the new 138 kV class. The billed demand will be the greater of the following:

(i) the greatest measured 15-minute interval demand read of the meter during the on-peak hours of the billing period;

(ii) 75% of the greatest on-peak period billing demand used for billing purposes in the preceding 11 months; or

(iii) the contract capacity or 3,000 kW (20 kW for MGS TOU, 200 kW for Rate LGS-85 and 10 MW for the 138 kV rate), whichever is greater.

PLUS: the greatest measured 15-minute interval demand read of the meter during the off-peak hours of the billing period that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak billed demand.

These provisions add consistency between the classes and allow the TOU customer the opportunity to save costs in recognition of moving load to off-peak periods.

The Company is proposing to apply one general method to the non-residential non-TOU rate classes that is the same as the method used for the current LGS class. In applying sound cost of service principles, the Company wishes to maintain the billing demand based on the "ratchet" being set at the levels defined above and in the tariffs.

Consistent with the criteria in the current LGS and proposed MGS tariff, monthly billing demand shall be the greater of the following:

(i) the greatest measured 15-minute interval demand read of the meter during all hours of the billing period;

(ii) 75% of the greatest demand used for billing purposes in the preceding 11 months; or

(iii) the contract capacity or 200 kW (20 kW for the MGS class), whichever is greater.

In most of the larger non-interruptible rate classes with a demand charge, the current CCOSS results indicate they are paying more than the levelized system return on plant as can be seen in Schedule G-2 –Proposed Rates, line 38. Therefore, the Company is proposing to make only moderate changes to the demand charge as set forth in Schedule H-3.

This design continues to allow higher load factor customers to benefit from their current usage patterns, which reflect a more efficient utilization of the system and is consistent with sound rate making principles.

c. <u>Volumetric Rates.</u>

Q. What is the Company proposing for the non-residential volumetric rates?

A. Any remaining authorized revenue requirement allocated to these classes will be recovered through an adjustment to the per-kWh delivery rate for the specific class. The volumetric rates vary by class and can be found in Schedule H-3.

Q. Currently, the tariffs that apply to some of TEP's large customers include a charge if they fall below a certain power factor. Is the Company proposing to change this tariff provision?

A. Yes. The Company is proposing to change the way the power factor is applied and billed in the large power service tariffs (Rates LPS-90 and 138 kV). The Company is proposing to change the current tariffs' power factor related charges to a method that matches what is currently in place for TEP's sister company UNS Electric. This method tracks the amount a customer's monthly power factor varies from 100% and applies the current tariff's demand charge to the equivalent demand calculated from the power factor variance from 95%. TEP will also apply the provision in its Rules and Regulations that allows the Company to require installation of power factor correcting equipment on a regular basis, if the provision in the tariffs does not encourage the customers to operate at improved power factors.

The Company is proposing to add language to the proposed 138 kV rate that will require a customer to install equipment that will allow for calculating and tracking the Power Factor to allow for appropriate billing when the customer's equipment places a burden on the system. Additionally, for current LGS rates a provision will be included that will allow the Company to require equipment to be installed to monitor the customer's Power Factor in circumstances where the customer's usage habits are detrimental to the system.

3. TOU Rates.

Q. What changes is the Company proposing to its TOU rates?

A. As discussed above, the Company is proposing to add tiers to all TOU rates at the same consumption level as in the comparable non-TOU rates. In the interest of simplifying the TOU rates in the Company's last rate case, all the tiers were eliminated in the residential and SGS TOU rates and only a single on-peak and single off-peak rate are included in the tariffs, varying by season. After reviewing customers' usage and the associated bills, it was determined that an inadvertent incentive was created for the largest customers to shift to TOU without changing consumption patterns. As a result, the Company is proposing to maintain the same tier rate structure between the non-TOU and TOU rates to encourage TOU customers to move consumption from the on-peak hours to the off-peak hours. Adding the tiers back to the residential TOU rates will result in price signals that are more consistent with the non-TOU rates with an incentive to move their consumption from on-peak hours to off-peak hours in order to generate savings on their bill. The Company is also proposing to retain the current Residential Super Peak TOU rate with only conforming changes (i.e. modify the tier break points to match the proposed Rate R-01 design) and updating the rates and basic service charge.

Additionally, with the proposed increases in the Basic Service Charges to more appropriate levels for all classes, the residential TOU customer's Basic Service Charge will be the same as the rate proposed for the R-01 rate.

The SGS-TOU rate will experience a larger increase overall due to the inadvertently low rate that was proposed by TEP and approved in the Company's last rate case. The elimination of the tier in Rate GS-76 (SGS-TOU) resulted in the unintended consequence of overly reduced rates for the class. The Company seeks to correct that error in this case by proposing TOU rates for the small general service customers that are comparable to the non-TOU SGS rates. This will provide the necessary incentive for TOU customers to modify their peak consumption to save on their bill when compared to the Rate GS-10 rates in effect. The rates proposed are similar to the equivalent standard service rate with TOU based on-peak and off-peak fuel costs.

4. Lighting Rates.

Q. What changes are being proposed to TEP's Lighting Rates?

A. The Company is proposing to continue updating its lighting rates. Lighting services are designed to be offered to lighting conditions where no meter is installed. The prices vary by "equivalent" wattage and type of light bulb. This change is being proposed to allow for charges more in line with the cost of providing fixtures for LED lights. Once more lights have been installed in the Company's service territory, an analysis will be performed to determine if an increase in charges for LED lighting is warranted. The service includes the recovery of the initial cost of the pole, wiring, and fixture, as well as a normalized cost to maintain the light itself. The maintenance costs have continued to increase, however the rates have not kept up.

The lighting rates were substantially below the cost of service levels in TEP's last rate case and required an increase to bring them up to the appropriate levels. The Company's current review indicates that the lighting rates are being heavily subsidized and increases are warranted. The proposed rate increase, although higher on a percentage basis than most other classes, will not fully recover the costs incurred to serve the lighting customers.

5. <u>Community Solar Rate.</u>

Q. Will the Community Solar rate be changed?

A. Yes. The existing rate will be locked in place for the remainder of the customer's 20-year agreement. A new rate based on the revised fuel cost will be calculated and have the same, Commission approved, $0.02 per kWh premium added to it and placed on the Community Solar tariff for use by any customer signing up after the effective date of the new rates. This is the same process approved in the Company's last rate case.

The existing frozen Community Solar rates have a 20-year term and are based on fuel costs established in prior rate cases. For customers being migrated from the current SGS rate to the MGS rate, they will pay the MGS delivery rates, but will be allowed to maintain the fixed Community Solar rate for the energy blocks they currently have. They will only need to pay the new MGS Community Solar rate if they choose to purchase new blocks or replace blocks they dropped.

6. <u>138kV Rate.</u>

Q. Please describe the customer eligibility requirements for 138kV rate and the character of service they will receive.

A. This is a firm full-requirements service (three-phase, 60 Hertz, Primary Service) offered to customers taking service at a delivery voltage of 138kV or higher and delivered at a <u>single</u> point of delivery. Customers taking service on this rate are subject to a 10,000 kW minimum monthly billing demand. Fixed and variable costs are allocated to customers in this class assuming only transmission level losses. I have included the proposed tariff in **Exhibit CAJ-3** (Sheet No. 301).

Q. How is the cost of the 138kV+ system currently recovered from customers?

A. The cost of this system is part of the Company's Transmission system and is currently recovered through the assignment of the Company's current Open Access Transmission Tariff ("OATT") to retail customers as part of their operating expenses. The OATT currently recovers transmission system costs including losses from all customers. All distribution costs are recovered from customers, including LPS-90 customers, as determined in the CCOSS.

Q. Have you prepared a 138kV+ Rate?

A. Yes. I have prepared a tariff and the related rates for a single point of delivery when the customer takes service at 138kV and above.

Q. Please describe how you calculated this rate.

A. I supervised the inclusion of a specific rate class in the Company's cost of service study (Schedule G) for 138kV service. For class allocation purposes I requested the following assumptions be used in the study for the 138kV rate class:

1. Non-Coincident Peak Allocator (Fixed distribution costs and certain distribution expenses) – applied on transmission losses to derive this allocator that is used to allocate certain limited distribution functionalized and classified plant and expenses.
2. Distribution Plant Account Nos. 360-368 – for these distribution plant accounts (land & rights, structures and improvements, station equipment, poles, towers fixtures; overhead and underground conduits, and line transformers) the study did not assign any distribution functionalized and classified plant costs and related expenses to this class. In addition, the study

removed any plant and associated expenses related to Services (Account No. 369).

3. Average and Excess Factor– apply only transmission losses to derive this allocator that is used to allocate certain functionalized and classified fixed production costs.
4. Customer Costs Allocator – assume a single meter/customer count for the purpose of deriving the factor allocating functionalized and classified meter and customer information plant costs and related expenses.
5. Energy-related costs (fuel and variable O&M) – do not assign distribution losses to the sales units used to derive the energy cost allocator to this class.
6. Other costs – I requested no other changes related to allocators for all other costs not specifically identified in the items above.

Q. Do you believe this cost of service treatment is appropriate for the 138kV rate?

A. Yes. Under this approach a customer taking transmission level service at 138kV or higher voltage will avoid paying certain distribution plant costs and related expenses that are not used to provide service; in addition, only transmission losses have been assigned to the NCP allocator for these costs to properly reflect the higher voltage level nature of the service. Other costs such as fixed production costs and energy related costs are allocated using transmission losses only. The rate also appropriately recovers through the basic service charge, the costs of the 138kV meter as well as related customer information and general expenses – all of which are not avoided by customers taking service on this rate. Because of these facts, I believe the rate properly reflects sound cost causative factors that results in an appropriate level of costs assigned to customers on this rate while also avoiding any undue subsidy to this class by other rate classes.

7. <u>Interruptible Rates.</u>

Q. Please describe what changes the Company is proposing for the Interruptible Rate class.

A. The Company proposes to maintain the current Interruptible Rider. This rider provides for a customer to pay standard tariff rates, but allows the customer to designate a portion of their load as interruptible and receive a credit on their bill for the amount of capacity they offered as interruptible. This results in a more cost based credit for the real value of interruptible capacity in the year it is offered and protects the remaining customers. The rider can be seen in the attached **Exhibit CAJ-3** (Sheet No. 712).

8. <u>Economic Development Rate.</u>

Q. Is the Company proposing an Economic Development Rate ("EDR")?

A. Yes. TEP witness Dallas J. Dukes describes the EDR rider in detail. I have included the proposed rider in **Exhibit CAJ-3** (Sheet No. 713).

9. <u>Lifeline Rates.</u>

Q. What is the Company proposing with respect to its Lifeline rates?

A. The Company's low income rates are referred to as Lifeline rates. The Company proposes to simplify the currently available Lifeline rates by offering a single uniform discount off of each of the residential rates. The modifications would reduce the 27 existing tariffs, which contain multi-leveled percentage discount variations as well as fixed discount variations, 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.) The Company is also proposing changes to its frozen Lifeline rate options that will reduce them from 22 to five different options.

The combination of these rate discounts totaled $1,798,110 during the test year for nearly 15,000 Lifeline customers.

Q. Please describe the current Lifeline rate structures.

A. There are five Residential rates: R-01, R-80, R-201A, R-201B and R-8. Each of these rates has a fixed discount option in place for a customer who qualifies for a Lifeline discount. Currently that flat discount is $9.00 per month regardless of the class the customer chooses and regardless of the consumption. This makes for a simple to understand and simple to administer $108.00 annual discount for each qualifying Lifeline customer.

Where the Lifeline rates become complicated is when one considers all of the Lifeline variations that have been created and grandfathered for different usage levels over the last couple of decades. Some of these "frozen" rates were frozen in the mid 1990's. Some of these current discounts exceed $500 per year. This is as much as a 46% discount from the equivalent full retail rate for which the customer would otherwise qualify. With 27 different variations of Lifeline discounts that differ by consumption in any given month and also apply to Bright Community Solar customers, net metering customers and even Super Peak TOU customers, 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. Also noteworthy is 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.

Given the situation set forth above, the Company is proposing to simplify its Lifeline rates so that: (1) customers can better understand these rates; and (2) the Company can more efficiently manage these rates. The Company is proposing to reduce the number of Lifeline rates from 27 to 10, five of which will continue to be available to new customers. 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. The discount for these customers will be increased to mitigate a portion of the overall impact on bills and the discount will be applied in a way 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. Most of the Lifeline 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. One of the proposed frozen Lifeline rate will receive an even larger fixed discount (in combination with the $12.00 per month basic service charge) due to the very large subsidy they were receiving in the past. The amount of the discount will be one of two amounts for the various types of customers, but in general will be designed to moderate the amount of the increase.

Q. Please describe the new Lifeline rates that TEP is proposing.

A. Any new customer qualifying for the Lifeline program (or existing Lifeline customer moving to a new location) will become a standard residential R-01 (or R-80, R-201A, R-201B or R-8) 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).

Q. What will happen to customers who are currently on a frozen Lifeline rate?

A. The Company is proposing to maintain frozen Lifeline rates for the existing customers on a frozen Lifeline rate, but redesign the rates and create only five new options for the different types of residential customers. Customers on the new frozen Lifeline rates will experience a rate increase, but the increase will be limited for most and will still provide the customer with a substantial discount from the bill a standard non-Lifeline residential customer would pay. This discount will no longer be a percentage based discount that varies based on the customer's monthly consumption but will be a flat discount that varies from $15.00 per month up to $20.00 per month. This will still provide an annual discount of between $180 and $336 per year (based on a $15.00 to $20.00 per month discount and a $12.00 per month customer charge for the frozen rates).

10. <u>Prepay Rate.</u>

Q. Is the Company proposing a Prepay Rate?

A. Yes. TEP witness Denise Richardson-Smith describes the Prepay Rate and the details of why the Company believes it is a service the Company's customers want. I have included the proposed tariff in **Exhibit CAJ-3** (Sheet No. 108).

Q. Is the Rate available to all customers?

A. No. It is only available to standard Residential customers.

Q. Is it designed to be used in conjunction with any other tariff offering or riders?

A. No. It is a tariff service that cannot be used with other riders such as the Bright Tucson Community Solar rate, the Residential Solar – Company Owned Program, net-metering or Lifeline.

Q. How is the Prepay Rate calculated?

A. The rate is based on the Residential R-01 rate. It has a blended per kWh rate that is based on the weighted average of the two rate tiers on Rate R-01. However, a stepped rate has been proposed to avoid creating an average rate that automatically becomes an economic choice for large users. To prevent this from becoming an issue, an increased rate is applicable to any usage in excess of 20 kWh in a 24-hour period.

The rate also has a daily basic service charge. The basic service charge is based on the $20 monthly basic service charge proposed for Rate R-01 plus $2 per month to cover the cost of the cellular system needed to support the new rate; $1 per month to cover a portion of the added cost associated with the meter required to provide this service; and $2 per month to cover the cost of integrating the data management necessary to offer the service. This results in a $0.84 per day basic service charge (approximately $25.20 per month). The rates and tariff provisions can be found in **Exhibit CAJ-3** (Sheet No. 108).

11. <u>Alternative Generation Service Experimental Rider.</u>

Q. Why is the Company presenting an Alternative Generation Service Rider?

A. As part of the Settlement Agreement in the acquisition of UNS Energy by Fortis, UNS Energy agreed that UNS Electric and TEP would submit an alternative generation service tariff in their next rate case applications.

Q. Does the Company support approval of an alternate generation service rider in this proceeding?

A. No. The Company does not support it, and in fact, is opposed to the implementation of this tariff. It allows for certain large customers to "cherry pick" currently available capacity resulting from short-term energy market conditions and will ultimately result in costs being shifted to the remaining customers.

Q. Please describe Experimental Rider 14, Alternative Generation Service the Company is presenting?

A. Experimental Rider 14, Alternative Generation Service, if approved, would be an optional, experimental program designed to provide an alternative generation arrangement for participating LPS-TOU or 138 kV customers. It would be available for a maximum of 30 MW of peak load and would be available for no more than four years from the effective date of new rates in this docket.

Under the program, the customer would select an approved wholesale generation service provider to sell power to the Company on the customer's behalf. The power must be delivered to one or more of the Company's points of delivery for wholesale power, as designated in a power supply agreement. The Company would take title to the power and provide it to the customer, who in turn would pay for the power pursuant to the terms and conditions in the power supply agreement, the terms of Experimental Rider 14, and other program provisions. TEP would continue to supply all retail services to the customer under the provisions of the customer's current retail rate schedule and the customer would continue to pay all non-fuel rates specified in that tariff. The customer would also be subject to all of the charges and adjustments in the retail rate schedule, except for Base Power Supply Charges and the PPFAC.

The Company would purchase and manage this generation on behalf of the customer for a management fee of $0.0040 per kWh. The Company would also provide scheduling and energy imbalance service. Furthermore, the billed amounts under the retail rate and applicable adjustments would be based on the total billed kWh, kW, or billed dollar amount, including the cost of the alternative generation.

Q. Who could participate?

A. The program would be available to customers in the LPS-TOU and 138 kV rate classes with peak demands of 3,000 kW or more. As stated above, the program is limited to a total of 30 MW of peak load.

Q. How would customers be selected?

A. The Company would establish an initial enrollment period during which eligible customers could apply for the program. If the total MW of peak load from the applications exceeds the program maximum, customers would be selected for enrollment through a lottery process to be developed by TEP.

Q. What happens if the alternative Generation Service Provider defaults or the customer wants to return to standard TEP generation service?

A. The customer will be required to contract for service under this schedule for at least one year, but no longer than the termination date of the offering, if approved. If the alternative generation service provider defaults, the customer would have 60 days to find an alternate supplier or be considered a "returning customer". Default provisions would be specified in the power supply agreement.

If the customer desired to return to the standard TEP generation service before the contract term, due to a default or other reason, they would be allowed to do so without charge if: (1) they provide at least one year notice to the Company; (2) if the rider is discontinued at the end of the four-year experimental period; or (3) the Commission terminates the program prior to the end of the four-year experimental period. Absent one of these three conditions, the Company would provide the customer with generation service at market rates specified in the rider, which include a premium, until the Company was reasonably able to integrate the customer back into their generation planning and provide power at the applicable retail rate schedule. I have included the proposed tariff in **Exhibit CAJ-3** (Sheet No. 714).

C. Bill Impacts.

Q. What is the bill impact of TEP's rate design proposals?

A. The bill impact of any rate case on the Company's customers is always TEP's paramount concern. A great deal of time and effort was put into creating a set of rates that would keep the impact on the customers within a reasonable range and be generally consistent with other similarly situated customers. These impacts have been summarized in **Exhibit CAJ-2.**

Additional bill impact data has been provided in Schedule H-4. **Exhibit CAJ-2** is based on current versus proposed fuel costs and current versus proposed rates for all bill calculations.

While Schedule H-4 reflects varying levels of energy consumption, **Exhibit CAJ-2** reflects bill impact comparisons by class by using "typical" usage amounts for each general rate class and uses the same level of consumption for like situated customers in order to create an "apples to apples" comparison of bill impacts. With respect to the residential classes, the comparisons reflect a customer that uses 1,150 kWh per month in the summer months and 785 kWh per month in the winter months. Residential customers under our basic residential rate (Rate R-01) will experience an increase of approximately 11.3%, which equates to just over $11.91 per month on average if the Company's full revenue requirement is approved. The Lifeline customers' existing rates are lower;

therefore, even though the percentage impact is higher than the Rate R-01 customer, the actual dollar change to the total bill for the same average monthly usage is generally the same total dollar increase or less as is proposed for the Rate R-01 customer for most of the classes. The Residential TOU customers will experience increases necessary to correct the pricing currently embedded in the TOU rates. Ideally, the customer should adjust their usage habits to experience a savings on a TOU rate. That has not been the case under the current rates; therefore the Company has proposed to adjust the TOU rates to address this issue. TOU customers that don't change their usage habits will pay approximately the same as a standard customer, but can experience a savings by shifting consumption to an off-peak period.

The bill impacts for the Residential classes are greater than what is being proposed for the larger classes in order to move toward a more equitable contribution to the overall return on plant identified in the CCOSS.

The overall increase the SGS customers will experience is an approximate 10.2% increase for the typical customer. The MGS class is new and will not have a former rate to compare to, but calculations have been made for all migrating customers and compared to the former GS-10 rate. Because these customers are migrating from two different rate classes, the range of expected bill impacts may be wider than typically experienced. The average bill increase for the class is approximately 10.7%. For all customers with increases at the high end of the range, individual concessions and communications will be made in order to mitigate the impact and allow the customer additional time if needed to adapt to the new rate design. The LGS customers will see an approximate 7.5% increase and the LPS customers will see an approximate decrease of 9.0 %.

All rates also reflect a realignment of non-fuel components to reflect results consistent with the CCOSS and an adjustment to fuel components to move customers closer to the average cost of fuel where appropriate. All of these changes are being proposed to reflect the recovery of costs more equitably between customers within a rate class and between rate classes.

IV. PROPOSED TARIFFS.

Q. Are you sponsoring the rate related tariffs TEP is proposing in this rate case?

A. Yes. The proposed rate-related tariffs will be submitted and attached to my Direct Testimony as **Exhibit CAJ-3** (clean copy) and **Exhibit CAJ-4** (redlined copy) shortly after this testimony is filed.

V. PRO FORMA ADJUSTMENTS

A. <u>Weather Normalization Adjustment</u>

Q. What is the purpose of a weather normalization adjustment?

A. Weather normalization is a standard adjustment commonly performed in rate cases. It is performed to provide a best estimate of test year sales, revenues, and costs as they would have been under normal weather conditions. Energy consumption for some of TEP's customer classes are weather sensitive. For instance, a significant portion of energy usage in the summer comes from air conditioning load. Some summers, however, are warmer than normal and result in the Company selling more power and receiving more revenues than in a "normal" year. The reverse of this occurs when cooler than normal summer weather is experienced. The purpose of weather normalization is to "average" out these differences, so one can get a better sense as to what the Company is likely to receive in revenues during a year with normal weather.

Q. How has the weather normalization adjustment traditionally been calculated?

A. Historically, a typical industry practice was to use a variable known as heating degree days ("HDD") to measure heating load and another variable known as cooling degree days ("CDD") to measure cooling load. The theory has been that electric heating requirements are smaller when average daily temperatures are greater than 65 degrees Fahrenheit, and cooling requirements are smaller when the average daily temperatures are less than 75 degrees Fahrenheit. An HDD is measured by subtracting the average of the maximum and minimum temperature for that day from 65 degrees and a CDD is measured by subtracting 75 degrees from the average of the maximum and minimum temperature for that day. Negative results for both CDD and HDD calculations were set to zero. To obtain monthly HDD and CDD values, the daily values for each day of the month are summed.

The normal weather for each calendar month was assumed to be the average of the previous 10-years monthly CDD and HDD values as reported by the National Oceanic and Atmospheric Administration ("NOAA"). Actual monthly CDD and HDD for the TEP service area were then compared with the normal weather.

Q. Is this the method you are proposing to use in this proceeding?

A. No. The Company has developed a more precise method to weather-normalize sales which it has been using for its internal sales forecasts. The Company's refined method has consistently produced forecasts that are more closely aligned with actual results. Therefore, I am proposing it be used in this proceeding.

Q. Please describe the method you are proposing to use in this proceeding?

A. Much like the former method, NOAA-published information for the most recent 10-year period excluding the test year is utilized for the geographic territories served by TEP. Instead of two data points for each day being used as in the former method (the former method used the average of the high and low temperatures for each day to determine HDD or CDD for the day) the proposed method uses hourly average temperatures and hourly average dew points for each month. This data is directly out of the NOAA data base and is scrutinized through NOAA's validation process. Therefore it accurately reflects the actual temperatures in the area. Using 10 years of historical data allows the determination of a reasonable estimation of normal temperature and weather.

Q. Why change from the former Degree Day method to the proposed Average Temperature method?

A. The main purposes of the change in methodology are to more accurately capture the weather variability of sales and to isolate it from non-weather related effects. To accomplish this, a more accurate approximation of monthly weather is used, a trend variable is used to capture annual changes, and auto-regressive terms are used to capture non-weather related seasonal effects.

HDDs and CDDs were initially used as an approximation to daily weather and had several advantages to average temperature in the pre-computer era, since only two data points per day needed to be recorded and analyzed, thereby producing relatively easy calculations and requiring relatively small amounts of storage space. With the processing abilities of modern computers and available storage space, it is much easier, much less costly and much more accurate to use the more detailed average temperature (24 data points per day versus 2 data points per day) and average dew point data to approximate normal weather. Thus, it is appropriate to use the more accurate weather approximation since there is no more difficulty to use.

Some other advantages to the proposed method result from the subjective definition of degree days. Degree days use a sense of "feel" to determine that heating dominates load below 65 degrees and cooling dominates load above 75 degrees. In reality, the Company's data indicates the residential class reacts to base temperatures of 62 degrees and the commercial class reacts to base temperatures closer to 50 degrees. Especially for the commercial class, this resulted in negative coefficients in winter months which the former method rejected and set to zero, thereby skewing the results and making them less accurate. The proposed method does not make subjective assertions as to which temperature heating or cooling load dominate, but instead allows the data to objectively establish that relationship.

Another disadvantage of degree days is they change linearly with temperature while the relationship of load to temperature is non-linear. To circumvent this problem, the degree day method used monthly weather coefficients where the new method accurately captures the non-linear relationship by using quadratic, and in some cases, cubic terms. The new method more robustly estimates the weather coefficients because each coefficient is based on more data points and they more accurately follow the load to temperature relationship. Further the model's accuracy was greatly improved but the model's complexity was actually reduced by eliminating variables. Thus, it is exceptionally clear that polynomial average weather coefficients are a superior weather variable compared to monthly degree days.

The proposed model also utilizes the effects of economic trends in its evaluation. Without a trend variable the regression process will attempt to explain some of the trend variation by changing the weather coefficients which reduces their ability to accurately capture how weather affects sales. Thus, if the goal is to isolate the weather effect as much as possible, as it should be, then it is best to include a statistically significant economic variable that helps to explain the annual changes in load.

The final change to the model was for the treatment of seasonal effects influencing load that are not caused by the weather. Examples in our service territory include the seasonal migration of retirees and students moving to Tucson to attend the University of Arizona, Gem Show visitors or increased holiday hours for retail stores. These events occur roughly the same time each year and will influence load when they occur, but they are not events caused by the weather and should be isolated from the weather coefficients. In the degree day model, the use of monthly coefficients absorbed seasonal variations into the weather coefficient. Therefore, the degree day model did not properly separate weather from seasonal effects. In the average weather model, auto-regressive and moving average terms are used in conjunction with the weather variables in what is generally known as an ARIMAX model. The seasonal effects are handled very well by the auto-regressive and moving average terms which help to better isolate the weather from the seasonal effects. Thus, the average weather model estimates the true weather variability of load in a far superior way than the degree day model by isolating it from non-weather related seasonal effects.

Q. Was the weather normalization adjustment performed for all classes?

A. No. Weather normalization calculations were performed only for weather-sensitive residential, commercial and certain industrial classes, which were identified through regression analysis. Regression analysis revealed no statistically significant relationship between usage and weather for the large industrial, mining, or street lighting classes; therefore, no weather adjustment is proposed for these classes.

Q. What did your calculations show?

A. Overall, weather during the test year was more favorable for sales than normal. Therefore, actual sales were higher than normal resulting in a "negative" adjustment to sales volumes and revenues.

B. Customer Annualization Adjustment.

Q. Please describe the customer annualization adjustment.

A. The customer annualization adjustment revises the number of test year bills and volumes to be consistent with the number of customers on the system at the end of the test year. The Company is proposing to use the method that has been approved by this Commission in prior electric rate cases. The early months of the test year typically reflect more adjustment in the number of customers. For instance, the first month of the test year must be adjusted for 11 months of growth to reach adjusted test year end levels, whereas the eleventh month of the test year only requires one month of adjustment. Adjustments to the monthly volumes were made by multiplying the monthly bill count adjustment by the normalized usage per bill for the month.

Q. Why is your customer annualization adjustment reflective of test year-end customer values, as opposed to some other adjusting point?

A. The customer annualization adjustment – when added to normalized billing determinants – should result in adjusted billing determinants that will better reflect the bills and volumes at the time rates will be effective. Under the conditions described above and existing in this case, there is a nominal positive growth rate in the number of customers, and the last month of the test year reflects a customer count at or statistically close to the test year maximum. Therefore, the year-end adjustment technique results are the most accurate method to forecast the sales levels at the time new rates are effective. Also, adjusting to year-end values provides a larger reduction in the rate increase versus adjusting to other test year levels, such as a mid-year level. The year-end technique is therefore the most effective in mitigating the rate increase TEP is requesting in this application.

Q. You mentioned earlier in your testimony that your largest customer recently announced its intent to reduce its consumption. Did you reflect this announcement in your annualization numbers?

A. No. The Company has not included it in the initial calculations being proposed in this filing. Although the customer has announced plans to curtail mining production by approximately 50% starting January 1, 2016, it is not clear at this time what exact impact this will have on the customer's energy and demand needs. As more information becomes available the Company will provide support and modifications to its filing, prior to the hearing in this case.

Q. What is the effect of the customer annualization adjustment on test year sales volumes?

A. As changes in the number of customers were reviewed and annualized, certain classes experienced increases, such as the Residential class. For the Small General Service class the test year number of customers was annualized and did increase slightly. However, due to the creation of the MGS class, many of those customers, based on the Company's evaluation of usage patterns, were moved to the new MGS class and in some cases to the LGS rate class. Additionally, for the larger rate classes, the standard customer annualization was calculated to reflect changes in customer counts or any identified substantial reduction in usage. For the entire rate class, counts were adjusted to reflect any likely migration the Company identified as highly probable due to redefined tariff provisions. Ultimately, the annualization of test year sales resulted in an overall reduction in the sales volumes used as billing determinants to determine annualized revenues.

Q. **Why does the customer annualization adjustment have an impact on test year revenue and costs?**

A. As I mentioned above, even small customer annualization adjustments can affect the number of customers, kWh consumed, and kW demand. Any increase, even a small one, means that adjusted billing determinants would typically be adjusted upward. So, increasing these billing determinants increases both adjusted revenues and expenses. More specifically, incremental customer growth will increase revenue and certain expenses. In evaluating the test year activity for this filing, the normal customer growth has produced only a slight increase in billing determinants. The increase in billing determinants is smaller than what normally would have been expected as the result of items such as a decreased use per customer and reductions in overall sales due to the increase in distributed generation and the continued promotion of energy efficiency. All are beneficial to society as a whole, but result in less sales volumes to spread costs to. In this case, when all adjustments are made, the incremental net margin (the difference in revenue and expenses) is negative. Therefore, because the incremental net margin is negative, that will decrease the <u>total</u> operating income and increase the <u>total</u> revenue increase thereby increasing the revenue deficiency identified in this proceeding

C. Transmission Expense Adjustment.

Q. **Please describe the Company's treatment of transmission costs.**

A. TEP's retail rates include transmission costs based on TEP's FERC-approved Open Access Transmission Tariff ("OATT") rates applied to TEP's transmission system. TEP's retail customers use the transmission system to bring energy from the source to the TEP distribution system. Accordingly, transmission expenses which are included as an O&M expense are based on the FERC approved OATT rates being applied to the adjusted test year billing determinants associated with only native load.

VI. SERVICE FEES.

Q. Please describe the proposed changes in charges reflected on the "Statement of Charges".

A. The Company has reviewed the costs associated with providing these other various services to customers. This is being done during the rate case so any change in revenues resulting from changes to the rates can be accurately reflected in the Company's total revenue requirement. TEP has calculated updated charges after quantifying the actual costs of providing these services. These charges were then applied to the actual number of units of each service occurring in the test year. The incremental increase produced by these changes will reduce the overall revenue requirement allocated to general rates based on the weighted proportion each rate class contributes to the total revenues from these services. Please refer to attached **Exhibit CAJ-3** (Sheet No. 801), to see the specific charges the Company is proposing.

Q. Were any new service fees added?

A. Yes. The Company is proposing to establish a charge to provide customer usage data or interval data (if more than one request for standard usage data is made in a twelve-month period). The new charge is: (1) an hourly charge based on the time required to provide the data; (2) incremental to existing service fees; and (3) included in the revenue calculation. These charges can be found on **Exhibit CAJ-3** (Sheet No. 801).

Q. Will TEP offer an opt-out option for those customers that do not want an Automated Meter Reading ("AMR") meter that uses radio frequency for meter readings?

A. Yes. The Company is proposing to add language to the Rules and Regulations that provide for the cost-based charges and conditions associated with a Rate R-01 customer choosing to either not have an AMR installed or to have an AMR unit replaced in order to have an "analog" meter measure their electrical usage.

Q. Have any TEP customers requested to not have AMR meters installed?

A. Yes. So far, just over 1,000 customers or 0.25% of the Company's customers have indicated to the Company that they prefer not to have an AMR unit installed.

Q. Why should these customers pay additional fees to not have an AMR unit installed?

A. Currently the Company is installing AMR units throughout its service territory. The installation of AMR units allows for more automated meter reading and as a result a reduction in the cost to serve the customers. This reduction in cost is shared with all customers. AMR units allow for better tracking of any fraudulent or unauthorized use as well, which provides savings to all customers. Meter technology is advancing and analog meters will soon be obsolete, thereby making them much more expensive to purchase and maintain than AMR units. This means that customers expressing a desire to keep analog meters will cost the rest of TEP's customers more and more each year. It is the Company's position that the other customers should not have to pay for added expenses created by these 1,000 or so customers who have decided to make a unique and more expensive choice.

Q. What other costs are associated with offering these customers the opportunity to opt-out of an AMR unit?

A. Because analog meters prevent the use of a fixed network system that remotely reads meters and provides the data to the Company remotely, actual meter readers will need to be dispatched on a regular basis to physically read the meters. The large geographic area over which these customers may be located could make this a very expensive activity, resulting in incremental costs associated with labor, transportation, modified processes and equipment to maintain the manual reads and historical data, additional reporting requirements, etc. All of these are incremental costs that could be avoided if a standard AMR unit were installed. These costs should be paid by the customer with the desire to maintain soon to be obsolete equipment.

Q. Would special conditions need to be made if the customer chooses to opt out of the AMR meter?

A. Yes. Without AMR equipment installed, the customer would not be eligible to enjoy TOU rates, electric vehicle rates, net metering, pre-pay rates or any other service requiring more advanced meter reading equipment.

VII. MODIFICATIONS TO ADJUSTOR MECHANISMS.

Q. Is TEP requesting any changes to its adjustor mechanisms in this case?

A. Yes. I will address the Company's proposed changes to how the PPFAC mechanism is administered to customers' rates and modifications to the LFCR and ECA mechanisms. The Company's adjustor mechanisms will also be reset as certain costs are incorporated into TEP's new base rates.

A. Purchased Power and Fuel Adjustment Clause.

Q. How is TEP proposing to modify its PPFAC?

A. The PPFAC rate is currently adjusted annually and charged to customers on a per-kWh basis. The Company proposes to adjust the PPFAC monthly and allocate the PPFAC costs, as currently calculated, on a percentage of the average base fuel rate established in this rate case. The monthly PPFAC charge will be a single percentage adjustment applied to all base fuel rates for all customer classes.

Q. Why is TEP proposing to modify the methodology for allocating the PPFAC to the various classes of customers?

A. The Company believes this method better aligns the changes in fuel costs with each rate classes' base fuel costs. For example, suppose an LPS customer's base fuel is $0.03 per kWh and the residential base fuel cost is $0.05 per kWh. Under the current method a ($0.0003) per kWh PPFAC change is a 1% decrease to the LPS customer's fuel costs, but is only a 0.6% decrease to the residential customer's fuel costs and visa-versa if it were a $0.0003 increase. By using an overall percentage based adjustment to base fuel costs; a 0.5% PPFAC increase will equate to a 0.5% increase for all classes.

B. Lost Fixed Cost Recovery Mechanism.

Q. Describe what additional fixed costs the Company proposes to recover through the LFCR.

A. Currently, the LFCR mechanism excludes recovery of the Company's fixed costs attributable to generation and fixed must run. Fixed must run is a separate distribution related service supplied by generation facilities (fixed must run will be included in my reference to "generation" for purposes of this section of my testimony). Therefore the current LFCR mechanism prohibits the recovery of these fixed costs from customers when sales decline as a result of EE programs and DG. Additionally, the current LFCR only allows the recovery of 50% of the non-generation demand charges. The Company is proposing to update the LFCR to allow recovery of lost fixed costs attributable to generation as well as the full recovery of lost demand revenues.

Q. **Why do you believe the generation related costs should be included in the value of the lost sales?**

A. Since TEP's last rate case, the level of EE and DG has increased as has the level of unrecovered fixed costs necessary to provide safe, reliable service.

Q. **Have you been able to recover any of the generation costs and related charges that were avoided by retail customers participating in mandated EE and DG programs?**

A. No. Even if the Company was able to market its available generation, any revenue from that sale would go to the benefit of the PPFAC customers as a reduction to fuel costs, thereby reducing the end-users costs, but in no way aiding the Company in the recovery of its lost revenue.

Q. **What is the Company's estimate of the lost revenues from compliance with the EE Standard and REST attributable to generation and the reduced demand charge?**

A. Based on the kWh and kW losses reported in TEP's 2015 LFCR filing, the Company's estimate is that the lost revenue associated with excluding the generation components and reducing the demand charges is approximately $13 million.

Q. What is the Company proposing to do to fix this under-recovery associated with removing 50% of the demand charge and all of the generation costs from the LFCR calculation?

A. The LFCR rates used in the schedules to quantify the dollar value assigned to the lost kWh and kW should be fully reflective of the non-fuel energy rates and demand charges in each class. For tiered rates it should be the tail block rate since that is the most likely level where lost sales would occur. Since the calculation of demand-related losses specifically identifies the actual amount of offset to the customer's peak demand, the demand losses should be valued at the entire demand rate, not the current 50%.

Q. What other changes to the LFCR POA is the Company proposing?

A. Clarifying language has been included to make it consistent with the intent of the process. The main example is for DG related losses, the current spreadsheet specifies that last year's total losses be added to this year's new total. However, since we are calculating DG losses based on current production meter reads (less the production reads during the test year), it inherently captures losses from all systems and does not need to include the carry-over from the prior year. We have removed that reference in the worksheets. Another example is our proposal to eliminate the residential LFCR Fixed Cost Option. As of the preparation of this testimony, there were no collections from this option. Therefore, the Company is proposing to remove the option of paying the LFCR as a fixed charge.

Another revision is the change from a 1% year-over-year cap to a 2% year-over-year cap. This was done because the current LFCR (with the 1% cap) removes generation related components and 50% of the demand in the rates for the calculation of lost revenue. When the generation costs and full demand charges are appropriately added back into the LFCR, it would also be appropriate to increase the cap to 2%. While the Company agreed to the exclusion of generation in the settlement in the last rate case, the Company believes this unfairly understates the value of the lost sales and contributes to substantial under-recovery of lost revenues with no opportunity to recover them. Modifying the LFCR as proposed also promotes rate gradualism for customers. Another potential revision to the LFCR POA will be to include a provision that would allow for the recovery of any lost revenues resulting from any Alternate Generation Service rider that may be approved. This provision was discussed in the section of my testimony addressing the Alternate Generation Service rider.

The Company is also proposing to simplify the percentage-based LFCR Adjustment to be a single rate applied to customers' bills, rather than split the adjustment into two separate rates for EE and DG. Aside from these changes, we have also updated the LFCR to add consistency between the POA and the related schedules, and we have also updated the schedules to include sections for any new rate classes proposed in this filing. The Company's proposed changes to the LFCR POA and schedules are included as **Exhibit CAJ-5** in both clean and redline form.

Q. Does the Company wish to maintain the option for residential customers to choose to contribute to the LFCR in the form of a fixed charge instead of the percentage rate?

A. No. No customers have selected this option since it was adopted in the last rate case.

Q. Has the LFCR resulted in a large surcharge to customers?

A. No. First, the current annual 1% year-over-year cap reduces the impact of the LFCR to the customer. The combined EE and DG surcharge from the first TEP LFCR filing was approximately 0.7% and the 2015 LFCR filing resulted in approximately a 0.4% incremental increase for a total adjustment of approximately 1.1%. However, based on the data supporting the 2015 LFCR filing, the Company estimates that the incremental LFCR increase for including generation costs would have incrementally increased the total LFCR adjustment by an additional 1.7% to a total LFCR adjustment of 2.8%. However, our proposed increase to the basic service charges would collect a greater portion of the Company's fixed costs and partially offset the total dollars subject to adjustment in future LFCR adjustments.

The Company is proposing an annual year-over-year cap of 2% of total applicable revenues to provide for the changes in the LFCR that are being proposed.

C. <u>Environmental Cost Adjustment.</u>

Q. How is TEP proposing to modify its ECA?

A. The ECA rate is currently capped at a $0.00025 per kWh rate which was a cap based on 0.25% of prior test-year annual revenues. Based on current sales levels, this cap limits the total expenditures on environmental improvements that are recoverable between rate cases to approximately $2,000,000 per year. The Company expects annual ECA eligible costs related to environmental compliance to be at, or above, $4,000,000 per year. Therefore, the Company is proposing to increase the cap to allow for more timely recovery of a greater portion of its environmental compliance costs. The Company is also proposing that the ECA charge be converted from an energy-based charge to a percent-based charge. To be in conformity with that modification, the case should be converted to a percentage-based cap instead of the current kWh rate. The Company proposes that the new ECA cap level be set at 0.50% of annual revenues year over year. This will allow for a more equitable contribution for all classes. A revised POA for the ECA has been included as **Exhibit CAJ-6**.

D. Demand Side Management Surcharge.

Q. How is TEP proposing to modify its DSM?

A. The DSM rate is currently charged as a per kWh adjustment to the residential class and a percentage based charge for all other classes. The Company is proposing to apply the charge as a percentage based adjustment to all classes with the effective date of the next DSM filing.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit CAJ-1

Tucson Electric Power
Marginal Cost Study (2015)
Summary

CAJ-1
Schedule 1

Line	FERC A/C	Description	Residential Service	Small General Service
1		**Billing Determinants**		
2		Customer-Months	4,624,515	462,775
3				
4		**Customer Installation Annual Carrying Costs ($)**		
5	370	Meters	$ 37.19	$ 43.56
6	369	Services - Overhead/Underground	$ 10.13	$ -
7	368	Line Transformers	$ 81.49	$ 858.19
8	365-367	Conductors & Devices - Overhead/Underground	$ 148.28	$ 1,626.97
9	389-398	General Plant	$ 10.49	$ 40.47
10		**Subtotal: Customer Annual Carrying Costs**	**$ 287.58**	**$ 2,569.19**
11				
12		**Customer O&M Costs**		
13	902	Meter Reading Expenses	$ 3.62	$ 3.60
14	903	Customer Records & Collection Expenses	$ 41.33	$ 41.16
15	904	Uncollectible Accounts	$ -	$ -
16	905	Customer Accounts Expenses Supervision	$ -	$ -
17	908	Customer Assistance Expenses	$ -	$ -
18	909	Informational and Instructional Advertising Exp.	$ 0.45	$ 0.45
19	910	Misc. Customer Service & Informational Exp.	$ 0.24	$ 0.24
20	920-935	Customer A&G Costs	$ 20.65	$ 20.56
21		**Subtotal: Customer O&M Costs**	**$ 66.28**	**$ 66.01**
22				
23		**Marginal Cost per Customer (Annual)**	**$ 353.86**	**$ 2,635.20**
24		**Marginal Cost per Customer (Per Month)**	**$ 29.49**	**$ 219.60**
25		**Marginal Revenue Requirement**	**$ 136,370,393**	**$ 101,625,600**

Tucson Electric Power
Marginal Cost Study (2015)
Customer Installation Investment Costs

CAJ-1
Schedule 2

Line	FERC A/C	Description	Residential Service	Small General Service
1		**Billing Determinants**		
2		Customer-Months	4,624,515	462,775
3				
4	370	**Meters**		
5		Investment ($/Meter)	$ 216.00	$ 253.00
6		ECCR	17.22%	17.22%
7		Unit Annual Carrying Cost ($/Meter)	$ 37.19	$ 43.56
8		Total Annual Carrying Cost ($)	$ 14,332,043	$ 1,679,883
9				
10	369	**Services - Overhead/Underground**		
11		Unit Cost ($/Ft, New Service)	$ 1.74	
12		Footage (Ft)	75.00	
13		Investment ($/Meter)	$ 130.42	$ -
14		ECCR	7.77%	7.77%
15		Unit Annual Carrying Cost ($/Meter)	$ 10.13	$ -
16		Total Annual Carrying Cost ($)	$ 3,903,197	$ -
17				
18	368	**Line Transformers**		
19		Unit Cost ($/Transformer, New)	$ 2,548	$ 8,944
20		Customers per Transformers	3	1
21		Investment ($/Cust.)	$ 849.30	$ 8,943.76
22		ECCR	9.60%	9.60%
23		Unit Annual Carrying Cost ($/Cust.)	$ 81.49	$ 858.19
24		Total Annual Carrying Cost ($)	$ 31,405,641	$ 33,095,766
25				
26	366-367	**UG Conductor & Devices**		
27		Junction Cabinet ($/Install)	$ 3,812	
28		Number of customers per cabinate	30	
29		Avg. Cabinet Investment ($/Cust.)	$ 127	
30		Primary Conductor - Unit Cost ($/Ft)	$ 9.41	$ 29.14
31		Primary Conductor - Footage (Ft/Install)	133	500
32		Secondary Conductor - Unit Cost ($/Ft)	$ 1.73	
33		Secondary Conductor - Footage (Ft/Install)	33	
34		Conductor Investment ($/Install)	$ 1,312	$ 14,569
35		Riser ($/Install)		$ 2,717
36		Pedestal Unit Cost	$ 273	
37		Number of customers per pedestal	$ 2	
38		Pedestal Cost per customer ($/Cust)	$ 136	
39		UG Conductor & Devices Investment ($/Install)	$ 1,575.44	$ 17,285.78
40		ECCR	9.41%	9.41%
41		Unit Annual Carrying Cost ($/Cust.)	$ 148.28	$ 1,626.97
42		Total Annual Carrying Cost ($)	$ 57,145,071	$ 62,743,609
43				
44				
45	389-398	**General Plant**		
46		General Plant - ECOSS Customer Allocation	$ 33,492,683	$ 12,935,882
47		Less: Accumulated Depreciation	$ (9,229,347)	$ (3,564,652)
48		Net General Plant - Customer Allocation	$ 24,263,335	$ 9,371,230
49		Return on Ratebase (Pre Tax)	10.2%	10.2%
50		Return on Ratebase (Pre Tax)	$ 2,474,860	$ 955,865
51		Depreciation Expence	$ 1,565,922	$ 604,806
52		Total Annual Carrying Costs ($)	$4,040,782	$1,560,672
53		Unit Annual Carrying Costs ($/Cust.)	$ 10.49	$ 40.47

Tucson Electric Power
Marginal Cost Study (2015)
Customer O&M Costs

CAJ-1
Schedule 3

Line	FERC A/C	Description	Residential Service	Small General Service
1		**Billing Determinants**		
2		Customer-Months	4,624,515	462,775
3				
4	902	**Meter Reading Expenses**		
5		Meter Reading Expenses	$ 1,393,664	$ 138,892
6		Expenses per customer	$ 3.62	$ 3.60
7				
8	903	**Customer Records & Collection Expenses**		
9		Customer Records & Collection Expenses	$ 15,926,207	$ 1,587,199
10		Expenses per customer	$ 41.33	$ 41.16
11				
12	904	**Uncollectible Accounts**		
13		Uncollectible Accounts	$ -	$ -
14		Expenses per customer	$ -	$ -
15				
16	905	**Customer Accounts Expenses Supervision**		
17		Customer Accounts Expenses Supervision	$ -	$ -
18		Expenses per customer	$ -	$ -
19				
20	908	**Customer Assistance Expenses**		
21		Customer Assistance Expenses	$ -	$ -
22		Expenses per customer	$ -	$ -
23				
24	909	**Informational and Instructional Advertising Exp.**		
25		Informational and Instructional Advertising Exp.	$ 173,278	$ 17,269
26		Expenses per customer	$ 0.45	$ 0.45
27				
28	910	**Misc. Customer Service & Informational Exp.**		
29		Misc. Customer Service & Informational Exp.	$ 93,880	$ 9,356
30		Expenses per customer	$ 0.24	$ 0.24
31				
32	920-935	**Administrative and General Expense**		
33		Administrative and General Expense	$ 66,049,810	$ 6,582,497
34		A&G Expense - Customer Allocation	$ 7,956,629	$ 792,954
35		Expenses per customer	$ 20.65	$ 20.56
36				
37		**Total Customer Expense**	$ 66.28	$ 66.01

Exhibit CAJ-2

Tucson Electric Power
Bill Impacts
Test Year Ending June 30, 2015

Class Description	Customer Counts 10/1/15	Average Summer kWh	Average Winter kWh	New Annual Bill	Annual Bill Change	$ Change from Standard Tariff	Revised Percent Change to Total Bill	Monthly $ change in bill
Residential R-01	341,759	1,150	785	$1,409.79	$142.88		11.3%	$11.91
Residential Lifeline R-01LL	6,812	1,150	785	$1,229.79	$70.88	($180.00)	6.1%	$5.91
Residential Lifeline R-04-01F	444	1,150	785	$1,073.79	$145.08	($336.00)	15.6%	$12.09
Residential Lifeline R-05-01F	1,067	1,150	785	$1,133.79	$58.71	($276.00)	5.5%	$4.89
Residential Lifeline R-06-01F	5,685	1,150	785	$1,133.79	$85.65	($276.00)	8.2%	$7.14
Residential Lifeline R-08-01F	572	1,150	785	$1,073.79	$291.52	($336.00)	37.3%	$24.29
Residential R-201A	11,221	1,150	785	$1,349.73	$152.12	($60.06)	12.7%	$12.68
Residential Lifeline R-201AL	198	1,150	785	$1,169.73	$80.12	($240.06)	7.4%	$6.68
Residential Lifeline 06-201AF	270	1,150	785	$1,073.73	$103.64	($336.06)	10.7%	$8.64
Residential Lifeline 08-201AF	9	1,150	785	$1,073.73	$342.21	($336.06)	46.8%	$28.52
Residential TOU R-80	8,001	1,150	785	$1,370.95	$247.09	($38.84)	22.0%	$20.59
Residential Lifeline TOU R-80LL	85	1,150	785	$1,190.95	$175.09	($218.84)	17.2%	$14.59
Residential Lifeline R-04-21F	2	1,150	785	$1,094.95	$273.60	($314.84)	33.3%	$22.80
Residential Lifeline R-05-21F	1	1,150	785	$1,094.95	$138.14	($314.84)	14.4%	$11.51
Residential Lifeline R-06-21F	17	1,150	785	$1,094.95	$193.86	($314.84)	21.5%	$16.16
Residential Lifeline R-08-21F	7	1,150	785	$1,094.95	$405.36	($314.84)	58.8%	$33.78
Residential Lifeline R-04-70F	6	1,150	785	$1,094.95	$216.10	($314.84)	24.6%	$18.01
Residential Lifeline R-05-70F	10	1,150	785	$1,094.95	$97.03	($314.84)	9.7%	$8.09
Residential Lifeline R-06-70F	54	1,150	785	$1,094.95	$120.76	($314.84)	12.4%	$10.06
Residential Lifeline R-08-70F	16	1,150	785	$1,094.95	$369.62	($314.84)	51.0%	$30.80
Residential TOU Super Peak R-8	162	1,150	785	$1,377.87	$293.38	($31.92)	27.1%	$24.45
Residential Lifeline TOU Super Peak R-	4	1,150	785	$1,197.87	$221.38	($211.92)	22.7%	$18.45
Residential R-201B	645	1,150	785	$1,319.77	$279.30	($90.02)	26.8%	$23.28
Residential Lifeline R-201BL	2	1,150	785	$1,139.77	$207.30	($270.02)	22.2%	$17.28
Residential Lifeline 06-201BF	4	1,150	785	$1,043.77	$156.87	($366.02)	17.7%	$13.07
General Service R-10	35,396	1,886	1,340	$2,727.69	$252.54		10.2%	$21.05
SGS Time of Use R-76	1,167	1,886	1,340	$2,650.66	$275.07	($77.03)	11.6%	$22.92
General Service R-10 Municipal	840	1,886	1,340	$2,727.69	$630.25	$0.00	30.0%	$52.52
Mobile Home Park Service R-11	283	15,040	12,611	$20,176.91	$1,812.63		9.9%	$151.05
Municipal Water Pumping Service R-4	426	17,209	12,251	$18,756.94	$1,706.66		10.0%	$142.22
Municipal Interruptible WP Service R-	157	17,209	12,251	$14,123.82	$1,705.52	($4,633.12)	13.7%	$142.13
Medium General Service		24,544	17,563	$35,001.49	$3,369.00		10.7%	$280.75
Medium General Service TOU		24,544	17,563	$31,678.98	$3,169.43	($3,322.51)	11.1%	$264.12
Large General Service R-13	444	178,619	149,663	$204,808.97	$14,368.73		7.5%	$1,197.39
Large General Service TOU R-85	126	178,619	149,663	$193,090.71	$9,579.37	($11,718)	5.2%	$798.28
Large Power Service TOU R-90	18	6,174,912	5,193,148	$4,314,394.74	($424,533.73)		-9.0%	-$35,377.81
Traffic Signal& Street Light Service PS-	5,956	2,204	2,687	$2,863.66	$260.35		10.0%	$21.70

Tucons Electric Power
Bill Impacts
Test Year Ending June 30, 2015

Class Description	New Annual Bill	Annual Bill Change	Change to Standard Bill	Revised Percent Change to Total Bill	$ change in Mo. Bill
Residential R-01	$1,409.79	$142.88		11.3%	$11.91
Residential TOU R-80	$1,370.95	$247.09	($38.84)	22.0%	$20.59
General Service R-10	$2,727.69	$252.54		10.2%	$21.05
SGS Time of Use R-76	$2,650.66	$275.07	($77.03)	11.6%	$22.92
General Service R-10 Municipal	$2,727.69	$630.25		30.0%	$52.52
Medium General Service	$35,001.49	$3,369.00		10.7%	$280.75
Medium General Service TOU	$31,678.98	$3,169.43	($3,322.51)	11.1%	$264.12
Large General Service R-13	$204,808.97	$14,368.73		7.5%	$1,197.39
Large General Service TOU R-85	$193,090.71	$9,579.37	($11,718)	5.2%	$798.28
Large Power Service TOU R-90	$4,314,394.74	($424,533.73)		-9.0%	-$35,377.81

Exhibit CAJ-3

Residential Electric Service (RES)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase or three-phase residential electric service (subject to availability at point of delivery) in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to the Residential Electric Water Heating Service Rate (R-02F) which is no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge, Single-phase service	$20.00 per month
Basic Service Charge, Three-phase service	$25.00 per month

Energy Charges ($/kWh):

0 – 500 kWh	$0.0591 per kWh
Over 500 kWh	$0.0791 per kWh

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh):

	Summer (May – September)	Winter (October – April)
Base Power	$0.037325 per kWh	$0.033801 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

MONTHLY LIFELINE DISCOUNT:

For current and new eligible Lifeline customers taking service under RES, the monthly bill shall be in accordance to the rate above except that a discount of $15.00 per month shall be applied.

For current Lifeline customers formerly taking service under one of the following discontinued rates, the monthly bill shall be in accordance to the rate above except that the Basic Service Charge and Discount per month shall be applied as follows:

Frozen Lifeline Service Rate	Basic Service Charge	Discount
Residential Lifeline/Senior R-04-01F	$12	$20
Residential Lifeline Service R-05-01F	$12	$15
Residential Lifeline Service R-06-01F	$12	$15
Residential Lifeline Medical R-08-01F	$12	$20

For all customers, no Lifeline discount will be applied that will reduce the bill to less than zero.

LIFELINE ELIGIBILITY

1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single-Phase	Three-Phase	Frozen Lifeline
Meter Services	$2.25 per month	$7.25 per month	$1.35 per month
Meter Reading	$0.41 per month	$0.41 per month	$0.25 per month
Billing & Collection	$6.64 per month	$6.64 per month	$3.98 per month
Customer Delivery	$10.70 per month	$10.70 per month	$6.42 per month
Total	$20.00 per month	$25.00 per month	$12.00 per month

Energy Charge Components (per kWh) (Unbundled):

Component	
Local Delivery – Energy 0 – 500 kWh	$0.00571
Local Delivery – Energy Over 500 kWh	$0.02571
Generation Capacity	$0.035250
Fixed Must Run	$0.007270
Transmission	$0.008480
System Control & Dispatch	$0.000120
Reactive Supply and Voltage Control	$0.000450
Regulation and Frequency Response	$0.000440
Spinning Reserve Service	$0.001190
Supplemental Reserve Service	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

	Summer (May – September)	Winter (October - April)
Base Power Component (per kWh)	$0.037325 per kWh	$0.033801 per kWh
PPFAC (%)	In accordance with Rider 1	

Residential Time-of-Use (RES-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase residential electric service (subject to availability at point of delivery) in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other applicability conditions.

Service under this rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge	$20.00 per month
Energy Charges ($/kWh):	
0 - 500 kWh	$0.0591 per kWh
over 500 kWh	$0.0791 per kWh

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh):

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.060800 per kWh	$0.056000 per kWh
Base Power Off-Peak	$0.025700 per kWh	$0.022100 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply the TOU period percent usage by the tiered kWh usage.

Example: Consider a customer who used 2,000 kWh in a month with 20% on-peak usage and 80% off-peak usage. This customer will have 500 kWh in the first tier and 1500 kWh in the second tier. Applying Step 3, the customer has 100 kWh in on-peak first tier usage, 300 kWh in on-peak second tier usage, 400 kWh in off-peak first tier usage, and 1200 kWh in off-peak second tier usage.

kWh	On-Peak	Off-Peak	Total
0 – 500 kWh	100	400	500
Over 500 kWh	300	1,200	1,500
Total	400	1,600	2,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

MONTHLY LIFELINE DISCOUNT:

For current and new eligible Lifeline customers taking service under RES-TOU, the monthly bill shall be in accordance to the rate above except that a discount of $15.00 per month shall be applied.

For current Lifeline customers formerly taking service under one of the following discontinued rates, the monthly bill shall be in accordance to the rate above except that the Basic Service Charge and Discount per month shall be applied as follows:

Frozen Lifeline Service Rate	Basic Service Charge	Discount
Residential Lifeline/Senior R-04-21F	$12	$15
Residential Lifeline Service R-05-21F	$12	$15
Residential Lifeline Service R-06-21F	$12	$15
Residential Lifeline Medical R-08-21F	$12	$15
Residential Lifeline/Senior R-04-70F	$12	$15
Residential Lifeline Service R-05-70F	$12	$15
Residential Lifeline Service R-06-70F	$12	$15
Residential Lifeline Medical R-08-70F	$12	$15

For all customers, no Lifeline discount will be applied that will reduce the bill to less than zero.

LIFELINE ELIGIBILITY

1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

ELECTRIC VEHICLES

Customers who own and operate Electric Vehicles will receive a 5% discount to the Base Fuel during the off-peak period and the PPFAC. Customers must provide documentation for highway approved Electric Vehicles.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single-Phase	Frozen Lifeline
Meter Services	$2.25 per month	$1.35 per month
Meter Reading	$0.41 per month	$0.25 per month
Billing & Collection	$6.64 per month	$3.98 per month
Customer Delivery	$10.70 per month	$6.42 per month
Total	$20.00 per month	$12.00 per month

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 102-3
Superseding:

Energy Charge Components (per kWh) (Unbundled):

Component	
Local Delivery – Energy 0 – 500 kWh	$0.00571
Local Delivery – Energy Over 500 kWh	$0.02571
Generation	$0.035250
Fixed Must Run	$0.007270
Transmission	$0.008480
System Control & Dispatch	$0.000120
Reactive Supply and Voltage Control	$0.000450
Regulation and Frequency Response	$0.000440
Spinning Reserve Service	$0.001190
Supplemental Reserve Service	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.060800
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.025700
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.056000
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.022100
PPFAC (%) (see Rider-1 for current rate)	Varies

Residential Time-of-Use Peak (RES-TOU-P)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single phase residential electric service (subject to availability at point of delivery) in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electricial equipment that causes excessive voltage fluctuations.

Service under this rate will commence when the appropriate meter has been installed.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge	$20.00 per month
Energy Charges ($/kWh):	
0 - 500 kWh	$0.0591 per kWh
over 500 kWh	$0.0791 per kWh

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh):

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.082900 per kWh	$0.082900 per kWh
Base Power Off-Peak	$0.027700 per kWh	$0.024100 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

Calculation of Tiered (Block) Usage by TOU Period:
Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply the TOU period percent usage by the tiered kWh usage.

Example: Consider a customer who used 2,000 kWh in a month with 20% on-peak usage and 80% off-peak usage. This customer will have 500 kWh in the first tier and 1500 kWh in the second tier. Applying Step 3, the customer has 100 kWh in on-peak first tier usage, 300 kWh in on-peak second tier usage, 400 kWh in off-peak first tier usage, and 1200 kWh in off-peak second tier usage.

kWh	On-Peak	Off-Peak	Total
0 – 500 kWh	100	400	500
Over 500 kWh	300	1,200	1,500
Total	400	1,600	2,000

MONTHLY LIFELINE DISCOUNT:
This discount is only available to eligible Lifeline customers whose monthly bill shall be in accordance to the rate above except that a discount of $15.00 per month shall be applied. No Lifeline discount will be applied that will reduce the bill to less than zero.

LIFELINE ELIGIBILITY
1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 4:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak period is 4:00 p.m. to 7:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC VEHICLES
Customers who own and operate Electric Vehicles will receive a 5% discount to the Base Power Charge during the off-peak period and the PPFAC. Customers must provide documentation for highway approved Electric Vehicles.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges, which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single-Phase
Meter Services	$2.25 per month
Meter Reading	$0.41 per month
Billing & Collection	$6.64 per month
Customer Delivery	$10.70 per month
Total	$20.00 per month

Energy Charge Components (Per kWh) (Unbundled):

Component	
Local Delivery – Energy 0 – 500 kWh	$0.00571
Local Delivery – Energy Over 500 kWh	$0.02571
Generation Capacity	$0.035250
Fixed Must-Run	$0.007270
Transmission	$0.008480
System Control & Dispatch	$0.000120
Reactive Supply and Voltage Control	$0.000450
Regulation and Frequency Response	$0.000440
Spinning Reserve Service	$0.001190
Supplemental Reserve Service	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charge:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.082900
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.027700
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.082900
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.024100
PPFAC (%) (see Rider-1 for current rate)	Varies

Special Residential Electric Service (RES-S)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single-phase residential electric service (subject to availability at point of delivery) in individual residences when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this rate requires that the Customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below. New homes must conform to the standards of the Company's approved efficiency program for new construction as in effect at the time of subscription to this rate. Existing homes must conform to certain standards of the Company's approved efficiency program for existing homes as in effect at the time of subscription to this rate. Company accredited testing and inspection is required for verification. Notwithstanding the above, the Customer's use of solar energy for any purpose shall not preclude subscription to this rate.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to electrical equipment that causes excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge	$20.00 per month
Energy Charges ($/kWh):	
0 – 500 kWh	$0.0591 per kWh
Over 500 kWh	$0.0791 per kWh

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power	$0.031726 per kWh	$0.028731 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

MONTHLY LIFELINE DISCOUNT:

For current and new eligible Lifeline customers taking service under RES-S, the monthly bill shall be in accordance to the rate above except that a discount of $15.00 per month shall be applied.

For current Lifeline customers formerly taking service under one of the following discontinued rates, the monthly bill shall be in accordance to the rate above except that the Basic Service Charge and Discount per month shall be applied as follows:

Frozen Lifeline Service Rate	Basic Service Charge	Discount
Residential Lifeline Service R-06-201AF	$12	$15
Residential Lifeline Medical R-08-201AF	$12	$15

For all customers, no Lifeline discount will be applied that will reduce the bill to less than zero.

LIFELINE ELIGIBILITY

1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 104-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single-Phase	Frozen Lifeline
Meter Services	$2.25 per month	$1.35 per month
Meter Reading	$0.41 per month	$0.25 per month
Billing & Collection	$6.64 per month	$3.98 per month
Customer Delivery	$10.70 per month	$6.42 per month
Total	$20.00 per month	$12.00 per month

Energy Charge Components of Delivery Services (Per kWh) (Unbundled):

Component	
Local Delivery - Energy 0 - 500 kWh	$0.00571
Local Delivery – Energy Over 500 kWh	$0.02571
Generation Capacity	$0.035250
Fixed Must-Run	$0.007270
Transmission	$0.008480
System Control & Dispatch	$0.000120
Reactive Supply and Voltage Control	$0.000450
Regulation and Frequency Response	$0.000440
Spinning Reserve Service	$0.001190
Supplemental Reserve Service	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

	Summer (May – September)	Winter (October - April)
Base Power Component (per kWh)	$0.031726	$0.028731
PPFAC (%)	In accordance with Rider 1	

Special Residential Electric Service Time-of-Use Program (RES-TOU-S)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single-phase electric service (subject to availability at point of delivery) in individual residences when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this rate requires that the Customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below. New homes must conform to the standards of the Company's approved efficiency program for new construction as in effect at the time of subscription to this rate. Existing homes must conform to certain standards of the Company's approved efficiency program for existing homes as in effect at the time of subscription to this rate. Company accredited testing and inspection is required for verification. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this rate.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

Service under this rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge	$20.00 per month
Energy Charges ($/kWh):	
0 - 500 kWh	$0.0591 per kWh
over 500 kWh	$0.0791 per kWh

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.051680 per kWh	$0.047600 per kWh
Base Power Off-Peak	$0.021845 per kWh	$0.018785 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

Calculation of Tiered (Block) Usage by TOU Period:
Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply the TOU period percent usage by the tiered kWh usage.

Example: Consider a customer who used 2,000 kWh in a month with 20% on-peak usage and 80% off-peak usage. This customer will have 500 kWh in the first tier and 1500 kWh in the second tier. Applying Step 3, the customer has 100 kWh in on-peak first tier usage, 300 kWh in on-peak second tier usage, 400 kWh in off-peak first tier usage, and 1200 kWh in off-peak second tier usage.

kWh	On-Peak	Off-Peak	Total
0 – 500 kWh	100	400	500
Over 500 kWh	300	1,200	1,500
Total	400	1,600	2,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC VEHICLES

Customers who own and operate Electric Vehicles will receive a 5% discount to the Base Fuel during the off-peak period and the PPFAC. Customers must provide documentation for highway approved Electric Vehicles.

MONTHLY LIFELINE DISCOUNT

For current and new eligible Lifeline customers taking service under RES-TOU-S, the monthly bill shall be in accordance to the rate above except that a discount of $15.00 per month shall be applied.

For current Lifeline customers formerly taking service under one of the following discontinued rates, the monthly bill shall be in accordance to the rate above except that the Basic Service Charge and Discount per month shall be applied as follows:

Frozen Lifeline Service Rate	Basic Service Charge	Discount
Residential Lifeline Service R-06-201BF	$12	$15

For all customers, no Lifeline discount will be applied that will reduce the bill to less than zero.

LIFELINE ELIGIBILITY

1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single-Phase	Frozen Lifeline
Meter Services	$2.25 per month	$1.35 per month
Meter Reading	$0.41 per month	$0.25 per month
Billing & Collection	$6.64 per month	$3.98 per month
Customer Delivery	$10.70 per month	$6.42 per month
Total	$20.00 per month	$12.00 per month

Energy Charge Components (Per kWh) (Unbundled)

Component	
Local Delivery – Energy 0 – 500 kWh	$0.00571
Local Delivery – Energy Over 500 kWh	$0.02571
Generation Capacity	$0.035250
Fixed Must-Run	$0.007270
Transmission	$0.008480
System Control & Dispatch	$0.000120
Reactive Supply and Voltage Control	$0.000450
Regulation and Frequency Response	$0.000440
Spinning Reserve Service	$0.001190
Supplemental Reserve Service	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.051680
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.021845
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.047600
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.018785
PPFAC (%) (see Rider-1 for current rate)	Varies

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 106
Superseding:

Residential Electric Service Demand (RES-D)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single and three-phase residential electric service (subject to availability at point of delivery) in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

This rate is optional for Residential Service Customers, but mandatory for non-Time-of-Use Residential Service Customers taking service under Rider-15, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND, AND ENERGY CHARGES

Basic Service Charge, Single-phase service	$20.00 per month
Basic Service Charge, Three-phase service	$25.00 per month
Demand Charges (per kW):	
0 - 7 kW	$7.40
Over 7 kW	$11.90
Energy Charges (per kWh)	
All Kwh	$0.025000

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power	$0.037325 per kWh	$0.033801 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

BILLING DEMAND
The monthly billing demand shall be the maximum 1-hour measured demand in the billing month.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this Tariff will be applied to the Customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

TEP

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 106-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single Phase	Three Phase
Meter Services	$ 2.25 per month	$ 7.25 per month
Meter Reading	$ 0.41 per month	$ 0.41 per month
Billing & Collection	$ 6.64 per month	$ 6.64 per month
Customer Delivery	$10.70 per month	$10.70 per month
Total	$20.00 per month	$25.00 per month

Demand Charge Components (per kW) (Unbundled):

Component	
Delivery	
0 – 7 kW	$1.76
Over 7 kW	$6.26
Generation Capacity	$4.89
Transmission	$0.59
System Control & Dispatch	$0.01
Reactive Supply & Voltage Control	$0.03
Regulation & Frequency Response	$0.03
Spinning Reserve Service	$0.08
Supplemental Reserve Service	$0.01

Energy Charge Components (per kWh) (Unbundled):

Component	
Local Delivery - Energy	$0.009330
Generation Capacity	$0.003000
Fixed Must-Run	$0.007270
Transmission	$0.004220
System Control & Dispatch	$0.000060
Reactive Supply & Voltage Control	$0.000220
Regulation & Frequency Response	$0.000220
Spinning Reserve Service	$0.000590
Supplemental Reserve Service	$0.000090
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) (per kWh)	$0.037325
Base Power Supply Winter (October – April) (per kWh)	$0.033801
PPFAC (%) (see Rider-1 for current rate)	Varies

Residential Time-of-Use Demand (RES TOU-D)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase residential electric service (subject to availability at point of delivery) in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

This rate is optional for Residential Service Time-of-Use Customers, but mandatory for Residential Service Time-of-Use Customers taking service under Rider-15, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND, AND ENERGY CHARGES

Basic Service Charge:	$20.00 per month
Demand Charges (per kW):	
0 - 7 kW	$7.40
Over 7 kW	$11.90
Energy Charges (per kWh)	
All Kwh	$0.025000

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.060800 per kWh	$0.056000 per kWh
Base Power Off-Peak	$0.025700 per kWh	$0.022100 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

BILLING DEMAND
The monthly billing demand shall be the maximum 1-hour measured demand in the billing month.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC VEHICLES
Customers who own and operate Electric Vehicles will receive a 5% discount to the Base Fuel during the off-peak period and the PPFAC. Customers must provide documentation for highway approved Electric Vehicles.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single Phase
Meter Services	$ 2.25 per month
Meter Reading	$ 0.41 per month
Billing & Collection	$ 6.64 per month
Customer Delivery	$10.70 per month
Total	$20.00 per month

Demand Charge Components (per kW) (Unbundled):

Component	
Delivery	
0 – 7 kW	$1.76
Over 7 kW	$6.26
Generation Capacity	$4.89
Transmission	$0.59
System Control & Dispatch	$0.01
Reactive Supply & Voltage Control	$0.03
Regulation & Frequency Response	$0.03
Spinning Reserve Service	$0.08
Supplemental Reserve Service	$0.01

Energy Charge Components (per kWh) (Unbundled):

Component	
Local Delivery - Energy	$0.009330
Generation Capacity	$0.003000
Fixed Must-Run	$0.007270
Transmission	$0.004220
System Control & Dispatch	$0.000060
Reactive Supply & Voltage Control	$0.000220
Regulation & Frequency Response	$0.000220
Spinning Reserve Service	$0.000590
Supplemental Reserve Service	$0.000090
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.060800
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.025700
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.056000
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.022100
PPFAC (%) (see Rider-1 for current rate)	Varies

Prepay Energy Service (PES)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Prepay Energy Service is an optional "Pay-as-you-go" program that provides Customers with the ability to prepay an amount toward their electricity use (in lieu of receiving and paying a monthly bill). It also allows customers to track and receive feedback about their energy usage, costs and other information to save money and energy. TEP will make usage and billing information available to customers via TEP's secure website and by calling TEP. The Company will also send alerts to Prepay Customers to provide them with tools to help them manage their energy usage and account balance.

To all single-phase residential electric service (subject to availability at point of delivery) in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to electrical equipment that causes excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
The Customer's account will be charged at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge:	$0.84 per day
Energy Charges ($/kWh):	
0 – 20 kWh per day	$0.064000
Over 20 kWh per day	$0.079000

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power	$0.037325 per kWh	$0.033801 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$0.09 per day
Meter Reading	$0.02 per day
Billing & Collection	$0.28 per day
Customer Delivery	$0.45 per day
Total	$0.84 per day

Energy Charge Components (per kWh) (Unbundled):

Component	
Delivery	
0 – 20 kWh per day	$0.010610
Over 20 kWh per day	$0.025610
Generation Capacity	$0.035250
Fixed Must-Run	$0.007270
Transmission	$0.008480
System Control & Dispatch	$0.000120
Reactive Supply & Voltage Control	$0.000450
Regulation & Frequency Response	$0.000440
Spinning Reserve Service	$0.001190
Supplemental Reserve Service	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) (per kWh)	$0.037325
Base Power Supply Winter (October – April) (per kWh)	$0.033801
PPFAC (%) (see Rider-1 for current rate)	Varies

Residential Company Owned Solar Program (RES-COS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and configuration and are adjacent to the premises.

APPLICABILITY
To all Residential Electric Service (RES) Customers with the legal authority to enter into a contractual agreement assigning the rights to the Company necessary to allow production of electricity on the Customer's premises using photovoltaic solar equipment as a Renewable Resource. The photovoltaic solar equipment will be owned, operated, and maintained solely by the Company.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as determined by the Company and subject to availability at point of delivery.

RATE
A Customer will enter into a contract with the Company for a fixed rate for their total net monthly bill before taxes, assessments and other governmental charges. The fixed monthly rate will be $18.75 per kW based on the capacity of the solar equipment necessary to meet the customer's most recent 12 month historical usage.

The Company shall provide all of the Customer's electricity requirements at the contractual fixed rate. If in any calendar year a Customer's usage exceeds 115% of the Customer's contractually established historical annual usage, the customers' fixed rate shall be recalculated based on the new annual consumption data for the most recent year.

Additionally, if in any calendar year a customer consumes less than 85% of the contractually established historical annual usage, the Customer's fixed rate shall be recalculated based on the new annual consumption data for the most recent year.

The ACC may modify the program including the fixed rate. In the event the ACC modifies the program or the fixed rate, the Customer shall have the option of continuing service subject to such modifications or terminating service at no cost or penalty as provided in the contract.

TERMS AND CONDITIONS OF SERVICE

1) For initial participation in the program, Customer must have been an active Customer of the Company in good standing at the premises for no less than 12 months.

2) Customer will enter into a contract for 25 years. Customer must remain on the Residential Solar - Company Owned Program tariff for the term of the contract. As set forth in the contract, Customer may (i) assign the contract to a purchaser of the property, in which case the purchaser will receive service under this tariff or (ii) terminate service under this tariff through a purchase provision, payment of an Exit Fee in the event of the sale of the property, or upon an ACC initiated modification in the program or fixed rate not agreed to by the Customer.

3) Customer will continue to be charged for all other applicable ACC approved charges (except for the Lost Fixed Cost Recovery charge, the Environmental Compliance Adjustor charge and the Purchased Power and Fuel Adjustment Clause charge, or other charges subsequently approved for exclusion by the ACC) and Taxes and Assessments.

4) The terms and conditions discussed herein are not applicable to any other Company residential tariffs or Riders.

5) Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

6) A one-time Processing Fee of $250 will be charged at the time the Customer executes the contract.

7) Customer will be subject to terms and conditions as set forth in the contract.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate or the contract.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 110
Superseding:

Residential Community Solar Program (RES-COSC)

The Residential Community Solar Program application was filed in Docket No. E-01933A-15-0239 for approval in the 2016 Tucson Electric Power Company Renewable Energy Standard and Tariff Implementation Plan on July 1, 2015 and has yet to be approved by the Arizona Corporation Commission.

Small General Service (SGS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general service unless otherwise addressed by specific rates when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, standby, or auxiliary service.

If a Customer's two month accumulated consumption in the current billing month and the month proceding meets or exceeds 24,000 kWh, the Customer will be moved to the Medium General Service tariff.

All SGS Customers who are receiving service on the frozen Net Metering for Certain Partial Requirements Service (NM-PRS-F) Rider 4 will remain on SGS effective XXXX, even if usage would otherwise have moved them to another rate class. All new net metering Customers will receive service on the Small General Service Demand (SGS-D) tariff effective June 1, 2015.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate, plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge, single-phase service	$30.00 per month
Basic Service Charge, three-phase service	$35.00 per month

Energy Charges ($/kWh):

	Summer (May - September)	Winter (October - April)
0 – 500 kWh	$0.0835	$0.0685
Over 500 kWh	$0.1045	$0.0895

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh)

	Summer (May - September)	Winter (October - April)
Base Power	$0.037325	$0.033801

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single-Phase	Three-Phase
Meter Services	$3.37 per month	$8.37 per month
Meter Reading	$0.62 per month	$0.62 per month
Billing & Collection	$9.96 per month	$9.96 per month
Customer Delivery	$16.05 per month	$16.05 per month
Total	$30.00 per month	$35.00 per month

Energy Charge Components (Unbundled) (Per kWh):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy		
0 - 500 kWh	$0.039030	$0.024030
Over 500 kWh	$0.060030	$0.045030
Generation Capacity	$0.030000	$0.030000
Fixed Must-Run	$0.003970	$0.003970
Transmission	$0.008190	$0.008190
System Control & Dispatch	$0.000110	$0.000110
Reactive Supply and Voltage Control	$0.000440	$0.000440
Regulation and Frequency Response	$0.000420	$0.000420
Spinning Reserve Service	$0.001150	$0.001150
Supplemental Reserve Service	$0.000190	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.		

Power Supply Charges:

	Summer (May – September)	Winter (October - April)
Base Power Component (per kWh)	$0.037325	$0.033801
PPFAC (%)	In accordance with Rider 1	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 202
Superseding:

Mobile Home Park Electric Service (GS-M-F)

AVAILABILITY
Only available to premises historically served on a master metered mobile home park tariff. Not available to new facilities.

APPLICABILITY
To mobile home parks for service through a master meter to two or more mobile homes, provided each mobile home served through such master meter will be individually metered and billed by the park operator in accordance with applicable Orders of the Arizona Corporation Commission. Electric service to the park's facilities used by its residents may be supplied under this schedule only if such facilities are served through a master meter which serves two or more mobile homes.

Not applicable to resale, temporary, standby, or auxiliary service.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE
A monthly bill at the following rate, plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge, single-phase service	$30.00 per month
Basic Service Charge, three-phase service	$35.00 per month

Energy Charges:

	Summer (May - September)	Winter (October - April)
All kWh	$0.0912	$0.0812

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Base Power Charges:

	Summer (May - September)	Winter (October - April)
All kWh	$0.037325	$0.033801

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

PRIMARY SERVICE
The rates contained in this schedule are designed to reflect secondary service but where service is taken at primary voltage will be subject to a primary discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) on the billing demand each month.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single-Phase	Three-Phase
Meter Services	$3.37 per month	$8.37 per month
Meter Reading	$0.62 per month	$0.62 per month
Billing & Collection	$9.96 per month	$9.96 per month
Customer Delivery	$16.05 per month	$16.05 per month
Total	$30.00 per month	$35.00 per month

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 202-2
Superseding:

Energy Charge Components (Unbundled) (Per kWh):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.04673	$0.03673
Generation Capacity	$0.030000	$0.030000
Fixed Must-Run	$0.003970	$0.003970
Transmission	$0.008190	$0.008190
System Control & Dispatch	$0.000110	$0.000110
Reactive Supply and Voltage Control	$0.000440	$0.000440
Regulation and Frequency Response	$0.000420	$0.000420
Spinning Reserve Service	$0.001150	$0.001150
Supplemental Reserve Service	$0.000190	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charges:

	Summer (May – September)	Winter (October - April)
Base Power Component (per kWh)	$0.037325	$0.033801
PPFAC (%)	In accordance with Rider 1	

Small General Service
Time-of-Use Program (SGS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general services unless otherwise addressed by a specific tariff, when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service. Service under this rate will commence when the appropriate meter has been installed.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

If a Customer's two month accumulated consumption in the current billing month and the month proceding meets or exceeds 24,000 kWh, the Customer will be moved to the Medium General Service tariff.

All SGS TOU Customers who are receiving service on the frozen Net Metering for Certain Partial Requirements Service (NM-PRS-F) Rider 4 will remain on SGS TOU effective XXXX, even if usage would otherwise have moved them to another rate class. All new net metering Customers will receive service on the Small General Service TOU Demand (SGS-TOU-D) tariff effective June 1, 2015.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge, single-phase service	$30.00 per month

Energy Charges ($/kWh):

	Summer (May - September)	Winter (October - April)
0 – 500 kWh	$0.0835	$0.0685
Over 500 kWh	$0.1045	$0.0895

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.060800 per kWh	$0.056000 per kWh
Base Power Off-Peak	$0.025700 per kWh	$0.022100 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider 1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply the TOU period percent usage by the tiered kWh usage.

Example: Consider a customer who used 2,000 kWh in a month with 20% on-peak usage and 80% off-peak usage. This customer will have 500 kWh in the first tier and 1500 kWh in the second tier. Applying Step 3, the customer has 100 kWh in on-peak first tier usage, 300 kWh in on-peak second tier usage, 400 kWh in off-peak first tier usage, and 1200 kWh in off-peak second tier usage.

kWh	On-Peak	Off-Peak	Total
0 – 500 kWh	100	400	500
Over 500 kWh	300	1,200	1,500
Total	400	1,600	2,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$3.37 per month
Meter Reading	$0.62 per month
Billing & Collection	$9.96 per month
Customer Delivery	$16.05 per month
Total	$30.00 per month

Energy Charge Components (Unbundled) (Per kWh)

	Summer	Winter
Local Delivery – Energy 0 – 500 kWh	$0.039030	$0.024030
Local Delivery – Energy Over 500 kWh	$0.060030	$0.045030
Generation Capacity	$0.030000	$0.030000
Fixed Must-Run	$0.003970	$0.003970
Transmission	$0.008190	$0.008190
System Control & Dispatch	$0.000110	$0.000110
Reactive Supply and Voltage Control	$0.000440	$0.000440
Regulation and Frequency Response	$0.000420	$0.000420
Spinning Reserve Service	$0.001150	$0.001150
Supplemental Reserve Service	$0.000190	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.		

Power Supply Charges:

	Summer (May – September)	Winter (October - April)
Base Power Component On-Peak (per kWh)	$0.060800	$0.056000
Base Power Component Off-Peak (per kWh)	$0.025700	$0.022100
PPFAC (%)	In accordance with Rider 1	

Small General Service Demand (SGS-D)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general services unless otherwise addressed by specific rates, when all energy is supplied at one point of delivery and through one metered service.

This rate is optional for Small General Service Customers, but mandatory for non-Time-of-Use Small General Service Customers taking service under Rider-15, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

In the event billed kW meets or exceeds 40 kW in a billing period, the Customer no longer will be eligible for the SGS-D rate and moved to the Medium General Service rate.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND, AND ENERGY CHARGES

Basic Service Charge, Single-phase service	$30.00 per month
Basic Service Charge, Three-phase service	$35.00 per month

Demand Charges (per kW):

0 - 7 kW	$ 9.95
Over 7 kW	$13.90

Energy Charges (per kWh)

	Summer (May – September)	Winter (October – April)
All kWh	$0.057500 per kWh	$0.047500 per kWh

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power	$0.037325 per kWh	$0.033801 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

BILLING DEMAND
The monthly billing demand shall be the maximum 1-hour measured demand in the billing month.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 204-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single-Phase	Three-Phase
Meter Services	$ 3.37 per month	$ 8.37 per month
Meter Reading	$ 0.62 per month	$ 0.62 per month
Billing & Collection	$ 9.96 per month	$ 9.96 per month
Customer Delivery	$ 16.05 per month	$ 16.05 per month
Total	$ 30.00 per month	$ 35.00 per month

Demand Charge Components (per kW) (Unbundled):

Component	
Delivery	
0 – 7 kW	$4.16
Over 7 kW	$7.36
Generation Capacity	
0 – 7 kW	$4.50
Over 7 kW	$5.25
Transmission	$1.02
System Control & Dispatch	$0.01
Reactive Supply & Voltage Control	$0.05
Regulation & Frequency Response	$0.05
Spinning Reserve Service	$0.14
Supplemental Reserve Service	$0.02

Energy Charge Components (per kWh) (Unbundled):

Component	
Local Delivery – Energy Summer	$0.030630
Local Delivery – Energy Winter	$0.020630
Generation Capacity	$0.016000
Fixed Must-Run	$0.003970
Transmission	$0.005390
System Control & Dispatch	$0.000070
Reactive Supply & Voltage Control	$0.000290
Regulation & Frequency Response	$0.000280
Spinning Reserve Service	$0.000750
Supplemental Reserve Service	$0.000120
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) (per kWh)	$0.037325
Base Power Supply Winter (October – April) (per kWh)	$0.033801
PPFAC (%) (see Rider-1 for current rate)	Varies

Small General Service Time-of-Use Demand (SGS TOU-D)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general services unless otherwise addressed by specific rates, when all energy is supplied at one point of delivery and through one metered service.

This rate is optional for Small General Service Time-of-Use Customers, but mandatory for Small General Service Time-of-Use Customers taking service under Rider-15, Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

Service under this rate will commence when the appropriate meter has been installed.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

In the event billed kW meets or exceeds 40 kW in a billing period, the Customer no longer will be eligible for the SGS TOU-D rate and moved to the Medium General Service TOU rate.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND, AND ENERGY CHARGES

Basic Service Charge:	$30.00 per month
Demand Charges (per kW)	
0 - 7 kW	$9.95
Over 7 kW	$13.90

Energy Charges (per kWh):

	Summer (May-September)	Winter (October-April)
All Kwh	$0.057500	$0.047500

Power Supply Charge (per kWh):

	Summer (May-September)	Winter (October-April)
Base Power On-Peak	$0.060800	$0.056000
Base Power Off-Peak	$0.025700	$0.022100

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

BILLING DEMAND
The monthly billing demand shall be the maximum 1-hour measured demand in the billing month.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 3.37 per month
Meter Reading	$ 0.62 per month
Billing & Collection	$ 9.96 per month
Customer Delivery	$16.05 per month
Total	$30.00 per month

Demand Charge Components (per kW) (Unbundled):

Component	
Delivery	
0 – 7 kW	$4.16
Over 7 kW	$7.36
Generation Capacity	
0 – 7 kW	$4.50
Over 7 kW	$5.25
Transmission	$1.02
System Control & Dispatch	$0.01
Reactive Supply & Voltage Control	$0.05
Regulation & Frequency Response	$0.05
Spinning Reserve Service	$0.14
Supplemental Reserve Service	$0.02
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Energy Charge Components (per kWh) (Unbundled):

Component	
Local Delivery – Energy – Summer	$0.030630
Local Delivery – Energy – Winter	$0.020630
Generation Capacity	$0.016000
Fixed Must-Run	$0.003970
Transmission	$0.005390
System Control & Dispatch	$0.000070
Reactive Supply & Voltage Control	$0.000290
Regulation & Frequency Response	$0.000280
Spinning Reserve Service	$0.000750
Supplemental Reserve Service	$0.000120
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.060800
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.025700
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.056000
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.022100
PPFAC (%) (see Rider-1 for current rate)	Varies

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 210
Superseding:

Medium General Service (MGS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general service customers when all energy is supplied at one point of delivery and through one metered service.

In the event billed kW meets or exceeds 250 kW in a billing period, the Customer will no longer be eligible for the MGS rate and will be moved to the Large General Service rate.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge:	$40.00 per month
Demand Charge:	
Summer (May-September)	$7.00 per kW
Winter (October –April)	$5.00 per kW

Energy Charge (per kWh):

	Summer (May – September)	Winter (October – April)
All kWh	$0.087600 per kWh	$0.076600 per kWh

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power	$0.037325 per kWh	$0.033801 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

BILLING DEMAND
The monthly billing demand shall be the the greatest of the following:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. 75% of the greatest demand used for billing purposes in the preceding 11 months; or
3. The contract capacity or 20 kW, whichever is greater.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a Customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 210-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.55 per month
Meter Reading	$ 0.02 per month
Billing & Collection	$ 0.25 per month
Customer Delivery	$38.18 per month
Total	$40.00 per month

Demand Charges (per kW) (Unbundled):

Component	
Demand Delivery	
Summer	$2.71
Winter	$1.71
Generation Capacity	
Summer	$2.00
Winter	$1.00
Transmission	$1.79
System Control & Dispatch	$0.02
Reactive Supply & Voltage Control	$0.10
Regulation & Frequency Response	$0.09
Spinning Reserve Service	$0.25
Supplemental Reserve Service	$0.04

Energy Charge Components (per kWh) (Unbundled):

Local Delivery – Summer	$0.048610
Local Delivery – Winter	$0.037610
Generation Capacity	$0.025000
Fixed Must-Run	$0.006510
Transmission	$0.005840
System Control & Dispatch	$0.000080
Reactive Supply & Voltage Control	$0.000310
Regulation & Frequency Response	$0.000300
Spinning Reserve Service	$0.000820
Supplemental Reserve Service	$0.000130
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

Component	
Base Power Supply Summer (per kWh)	$0.037325
Base Power Supply Winter (per kWh)	$0.033801
PPFAC (%) (see Rider-1 for current rate)	Varies

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: MGS
Effective: Pending
Decision No.: Pending

Medium General Service Time-of-Use (MGS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all general service on an optional basis when all energy is supplied at one point of delivery and through one metered service. Services under this rate will commence when the appropriate meter has been installed.

In the event billed kW meets or exceeds 250 kW in a billing period, the Customer will no longer be eligible for the MGS-TOU rate and will be moved to the Large General Service Time-of-Use rate.

Not applicable to resale, breakdown, temporary, standby or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge:	$40.00 per month
Demand Charges:	
Summer On-peak	$ 8.00 per kW
Summer Off-peak Excess Demand	$ 4.76 per kW
Winter On-peak	$ 4.00 per kW
Winter Off-peak Excess Demand	$ 3.50 per kW
Energy Charges (per kWh):	
On-Peak	$0.076810 per kWh
Off-Peak	$0.034110 per kWh

Power Supply Charge (per kWh):

	Summer (May-September)	Winter (October-April)
Base Power On-Peak	$0.060800	$0.056000
Base Power Off-Peak	$0.025700	$0.022100

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

BILLING DEMAND

The monthly billing demand shall be the greatest of the following:

1. The greatest measured 15-minute interval demand read of the meter during the on-peak hours of the billing period;
2. 75% of the greatest on-peak period billing demand used for billing purposes in the preceding 11 months;
3. The contract capacity or 20 kW, whichever is greater.

Additionally, the greatest measured 15-minute interval demand read of the meter during the off-peak hours of the billing period that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak measured demand.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 1.55 per month
Meter Reading	$ 0.02 per month
Billing & Collection	$ 0.25 per month
Customer Delivery	$38.18 per month
Total	$40.00 per month

Demand Charge (per kW) (Unbundled):

Component	
Demand Delivery	
Summer On-Peak	$3.71
Summer Off-Peak	$1.47
Winter On-Peak	$1.02
Winter Off- Peak	$1.02
Generation Capacity	
Summer On-Peak	$2.00
Summer Off-Peak	$1.00
Winter On-Peak	$0.69
Winter Off- Peak	$0.19
Transmission	$1.79
System Control & Dispatch	$0.02
Reactive Supply & Voltage Control	$0.10
Regulation & Frequency Response	$0.09
Spinning Reserve Service	$0.25
Supplemental Reserve Service	$0.04

Energy Charge Components (per kWh) (Unbundled):

Local Delivery – Summer	$0.078610
Local Delivery –Winter	$0.034110
Generation Capacity	$0.025000
Fixed Must-Run	$0.006510
Transmission	$0.005840
System Control & Dispatch	$0.000080
Reactive Supply & Voltage Control	$0.000310
Regulation & Frequency Response	$0.000300
Spinning Reserve Service	$0.000820
Supplemental Reserve Service	$0.000130
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.060800
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.025700
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.056000
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.022100
PPFAC (%) (see Rider -1 for current rate)	Varies

Large General Service (LGS)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To applicable general services when all energy is supplied at one point of delivery and through one metered service.

The minimum monthly billing demand hereunder is 200 kW. In the event billed kW meets or exceeds 5,000 kW, the Customer will no longer be eligible for the LGS rate and will be moved to the Large Power Service Time-of-Use rate.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge:	$1,000.00 per month
Demand Charge:	$17.50 per kW
Energy Charges:	
Summer (May – September)	$0.0251 per kWh
Winter (October – April)	$0.0178 per kWh
Base Power Charges:	
Summer (May – September)	$0.037325 per kWh
Winter (October – April)	$0.033801 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The greatest measured 15 minute interval demand read of the meter during all hours of the billing period;
2. 75% of the greatest demand used for billing purposes in the preceding 11 months;
3. The contract capacity or 200 kW, whichever is greater.

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

PRIMARY SERVICE
The Rates contained in this Schedule are designed to reflect secondary service but where service is taken at primary voltage will be subject to a primary discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) on the billing demand each month.

The Company may require a written contract with a minimum contract demand and a minimum term of contract.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

TEP

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 220-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charges:	
Meter Services	$ 38.63 per month
Meter Reading	$ 0.39 per month
Billing & Collection	$ 6.29 per month
Customer Delivery	$ 954.69 per month
Total	$1,000.00 per month
Demand Charge (in $/kW):	
Delivery Charge	$3.86 per kW
Generation Capacity	$7.95 per kW
Fixed Must-Run	$1.33 per kW
Transmission	$3.39 per kW
Transmission Ancillary Services	
System Control & Dispatch	$0.05 per kW
Reactive Supply and Voltage Control	$0.18 per kW
Regulation and Frequency Response	$0.18 per kW
Spinning Reserve Service	$0.48 per kW
Supplemental Reserve Service	$0.08 per kW
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	
Energy Charges (kWh): (in $/kWh)	
Delivery Charge	
Summer	$0.025100 per kWh
Winter	$0.017800 per kWh
Base Power Supply Charges:	
Summer	$0.037325 per kWh
Winter	$0.033801 per kWh

Large General Service
Time-of-Use Program (LGS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To applicabile general services when all energy is supplied at one point of delivery and through one metered service.

The minimum monthly billing demand hereunder is 200 kW.

In the event billed kW meets or exceeds 5,000 kW, the Customer will no longer be eligible for the LGS TOU rate and will be moved to the Large Power Service Time-of-Use rate.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge	$1,000.00 per month
Demand Charges:	
Summer On-peak	$20.00 per kW
Summer Off-peak Excess Demand	$10.92 per kW
Winter On-peak	$17.50 per kW
Winter Off-peak Excess Demand	$ 9.10 per kW

Energy Charges ($/kWh):

	Summer (May – September)	Winter (October - April)
On-Peak	$0.025100	$0.025100
Off-Peak	$0.016900	$0.016900

Power Supply Charges ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.060800	$0.056000
Base Power Off-Peak	$0.025700	$0.022100

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND

The monthly billing demand shall be the greatest of the following:

1. The greatest measured 15-minute interval demand read of the meter during the on-peak hours of the billing period;
2. 75% of the greatest on-peak period billing demand used for billing purposes in the preceding 11 months;
3. The contract capacity or 200 kW, whichever is greater

Additionally, the greatest measured 15-minute interval demand read of the meter during the off-peak hours of the billing period that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak measured demand.

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

PRIMARY SERVICE

The Rates contained in this Schedule are designed to reflect secondary service but where service is taken at a primary voltage, a discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) will be applied to the billing demand each month.

The Company may require a written contract with a minimum contract demand and a minimum term of contract.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charges:	
Meter Services	$ 38.63 per month
Meter Reading	$ 0.39 per month
Billing & Collection	$ 6.29 per month
Customer Delivery	$ 954.69 per month
	$1,000.00 per month
Demand Charges ($/kW)	
Delivery Charges	
Summer On-peak	$ 6.31 per kW
Summer Off-peak	$ 0.23 per kW
Winter On-peak	$ 4.81 per kW
Winter Off-peak	$ 0.41 per kW
Generation Capacity Charges (in $/kW):	
Summer On-peak	$ 8.00 per kW
Summer Off-peak	$ 5.00 per kW
Winter On-peak	$ 7.00 per kW
Winter Off-peak	$ 3.00 per kW
Fixed Must-Run Charges (in $/kW)	$ 1.33 per kW
Transmission (in $/kW)	$ 3.39 per kW
Transmission - Ancillary Services System Control & Dispatch (in $/kW)	
System Control & Dispatch	$ 0.05 per kW
Reactive Supply and Voltage Control	$ 0.18 per kW
Regulation and Frequency Response	$ 0.18 per kW
Spinning Reserve Service	$ 0.48 per kW
Supplemental Reserve Service	$ 0.08 per kW

Energy Imbalance Service: Currently charged pursuant to the Company's OATT

Energy Charges ($/kWh):	
Delivery Charges	
On-peak	$0.025100 per kWh
Off-peak	$0.016900 per kWh
Base Power Supply Charge	
Summer On-peak	$0.060800 per kWh
Summer Off-peak	$0.025700 per kWh
Winter On-peak	$0.056000 per kWh
Winter Off-peak	$0.022100 per kWh

Large Power Service
Time of Use (LPS-TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To applicable power services when all energy is supplied at one point of delivery and through one metered service. The minimum monthly billing demand hereunder is 3,000 kW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service. Service under this rate will commence when the appropriate meter has been installed.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
Service shall be three-phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge	$2,000.00 per month
Demand Charges:	
Summer On-peak	$ 18.00 per kW
Summer Off-peak Excess Demand	$ 12.49 per kW
Winter On-peak	$ 15.00 per kW
Winter Off-peak Excess Demand	$ 9.99 per kW
Energy Charges ($/kWh):	
All kWh	$0.007100 per kWh

Power Supply Charges ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.057760	$0.053200
Base Power Off-Peak	$0.024415	$0.020995

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The greatest measured 15-minute interval demand read of the meter during the on-peak hours of the billing period;
2. 75% of the greatest on-peak period billing demand used for billing purposes in the preceding 11 months;
3. The contract capacity or 3,000 kW, whichever is greater

Additionally, the greatest measured 15-minute interval demand read of the meter during the off-peak hours of the billing period that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak measured demand.

PRIMARY SERVICE
The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than ninety-five percent (95%), an adjustment shall be applied to the bill as follows:

POWER FACTOR ADJUSTMENT
(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR
1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.
2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.

5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 77.26 per month
Meter Reading	$ 0.78 per month
Billing & Collection	$ 12.59 per month
Customer Delivery	$1,909.37 per month
Total	$2,000.00 per month

Demand Charges (per kW) (Unbundled):

Component	
Demand Delivery	
Summer On-Peak	$2.73
Summer Off-Peak	$1.40
Winter On-Peak	$1.41
Winter Off-Peak	$0.40
Generation Capacity	
Summer On-Peak	$9.68
Summer Off-Peak	$5.50
Winter On-Peak	$8.00
Winter Off-Peak	$4.00
Fixed Must-run	$1.30
Transmission	$3.34
System Control & Dispatch	$0.05
Reactive Supply & Voltage Control	$0.18
Regulation & Frequency Response	$0.17
Spinning Reserve Service	$0.47
Supplemental Reserve Service	$0.08
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.	

Energy Charges ($/kWh): $0.007100 per kWh

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.057760
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.024415
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.053200
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.020995
PPFAC (%) (see Rider-1 for current rate)	Varies

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 302
Superseding: ________

Large Power Service Time-of-Use – High Voltage (LPS TOU-HV)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To applicable power services where the Company specifies service at a nominal transmission system voltage of 138,000 volts or higher, and the Company determines that facilities of adequate capacity are available and adjacent to the premises to be served. Electric service must be supplied at one point of delivery and through one metered service. The minimum monthly billing demand hereunder is 10,000 kW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
Service shall be three-phase, 60 Hertz, Primary Service, and shall be supplied directly from any 138,000 volt, or higher voltage, system at a delivery voltage of not less than 138,000 volts and delivered at a single point of delivery unless otherwise specified in the contract.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF BASIC SERVICE, DEMAND AND ENERGY CHARGES

Basic Service Charge:	$3,000 per month
Demand Charges:	
Summer On-peak	$ 17.15 per kW
Summer Off-peak Excess Demand	$ 12.49 per kW
Winter On-peak	$ 14.15 per kW
Winter Off-peak Excess Demand	$ 9.99 per kW
Energy Charges:	
All kWh	$0.007100 per kWh

Power Supply Charges ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.056544	$0.052080
Base Power Off-Peak	$0.023901	$0.020553

Purchased Power and Fuel Adjustment Clause (PPFAC): TheBase Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below thebase cost of purchased power and fuel.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The greatest measured 15-minute interval demand read of the meter during the on-peak hours of the billing period;
2. 75% of the greatest on-peak period billing demand used for billing purposes in the preceding 11 months;
3. The contract capacity or 10,000 kW, whichever is greater

Additionally, the greatest measured 15-minute interval demand read of the meter during the off-peak hours of the billing period that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak measured demand.

PRIMARY SERVICE
The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than ninety-five percent (95%), an adjustment shall be applied to the bill as follows:

POWER FACTOR ADJUSTMENT
(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR
1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.
2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 115.88 per month
Meter Reading	$ 1.18 per month
Billing & Collection	$ 18.88 per month
Customer Delivery	$ 2,864.06 per month
Total	$ 3,000.00 per month

Demand Charges (per kW) (Unbundled):

Component	
Demand Delivery	
Summer On-Peak	$1.86
Summer Off-Peak	$0.15
Winter On-Peak	$0.56
Winter Off-Peak	$0.40
Generation Capacity	
Summer On-Peak	$9.70
Summer Off-Peak	$6.75
Winter On-Peak	$8.00
Winter Off-Peak	$4.00
Fixed Must-run	$1.30
Transmission	$3.34
System Control & Dispatch	$0.05
Reactive Supply & Voltage Control	$0.18
Regulation & Frequency Response	$0.17
Spinning Reserve Service	$0.47
Supplemental Reserve Service	$0.08
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.056544
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.023901
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.052080
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.020553
PPFAC (%) (see Rider-1 for current rate)	Varies

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 501
Superseding:

Traffic Signal and Street Lighting Service (TSL)

AVAILABILITY
Available for service to any Public Authority for Traffic Signal and Street Lighting purposes where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable to Customer owned and maintained traffic signals and public street and highway lighting.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

CHARACTER OF SERVICE
Service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF ENERGY CHARGES

Energy Charges: All energy charges below are charged on a per kWh basis.

Delivery Charge:	$0.060900 per kWh
Base Power Charges:	
Summer (May – September)	$0.037325 per kWh
Winter (October – April)	$0.033801 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this rate will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges: All energy charges below are charged on a per kWh basis.

Delivery Charge (in $/kWh)	
All kWh	$0.027879 per kWh
Generation Capacity (in $/kWh)	
All kWh	$0.015000 per kWh
Fixed Must-Run (in $/kWh)	$0.005908 per kWh
Transmission (in $/kWh)	$0.009450 per kWh
Transmission Ancillary Services (in $/kWh)	
System Control & Dispatch	$0.000128 per kWh
Reactive Supply and Voltage Control	$0.000504 per kWh
Regulation and Frequency Response	$0.000489 per kWh
Spinning Reserve Service	$0.001325 per kWh
Supplemental Reserve Service	$0.000216 per kWh
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.	
Base Power Supply Charge:	
Summer	$0.037325 per kWh
Winter	$0.033801 per kWh

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 502
Superseding:

Lighting Service (LS)

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
Applicable to any Customer for private and public street lighting or outdoor area lighting where this service can be supplied from existing facilities of the Company.

The Company will install, own, operate, and maintain the complete lighting installation including lamp and globe replacements. Not applicable to resale service.

CHARACTER OF SERVICE
Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages. Multiple or series street lighting systems may be installed at the option of Company and at one standard nominal voltage.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

Delivery Charge (wattages are for incandescent bulbs or the equivalent wattage rating for other bulbs):

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Per unit Per month	$11.95	$11.95	$11.95	$17.92	$27.29	$22.65	$4.17

Note:
1. *The high pressure sodium lamps are charged per unit per month.*
2. *Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.*

Base Power Supply Charge (based on the actual rated wattage value of each lamp installed per month):

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Per unit Per month	$0.87	$0.96	$1.37	$3.42	$5.30	$0.00	$0.00

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth herein will be applied to the Customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

CONTRACT PERIOD
All lighting installations will require a contract for service as follows:

Three (3) years initial term for installation on existing facilities.
Four (4) years initial term for installation on new facilities.

After the minimum contract period has expired, this agreement shall be extended from month-to-month. The Company reserves the right to cancel the contract at any time after the initial minimum contract period has expired. It is further understood and agreed that if service is terminated by the Customer prior to the expiration of the term of the agreement, or by the Company due to the Customer's failure to pay the stated monthly service charge when due and payable, the Customer shall pay to the Company said monthly service charge, including any applicable adjustments, multiplied by the number of months remaining under the agreement.

TERMS AND CONDITIONS
1. Installation of a light on an existing pole is subject to prior approval of Company.
2. Extensions beyond 100 feet and all installations other than those addressed in this rate will require specific agreements providing adequate revenue or arrangements for construction financing.
3. The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.
4. If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.
5. The Customer is expected to notify the Company when lamp outages occur.
6. The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.
7. Light installation is subject to the governmental agency approval process.
8. The Customer is responsible for all civil installation requirements as specified by the Company in accordance with the Electrical Service Requirements.
9. In the event a public improvement project conflict(s) with existing lighting facilities, the impacted facilities will be removed and the contract terminated.
10. The Company will require a non-refundable contribution for the installation of new construction for facilities of $150.00.
11. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a Customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

55/55P WATT

Local Delivery	$ 10.44
Generation Capacity ($/Unit)	$ 0.52
Fixed Must Run ($/Unit)	$ 0.06
System Benefits ($Unit)	$ 0.01
Transmission	$ 0.71
System Control & Dispatch	$ 0.01
Reactive Supply and Voltage Control	$ 0.04
Regulation and Frequency Response	$ 0.04
Spinning Reserve Service	$ 0.10
Supplemental Reserve Service	$ 0.02
Energy Imbalance Service: currently charged pursuant to the Company's OATT	

70 WATT

Local Delivery	$ 10.03
Generation Capacity ($/Unit)	$ 0.66
Fixed Must Run ($/Unit)	$ 0.08
System Benefits ($/Unit)	$ 0.01
Transmission	$ 0.91
System Control & Dispatch	$ 0.01
Reactive Supply and Voltage Control	$ 0.05
Regulation and Frequency Response	$ 0.05
Spinning Reserve Service	$ 0.13
Supplemental Reserve Service	$ 0.02
Energy Imbalance Service: currently charged pursuant to the Company's OATT	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 502-3
Superseding:

100 WATT

Local Delivery	$ 9.21
Generation Capacity ($/Unit)	$ 0.94
Fixed Must Run ($/Unit)	$ 0.11
System Benefits ($/Unit)	$ 0.02
Transmission	$ 1.30
System Control & Dispatch	$ 0.02
Reactive Supply and Voltage Control	$ 0.07
Regulation and Frequency Response	$ 0.07
Spinning Reserve Service	$ 0.18
Supplemental Reserve Service	$ 0.03
Energy Imbalance Service: currently charged pursuant to the Company's OATT	

250 WATT

Local Delivery	$ 11.08
Generation Capacity ($/Unit)	$ 2.35
Fixed Must Run ($/Unit)	$ 0.28
System Benefits ($/Unit)	$ 0.05
Transmission	$ 3.25
System Control & Dispatch	$ 0.04
Reactive Supply and Voltage Control	$ 0.17
Regulation and Frequency Response	$ 0.17
Spinning Reserve Service	$ 0.46
Supplemental Reserve Service	$ 0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT	

400 WATT

Local Delivery	$ 16.49
Generation Capacity ($/Unit)	$ 3.71
Fixed Must Run ($/Unit)	$ 0.44
System Benefits ($/Unit)	$ 0.08
Transmission	$ 5.13
System Control & Dispatch	$ 0.07
Reactive Supply and Voltage Control	$ 0.27
Regulation and Frequency Response	$ 0.26
Spinning Reserve Service	$ 0.72
Supplemental Reserve Service	$ 0.12
Energy Imbalance Service: currently charged pursuant to the Company's OATT	

Base Power Supply Charge:

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Per unit Per month	$0.87	$0.96	$1.37	$3.42	$5.30

Water Pumping Service (GS-WP)

AVAILABILITY
Available for service to the City of Tucson Water Utility and private water Companies where the facilities of the Company are of adequate capacity and are adjacent to the premises.

Available for interruptible service agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable for service to booster stations and wells used for domestic water supply. For Interruptible service this is applicable to separately metered interruptible agricultural water pumping service for irrigation purposes of the Customer only.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

CHARACTER OF SERVICE
The service shall be single-phase and three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company. Primary metering may be used by mutual agreement.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge:	$30.00 per month
Energy Charges:	
Firm Service:	
Delivery Charge	
Summer (May – September)	$0.081500 per kWh
Winter (October – April)	$0.061500 per kWh
Interruptible Service:	
Delivery Charge	
Summer (May – September)	$0.055500 per kWh
Winter (October – April)	$0.040500 per kWh

Base Power Supply Charges:

	Summer (May-September)	Winter (October – April)
Firm Service	$0.037325	$0.033801
Interruptible Service	$0.033500	$0.030700

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

PRIMARY VOLTAGE DISCOUNT
A discount of 5% will be applied to the Delivery Charges (excluding the Basic Service Charge) and Power Supply Charges allowed from the above rates where Customer owns the transformers and service is metered at primary voltage.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the Customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TERMS AND CONDITIONS OF INTERRUPTIBLE SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.

2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.

3. Company will endeavor to give Customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.

4. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving Customer's firm load. Conversely, the firm load shall be separately served and metered and shall at no time be connected to facilities serving Customer's interruptible load.

5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a Customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Firm Service

Basic Service Charge Components (Unbundled):

Description	Basic Service Charge
Meter Services	$ 3.37 per month
Meter Reading	$ 0.62 per month
Billing & Collection	$ 9.96 per month
Customer Delivery	$ 16.05 per month
Total	$ 30.00 per month

Energy Charge Components (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.03703	$0.01703
Generation Capacity	$0.03000	$0.03000
Fixed Must-Run	$0.003970	$0.003970
Transmission	$0.008190	$0.008190
System Control & Dispatch	$0.000110	$0.000110
Reactive Supply and Voltage Control	$0.000440	$0.000440
Regulation and Frequency Response	$0.000420	$0.000420
Spinning Reserve Service	$0.001150	$0.001150
Supplemental Reserve Service	$0.000190	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge (per kWh)	$0.037325	$0.033801
PPFAC (%)	In accordance with Rider 1	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 601-3
Superseding:

Interruptible Service

Basic Service Charge Components (Unbundled):

Description	Basic Service Charge
Meter Services	$ 3.37 per month
Meter Reading	$ 0.62 per month
Billing & Collection	$ 9.96 per month
Customer Delivery	$ 16.05 per month
Total	$ 30.00 per month

Energy Charge Components (Per kWh) (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.01913	$0.00413
Generation Capacity	$0.021900	$0.021900
Fixed Must-Run	$0.003970	$0.003970
Transmission	$0.008190	$0.008190
System Control & Dispatch	$0.000110	$0.000110
Reactive Supply and Voltage Control	$0.000440	$0.000440
Regulation and Frequency Response	$0.000420	$0.000420
Spinning Reserve Service	$0.001150	$0.001150
Supplemental Reserve Service	$0.000190	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge (per kWh)	$0.033500	$0.030700
PPFAC (%)	In accordance with Rider 1	

Rider-1
Purchased Power and Fuel Adjustment Clause (PPFAC)

APPLICABILITY
The Purchased Power and Fuel Adjustment Clause (PPFAC) will be applied to all Customers taking service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. 70628 (December 1, 2008) and as updated and defined in the Company's PPFAC Plan of Administration approved in ACC Decision No. XXXXX.

RATE
The Customer's monthly bill shall consist of applicable rate charges and adjustments in addition to the PPFAC. The percentage-based PPFAC adjustment, as shown below which reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. The percentage-based PPFAC adjustment will apply to the Customer's Base Power Charge.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 701-1
Superseding:

Purchased Power Fuel Adjustment Clause
RIDER 1

APPLICABILITY: To all Company Rates, unless otherwise specified.

Issued: ______________
Month Day Year

Effective: ______________
Month Day Year

Filed By:	Kentton C. Grant	Rate:	R-1
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	Pending

Rider-2
Demand Side Management Surcharge (DSMS)

APPLICABILITY
The Demand Side Management Surcharge (DSMS) will be applied to all Customers taking service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. xxxxx (mmm dd. 20xx).

RATE
The DSMS shall be applied to all monthly bills. The DSMS will be assessed as a percentage of the bill before taxes and assessments. The rate and effective date are shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider-3
Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F

AVAILABILITY

The Market Cost of Comparable Conventional Generation (MCCCG) calculation, Rider-3, is restricted solely to Rider-4, Net Metering for Certain Partial Requirements Service (NM-PRS-F). If for a billing month a Rider-4 NM-PRS-F Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation as described in Rider-4 NM-PRS-F. The excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the positive balance of excess kWh (if any) after netting against billing period usage. The payment for the purchase of the excess kWh will be at the Company's applicable avoided cost, which for purposes of Rider-4 NM-PRS-F shall be the simple average of the hourly MCCCG as described below for the applicable year.

The Arizona Corporation Commission (ACC) provided guidance on defining MCCCG in the context of its REST Rules and identified the MCCCG as "the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal and long term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs." R14-2-1801.11.

CALCULATION/METHODOLOGY

For purposes of calculating credits to the Customer for Excess Generation, the unit price paid (Credit for Excess Generation) shall be the simple average of the MCCCG over the 8,760 hours (8,784 in a leap year) in the forecasted year. The MCCCG in each hour is based on whether native load requirements will be met by internally owned or contracted generation resources or if market purchases will be required to meet native load requirements. The following table provides a description of the MCCCG methodology. The hourly MCCCG cost determination criteria is based on the Market Condition and Dispatch Type. This method of cost determination is very data intensive and will be calculated annually by running TEP's "Planning and Risk" modeling software, and the rate will be filed with the Commission by February 1 of each year.

RATE

The customer monthly bill shall consist of the applicable rate charges and adjustments in addition to the Credit for Excess Generation based on the MCCCG. The MCCCG is an amount expressed as a rate per kWh charge that is approved by the ACC on or before April 1 of each year and effective with the first billing cycle in April, as shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

MCCCG Cost Determination Matrix

Market Condition and Dispatch Type					
	Selling to Market from In House Real and Contracted Generation Sources	MCCCG Cost Based on Incremental Production/Purchase Cost of Base Load Generation for that hour			
	No Market Transactions from/to In House and Contracted Generation Sources				
	Purchasing from Day Ahead Market, but not Spot Market, to meet Native Load Requirements	MCCCG Cost Based on Average Day Ahead Market Price of Purchased Power for that hour			
	Purchasing from Spot Market to meet Native Load Requirements	MCCCG Cost Based on Average Spot Market Price of Purchased Power for that hour			

Incremental Production / Purchase of Base Load - The cost of the next kWh (incremental) amount of load that has to be provided by TEP generation sources and/or purchased power. This will be dependent on the season, month and time of day.

If Day Ahead Market or Spot Market purchases are being used to provide for reliability support capacity to meet native load requirements by freeing up in house or contracted generation resources for regulation or spinning reserve purposes for support of native load requirements, that would still represent a Market Purchase for purposes of determining which matrix box is applicable.

Rider-4
Net Metering for Certain
Partial Requirements Service (NM-PRS-F)

AVAILABILITY
Available to all existing Net Metering customers interconnected to TEP's system prior to June 1, 2015 and those with completed interconnection applications that were submitted prior to or on June 1, 2015 (and ultimately approved) will stay on the Net Metering Rider R-4 for a period not to exceed twenty years. TEP is proposing that the Rider R-4 expire no later than May 31, 2035.

Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources [1], a Fuel Cell [2] or Combined Heat and Power (CHP) [3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this rate, the following notes and/or definitions apply:

[1]Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2]Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3]Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE
Basic Service Charges shall be billed pursuant to the Customer's rate otherwise applicable under full requirements of service.

Power sales and special services supplied by the Company to the Customer in order to meet the Customer's supplemental or interruptible electric requirements will be priced pursuant to the Customer's Rate otherwise applicable under full requirements service.

Non-Time-of-Use Rates: For Customers taking service under a tariff that is not a time-of-use rate, the Customer Supplied kWh shall be credited against the Company Supplied kWh. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

Time-of-Use Rates: For Customers taking service under a tariff that is a time-of-use rate, the Customer Supplied kWh during on-peak hours shall be credited against the Company Supplied kWh during on-peak hours. All Customer Supplied kWh during off-peak hours shall be credited against the Company Supplied kWh during off-peak hours. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

EXCESS GENERATION

If for a billing month the Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation. That is, the excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Customers taking service under a time-of-use rate who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit in the next billing period for the on-peak or off-peak periods in which the kWh were generated by the Customer. Time-of-Use Customer's taking service in the billing month of April shall receive a credit to summer on-peak and summer off-peak usage in the billing month of May for any winter on-peak and/or winter off-peak excess generation for April.

Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the balance of excess kWhs after netting. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of this rate shall be the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) Rider-3 for the applicable year. The MCCCG, as it applies to this rate, is specified in Rider-3 MCCCG - Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F (Net Metering for Certain Partial Requirements Service).

METERING

The Company will install a bi-directional meter at the point of delivery to the Customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the Customer to the metering to allow remote interrogation of the meters at each site. If by mutual agreement between Company and Customer that a phone line is impractical or cannot be provided - the Customer will work with Company to allow for the installation of equipment, on or with customer facilities or equipment to allow remote access to each meter. Any additional cost of communication, such as but not limited to, cell phone service fees will be the responsibility of the Customer.

A Customer that does not install the electrical equipment as specified to provide the verification of the required minimum CHP efficiency will not be eligible for Net Metering.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider-5
Electric Service Solar Rider
(Bright Tucson Community Solar™)

APPLICABILITY
Rider-5 is for individually metered Customers who wish to participate in the Bright Tucson Community Solar Program. Under Rider-5, Customers will be able to purchase blocks of electricity from solar generation sources. Participation in Rider-5 is limited in the Company's sole discretion to the amount of solar generation available and subscription will be made on a first come, first served basis. In order to maximize subscription under Rider-5, TEP may limit the amount of solar block energy purchased by individual Customers.

Rider-5 available prior to July 1, 2013 is further restricted to Customers being served under one of the following rates in effect at that time:

1) Residential Lifeline Discount, Rate R-06-01
2) Residential Electric Service, Rate R-01
3) Small General Service, Rate GS-10
4) Large General Service, Rate LGS-13
5) Municipal Service, Rate PS-40

Rider-5 effective after July 1, 2013 but before xx,xx, 20xx is further restricted to Customers being served under one of the following rates in effect at that time:

1) Residential Electric Service, Rate R-01
2) Small General Service, Rate GS-10
3) Large General Service, Rate LGS-13

Rider-5 effective after xx,xx, 20xx is further restricted to Customers being served under one of the following rates in effect at that time:

1) Residential Electric Service, Rate RES
2) Small General Service, Rate SGS
3) Medium General Service, Rate MGS

Customers being served under self-generation riders or plans may not purchase power under Rider-5 including, but not limited to Rider-4 Net Metering for Certain Partial Requirements Service (NM-PRS-F) and Rider-15 Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.

RATE
Customers can contract for a portion or up to their average annual usage in solar blocks of 150 kilowatt hours (kWh) each. Delivery charges will be applied to all energy delivered, including energy delivered under Rider-5. The Customer is responsible for paying (each month) all charges incurred under their applicable rate, and the total solar energy contracted for multiplied by the applicable solar block energy rate. Any demand based charges under the Customer's current rate will not be affected by elections under Rider-5. No discounts specified in any of the above-listed tariffs will apply to this rider. The rates are shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMS AND CONDITIONS

1) Customers may contract for a portion or up to their average annual usage in solar blocks of 150 kWh. If Customer's annual average usage is not available, TEP will apply the appropriate class average. This limit can be reviewed annually at the request of the Customer.

2) Each solar block's energy rate will be maintained for twenty years from the date of purchase. For the purposes of the twenty year energy rate, solar blocks will be attributed to the Customer's original service address. Transfer of service under Rider-5 is prohibited. Should the Customer cancel service for any reason, his or her subscription under Rider-5 will expire.

3) Customers may add or delete solar blocks once within a twelve month period. Any addition of solar blocks will be at the then offered solar block energy rate.

4) Solar blocks will be applied to the actual energy usage each month. Electricity used in excess of the purchased solar blocks will be billed at the Customer's regular Base Fuel and PPFAC rates. If electricity usage is below the amount covered by the solar block(s), then the excess kWhs will be rolled forward and credited against the Customer's usage in the following month. The Customer will still be responsible for the full cost of the block(s) each month.

   Customers will be credited for the balance of any excess kWhs annually, or on their final bill should the Customer terminate service under Rider-5. Each year, for the bills produced in October (September usage), TEP will credit Customers their excess kWhs after netting and reset their balance to zero. Credit for excess kWhs will be at the energy rate of the oldest solar block.

5) All contracted solar block kWhs and associated charges in a billing month will be excluded from the calculation of PPFAC and REST charges and/or credits.

Rider-6
Renewable Energy Standard and Tariff (REST) Surcharge
REST-TS1 Renewable Energy Program Expense Recovery

APPLICABILITY
Mandatory, non-bypassable surcharge applied to all energy consumed by all Customers throughout Company's entire electric service area.

RATES
For all energy billed which is supplied by the Company to the Customer. The REST surcharge shall be applied to all monthly bills. The REST rates are shown in the TEP Statement of Charges.

Notes:

1. A Large Commercial Customer is one with monthly demand greater or equal to 200 kW but less than 3,000 kW.
2. An Industrial Customer is one with monthly demand equal to or greater than 3,000 kW.
3. For non-metered services, the lesser of the load profile or otherwise estimated kWh required to provide the service in question, or the service's contract kWh, shall be used in the calculation of the surcharge.

This charge will be a line item on customer bills reading "Renewable Energy Standard Tariff."

Per Decision No. 73637 effective March 21, 2013, any Customer who has received incentives on and after January 1, 2012 under the REST Rules, shall pay the average of the REST surcharge paid by members of their Customer class. Any Customer who has a renewable installation without incentives that is interconnected with TEP's system on and after February 1, 2013 shall pay the average of the REST surcharge paid by members of their Customer class. The average price by class is shown in the TEP Statement of Charges

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 707
Superseding:

Rider-7
Customer Self-Directed Renewable Energy Option
REST-TS2 Renewable Energy Standard Tariff

AVAILABILITY
Open to all Eligible Customers as defined at A.A.C. R14-02-1801.H.

APPLICABILITY
Any Eligible Customer that applies to the Company under this program and receives approval shall participate at its option.

PARTICIPATION PROCESS
An Eligible Customer seeking to participate shall submit to the Company a written application that describes the Distributed Renewable Energy (DRE) resources or facilities that it proposes to install and the estimated costs of the project. The Company shall have sixty (60) calendar days to evaluate and respond in writing to the Eligible Customer, either accepting or declining the project. If accepted, the Customer shall be reimbursed up to the actual dollar amounts of customer surcharge paid under the REST-TS1 Tariff in any calendar year in which DRE facilities are installed as part of the accepted project. To qualify for such funds, the Customer shall provide at least half of the funding necessary to complete the project described in the accepted application, and shall provide the Company with sufficient and reasonable written documentation of the project's costs. Customer shall submit their application prior to May 1 of a given year to apply for funding in the following calendar year.

FACILITIES INSTALLED
The maintenance and repair of the facilities installed by a Customer under this program shall be the responsibility of the Customer following completion of the project. In order to be accepted by the Company for reimbursement purposes, the project shall, at a minimum, conform to the Company's System Qualification standards on file with the Commission. (REST Implementation Plan, Renewable Energy Credit Purchase Program – RECPP, Distributed Generation Interconnection Requirements, Net Metering Tariff, Company's Interconnection Manual)

PAYMENTS AND CREDITS
All funds reimbursed by the Company to the Customer for installation of approved DRE facilities shall be paid on an annual basis no later than March 30th of each calendar year. All Renewable Energy Credits derived from a project, including generation and Extra Credit Multipliers, shall become the property of the Company and shall be applied towards the Company's Annual Renewable Energy Requirement as defined in A.A.C. R14-2-1801.B.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rider.

RELATED RIDER

- REST-TS1 - Renewable Energy Program Expense Recovery

Rider-8
Lost Fixed Cost Recovery (LFCR)

APPLICABILITY
The Lost Fixed Cost Recovery (LFCR) will be applied to all Customers taking service from the Company other than residential solar – company owned program, traffic signal and street lighting service, lighting service, water pumping service, and large power service as defined in the Company's LFCR Plan of Administration (POA).

CHANGE IN RATE
The LFCR recovers a portion of the authorized margin approved in the Company's most recent rate case that has been lost as the result of implementing ACC-mandated Energy Efficiency and Distributed Generation programs. Each year, a percentage charge will be placed in effect and charged to the participating Rate classes for the 12-month period the LFCR adjustment is applicable. The total year-on-year adjustment cannot exceed 2% of the Company's most recent total combined retail calendar year revenues for all participating rate classes. The LFCR rate is shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider-9
Environmental Compliance Adjustor (ECA)

APPLICABILITY
The Environmental Compliance Adjustor (ECA) will be applied to all Customers taking service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. 73912 dated June 27, 2013 and as modified in the Company's ECA Plan of Administration approved in ACC Decision No. xxxxx dated xxx, xx, 20xx.

RATE
The Customer's monthly bill shall consist of the applicable rate charges and adjustments including the ECA. The ECA adjustor rate is expressed as a percentage rate and shall be assessed to the Customer's bill before taxes and assessments. The rate and effective date are shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider R–11
Partial Requirements Service (PRS)

AVAILABILITY
For all Qualifying Facilities ("QF") that have entered into a Service Agreement with the Company in all territories served by the Company at all points where the adjacent facilities are adequate and suitable. This rate is not available for temporary or resale service. Customers eligible for taking service under Partial Requirements Service are those customers who are not otherwise subscribed to the Company's approved Net Metering Rider.

APPLICABILITY
To QFs operating in Partial Requirements Mode for partial requirements including supplemental power, stand-by power, and maintenance power service.

CHARACTER OF SERVICE
Electric sales to the Company must be single or three phase, 60 Hertz, at a standard voltage subject to availability at the premises. The QF will have the option to sell energy to the Company at a voltage level different from that for purchases from the Company; however, the QF will be responsible for all costs incurred to accommodate such an arrangement.

DEFINITIONS
1. Commission – Arizona Corporation Commission which has jurisdiction over this Company.

2. Energy - Electric energy which is supplied by the QF and/or Company.

3. Firm Capacity - Capacity available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement from the QF with an availability factor of at least 80%, as defined by the North American Electric Reliability Corporation.

4. Full Requirements Service - Any instance whereby the Company provides all the electric requirements

5. Maintenance Power - Electric capacity and energy supplied by the Company during scheduled outages of the QF.

6. Net Energy - The total kilowatt hours ("kWh") sold to the QF by the company less the total kWhs purchased by the Company from the QF.

7. Partial Requirements Mode of Operation - A QF's generation output first goes to supply its own electric requirements with any excess energy (over and above its own requirements) then being sold to the Company. The company supplies the QF's electric requirements not met by the QF's own-generating facilities. This also may be referred to as the "parallel mode" of operation.

8. Purchase Agreement - Agreements for the purchase of electric energy and capacity from and the sale of power to the QF entered into between the Company and QF.

9. Qualifying Facilities - Cogeneration and small power production facilities where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying criteria for size, fuel use, efficiency and ownership as promulgated in 18 C.F.R., Chapter I, Part 292, Subpart B of Federal Energy Regulatory Commission regulations.

10. Supplemental Power - Electric capacity and energy supplied by the Company regularly used by the QF in addition to that which the facility generates itself.

11. Stand-by Power - Electric capacity and energy supplied by the Company to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

RATES FOR SALES TO QFs

Supplemental Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable tariff but not to be less than $25.00 per month.

B. Energy Charge - The energy charge shall be the energy charge (including Base Power Fuel & Purchased Power) using the otherwise applicable tariff.

C. Demand Charge - The demand charge shall be the demand charge using the otherwise applicable tariff, or $12.00 per kW if none is specified in the tariff, times the higher of the current month's measured demand or the maximum billed Demand in the proceeding 23 months used to meet only supplemental power and is not applied to total requirements.

Standby Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable tariff but not to be less than $25.00 per month.

B. Energy Charge - The energy charge shall be the energy charge (including Base Fuel & Purchased Power) using the otherwise applicable tariff plus 50%.

C. Demand Charge - The demand charge shall be the 1.5 times the applicable tariff with a minimum of $18.00 per kW, if no demand charge is specified.

Maintenance Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable tariff but not to be less than $25.00 per month.

B. Energy Charge - The energy charge shall be the energy charge (including Base Fuel & Purchased Power) using the otherwise applicable tariff.

C. Demand Charge - The demand charge shall be the demand charge using the otherwise applicable tariff, or $12.00 per kW if none is specified in the tariff, times the maximum measured Demand.

D. Maintenance Service - Must be scheduled with and approved by the Company and may only be scheduled during the period October through April.

Only one service charge will be applied for each billing period.

RATES FOR PURCHASES FROM QFs

Minimum Basic Service Charge per month at $25.00 will be assessed each QF selling energy to the Company under this pricing plan. A service charge for purchases from the QF will only be charged if a service charge was not assessed for sales to the QF.

Rates for Energy purchased from the QF shall be priced at short-run avoided cost as provided in the Service Agreement applicable herein and approved by the Commission.

Rates for Firm Capacity purchased from the QF shall be priced at long-run avoided cost based upon deferral of capacity additions indicated in Company's resource plan as provided in the Service Agreement applicable herein and approved by the Commission.

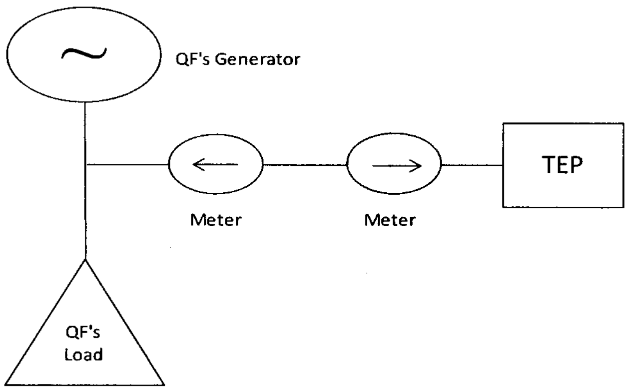
ADJUSTMENTS

All other charges specified in the applicable tariff apply for all energy purchased from the Company by the QF.

METER CONFIGURATION

As provided for in the Service Agreement. If not otherwise provided for in the Service Agreement then as follows:

If in Partial Requirements mode:



CONTRACT PERIOD

As provided for in the Service Agreement.

TERMS AND CONDITIONS

A Customer that qualifies for service for their full requirements, but now desires to install a generator shall take partial requirements service under the conditions of the tariff herein. In addition to the requirements of the Service Agreement, these conditions include:

1. Must have a demand meter installed and operating before service will be allowed. Any equipment necessary to provide partial requirement service, including equipment to measure the output of the generator(s), that would not otherwise be necessary for full requirements service must meet all Company standards and will be installed at the Customer's expense.

2. The Capacity of the Customer's installed generator(s) must be certified by the Company prior to the receipt of any partial requirements service. This certification will be done by the Company at the Customer's expense. The generating unit cannot be sized at more than 125% of the Customer's connected Capacity. If output of the Customer's generator(s) appears to increase above the certified level, the Company, at its discretion, may require recertification of the equipment. If it is confirmed that the equipment has been expanded or otherwise modified to increase its production ability, the cost of the recertification will be at the Customer's expense. If no changes were found there will be no cost to the Customer for the recertification.

3. Any unpaid balances will be subject to the standard late payment charges as provided for in the currently approved Rules and Regulations.

4. Primary Service and Metering is required for all services that have a certified kW output of the generating unit(s) greater than 300 kW.

5. The Company may require a written contract and a minimum term of contract, at its discretion.
6. Prior to construction, the Customer will contribute to the Company the total amount of the estimated interconnection construction costs directly related to distribution and transmission service. The Customer will furnish, install, and maintain incremental non-distribution system or non-transmission system equipment at their expense. The equipment must meet the standards of the Company's Electric Service Requirements.

TAX CLAUSE
To the charges computed under the above rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rider.

Rider–12
Interruptible Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Available to Customers qualifying for and receiving electric service over 3,000 kW and are willing to subscribe to at least 1,000 kW of interruptible load at a contiguous facility. This rider is not available for standby, temporary, resale or in conjunction with other interruptible rate schedules.

CHARACTER OF SERVICE
Must meet all service requirements for the Customer's applicable tariff.

TERMS AND CONDITIONS OF SERVICE

1. Customers taking service under this rider are eligible for credits in exchange for curtailing load at the request of the Company.

2. Interruptions can be called for economic or non-economic reasons and are to be called at the sole discretion of the Company.

3. The Customer must designate each service point that may be available for interruption with a 30 minute notice. Interruption will be at the discretion of the Company.

4. No more than two interruption events will occur in a given calendar day.

5. A Customer will be limited to no more than two interruptions in a day during the five summer months for a maximum of six (6) hours for each daily interruption event, even if the duration per event is less than 6 hours.

6. To receive service under this Rider–12, the Customer will install, at the Customer's expense, all necessary communication, relay and breaker equipment to qualify for service under this Rider-12, subject to Company approval and will pay for associated hardware cost. The Customer must maintain all Company-approved equipment at their service location necessary for the Company to provide interruption notification and to remotely interrupt the Customer from its master control station.

7. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

8. Nothing herein prevents the Company from interrupting service for emergency circumstances, determined at the Company's sole discretion. Emergency interruptions, as defined by the Company's Rules and Regulations, shall not count as interruption events for purposes of this rider.

9. The standard Rules and Regulations of the Company, as on file with the Arizona Corporation Commission, shall apply where not inconsistent with this rider.

10. The total of all interruption events (excluding Emergency interruptions) will not exceed 120 hours per year.

BID COMMITMENT PERIOD

The Company will post Market Value Capacity Price (MVCP) (defined below) and available Interruptible Credits ($/kW) based on market value capacity for day-ahead dispatch notice for the coming months of May through September by March 15 in the same calendar year.

NOMINATION OF INTERRUPTIBLE LOAD BY CUSTOMER

Nomination will occur before April 15 of the calendar year of each interruption season. Participating Customers shall designate by service point the portion of their load that is Interruptible Load (in kW). A minimum of a thirty minute notice requirement, and a maximum interruption of six hours per event applies to all load nominated at a single service point. Customers with multiple service points may designate different maximum load (kW) for different contiguous service points. If the Customer intends to interrupt a specific activity or function at its operation, the Customer should state this activity or function at the time Interruptible Load is nominated. The minimum nomination of interruptible load summed over a participating Customer's contiguous service points shall be at least 1,000 kW.

INTERRUPTIBLE CREDIT

Customers who elect service under this Rider–12 will receive a monthly Interruptible credit for each of the five summer months in which an interruption may occur. The credit will be calculated by taking the Market Value Capacity Price applicable for the interruptible load season (May through September) times the nominated interruptible load of the individual Customer.

MARKET VALUE CAPACITY PRICE (MVCP)

The Market Value Capacity Price (MVCP) reflects opportunity cost of capacity as revealed through the Company's resource procurement process, adjusted to reflect line losses, and reserves avoided. Resource prices are sensitive and confidential information based on competitive bids; however this information will be made available to the Arizona Corporation Commission Staff and/or an Independent Monitor(s) for review. The MVCP is a price applicable to the five summer months only.

RECOVERY OF PROGRAM COSTS

The cost of the interruptible resource under this Rider–12 (the credits applied to qualifying Customers' bills) shall be treated as "Purchased Power" and shall be recorded in FERC account 555 and appropriately treated through the Purchased Power and Fuel Adjustment Clause (PPFAC) as any other prudent fuel or purchased power cost.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rider.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Rider-13
Economic Development Rider (EDR)

AVAILABILITY
Available throughout the Company's entire electric service area at all points where facilities of adequate capacity, required phase, and suitable voltage are adjacent to the sites served. This rider is available for commercial or industrial Customers with a projected peak demand of 3,000 kW or more and a load factor of 75% or higher for the highest 4 coincident-peak months in a rolling 12-month period.

APPLICABILITY
This rider is applicable to the qualifying additional load of an existing or new Customer meeting the criteria specified herein. All provisions of the Customer's applicable rate will apply to the qualifying additional load, except as modified herein. This rider shall be available for five years from the effective date of the Economic Development Rider. Total program participation shall be limited to 200 MW of applicable Customer load.

New and existing Customers taking service under this rider must provide written documentation that they have qualified for at least one of the following Arizona state tax credits designed to promote business recruitment and expansion:

- Arizona's Quality Jobs Tax Credit (A.R.S. § 41-1525). The program provides a tax credit for net increases in full-time employees residing in the state and hired in qualified employment positions.
  - If located in a city or town with a population of 50,000 persons or more and a county of 800,000 or more, companies must make at least a $5 million capital investment, create at least 25 net new full-time jobs that pay 100 percent of the median county wage, and cover at least 65 percent of employee health insurance costs.
  - In any other location, companies must invest at least $1 million of capital and create at least 5 qualified employment positions.
- Qualified Facility Tax Credit (A.R.S. § 41-1512). The program provides a refundable tax credit for qualifying capital investment in a manufacturing facility – including a manufacturing-related research and development or headquarters facility – that creates new jobs, of which at least 51 percent pay a wage that equals or exceeds 125 percent of the median state wage. Also, the applicant shall provide health insurance coverage for all net new full-time employment positions for which the applicant pays at least 80 percent of new employees' health care premiums.

The incremental jobs created by the qualifying additional load must be located within the Company's electric service area. If either or both of the above Arizona Revised Statutes are superseded by subsequent legislation, the effective Statute shall apply. Exceptions to any of the above criteria will be reviewed and evaluated by the Company on a case-by-case basis.

For purposes of this rider, the following notes and/or definitions apply:

[1] Economic Development means new or expanding business operations that build new facilities.

[2] Economic Redevelopment means new or expanding business operations that occupy existing vacant facilities.

CHARACTER OF SERVICE
Must meet all service requirements for the Customer's applicable tariff.

RATE
All provisions, charges, and adjustments in the Customer's applicable retail rate schedule will continue to apply to the qualifying additional load except as follows:

Category	Program Term	Discount on Total Bill before Taxes	Qualifications
Economic Development	5 years	Year 1: 20% Year 2: 15% Year 3: 10% Year 4: 5% Year 5: 2.5%	1. Meet (i) criteria for Arizona's Quality Jobs Tax Credit or (ii) Qualified Facility Tax Credit, and 2. Create new/expanding load of 1,000 kW.
Economic Redevelopment	5 years	Year 1: 30% Year 2: 25% Year 3: 20% Year 4: 10% Year 5: 5%	1. Meet (i) criteria for Arizona's Quality Jobs Tax Credit or (ii) Qualified Facility Tax Credit, 2. Create new/expanding load of 1,000 kW, and 3. The business moves into an existing site.

ECONOMIC DEVELOPMENT RIDER SERVICE AGREEMENT
The Customer must execute an Economic Development Rider Service Agreement with the Company. The Service Agreement establishes the terms and conditions of participation in the program consistent with A.R.S. § 41-1525 and A.R.S. § 41-1512, the Arizona Corporation Commission's regulations, and this rider.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Experimental Rider-14
Alternative Generation Service (AGS)

AVAILABILITY

Available throughout the Company's entire electric service area at all points where facilities of adequate capacity and required phase and suitable voltage are adjacent to the sites served. This rider is available for Customers who have a peak load of 3,000 kW or more at a single service point and are served under rates LPS-TOU or LPS-TOU-HV.

Customers must have interval metering or advanced metering infrastructure in place at all times under this rider. Customers shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

All provisions of the Customer's applicable rate will apply in addition to this Experimental Rider-14, except as modified herein. This rider shall be available for four years from the effective date of Experimental Rider-14, unless extended by the Arizona Corporation Commission. Total program participation shall be limited to 30 MW of Customer load.

For purposes of this rider, the following notes and/or definitions apply:

[1] Generation Service means wholesale power delivered to TEP by a Generation Service Provider.

[2] Generation Service Provider means a Company-approved third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.

[3] Energy Imbalance Service means the calculation and management of the hourly deviations in energy supply for Imbalance Energy.

[4] Imbalance Energy means the difference between the hourly scheduled energy from the Generation Service Provider and the actual hourly metered loads for each Customer for all Customers that have selected the Generation Service Provider under this rider. Imbalance Energy will be calculated by the Company.

[5] Standard Generation Service means power provided by the Company to a retail Customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate other than Experimental Rider-14.

[6] Total Load Requirements means the Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Company's sites for the duration of the contract.

CHARACTER OF SERVICE

The service shall be three-phase, 60 Hertz, and at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

CUSTOMER PARTICIPATION PROCESS

The Company shall establish an initial enrollment period during which Customers can apply for service under this rider. If the applications for service are greater than the program maximum amount, then Customers shall be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rider.

DESCRIPTION OF SERVICES AND OBLIGATIONS
The Customer shall apply for service under this rider.

The Company shall conduct the enrollment process in accordance with the provisions of this rider.

The Customer shall select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines.

The Company shall enter into a contract with the Company-approved Generation Service Provider to receive delivery and title to the power on the Customer's behalf.

The Generation Service Provider shall provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the elected metered accounts, and will attest in its contract with the Company that this condition is met. For the purposes of this rider, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

Any incremental costs or penalties incurred by the Company as the result of actions or inactions of the Generation Service Provider will be the responsibility of the Customer to pay or arrange for resolution of or service under this rider will be terminated immediately and the provisions of the section referring to the Default of the Generation Service Provider will be applied.

The Company shall provide transmission, delivery and network services to the Customer according to normal retail electric service.

Following receipt of payment by the Company, settlement will be made with the Generation Service Provider for Energy Imbalance Service and other relevant costs on a monthly basis according to the program guidelines.

The Generation Service Provider shall bill the Company the monthly billed amounts for each Customer for Generation Service and Energy Imbalance Service according to the program guidelines.

The Company shall bill the Customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider including any applicable taxes and assessments.

The Customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rider and will be subject to disconnection in the manner consistent with the Rules and Regulations for the equivalent retail service in the event of non-payment or late payment.

RATE
All provisions, charges, and adjustments in the Customer's applicable retail rate schedule will continue to apply except as follows:

1. The Base Power Charge will not apply.
2. The Purchased Power and Fuel Adjustment Clause (PPFAC) will not apply.

Experimental Rider-14 charges determined and billed by the Company include:

1. A monthly Management Fee of $0.0040 per kWh applied to the Customer's metered kWh.
2. An initial charge or credit for fuel hedging costs, as describe herein.

Experimental Rider-14 Generation Service and Energy Imbalance Service charges billed by the Company include:

1. Generation Service charges shall be charged at a rate specified in the contract between the Customer and the Generation Service Provider.
2. Energy Imbalance Service charges shall be charged at a rate greater than $0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Energy Imbalance Service as specified herein.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at a point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company shall serve as the Scheduling Coordinator. The Generation Service Provider shall provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 5.62%, from the point of delivery to the Customer's sites shall be either scheduled or financially settled.

ENERGY IMBALANCE SERVICE

The Company will provide Energy Imbalance Service according to the terms and provisions in the Company's Open Access Transmission Tariff, Schedule 4. Imbalance Energy will be based on the Generation Service Provider's portfolio of Customer loads.

HEDGING COST

The Customer will pay for the hedging cost associated with the Customer's Standard Generation Service at the time the Customer takes service under this rider. For the purpose of this rider, the Company will determine the applicable pro rata hedge cost based on the market price for hedge costs at the time the Customer takes service under this rider.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider shall be for not less than one year and shall not exceed the termination date of this rider or 4 years, whichever is shorter.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery, and other terms related to the Company's management of the generation resource.

DEFAULT OF THE THIRD PARTY GENERATION SERVICE PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the Customer must notify the Company and select another Generation Service Provider within 60 days. Prior to execution of any new power contract, the Company shall, if available, provide the required power to the Customer, which will be charged at the Dow Jones Electricity Palo Verde Daily Index price or an equivalent for the power delivery date plus $20 per MWh. In addition, all other provisions of this rider will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the Customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Where possible, Customer may return to the Company's Standard Generation Service under their applicable retail rate schedule without charge if: (1) they provide one year notice (or longer) to the Company; or (2) if this rider is discontinued at the end of the 4-year experimental period; or (3) the Commission terminates the program prior to the end of the initial 4-year experimental period. Absent one of these three conditions, the Company will use its best efforts to provide the Customer with generation service at the Dow Jones Electricity Palo Verde Daily Index price or an equivalent for the power delivery date plus $20 per MWh until the Company is reasonably able to integrate the Customer back into their generation planning and provide power at the applicable retail rate schedule. This transition will be at the Company's determination but no longer than 1 year. The returning Customer must remain with the Company's Standard Generation Service for at least 1 year and compensate the Company for all fixed generation costs avoided by the Customer during the period the Customer was receiving service under this rider.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider-15
Net Metering for Certain
Partial Requirements Service (NM-PRS), Post June 1, 2015

AVAILABILITY
Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources [1], a Fuel Cell [2] or Combined Heat and Power (CHP) [3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this Rate, the following notes and/or definitions apply:

[1] Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2] Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3] Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE
Basic Service Charges shall be billed pursuant to the Customer's Rate otherwise applicable tariff.

All power sales defined as "kWh" and special services supplied by the Company to the Customer in order to meet the Customer's electric requirements will be priced pursuant to the Customer's otherwise applicable tariff.

All energy produced by the Customer's generator in excess of the Customer's consumption at the time of the production is defined as excess generation and will be tracked throughout the month as excess generation and will be treated in accordance with the provisions outlined below.

EXCESS GENERATION
If at any time within a billing month the Customer's generation facility's energy production exceeds the energy consumed by the Customer, the Customer's bill for the same billing period shall be credited for the excess generation priced at the approved Renewable Credit Rate. In the event the credit exceeds the billable amount during that billing period, the unused credit will carry forward to the bill for the next billing period. The excess generation is treated the same for non-Time-of-Use service Customers and Time-of-Use service Customers.

METERING
The Company will install a bi-directional meter at the point of delivery to the Customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the Customer to the metering to allow remote interrogation of the meters at each site. If by mutual agreement between Company and Customer that a phone line is impractical or cannot be provided - the Customer will work with Company to allow for the installation of equipment, on or with customer facilities or equipment to allow remote access to each meter. Any additional cost of communication, such as but not limited to, cell phone service fees will be the responsibility of the Customer.

A Customer that does not install the electrical equipment as specified to provide the verification of the required minimum CHP efficiency will not be eligible for Net Metering.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this rider, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RENEWABLE CREDIT RATE
The "Renewable Credit Rate" is the Rate equivalent to the most recent utility scale renewable energy purchased power agreement connected to the Company's distribution system and is set forth in the TEP Statement of Charges.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider.

Rider–16
Renewable Credit Rate (RCR)

RATE
The RCR is an amount expressed as a rate per kWh credit that is approved by the ACC on or before January 1 of each year and effective with the first billing cycle in January, as shown in the TEP Statement of Charges.

CALCULATION/METHODOLOGY
The RCR is the rate equivalent to the most recent utility scale renewable energy PPA connected to TEP's distribution system, that uses a technology specific to the Customer's generation facility at the time service is requested.

If no utility scale PPA meeting the criteria above exists, the RCR is equal to the TEP Market Cost of Comparable Conventional Generation (MCCCG) as defined in Rider-3 MCCCG.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 801

Superseding :

TEP STATEMENT OF CHARGES

Fee No.	Description	Rate	Effective Date	Decision No.
1.	Service Transfer Fee	$26.00	Pending	Pending
2.	Customer-Requested Meter Re-read	$26.00	Pending	Pending
3.	Special Meter Reading Fee (including Customer Self-Reads)	$26.00	Pending	Pending
4.	Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regulator Business Hours – Single-Phase Service	$38.00	Pending	Pending
5.	Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Single-Phase Service	$61.00	Pending	Pending
6.	Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours – Three-Phase Service	$129.00	Pending	Pending
7.	Service Establishment, Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Three-Phase Service	$271.00	Pending	Pending
8.	Service Reestablishment under other than usual operating procedures (including Automated Meter Opt-Out Set-Up Fee) – Single-Phase Service	$187.00	Pending	Pending
9.	Single-Phase Line Extension Charge per Foot	$17.00	Pending	Pending
10.	Three-Phase Line Extension Charge per Foot	$27.00	Pending	Pending
11.	Underground Differential Line Extension Charge per Foot	$21.00	Pending	Pending
12.	PME Switchgear Cabinet	$20,500.00	Pending	Pending
13.	Meter Test	$211.00	Pending	Pending
14.	Returned Payment Fee	$10.00	Pending	Pending
15.	Late Payment Finance Charge	1.5%	Pending	Pending
16.	Residential Solar – Company Owned Program Processing Fee	$250.00	Pending	Pending
17	Consumption History Request and Interval History Request	$65.00 an hour	Pending	Pending

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 801-1

Superseding:

TEP STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-1 – Purchased Power and Fuel Adjustment Clause (PPFAC)	Varies – See Rider-1	Pending	Pending
Rider R-2 – Demand Side Management Surcharge (DSMS)	Pending	Pending	Pending
Rider R-3 – Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F	$0.028653 per kWh	April 1, 2015	74973
Rider R-5 – Electric Service Solar Rider (Bright Tucson Community Solar™) Solar Block Energy Rate for Residential Lifeline Discount, Rate R-06-01 Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate GS-10 Solar Block Energy Rate for Large General Service, Rate LGS-13 Solar Block Energy Rate for Municipal Service, Rate PS-40	$0.050198 per kWh $0.050324 per kWh $0.048475 per kWh $0.049371 per kWh $0.049086 per kWh	February 1, 2011 Through June 30, 2013	71835
Rider R-5 – Electric Service Solar Rider (Bright Tucson Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for Small General Service, Rate GS-10 Solar Block Energy Rate for Large General Service, Rate LGS-13	$0.053463 per kWh $0.053274 per kWh $0.053227 per kWh	July 1, 2013 Through Pending	73912
Rider R-5 – Electric Service Solar Rider (Bright Tucson Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate RES Solar Block Energy Rate for Small General Service, Rate SGS Solar Block Energy Rate for Medium General Service, Rate MGS	Pending	Pending	Pending
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Monthly Cap For Residential Customers: For Small General Service Customers: For Large General Service Customers: For Large Power Service Customers: For Lighting Customers:	$0.008000 per kWh Monthly Cap $ 3.76 per month $ 100.00 per month $1,015.00 per month $8,000.00 per month $ 100.00 per month	January 1, 2015	74884

TEP STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Average price by class: Average Rate For Residential Customers: For Small General Service Customers: For Large General Service Customers: For Large Power Service Customers: For Lighting Customers:	Average Rate $ 3.19 per month $ 20.77 per month $ 779.66 per month $8,000.00 per month $ 11.71 per month	January 1, 2015	74884
Rider R-8 - Lost Fixed Cost Recovery (LFCR) Mechanism	Pending	Pending	Pending
Rider R-9 – Environmental Compliance Adjustor (ECA)	Pending	Pending	Pending
Rider R-16 – Renewable Credit Rate (RCR)	Pending	Pending	Pending

TEP

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 802
Superseding:

Bill Estimation Methodologies

Tucson Electric Power Company (TEP) regularly encounters situations in which TEP cannot obtain a complete and valid meter read. No matter the cause of the need to estimate the read, the following methods are used depending on the circumstances.

PREVIOUS YEAR FORMULA

SAME CUSTOMER WITH AT LEAST ONE YEAR OF HISTORY

TEP would generate a bill based on customer usage from the previous year using the "PREVIOUS YEAR" formula as follows:

If last year's usage was estimated, see Previous Month Formula:

LAST YEAR'S USAGE FOR SAME MONTH / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR "TIME OF USE" (TOU) THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

PREVIOUS MONTH FORMULA

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

TEP would generate a bill based on customer usage from the previous month using the "PREVIOUS MONTH" formula as follows:

If last month's usage was estimated, see Trend Formula:

LAST MONTHS USAGE / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)
PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

TREND FORMULA

NEW CUSTOMER AT SAME PREMISE

TEP would generate a bill using the "TREND" formula, based on customer's usage trend as described below:

TEP's customer information system (CIS) would generate a bill based on trend. Customers are assigned to a Trend area which differentiate consumption based on different geographic areas. Secondly, the customer is assigned to a Trend class which is used to differentiate consumption trends based on the type of service and type of property. An example of this would be residential, commercial, and industrial usage. Thirdly, all consumption is identified using unit of measure code and a time of use code. Within TEP's CIS, a trend record is created from each billed service. This record becomes part of a trend table. During estimation, consumption from three prior bill cycles is compared to the consumption from the same cycle in the previous month to determine a trend. This trend, plus a tolerance, is used to create a usage amount for bill estimation.

CUSTOMER'S USAGE IN PREVIOUS PERIOD/ AVERAGE CUSTOMER'S USAGE IN PREVIOUS PERIOD X AVERAGE CUSTOMER'S USAGE IN CURRENT PERIOD = ESTIMATED CONSUMPTION FOR REGISTER READ

NO HISTORY

TEP would not generate a bill until a good meter read was acquired then use known consumption to estimate previous bills.

Filed By:	Kentton C. Grant	Rate:	Bill Estimation - 1
Title:	Vice President of Finance and Rates	Effective:	Pending
District:	Entire Electric Service Area	Decision No.:	Pending

Demand Estimate

For accounts that have a demand billing component TEP collects interval data. This interval data is used to manually estimate demands using the following methodologies:

SAME CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous year using the following formula:

LAST YEAR'S DEMAND FOR SAME MONTH = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NO HISTORY
TEP would not generate a bill until a good demand read was acquired then use known demand to estimate previous bills.

Residential Electric Service (RES-~~01~~)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase or three-phase ~~(subject to availability at point of delivery)~~ residential electric service (subject to availability at point of delivery) -in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

For those dwellings and apartments where electric service has historically been measured through two meters, when one of the meters was installed pursuant to the Residential Electric Water Heating Service Rate (R-02F) which is no longer in effect, the electric service measured by such meters shall be combined for billing purposes.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electrical equipment that causes excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~**Customer Charge of Delivery Services:**~~
~~Standard~~

~~Customer~~Basic Service Charge, Ssingle-phase service ~~and minimum bill~~	$20~~10~~.00 per month
~~Customer~~Basic Service Charge, Tthree-phase service ~~and minimum bill~~	$25~~15~~.00 per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~

~~Customer Charge, single-phase with usage less than 2,000 kWh~~	~~$12.50 per month~~
~~Customer Charge, three-phase with usage less than 2,000 kWh~~	~~$17.50 per month~~
~~Customer Charge, single-phase with usage of 2,000 kWh or more~~	~~$16.50 per month~~
~~Customer Charge, three-phase with usage of 2,000 kWh or more~~	~~$21.50 per month~~

Energy Charges ($/kWh):

0 – 500 kWh	~~$0.0591~~	$0.0591 per kWh~~96425~~
Over 500 kWh	~~$0.0791~~	$0.0791 per kWh~~112901~~

~~Winter (October – April)~~	~~Delivery Services-Energy~~[1]	~~Power Supply Charges~~[2] ~~Base Power~~	~~PPFAC~~[2]	~~Total~~[3]

~~0 – 500 kWh~~	~~$0.056200~~	~~$0.031532~~	~~*varies*~~	~~$0.087732~~
~~501 – 1,000 kWh~~	~~$0.065200~~	~~$0.031532~~	~~*varies*~~	~~$0.096732~~
~~1,001 – 3,500 kWh~~	~~$0.078100~~	~~$0.031532~~	~~*varies*~~	~~$0.109632~~
~~Over 3,500 kWh~~	~~$0.087100~~	~~$0.031532~~	~~*varies*~~	~~$0.118632~~

~~1. Delivery Services~~ Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh):

	Summer (May – September)	Winter (October – April)
Base Power	$0.037325 per kWh	$0.033801 per kWh

~~2.~~ Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. ~~The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. Please see Rider-1 for current rate.The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent kWh adjustment in accordance with Rider-1-PPFAC. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuelper kWh sold.~~

~~3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).~~

MONTHLY LIFELINE DISCOUNT:

~~This discount is only available to new and eligible Lifeline Customers whose monthly bill shall be in accordance to the rate above except that a discount of $9.00 per month shall be applied. No Lifeline discount will be applied that will reduce the bill to less than zero.~~

For current and new eligible Lifeline customers taking service under RES, the monthly bill shall be in accordance to the rate above except that a discount of $15.00 per month shall be applied.

For current Lifeline customers formerly taking service under one of the following discontinued rates, the monthly bill shall be in accordance to the rate above except that the Basic Service Charge and Discount per month shall be applied as follows:

~~All applicable charges included in this tariff apply to current and former Lifeline rates listed below.~~

Frozen Lifeline Service Rate	Basic Service Charge	Discount
~~Residential Lifeline RES~~	~~$20~~	~~$15~~
Residential Lifeline/Senior R-04-01F	$12	$20
Residential Lifeline Service R-05-01F	$12	$15
Residential Lifeline Service R-06-01F	$12	$15
Residential Lifeline Medical R-08-01F	$12	$20

For all customers, no Lifeline discount will be applied that will reduce the bill to less than zero.

LIFELINE ELIGIBILITY

1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

~~LOST FIXED COST RECOVERY (LFCR) – RIDER 8~~

~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~			
Description	Single-Phase	Three-Phase	Frozen Lifeline
Meter Services	$2.25~~1.74~~ per month	$7~~2~~.25~~60~~ per month	$1.35 per month
Meter Reading	$0.41~~1.17~~ per month	$0.41~~1.77~~ per month	$0.25 per month
Billing & Collection	$6.64~~5.04~~ per month	$6.64~~7.56~~ per month	$3.98 per month
Customer Delivery	$10.70~~2.05~~ per month	$10.70~~3.07~~ per month	$6.42 per month
Total	$2~~1~~0.00 per month	$25~~15~~.00 per month	$12.00 per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage less than 2,000 kWh~~

~~Description~~	~~Single-Phase~~	~~Three-Phase~~
~~Meter Services~~	~~$1.74 per month~~	~~$2.60 per month~~
~~Meter Reading~~	~~$1.17 per month~~	~~$1.77 per month~~
~~Billing & Collection~~	~~$5.04 per month~~	~~$7.56 per month~~
~~Customer Delivery~~	~~$2.05 per month~~	~~$3.07 per month~~
~~LFCR~~	~~$2.50 per month~~	~~$2.50 per month~~
~~Total~~	~~$12.50 per month~~	~~$17.50 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more~~		
~~Description~~	~~Single-Phase~~	~~Three-Phase~~
~~Meter Services~~	~~$1.74 per month~~	~~$2.60 per month~~
~~Meter Reading~~	~~$1.17 per month~~	~~$1.77 per month~~
~~Billing & Collection~~	~~$5.04 per month~~	~~$7.56 per month~~
~~Customer Delivery~~	~~$2.05 per month~~	~~$3.07 per month~~
~~LFCR~~	~~$6.50 per month~~	~~$6.50 per month~~
~~Total~~	~~$16.50 per month~~	~~$21.50 per month~~

Energy Charge

Components (per kWh) (Unbundled):

Component	~~Summer (May – September)~~
Local Delivery – Energy 0 – 500 kWh	$0.00571~~$0.001800~~
Local Delivery – Energy Over 500~~501 – 1,000~~ kWh	$0.02571~~$0.012800~~
~~1,001 – 3,500 kWh~~	$0.028830$0.007270 $0.035250~~$0.025400~~
~~Over 3,500 kWh~~	$0.007270 ~~$0.033800~~
Generation Capacity	$0.035250~~$0.039800~~
Fixed Must Run	$0.007270 ~~$0.003000~~
Transmission	$0.008480~~$0.009000~~
System Control & Dispatch	$0.000120~~$0.000100~~
Reactive Supply and Voltage Control	$0.000450 ~~$0.000500~~
Regulation and Frequency Response	$0.000440 ~~$0.000500~~
Spinning Reserve Service	$0.001190 ~~$0.001300~~
Supplemental Reserve Service	$0.000190 ~~$0.000200~~
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

	Summer	Winter

Tucson Electric Power Company

Original Sheet No.: 101-4
Superseding:

	(May – September)	(October - April)
Base Power Component (per kWh)	$0.037325~~35111~~ per kWh	$0.033801~~31532~~ per kWh
PPFAC (%)	In accordance with Rider 1~~—PPFAC~~	

Filed By:	Kentton C. Grant	Rate:	RES~~-01~~
Title:	Vice President of Finance and Rates	Effective:	~~July 1, 2013~~Pending
District:	Entire Electric Service Area	Decision No.:	~~73912~~ Pending

Residential Time-of-Use (RES-TOU-~~80~~)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all single-phase ~~(subject to availability at point of delivery)~~ residential electric service (subject to availability at point of delivery) in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Aapplicability conditions.

Service under this rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~	
~~Standard~~	
~~Customer~~	
Basic Service Charge~~, single-phase service and minimum bill~~	$20.00~~11.50~~ per month
~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~	
~~Customer Charge, single-phase with usage less than 2,000 kWh~~	~~$14.00 per month~~
~~Customer Charge, single-phase with usage of 2,000 kWh or more~~	~~$18.00 per month~~

Energy Charges ($/kWh):

0 - ~~Off-Peak Over~~ 500 kWh	$0.0591 per kWh~~791~~
~~On-Peak all Remaining~~Over 500 kWh	$0.0791 per kWh
~~Off -Peak All remainging~~	

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh):

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.060800 per kWh	$0.056000 per kWh
Base Power Off-Peak	$0.025700 per kWh	$0.022100 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

1. ~~Delivery Services Energy is a bundled charge that includes: Local Delivery Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.~~

2. ~~The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent kWh adjustment in accordance with Rider-1 PPFAC. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuelper kWh sold.~~

3. ~~Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).~~

Calculation of Tiered (Block) Usage by TOU Period:
Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply the TOU period percent usage by the tiered kWh usage.

Example: Consider a customer who used 2,000 kWh in a month with 20% on-peak usage and 80% off-peak usage. This customer will have 500 kWh in the first tier and 1500 kWh in the second tier. Applying Step 3, the customer has 100 kWh in on-peak first tier usage, 300 kWh in on-peak second tier usage, 400 kWh in off-peak first tier usage, and 1200 kWh in off-peak second tier usage.

kWh	On-Peak	Off-Peak	Total
0 – 500 kWh	100	400	500
Over 500 kWh	300	1,200	1,500
Total	400	1,600	2,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

MONTHLY LIFELINE DISCOUNT:

~~All applicable charges included in this tariff apply to current and former Lifeline rates listed below.~~

For current and new eligible Lifeline customers taking service under RES-TOU, the monthly bill shall be in accordance to the rate above except that a discount of $15.00 per month shall be applied.

For current Lifeline customers formerly taking service under one of the following discontinued rates, the monthly bill shall be in accordance to the rate above except that the Basic Service Charge and Discount per month shall be applied as follows:

TEP
-Tucson Electric Power

~~This discount is only available to new and eligible Lifeline customers whose monthly bill shall be in accordance to the rate above except that a discount of $9.00 per month shall be applied. No Lifeline discount will be applied that will reduce the bill to less than zero.~~

Frozen Lifeline Service Rate	Basic Service Charge	Discount
Residential Lifeline RES-TOU	$20	$15
Residential Lifeline/Senior R-04-21F	$12	$20
Residential Lifeline Service R-05-21F	$12	$15
Residential Lifeline Service R-06-21F	$12	$15
Residential Lifeline Medical R-08-21F	$12	$15
Residential Lifeline/Senior R-04-70F	$12	$15
Residential Lifeline Service R-05-70F	$12	$15
~~Residential Lifeline Service R-06-70F~~	~~$12~~	~~$15~~
~~Residential Lifeline Medical R-08-70F~~	~~$12~~	~~$15~~

~~Lifeline Service Rate~~	~~Basic Service Charge~~	~~Discount~~
~~Residential Lifeline/Senior R-04-21F~~	~~$12~~	~~$15~~
~~Residential Lifeline Service R-05-21F~~	~~$12~~	~~$15~~
~~Residential Lifeline Service R-06-21F~~	~~$12~~	~~$15~~
~~Residential Lifeline Medical R-08-21F~~	~~$12~~	~~$15~~
~~Residential Lifeline/Senior R-04-70F~~	~~$12~~	~~$15~~
~~Residential Lifeline Service R-05-70F~~	~~$12~~	~~$15~~
~~Residential Lifeline Service R-06-70F~~	~~$12~~	~~$15~~
~~Residential Lifeline Medical R-08-70F~~	~~$12~~	~~$15~~

For all customers, no Lifeline discount will be applied that will reduce the bill to less than zero.

LIFELINE ELIGIBILITY

1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

ELECTRIC VEHICLES

Customers who own and operate Electric Vehicles will receive a 5% discount to the Base Fuel during the off-peak period and the PPFAC. Customers must provide documentation for highway approved Electric Vehicles.

~~LOST FIXED COST RECOVERY (LFCR) – RIDER 8~~

~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~		
Description	Single-Phase	Frozen Lifeline
Meter Services	$2.25~~00~~ per month	$1.35 per month
Meter Reading	$0.41~~1.34~~ per month	$0.25 per month
Billing & Collection	$6.64~~5.80~~ per month	$3.98 per month
Customer Delivery	$10.70~~2.36~~ per month	$6.42 per month
Total	$20.00~~11.50~~ per month	$12.00 per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh~~	
~~Description~~	~~Single-Phase~~
~~Meter Services~~	~~$2.00 per month~~
~~Meter Reading~~	~~$1.34 per month~~
~~Billing & Collection~~	~~$5.80 per month~~
~~Customer Delivery~~	~~$2.36 per month~~
~~LFCR~~	~~$2.50 per month~~
~~Total~~	~~$14.00 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more~~	
~~Description~~	~~Single-Phase~~
~~Meter Services~~	~~$2.00 per month~~
~~Meter Reading~~	~~$1.34 per month~~
~~Billing & Collection~~	~~$5.80 per month~~
~~Customer Delivery~~	~~$2.36 per month~~
~~LFCR~~	~~$6.50 per month~~
~~Total~~	~~$18.00 per month~~

~~Energy Charge Components (Unbundled):~~

~~Summer (May – September)~~	~~On-Peak~~	~~Off-Peak~~
~~Delivery-Energy~~	~~$0.011300~~	~~$0.011300~~
~~Generation Capacity~~	~~$0.040900~~	~~$0.025900~~
~~Fixed Must-Run~~	~~$0.003000~~	~~$0.003000~~
~~Transmission~~	~~$0.009000~~	~~$0.009000~~
~~Transmission Ancillary Services consists of the following charges:~~		
~~System Control & Dispatch~~	~~$0.000100~~	~~$0.000100~~
~~Reactive Supply and Voltage Control~~	~~$0.000500~~	~~$0.000500~~
~~Regulation and Frequency Response~~	~~$0.000500~~	~~$0.000500~~
~~Spinning Reserve Service~~	~~$0.001300~~	~~$0.001300~~
~~Supplemental Reserve Service~~	~~$0.000200~~	~~$0.000200~~
~~Energy Imbalance Service: Currently charged pursuant to the Company's OATT~~		

~~Power Supply Charge~~

~~Summer (May – September)~~	~~On-Peak~~	~~Off-Peak~~
~~Base Power Component~~	~~$0.050669~~	~~$0.026679~~
~~PPFAC~~	~~In accordance with Rider 1 - PPFAC~~	

~~Energy Charge Components (Unbundled):~~

~~Winter (October - April)~~	~~On-Peak~~	~~Off-Peak~~
~~Delivery Energy~~	~~$0.011300~~	~~$0.011300~~
~~Generation Capacity~~	~~$0.030900~~	~~$0.015900~~
~~Fixed Must-Run~~	~~$0.003000~~	~~$0.003000~~
~~Transmission~~	~~$0.009000~~	~~$0.009000~~
~~Transmission Ancillary Services consists of the following charges:~~		
~~System Control & Dispatch~~	~~$0.000100~~	~~$0.000100~~
~~Reactive Supply and Voltage Control~~	~~$0.000500~~	~~$0.000500~~
~~Regulation and Frequency Response~~	~~$0.000500~~	~~$0.000500~~
~~Spinning Reserve Service~~	~~$0.001300~~	~~$0.001300~~
~~Supplemental Reserve Service~~	~~$0.000200~~	~~$0.000200~~
~~Energy Imbalance Service: Currently charged pursuant to the Company's OATT~~		

~~Power Supply Charge~~

~~Winter (October - April)~~	~~On-Peak~~	~~Off-Peak~~
~~Base Power Component~~	~~$0.032893~~	~~$0.027092~~
~~PPFAC~~	~~In accordance with Rider 1 - PPFAC~~	

Energy Charge Components (per kWh) (Unbundled):

~~Local Delivery~~Component	
Local Delivery – Energy 0 – 500 kWh	0.00571
Local Delivery – Energy Over 500 kWh	0.02571
Generation	0.035250
Fixed Must Run	$0.007270
Transmission	0.008480
System Control & Dispatch	$0.000120
Reactive Supply and Voltage Control	$0.000450
Regulation and Frequency Response	$0.000440
Spinning Reserve Service	$0.001190
Supplemental Reserve Service	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.060800
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.025700
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.056000
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.022100
PPFAC (%) (see Rider-1 for current rate)	Varies

Tucson Electric Power Company

~~First Substitute~~Original Sheet No.: 103~~21~~

Superseding ~~Original Sheet No~~: ~~121~~

TEP
Tucson Electric Power

Residential Time-of-Use ~~Super Peak (R-8)~~Peak (RES-TOU-P)

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

To all single phase ~~(subject to availability at point of delivery)~~ residential electric service (subject to availability at point of delivery)- in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electricial equipment that causes excessive voltage fluctuations.

Service under this rate will commence when the appropriate meter has been installed.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

~~After an initial 3-month trial period, any Customer not requesting to be moved to a new rate will be required to stay on this rate for a minimum period of one (1) year.~~

CHARACTER OF SERVICE

The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE

A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~

~~Standard~~

~~Customer~~Basic Service Charge~~, single-phase service and minimum bill~~ $20.00~~11.50~~ per month

Energy Charges ($/kWh):

0 - 500 kWh	$0.0591 per kWh
over 500 kWh	$0.0791 per kWh

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh):

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.082900 per kWh	$0.082900 per kWh
Base Power Off-Peak	$0.027700 per kWh	$0.024100 per kWh

Filed By:	Kentton C. Grant	Rate:	RES-TOU~~8~~-P
Title:	Vice President of Finance and Rates	Effective:	~~June 1, 2014~~Pending
District:	Entire Electric Service Area	Decision No.:	~~74498~~Pending

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~

~~Customer Charge, single-phase with usage less than 2,000 kWh $14.00 per month~~
~~Customer Charge, single-phase with usage of 2,000 kWh or more $18.00 per month~~

~~Energy Charges ($/kWh):~~

1. ~~Delivery Services Energy is a bundled charge that includes: Local Delivery Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.~~

2. ~~The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent kWh adjustment in accordance with Rider-1-PPFAC. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuelper kWh sold.~~

3. ~~Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).~~

~~**Summer** (May – September)~~	~~Delivery Services-Energy[1]~~	~~Power Supply Charges[2] Base Power~~	~~PPFAC~~	~~Total[3]~~
~~On-Peak First 1,000 kWh~~	~~$0.0971~~	~~$0.0801~~	~~*varies*~~	~~$0.1772~~
~~On-Peak Over 1,000 kWh~~	~~$0.1201~~	~~$0.0801~~	~~*varies*~~	~~$0.2002~~
~~Off-Peak First 1,000 kWh~~	~~$0.0485~~	~~$0.0222~~	~~*varies*~~	~~$0.0707~~
~~Off-Peak Over 1,000 kWh~~	~~$0.0715~~	~~$0.0222~~	~~*varies*~~	~~$0.0937~~

~~**Winter** (October – April)~~	~~Delivery Services-Energy[1]~~	~~Power Supply Charges[2] Base Power~~	~~PPFAC~~	~~Total[3]~~
~~On-Peak First 1,000 kWh~~	~~$0.0891~~	~~$0.0402~~	~~*varies*~~	~~$0.1293~~
~~On-Peak Over 1,000 kWh~~	~~$0.1121~~	~~$0.0402~~	~~*varies*~~	~~$0.1523~~
~~Off-Peak First 1,000 kWh~~	~~$0.0385~~	~~$0.0205~~	~~*varies*~~	~~$0.0590~~
~~Off-Peak Over 1,000 kWh~~	~~$0.0615~~	~~$0.0205~~	~~*varies*~~	~~$0.0820~~

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.

Step 2: Calculate the kWh usage by tier (block).

Step 3: Multiply the TOU period percent usage by the tiered kWh usage.

Example: Consider a customer who used 2,000 kWh in a month with 20% on-peak usage and 80% off-peak usage. This customer will have 500 kWh in the first tier and 1500 kWh in the second tier. Applying Step 3, the customer has 100 kWh in on-peak first tier usage, 300 kWh in on-peak second tier usage, 400 kWh in off-peak first tier usage, and 1200 kWh in off-peak second tier usage.

kWh	On-Peak	Off-Peak	Total
0 – 500 kWh	100	400	500
Over 500 kWh	300	1,200	1,500
Total	400	1,600	2,000

MONTHLY LIFELINE DISCOUNT:

This discount is only available to~~ new and~~ eligible Lifeline customers whose monthly bill shall be in accordance to the rate above except that a discount of $15~~9~~.00 per month shall be applied. No Lifeline discount will be applied that will reduce the bill to less than zero.

LIFELINE ELIGIBILITY

1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.

3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 4:00 p.m. to 7:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak period is 4:00 p.m. to 7:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC VEHICLES
Customers who own and operate Electric Vehicles will receive a 5% discount to the Base Power Charge during the off-peak period and the PPFAC. Customers must provide documentation for highway approved Electric Vehicles.
~~LOST FIXED COST RECOVERY (LFCR) – RIDER 8~~
~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges, which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~	
Description	Single-Phase
Meter Services	$2.25 per month~~$2.00 per month~~
Meter Reading	$0.41 per month~~$1.34 per month~~
Billing & Collection	$6.64 per month~~$5.80 per month~~
Customer Delivery	$10.70 per month~~$2.36 per month~~
Total	$20.00 per month~~$11.50 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh~~	
~~Description~~	~~Single-Phase~~
~~Meter Services~~	~~$2.00 per month~~
~~Meter Reading~~	~~$1.34 per month~~
~~Billing & Collection~~	~~$5.80 per month~~
~~Customer Delivery~~	~~$2.36 per month~~
~~LFCR~~	~~$2.50 per month~~
~~Total~~	~~$14.00 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more~~	
~~Description~~	~~Single-Phase~~
~~Meter Services~~	~~$2.00 per month~~
~~Meter Reading~~	~~$1.34 per month~~
~~Billing & Collection~~	~~$5.80 per month~~
~~Customer Delivery~~	~~$2.36 per month~~
~~LFCR~~	~~$6.50 per month~~

TEP
Tucson Electric Power

~~Total~~	~~$18.00 per month~~

Energy Charge Components (Per kWh) (Unbundled):

~~Summer (May – September)~~Component	~~On-Peak~~
Local Delivery – Energy 0 – 500 kWh~~Delivery-Energy First 1000 kWh~~	$0.00571~~$0.0416~~
Local Delivery – Energy Over 500 kWh~~Delivery-Energy Over 1,000 kWh~~	$0.02571~~$0.0646~~
	$0.028830
Generation Capacity	$0.035250~~$0.0409~~
Fixed Must-Run	$0.007270 ~~$0.0030~~
Transmission	$0.008480~~$0.0090~~
System Control & Dispatch	$0.000120~~$0.0001~~
Reactive Supply and Voltage Control	$0.000450 ~~$0.0005~~
Regulation and Frequency Response	$0.000440 ~~$0.0005~~
Spinning Reserve Service	$0.001190 ~~$0.0013~~
Supplemental Reserve Service	$0.000190 ~~$0.0002~~
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

~~Power Supply Charge~~

~~Summer (May – September)~~	~~On-Peak~~	~~Off-Peak~~
~~Base Power Component~~	~~$0.0801~~	~~$0.0222~~
~~PPFAC~~	~~In accordance with Rider 1 – PPFAC~~	

~~Energy Charge Components (Unbundled):~~

~~Winter (October - April)~~	~~On-Peak~~	~~Off-Peak~~
~~Local Delivery-Energy First 1000 kWh~~	~~$0.0436~~	~~$0.0080~~
~~Local Delivery-Energy Over 50000 kWh~~	~~$0.0666~~	~~$0.0310~~
~~Generation Capacity~~	~~$0.0309~~	~~$0.0159~~
~~Fixed Must-Run~~	~~$0.0030~~	~~$0.0030~~
~~Transmission~~	~~$0.0090~~	~~$0.0090~~

~~Transmission Ancillary Services consists of the following charges:~~		
~~System Control & Dispatch~~	~~$0.0001~~	~~$0.0001~~
~~Reactive Supply and Voltage Control~~	~~$0.0005~~	~~$0.0005~~
~~Regulation and Frequency Response~~	~~$0.0005~~	~~$0.0005~~
~~Spinning Reserve Service~~	~~$0.0013~~	~~$0.0013~~
~~Supplemental Reserve Service~~	~~$0.0002~~	~~$0.0002~~
~~Energy Imbalance Service: Currently charged pursuant to the Company's OATT~~		

Power Supply Charge:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.082900
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.027700
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.082900
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.024100
PPFAC (%) (see Rider-1 for current rate)	Varies

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 104~~19~~
Superseding:

Special Residential Electric Service (RES-S~~201A~~)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single-phase ~~(subject to availability at point of delivery)~~ residential ~~-~~electric service ~~in~~ (subject to availability at point of delivery) in iindividual residences when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this rate requires that the Customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below. New homes must conform to the standards of the Company's approved efficiency program for new construction as in effect at the time of subscription to this rate. Existing homes must conform to certain standards of the Company's approved efficiency program for existing homes as in effect at the time of subscription to this rate. Company accredited testing and inspection is required for verification. Notwithstanding the above, the Customer's use of solar energy for any purpose shall not preclude subscription to this rate.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electrical equipment that causes excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~
~~Standard~~
~~Customer~~Basic Service Charge~~, single-phase service and minimum bill~~ $20~~10~~.00 per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~
~~Customer Charge, single-phase with usage less than 2,000 kWh $12.50 per month~~
~~Customer Charge, single-phase with usage of 2,000 kWh or more $16.50 per month~~

~~Energy Charges ($/kWh):~~Energy Charges ($/kWh):

0 – 500 kWh	$0.0591 per kWh
Over 500 kWh	$0.0791 per kWh

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power	$0.031726 per kWh	$0.028731 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

~~1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries),Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.~~

~~2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent kWh adjustment in accordance with Rider-1-PPFAC. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuelper kWh sold.~~

~~3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).~~

~~LOST FIXED COST RECOVERY (LFCR) – RIDER 8~~
~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

MONTHLY LIFELINE DISCOUNT:

For current and new eligible Lifeline customers taking service under RES-S, the monthly bill shall be in accordance to the rate above except that a discount of $15.00 per month shall be applied.

For current Lifeline customers formerly taking service under one of the following discontinued rates, the monthly bill shall be in accordance to the rate above except that the Basic Service Charge and Discount per month shall be applied as follows:

Frozen Lifeline Service Rate	Basic Service Charge	Discount
Residential Lifeline Service R-06-201AF	$12	$15
Residential Lifeline Medical R-08-201AF	$12	$15

~~Lifeline Service Rate~~	~~Basic Service Charge~~	~~Discount~~
~~Residential Lifeline Service R-06-201AF~~	~~$12~~	~~$15~~
~~Residential Lifeline Medical R-08-201AF~~	~~$12~~	~~$15~~

~~Lifeline Service Rate~~	~~Basic Service Charge~~	~~Discount~~
~~Residential Lifeline RES-TOU~~	~~$20~~	~~$15~~
~~Residential Lifeline Service R-06-201AF~~	~~$12~~	~~$15~~
~~Residential Lifeline Medical R-08-201AF~~	~~$12~~	~~$15~~

For all customers, no Lifeline discount will be applied that will reduce the bill to less than zero.

~~This discount is only available to new and eligible Lifeline Customers whose monthly bill shall be in accordance to the rate above except that a discount of $9.00 per month shall be applied. No Lifeline discount will be applied that will reduce the bill to less than zero.~~LIFELINE ELIGIBILITY

1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~		
Description	Single-Phase	Frozen Lifeline
Meter Services	$2.25 per month~~$1.74 per month~~	$1.35 per month
Meter Reading	$0.41 per month~~$1.17 per month~~	$0.25 per month

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 104-~~319-1~~

Superseding:

Billing & Collection	$6.64 per month~~$5.04 per month~~	$3.98 per month
Customer Delivery	$10.70 per month~~$2.05 per month~~	$6.42 per month
Total	$20.00 per month~~$10.00 per month~~	$12.00 per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage less than 2,000 kWh~~	
~~Description~~	~~Single-Phase~~
~~Meter Services~~	~~$1.74 per month~~
~~Meter Reading~~	~~$1.17 per month~~
~~Billing & Collection~~	~~$5.04 per month~~
~~Customer Delivery~~	~~$2.05 per month~~
~~LFCR~~	~~$2.50 per month~~
~~Total~~	~~$12.50 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more~~	
~~Description~~	~~Single-Phase~~
~~Meter Services~~	~~$1.74 per month~~
~~Meter Reading~~	~~$1.17 per month~~
~~Billing & Collection~~	~~$5.04 per month~~
~~Customer Delivery~~	~~$2.05 per month~~
~~LFCR~~	~~$6.50 per month~~
~~Total~~	~~$16.50 per month~~

Energy Charge Components of Delivery Services (Per kWh) (Unbundled):

Component	~~Summer (May – September)~~
Local Delivery - Energy ~~Sum First~~0 - 500 kWh	$0.00571~~$0.003400~~
Local Delivery – Energy Over 500 kWh~~Sum 501-1,000 kWh~~	$0.02571~~$0.013300~~
~~Sum 1,001-3,500 kWh~~	$0.028830~~$0.024600~~
~~Sum>3,500 kWh~~	$0.007270 ~~$0.032200~~
Generation Capacity	$0.035250~~$0.032600~~
Fixed Must-Run	$0.007270 ~~$0.003000~~

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: RES-S
Effective: Pending
Decision No.: Pending

Transmission	$0.008480~~$0.009000~~
System Control & Dispatch	$0.000120~~$0.000100~~
Reactive Supply and Voltage Control	$0.000450 ~~$0.000500~~
Regulation and Frequency Response	$0.000440 ~~$0.000500~~
Spinning Reserve Service	$0.001190 ~~$0.001300~~
Supplemental Reserve Service	$0.000190 ~~$0.000200~~
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Power Supply Charges:

~~Base Power Component~~	Summer (May – September)	Winter (October - April)
~~All kWh~~Base Power Component (per kWh)	$0.03172~~635111~~	$0.028731~~031532~~
PPFAC (%)	In accordance with Rider 1~~ – PPFAC~~	

Special Residential Electric Service
Time-of-Use Program (RES-~~S-~~TOU-S~~201B~~)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To single-phase ~~(subject to availability at point of delivery)~~ electric service (subject to availability at point of delivery) in individual residences when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this rate requires that the Customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below. New homes must conform to the standards of the Company's approved efficiency program for new construction as in effect at the time of subscription to this rate. Existing homes must conform to certain standards of the Company's approved efficiency program for existing homes as in effect at the time of subscription to this rate. Company accredited testing and inspection is required for verification. Notwithstanding the above, the customer's use of solar energy for any purpose shall not preclude subscription to this rate.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service or service to ~~individual motors exceeding 40 amperes at a rating of 230 volts or which will~~electrical equipment that causes excessive voltage fluctuations.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

Service under this rate will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~
~~Standard~~

~~Customer~~Basic Service Charge~~, single-phase service and minimum bill~~	$20.00~~11.50~~ per month
~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option~~	
~~Customer Charge, single-phase with usage less than 2,000 kWh~~	~~$14.00 per month~~
~~Customer Charge, single-phase with usage of 2,000 kWh or more~~	~~$18.00 per month~~

Energy Charges ($/kWh):

0 - 500 kWh	$0.0591 per kWh
over 500 kWh	$0.0791 per kWh

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.051680 per kWh	$0.047600 per kWh
Base Power Off-Peak	$0.021845 per kWh	$0.018785 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.
~~Energy Charges~~ ($/kWh)~~:~~

1. ~~Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries),Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.~~
2. ~~The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent kWh adjustment in accordance with Rider-1-PPFAC. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuelper kWh sold.~~
3. ~~Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).~~

Calculation of Tiered (Block) Usage by TOU Period:

Step 1: Calculate percent usage by TOU period.

Step 2: Calculate the kWh usage by tier (block).

Step 3: Multiply the TOU period percent usage by the tiered kWh usage.

Example: Consider a customer who used 2,000 kWh in a month with 20% on-peak usage and 80% off-peak usage. This customer will have 500 kWh in the first tier and 1500 kWh in the second tier. Applying Step 3, the customer has 100 kWh in on-peak first tier usage, 300 kWh in on-peak second tier usage, 400 kWh in off-peak first tier usage, and 1200 kWh in off-peak second tier usage.

kWh	On-Peak	Off-Peak	Total
0 – 500 kWh	100	400	500
Over 500 kWh	300	1,200	1,500
Total	400	1,600	2,000

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

ELECTRIC VEHICLES

Customers who own and operate Electric Vehicles will receive a 5% discount to the Base Fuel during the off-peak period and the PPFAC. Customers must provide documentation for highway approved Electric Vehicles.

~~LOST FIXED COST RECOVERY (LFCR) – RIDER 8~~

~~For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.~~

MONTHLY LIFELINE DISCOUNT

For current and new eligible Lifeline customers taking service under RES-TOU-S, the monthly bill shall be in accordance to the rate above except that a discount of $15.00 per month shall be applied.

For current Lifeline customers formerly taking service under one of the following discontinued rates, the monthly bill shall be in accordance to the rate above except that the Basic Service Charge and Discount per month shall be applied as follows:

~~All applicable charges included in this tariff apply to current and former Lifeline rates listed below.This discount is only available to new and eligible Lifeline Customers whose monthly bill shall be in accordance to the rate above except that a discount of $9.00 per month shall be applied. No Lifeline discount will be applied that will reduce the bill to less than zero.~~

Frozen Lifeline Service Rate	Basic Service Charge	Discount
~~Residential Lifeline RES-TOU~~	~~$20~~	~~$15~~
Residential Lifeline Service R-06-201BF	$12	$15

For all customers, no Lifeline discount will be applied that will reduce the bill to less than zero.

LIFELINE ELIGIBILITY

1. The TEP account must be in the Customer's name applying for a Lifeline discount.
2. Applicant must be a TEP residential Customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Standard~~		
Description	Single-Phase	Frozen Lifeline
Meter Services	$2.25~~.00~~ per month	$1.35 per month
Meter Reading	$0.41~~1.34~~ per month	$0.25 per month
Billing & Collection	$6.64~~5.80~~ per month	$3.98 per month
Customer Delivery	$10.70~~2.36~~ per month	$6.42 per month
Total	$20.00~~11.50~~ per month	$12.00 per month

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh~~	
~~Description~~	~~Single-Phase~~
~~Meter Services~~	~~$2.00 per month~~
~~Meter Reading~~	~~$1.34 per month~~
~~Billing & Collection~~	~~$5.80 per month~~
~~Customer Delivery~~	~~$2.36 per month~~
~~LFCR~~	~~$2.50 per month~~
~~Total~~	~~$14.00 per month~~

~~Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more~~	
~~Description~~	~~Single-Phase~~
~~Meter Services~~	~~$2.00 per month~~
~~Meter Reading~~	~~$1.34 per month~~
~~Billing & Collection~~	~~$5.80 per month~~
~~Customer Delivery~~	~~$2.36 per month~~
~~LFCR~~	~~$6.50 per month~~

~~Total~~	~~$18.00 per month~~

Energy Charge Components (Per kWh) (Unbundled)

Component	
Local Delivery – Energy 0 – 500 kWh	$0.00571
Local Delivery – Energy Over 500 kWh	$0.02571
Generation Capacity	$0.035250
Fixed Must-Run	$0.007270
Transmission	$0.008480
System Control & Dispatch	$0.000120
Reactive Supply and Voltage Control	$0.000450
Regulation and Frequency Response	$0.000440
Spinning Reserve Service	$0.001190
Supplemental Reserve Service	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.	

~~Summer (May – September)~~	~~On-Peak~~	~~Off-Peak~~
~~Delivery Energy~~	~~$0.011300~~	~~$0.011300~~
~~Generation Capacity~~	~~$0.030900~~	~~$0.018100~~
~~Fixed Must-Run~~	~~$0.003000~~	~~$0.003000~~
~~Winter (October – April)~~	~~On-Peak~~	~~Off-Peak~~
~~Transmission~~	~~$0.009000~~	~~$0.009000~~
~~Delivery Energy~~	~~$0.011300~~	~~$0.011300~~
~~Ancillary Services consists of the following charges:~~		
~~Generation Capacity~~	~~$0.020100~~	~~$0.009300~~
~~System Control & Dispatch~~	~~$0.000100~~	~~$0.000100~~
~~Reactive Supply and Voltage Control~~	~~$0.000500~~	~~$0.000500~~
~~Regulation and Frequency Response~~	~~$0.000500~~	~~$0.000500~~
~~Spinning Reserve Service~~	~~$0.001300~~	~~$0.001300~~
~~Supplemental Reserve Service~~	~~$0.000200~~	~~$0.000200~~
~~Energy Imbalance Service: Currently charged pursuant to the Company's OATT~~		
~~Base Power Supply Charge~~ (per kWh)	~~$0.050669~~	~~$0.026679~~
~~PPFAC~~ (%)	~~In accordance with Rider 1 – PPFAC~~	

~~Fixed Must Run~~	~~$0.003000~~	~~$0.003000~~
~~Transmission~~	~~$0.009000~~	~~$0.009000~~
~~Transmission Ancillary Services consists of the following charges:~~		
~~System Control & Dispatch~~	~~$0.000100~~	~~$0.000100~~
~~Reactive Supply and Voltage Control~~	~~$0.000500~~	~~$0.000500~~
~~Regulation and Frequency Response~~	~~$0.000500~~	~~$0.000500~~
~~Spinning Reserve Service~~	~~$0.001300~~	~~$0.001300~~
~~Supplemental Reserve Service~~	~~$0.000200~~	~~$0.000200~~
~~Energy Imbalance Service: Currently charged pursuant to the Company's OATT~~		
~~Base Power Supply Charge per kWh)~~	~~$0.032893~~	~~$0.027092~~
~~PPFAC (%)~~	~~In accordance with Rider 1 – PPFAC~~	

~~Power Supply Charges:~~

~~Component~~	
~~Base Power Supply Summer (May – September) On-Peak (per kWh)~~	~~$~~
~~Base Power Supply Summer (May – September) Off-Peak (per kWh)~~	~~$~~
~~Base Power Supply Winter (October – April) On-Peak (per kWh)~~	~~$~~
~~Base Power Supply Winter (October – April) Off-Peak (per kWh)~~	~~$~~
~~PPFAC (%) (see Rider-1 for current rate)~~	~~Varies~~

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.051680
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.021845
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.047600
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.018785
PPFAC (%) (see Rider-1 for current rate)	Varies

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 109~~710~~
Superseding:

~~Rider R-10~~

Residential ~~Solar -~~Company Owned Solar Program (RES-COS)

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and configuration and are adjacent to the premises.

APPLICABILITY

To all ~~Standard~~ Residential Electric Service (RES) Customers with the legal authority to enter into a contractual agreement assigning the rights to the Company necessary to allow production of electricity on the Customer's premises using photovoltaic solar equipment as a Renewable Resource. The photovoltaic solar equipment will be owned, operated, and maintained solely by the Company.

CHARACTER OF SERVICE

The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as determined by the Company and subject to availability at point of delivery.

RATE

A Customer will enter into a contract with the Company for a fixed rate for their total net monthly bill before taxes, assessments and other governmental charges. The fixed monthly rate will be $18.75~~16.50~~ per kW based on the capacity of the solar equipment necessary to meet the customer's most recent 12 month historical usage.

The Company shall provide all of the Customer's electricity requirements at the contractual fixed rate. If in any calendar year a Customer's usage exceeds 115% of the Customer's contractually established historical annual usage, the customers' fixed rate shall be recalculated based on the new annual consumption data for the most recent year.

Additionally, if in any calendar year a customer consumes less than 85% of the contractually established historical annual usage, the Customer's fixed rate shall be recalculated based on the new annual consumption data for the most recent year.

The ACC may modify the program including the fixed rate. In the event the ACC modifies the program or the fixed rate, the Customer shall have the option of continuing service subject to such modifications or terminating service at no cost or penalty as provided in the contract.

TERMS AND CONDITIONS OF SERVICE

1) For initial participation in the program, Customer must have been an active Customer of the Company in good standing at the premises for no less than 12 months.

2) Customer will enter into a contract for 25 years. Customer must remain on the Residential Solar - Company Owned Program tariff for the term of the contract. As set forth in the contract, Customer may (i) assign the contract to a purchaser of the property, in which case the purchaser will receive service under this tariff or (ii) terminate service under this tariff through a purchase provision, payment of an Exit Fee in the event of the sale of the property, or upon an ACC initiated modification in the program or fixed rate not agreed to by the Customer.

3) Customer will continue to be charged for all other applicable ACC approved charges (except for the Lost Fixed Cost Recovery charge, the Environmental Compliance Adjustor charge and the Purchased Power and Fuel Adjustment Clause charge, or other charges subsequently approved for exclusion by the ACC) and Taxes and Assessments.

4) The terms and conditions discussed herein are not applicable to any other Company residential tariffs or Riders.

5) Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

6) A one-time Processing Fee of $250 will be charged at the time the Customer executes the contract.

7) Customer will be subject to terms and conditions as set forth in the contract.

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate or the contract.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Small General Service (SGS-~~1~~0)

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises. ~~To all general power and lighting service unless otherwise addressed by specific rates.~~

APPLICABILITY

To all general ~~power and lighting s~~service unless otherwise addressed by specific rates~~.~~

~~W~~when all energy is supplied at one point of delivery and through one metered service.

~~-~~Not applicable to resale, breakdown, ~~temporary,~~ standby, or auxiliary service.

If a customer's two month accumulated consumption in the current billing month and the month proceding meets or exceeds 24,000 kWh~~-~~, the customer will be moved to the Medium General Service tariff.

All SGS Customers who are receiving service on the frozen Net Metering for Certain Partial Requirements Service (NM-PRS-F) Rider 4 will remain on SGS effective XXXX, even if usage would otherwise have moved them to another rate class. All new net metering Customers will receive service on the Small General Service Demand (SGS-D) tariff effective June 1, 2015.

The supply of electric service under a residential rate ~~schedule~~ to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

~~For Customers who were previously on Municipal Service Rate (PS-40), a monthly transitional adjustment of 16.5% will be applied to the Delivery Charges (excluding the Customer Charge) and Power Supply Charges.~~

CHARACTER OF SERVICE

The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. ~~Primary metering may be used by mutual agreement.~~

RATE

A monthly bill at the following rate, plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~

~~Customer~~ Basic Service Charge, single-phase service ~~and minimum bill~~	$30.00~~15.50~~ per month
~~Customer~~Basic Service Charge, three-phase service ~~and minimum bill~~	$35.00~~20.50~~ per month

~~Energy Charges: All energy charges below are charged per kWh basis.~~

Energy~~Delivery~~ Charges ($/kWh):~~:~~

~~Summer~~ ~~(May – September)~~	~~Delivery Services-Energy[1]~~Summer (May - September)	~~Total[3]~~Winter (October - April)
0 – 500 kWh	$0.0835	$0.0685~~120825~~
Over 500 kWh	$0.1045	$0.0895~~141825~~

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh)

~~Winter (October – April)~~	Summer (May - September)~~Summer (May - September)~~	Winter (October - April)~~Winter (October – April)~~
Base Power ~~0 – 500 kWh~~	$0.037325~~685~~	$0.033801~~102301~~
~~Over 500 kWh~~	~~$0.0895~~	~~$0.123301~~

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider-1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

TEP

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 201-1
Superseding:
~~First Revised Sheet No.: 201-1~~
~~Superseding Original Sheet No.: 201-1~~

~~Base Power Supply Charges:~~

~~Summer~~ ~~Description~~ ~~Winter~~	~~Summer (May – September)~~	~~$0.035141 per kWh~~ ~~Winter~~ ~~$0.031532 per kWh~~ ~~(October – April)~~
~~First 500 kWh~~	~~$0.07700~~	~~$0.057000~~
~~All remaining kWh~~	~~$0.097800~~	~~$0.079000~~

~~Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with Rider-1 PPFAC to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.~~

1. ~~Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.~~

2. ~~The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.~~

3. ~~Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1).Calculation of Tiered (Block) Usage by TOU Period:~~

~~Step 1: Calculate percent usage by TOU period.~~

~~Step 2: Calculate the kWh usage by tier (block).~~

~~Step 3: Multiply the TOU period percent usage by the tiered kWh usage.~~

~~Example: Consider a customer who used 2,000 kWh in a month with 20% on-peak usage and 80% off-peak usage.~~

~~This customer will have 500 kWh in the first tier and 1500 kWh in the second tier. Applying Step 3, the customer has 100 kWh in on-peak first tier usage, 300 kWh in on-peak second tier usage, 400 kWh in off-peak first tier usage, and 1200 kWh in off-peak second tier usage.~~

~~kWh~~	~~On-Peak~~	~~Off-Peak~~	~~Total~~
~~0 – 500 kWh~~	~~100~~	~~400~~	~~500~~
~~Over 500 kWh~~	~~300~~	~~1,200~~	~~1,500~~

~~Total~~	~~400~~	~~1,600~~	~~2,000~~

~~PRIMARY SERVICE~~

~~The rates contained in this schedule are designed to reflect secondary service but where service is taken at primary voltage will be subject to a primary discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) on the billing demand each month.~~

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 201-3
Superseding:
~~First Revised Sheet No.: 201-1~~
~~Superseding Original Sheet No.: 201-1~~

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

Description	Single-Phase	Three-Phase
Meter Services	$3.37~~5.78~~ per month	$8.37~~7.65~~ per month
Meter Reading	$0.62~~74~~ per month	$0.62 per month~~$0.98 per month~~
Billing & Collection	$9.96~~3.19~~ per month	$9.96 per month~~$4.21 per month~~
Customer Delivery	$16.05~~5.79~~ per month	$16.05 per month~~$7.66 per month~~
Total	$30.00~~15.50~~ per month	$35.00~~20.50~~ per month

Energy Charge Components (Unbundled) (Per kWh):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy		
~~First~~0 - 500 kWh	$0.039030~~21900~~	$0.024030~~21900~~
Over 500 kWh ~~All remaining kWh~~	$0.060030~~22800~~	$0.045030~~22800~~
~~Generation Capacity~~		
Generation Capacity ~~0 - First 500 kWh~~	$0.030000~~042700~~	$0.030000~~022700~~
~~Over 500 kWhAll remaining kWh~~	~~$0.062600~~	~~$0.043800~~
Fixed Must-Run	$0.00397003500	$0.003970~~$0.003500~~
Transmission	$0.00819006800	$0.008190~~$0.006800~~
~~Transmission Ancillary Services consists of the following charges:~~		
System Control & Dispatch	$0.00011000	$0.000110~~$0.000100~~
Reactive Supply and Voltage Control	$0.00044000	$0.000440~~$0.000400~~
Regulation and Frequency Response	$0.00042000	$0.000420~~$0.000400~~
Spinning Reserve Service	$0.001150000	$0.001150~~$0.001000~~
Supplemental Reserve Service	$0.000190200	$0.000190~~$0.000200~~
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.		
~~Base Power Supply Charge (per kWh)~~	~~$0.035111~~	~~$0.031532~~
~~PPFAC (%)~~	~~In accordance with Rider 1 – PPFAC~~	

Power Supply Charges:

	Summer (May – September)	Winter (October - April)
Base Power Component (per	$0.037325	$0.033801

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: SGS-~~10~~
Effective: ~~October 24, 2014~~Pending
Decision No.: ~~74789~~Pending

kWh)		
PPFAC (%)	In accordance with Rider 1	

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 202
Superseding:

Mobile Home Park Electric Service (GS-M-~~11~~F)

AVAILABILITY

~~New Customers, including current Customers who move, are not eligible for service under this rate~~Only available to premises ~~Customers~~ historically served on a master metered mobile home park tariff. Not available to new facilities.

APPLICABILITY

To mobile home parks for service through a master meter to two or more mobile homes, provided each mobile home served through such master meter will be individually metered and billed by the park operator in accordance with applicable Orders of the Arizona Corporation Commission. Electric service to the park's facilities used by its residents may be supplied under this schedule only if such facilities are served through a master meter which serves two or more mobile homes.

Not applicable to resale, ~~breakdown,~~ temporary, standby, or auxiliary service.

CHARACTER OF SERVICE

The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering may be used by mutual agreement.

RATE

A monthly bill at the following rate, plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer Charges:~~

~~Customer~~ Basic Service Charge, single-phase service ~~and minimum bill~~	$30.00~~15.50~~ per month
~~Customer~~Basic Service Charge, three-phase service ~~and minimum bill~~	$35.00~~20.50~~ per month

Energy Charges:

	Summer (May - September)	Winter (October - April)
All kWh	$0.0912	$0.0812

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

~~Delivery Charge~~

~~Summer (May – September), all kWh~~	~~$0.09120082000 per kWh~~
~~Winter (October – April), all kWh~~	~~$0.081200062000 per kWh~~

Base Power Charges:

~~Delivery Charge~~

Summer (May - September)	Winter (October - April)

All kWh	$0.037325	$0.033801

~~Summer (May – September), all kWh~~ ~~$0.~~037325~~035111 per kWh~~
~~Winter (October – April), all kWh~~ ~~$0.~~033801~~031532 per kWh~~

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent ~~kWh~~ adjustment in accordance with Rider-1 ~~PPFAC~~ to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~.

PRIMARY SERVICE
The rates contained in this schedule are designed to reflect secondary service but where service is taken at primary voltage will be subject to a primary discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) on the billing demand each month.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Basic Service Charge Components (Unbundled):

Description	Single-Phase	Three-Phase
Meter Services	$3.37 per month	$8.37 per month
Meter Reading	$0.62 per month	$0.62 per month
Billing & Collection	$9.96 per month	$9.96 per month
Customer Delivery	$16.05 per month	$16.05 per month
Total	$30.00 per month	$35.00 per month

Energy Charge Components (Unbundled) (Per kWh):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.04673	$0.03673
Generation Capacity	$0.030000	$0.030000
Fixed Must-Run	$0.003970	$0.003970
Transmission	$0.008190	$0.008190
System Control & Dispatch	$0.000110	$0.000110
Reactive Supply and Voltage Control	$0.000440	$0.000440
Regulation and Frequency Response	$0.000420	$0.000420
Spinning Reserve Service	$0.001150	$0.001150
Supplemental Reserve Service	$0.000190	$0.000190
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charges:

	Summer (May – September)	Winter (October - April)
Base Power Component (per kWh)	$0.037325	$0.033801
PPFAC (%)	In accordance with Rider 1	

~~DIRECT ACCESS~~

~~A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.~~

~~FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE~~

~~A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.~~

~~TEP STATEMENT OF CHARGES~~

~~For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.~~

~~TAX CLAUSE~~

~~To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.~~

~~RULES AND REGULATIONS~~

~~The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.~~

~~ADDITIONAL NOTES~~
~~Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.~~

~~BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:~~

~~Customer~~Basic ~~Service Charge Components (Unbundled):~~

~~Description~~	~~Single-Phase~~	~~Three-Phase~~
~~Meter Services~~	~~$5.78 per month~~	~~$7.65 per month~~
~~Meter Reading~~	~~$0.74 per month~~	~~$0.98 per month~~
~~Billing & Collection~~	~~$3.19 per month~~	~~$4.21 per month~~
~~Customer Delivery~~	~~$5.79 per month~~	~~$7.66 per month~~
~~Total~~	~~$15.50 per month~~	~~$20.50 per month~~

~~Energy Charge Components (Unbundled):~~

~~Component~~	~~Summer (May – September)~~	~~Winter (October – April)~~
~~Local Delivery-Energy~~	~~$0.021700~~	~~$0.021700~~
~~Generation Capacity~~	~~$0.047900~~	~~$0.027900~~
~~Fixed Must-Run~~	~~$0.003500~~	~~$0.003500~~
~~Transmission~~	~~$0.006800~~	~~$0.006800~~
~~Transmission Ancillary Services consists of the following charges:~~		
~~System Control & Dispatch~~	~~$0.000100~~	~~$0.000100~~
~~Reactive Supply and Voltage Control~~	~~$0.000400~~	~~$0.000400~~
~~Regulation and Frequency Response~~	~~$0.000400~~	~~$0.000400~~
~~Spinning Reserve Service~~	~~$0.001000~~	~~$0.001000~~
~~Supplemental Reserve Service~~	~~$0.000200~~	~~$0.000200~~
~~Energy Imbalance Service: Currently charged pursuant to the Company's OATT~~		
~~Base Power Supply Charge (per kWh)~~	~~$0.035111~~	~~$0.031532~~
~~PPFAC (%)~~	~~In accordance with Rider 1 - PPFAC~~	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 203
Superseding:
~~First Revised Sheet No.: 203~~
~~Superseding Original Sheet No.: 203~~

Small General Service
Time-of-Use Program (SGS-TOU~~76F~~)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.
~~New Customers, including current Customers who move, are not eligible for service under this rate.~~

APPLICABILITY
To all ~~small~~ general ~~power and lighting~~ service unless otherwise addressed by a specific tariff~~rate schedules~~, when all energy is supplied at one point of delivery and through one metered service.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service. Service under this rate will commence when the appropriate meter has been installed.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

If a customer's two month accumulated consumption in the current billing month and the month proceding meets or exceeds 24,000 kWh, the customer will be moved to the Medium General Service tariff.

All SGS TOU Customers who are receiving service on the frozen Net Metering for Certain Partial Requirements Service (NM-PRS-F) Rider 4 will remain on SGS TOU effective XXXX, even if usage would otherwise have moved them to another rate class.~~-~~ All new net metering Customers will receive service on the Small General Service TOU Demand (SGS-TOU-D) tariff effective June 1, 2015.

The supply of electric service under a residential rate to a dwelling involving some business or professional activity will be permitted only where such activity is of only occasional occurrence, or where the electricity used in connection with such activity is small in amount and used only by equipment which would normally be in use if the space were used as living quarters. Where the portion of a dwelling is used regularly for business, professional or other gainful purposes, and any considerable amount of electricity is used for other than domestic purposes, or electrical equipment not normally used in living quarters is installed in connection with such activities referred to above, the entire premises must be classified as non-residential and the appropriate general service rate will be applied.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

Basic Service Charge, single-phase service $30.00 per month
~~Customer Charge:~~
~~Customer~~ Basic Service ~~Charge, single-phase or three-phase service and minimum bill~~ $30.00~~17.50 per month~~

Energy Charges ($/kWh):

	Summer (May - September)	Winter (October - April)
0 – 500 kWh	$0.0835	$0.0685
Over 500 kWh	$0.1045	$0.0895

Energy Charge is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

Power Supply Charge ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.060800 per kWh	$0.056000 per kWh
Base Power Off-Peak	$0.025700 per kWh	$0.022100 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent adjustment in accordance with Rider 1 to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.

Calculation of Tiered (Block) Usage by TOU Period:
Step 1: Calculate percent usage by TOU period.
Step 2: Calculate the kWh usage by tier (block).
Step 3: Multiply the TOU period percent usage by the tiered kWh usage.

Example: Consider a customer who used 2,000 kWh in a month with 20% on-peak usage and 80% off-peak usage. This customer will have 500 kWh in the first tier and 1500 kWh in the second tier. Applying Step 3, the customer has 100 kWh in on-peak first tier usage, 300 kWh in on-peak second tier usage, 400 kWh in off-peak first tier usage, and 1200 kWh in off-peak second tier usage.

kWh	On-Peak	Off-Peak	Total
0 – 500 kWh	100	400	500
Over 500 kWh	300	1,200	1,500
Total	400	1,600	2,000

~~Energy Charges ($/kWh):~~

~~Purchased Power and Fuel Adjustment Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with Rider-1 PPFAC to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.~~

1. ~~Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.~~

2. ~~The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a percent adjustment in accordance with Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel.~~

3. ~~Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1).~~

~~Description~~	~~Summer (May – September)~~	~~Winter (October - April)~~
~~On-Peak kWh~~	~~$0.099100~~	~~$0.081400~~
~~Off-Peak kWh~~	~~$0.084900~~	~~$0.064900~~

~~Base Power Supply Charges:~~
~~Summer On-Peak $0.050669 per kWh~~
~~Summer Off-Peak $0.026679 per kWh~~

~~Winter On-Peak $0.032893 per kWh~~
~~Winter Off-Peak $0.027092 per kWh~~

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

~~PRIMARY SERVICE~~
~~The Rates contained in this Schedule are designed to reflect secondary service but where service is taken at primary voltage will be subject to a primary discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) on the billing demand each month.~~

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 203-3
Superseding:
~~First Revised Sheet No.: 203-1~~
~~Superseding Original Sheet No.: 203-1~~

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charge Components (Unbundled):

~~Description~~	~~Customer Basic Service Charge~~
~~Meter Services~~	~~$6.53 per month~~
~~Meter Reading~~	~~$0.83 per month~~
~~Billing & Collection~~	~~$3.60 per month~~
~~Customer Delivery~~	~~$6.54 per month~~
~~Total~~	~~$17.50 per month~~

Description	
Meter Services	$3.37 per month
Meter Reading	$0.62 per month
Billing & Collection	$9.96 per month
Customer Delivery	$16.05 per month
Total	$30.00 per month

Energy Charge Components (Unbundled) (Per kWh)

~~Summer (May – September)~~	~~On-Peak~~Summer	~~Off-Peak~~Winter
Local Delivery – Energy 0 – 500 kWh~~Local Delivery-Energy¹~~	$0.03903~~022700~~	$0.02403~~022700~~
Local Delivery – Energy Over 500 kWh	$0.060030	$0.045030
Generation Capacity	$0.03000~~064000~~	$0.03000~~049800~~
Fixed Must-Run	$0.00397~~03500~~	$0.00397~~03500~~
Transmission	$0.008190~~006800~~	$0.00819~~006800~~
~~Transmission Ancillary Services consists of the following charges:~~		
System Control & Dispatch	$0.000110 ~~$0.000100~~	$0.00011~~000~~
Reactive Supply and Voltage Control	$0.000440 ~~$0.000400~~	$0.00044~~000~~
Regulation and Frequency Response	$0.000420 ~~$0.000400~~	$0.00042~~000~~
Spinning Reserve Service	$0.001150 ~~$0.001000~~	$0.001150~~000~~
Supplemental Reserve Service	$0.000190 ~~$0.000200~~	$0.000190~~200~~
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.		
~~Base Power Supply Charge (Per kWh)~~	~~$0.050669~~	~~$0.026679~~
~~PPFAC (%)~~	~~In accordance with Rider 1 - PPFAC~~	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: SGS-TOU
Effective: Pending
Decision No.: Pending

Power Supply Charges:

	Summer (May – September)	Winter (October - April)
Base Power Component On-Peak (per kWh)	$0.060800	$0.056000
Base Power Component Off-Peak (per kWh)	$0.025700	$0.022100
PPFAC (%)	In accordance with Rider 1	

~~Energy Charge Components (Unbundled)~~

~~Winter (October - April)~~	~~On-Peak~~	~~Off-Peak~~
~~Delivery Energy~~	~~$0.022700~~	~~$0.022700~~
~~Generation Capacity~~	~~$0.046300~~	~~$0.029800~~
~~Fixed Must-Run~~	~~$0.003500~~	~~$0.003500~~
~~Transmission~~	~~$0.006800~~	~~$0.006800~~
~~Transmission Ancillary Services consists of the following charges:~~		
~~System Control & Dispatch~~	~~$0.000100~~	~~$0.000100~~
~~Reactive Supply and Voltage Control~~	~~$0.000400~~	~~$0.000400~~
~~Regulation and Frequency Response~~	~~$0.000400~~	~~$0.000400~~
~~Spinning Reserve Service~~	~~$0.001000~~	~~$0.001000~~
~~Supplemental Reserve Service~~	~~$0.000200~~	~~$0.000200~~
~~Energy Imbalance Service: Currently charged pursuant to the Company's OATT~~		
~~Base Power Supply Charge~~	~~$0.032893~~	~~$0.027092~~
~~PPFAC~~	~~In accordance with Rider 1 - PPFAC~~	

TEP

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 2~~0~~420
Superseding:

Large General Service (LGS~~LGS-13~~)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To ~~all large~~ applicable general ~~power~~ services ~~and lighting service on an optional basis~~ when all energy is supplied at one point of delivery and through one metered service.

The minimum monthly billing demand hereunder is 200 kW. In the event billed kW meets or exceeds 5,000 kW, the Customer will no longer be eligible for the LGS rate and will be moved to the Large Power Service Time-of-Use rate.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, ~~, and at one standard nominal voltage as mutually agreed~~ and subject to availability at point of delivery.

Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF ~~CUSTOMER~~BASIC SERVICE, DEMAND AND ENERGY CHARGES

~~Customer~~Basic Service Charge:	$1,000.00~~775.00~~ per month
Demand Charge:	$17.50~~15.25~~ per kW
Energy Charges:	
Summer (May – September)	$0.0251~~019200~~ per kWh
Winter (October – April)	$0.0178~~013400~~ per kWh
Base Power Charges:	
Summer (May – September)	$0.037325~~5111~~ per kWh
Winter (October – April)	$0.033801~~031532~~ per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent~~ kWh~~ adjustment in accordance with Rider-1 ~~PPFAC~~ to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~.

BILLING DEMAND
The monthly billing demand shall be the greatest~~rst~~ of the following:

1. The greatest measured ~~maximum~~ 15 minute interval~~measured~~ demand read of the meter during all hours of ~~in~~ the billing period~~month~~;
2. 75% of the ~~maximum~~greatest demand used for billing purposes in the preceding 11 months; ~~or~~
3. The contract capacity or ~~demand amount, not to be less than 200~~200450 kW, whichever is greater.

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

PRIMARY SERVICE
The Rates contained in this Schedule are designed to reflect secondary service but where service is taken at primary voltage will be subject to a primary discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) on the billing demand each month.

The Company may require a written contract with a minimum contract demand and a minimum term of contract.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 220~~04~~-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charges:	
Meter Services	$ 38.63~~211.38~~ per month
Meter Reading	$ 0.39 ~~32.43~~ per month
Billing & Collection	$ 6.29~~140.81~~ per month
Customer Delivery	$ 954.69~~390.38~~ per month
Total	$1,000~~775~~.00 per month
Demand Charge (in $/kW):	
Delivery Charge	$3.86~~1.71~~ per kW
Generation Capacity	$7.95~~9.17~~ per kW
Fixed Must-Run	$1.33~~0.95~~ per kW
Transmission	$3.~~5139022.67~~ per kW
Transmission Ancillary Services	
System Control & Dispatch	$0.05~~4~~ per kW
Reactive Supply and Voltage Control	$0.18~~4~~ per kW
Regulation and Frequency Response	$0.18~~4~~ per kW
Spinning Reserve Service	$0.48~~37~~ per kW
Supplemental Reserve Service	$0.08~~6~~ per kW
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	
Energy Charges (kWh): (in $/kWh)	
Delivery Charge	
Summer	$0.0~~0~~251005~~800~~ per kWh
Winter	$0.017800~~004000~~ per kWh
~~Generation Capacity:~~	
~~Summer~~	~~$0.00000013400 per kWh~~
~~Winter~~	~~$0.0000009400 per kWh~~
Base Power Supply Charges:	
Summer	$0.0373255~~111~~ per kWh
Winter	$0.0338011~~532~~ per kWh

Filed By:	Kentton C. Grant	Rate:	LGS-~~13~~
Title:	Vice President of Finance and Rates	Effective:	~~July 1, 2013~~Pending
District:	Entire Electric Service Area	Decision No.:	~~73912~~Pending

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 2~~05~~21
Superseding:

Large General Service
Time-of-Use Program (LGS-TOU~~85~~)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises. ~~To all general power and lighting service unless otherwise addressed by specific rate schedules.~~

APPLICABILITY
To applicable general services when all energy is supplied at one point of delivery and through one metered service. ~~When all energy is supplied at one point of delivery and through one metered service. Not applicable to resale, breakdown, temporary, standby, or auxiliary service. Service under this rate will commence when the appropriate meter has been installed.~~

The minimum monthly billing demand hereunder is 200 kW. In the event billed kW meets or exceeds 5,000 kW, the Customer will no longer be eligible for the LGS rate and will be moved to the Large Power Service Time-of-Use rate.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery. Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF ~~CUSTOMER~~BASIC SERVICE, DEMAND AND ENERGY CHARGES

~~Customer~~Basic Service Charge ~~and minimum bill~~	$1,000.00~~950.00~~ per month
Demand Charges ~~(includes Generation Capacity)~~:	
Summer On-peak	$20.00~~14.55~~ per kW
Summer Off-peak Excess Demand ~~(applies to all off-peak demand bill determinates)~~	$10.92 per kW
Winter On-peak	$17.50~~11.59~~ per kW
Winter Off-peak Excess Demand ~~(applies to all off-peak demand bill determinates)~~	$ 9.10 per kW

~~*Note:*~~
~~*1. For demand billing, "on-peak demand" shall be based on demand measured during peak periods.*~~
~~*2. For demand billing, "off-peak demand" shall be based on demand measured during the off- peak periods.*~~
~~*3. Unlike Schedule LLP Rate 90 the demand charges above are NOT excess demand charges; they apply to all Off-Peak kW, not just Off-Peak kW in excess of 150% of Peak kW.*~~

Energy Charges ($/kWh): ~~All energy charges below are charged on a per kWh basis.~~

	Summer (May – September)	Winter (October - April)
On-Peak	$0.025100	$0.025100
Off-Peak	$0.016900	$0.016900

Filed By:	Kentton C. Grant	Rate:	LGS-TOU~~85~~
Title:	Vice President of Finance and Rates	Effective:	~~July 1, 2013~~Pending
District:	Entire Electric Service Area	Decision No.:	~~73912~~Pending

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 20~~0~~521
Superseding:

~~—~~	~~Summer (May – September)~~	~~Winter (October - April)~~
~~On-Peak~~	~~$0.025100008600~~	~~$0.025100003000~~
~~Off-Peak~~	~~$0.016900006000~~	~~$0.016900000500~~

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 221~~05~~-1
Superseding:

~~Base~~ Power Supply Charges ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.060800~~050669~~	$0.056000~~032893~~
Base Power Off-Peak	$0.025700~~026679~~	$0.022100~~027092~~

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent ~~kWh~~ adjustment in accordance with Rider-1 ~~PPFAC~~ to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

~~DETERMINATION OF~~ BILLING DEMAND

The monthly billing demand shall be the greatest of the following:

1. The greatest measured 15-minute interval demand read of the meter during the on-peak hours of the billing period;
2. 75% of the greatest on-peak period billing demand used for billing purposes in the preceding 11 months;
3. The contract capacity or 200 kW, whichever is greater

Additionally, the greatest measured 15-minute interval demand read of the meter during the off-peak hours of the billing period that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak ~~billed~~measured demand.

~~The greatest of the following during the On-Peak period:~~

~~1. The greatest measured maximum15 minute intervalmeasured demand read of the meter during all hoursduring the on-peak period of the billing periodmonth;~~

~~2. 75% of the greatest maximum on-peak period billing demand used for billing purposes in the preceding 11 months; or~~

~~3. The contract capacity or demand amount, not to be less than 200 kW, whichever is greater.and~~

~~4.~~

~~5. The maximum 15 minute measured demand during the off-peak period of the billing month.~~

The Company reserves the right to require a Customer to install equipment to maintain an acceptable power factor at the Customer's expense.

PRIMARY SERVICE

The Rates contained in this Schedule are designed to reflect secondary service but where service is taken at a primary voltage, a discount of 20.6 cents per kW per month (on the bundled rate, with the discount taken from the unbundled kW delivery charge) will be applied to the billing demand each month.

The Company may require a written contract with a minimum contract demand and a minimum term of contract.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service Charges:	
Meter Services	$ 38.63~~259.11~~ per month
Meter Reading	$ 0.39~~39.75~~ per month
Billing & Collection	$ 6.29~~172.61~~ per month
Customer Delivery	$ 954.69~~478.53~~ per month
	$1,00~~950~~.00 per month
Demand Charges ($/kW)	
~~Delivery Charges~~	
~~Summer On-peak~~	~~$ 6.31 per kW~~
~~Summer Off-peak~~	~~$ 0.23 per kW~~
~~Winter On-peak~~	~~$ 4.81 per kW~~
~~Winter Off-peak~~	~~$ 0.41 per kW~~
Generation Capacity Charges (in $/kW):	
Summer On-peak	$ 8.00~~10.18~~ per kW
Summer Off-peak	$ 5.00~~6.55~~ per kW
Winter On-peak	$ 7.00~~7.22~~ per kW
Winter Off-peak	$ 3.00~~4.73~~ per kW

Fixed Must-Run Charges (in $/kW)	$ 1.33~~0.95~~ per kW
Transmission (in $/kW)	$ 3.39~~02512.67~~ per kW

Transmission - Ancillary Services System Control & Dispatch (in $/kW)

System Control & Dispatch	$ 0.054 per kW
Reactive Supply and Voltage Control	$ 0.184 per kW
Regulation and Frequency Response	$ 0.184 per kW
Spinning Reserve Service	$ 0.48~~37~~ per kW
Supplemental Reserve Service	$ 0.08~~6~~ per kW

Energy Imbalance Service: Currently charged pursuant to the Company's OATT

Energy Charges ($/kWh):

Delivery Charges

~~Summer~~ On-peak	$0.025100~~02600~~ per kWh
~~Summer~~ Off-peak	$0.016900~~01800~~ per kWh
~~Winter On-peak~~	~~$0.000900 per kWh~~
~~Winter Off-peak~~	~~$0.000150 per kWh~~

~~Generation Capacity~~

~~Summer On-peak~~	~~$0.0006000 per kWh~~
~~Summer Off-peak~~	~~$0.00004200 per kWh~~
~~Winter On-peak~~	~~$0.002100 per kWh~~
~~Winter Off-peak~~	~~$0.000350 per kWh~~

Base Power Supply Charge

Summer On-peak	$0.~~0~~060800~~50669~~ per kWh
Summer Off-peak	$0.025700~~26679~~ per kWh
Winter On-peak	$0.056000~~32893~~ per kWh
Winter Off-peak	$0.022100~~27092~~ per kWh

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 30~~2~~1~~1~~
Superseding:

Large ~~Light and~~ Power Service
Time of Use ~~Program~~ (L~~L~~PS ~~-90~~TOU)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To ~~all~~applicable ~~large~~ power services ~~general power and lighting service on an optional basis~~ when all energy is supplied at one point of delivery and through one metered service. The minimum monthly billing demand hereunder is 3,000 kW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service. Service under this rate will commence when the appropriate meter has been installed.

Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.

CHARACTER OF SERVICE
Service shall be three-phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

~~Customers must stay on this rate for a minimum period of one (1) year, unless the Customer is disqualified by one of the other Applicability conditions.~~

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF ~~CUSTOMER~~BASIC SERVICE, DEMAND AND ENERGY CHARGES

~~Customer~~Basic Service Charge ~~and minimum bill~~	$2,000.00 per month
Demand Charges ~~(includes Generation Capacity)~~:	
Summer On-peak	$ 18.00~~20.49~~ per kW
Summer Off-peak Excess Demand	$ 12.49 per kW
Winter On-peak	$ 15.00~~15.49~~ per kW
Winter Off-peak Excess Demand	$ 9.99 per kW

~~*Note:*~~
~~*1. For demand billing, "on-peak demand" shall be based on demand measured during peak periods.*~~
~~*2. For demand billing, "off-peak demand" shall be based on demand measured during the off- peak periods.*~~

Energy Charges ($/kWh):~~:~~

~~All energy charges below are charged on a per kWh basis.~~ All kWh
$0.007100 per kWh

~~Delivery Charges ($/kWh):~~

	~~Summer (May – September)~~	~~Winter (October – April)~~
~~On-Peak~~	~~$0.007100069000~~	~~$0.007100007500~~
~~Off-Peak~~	~~$0.007100006500~~	~~$0.007100~~

Power Supply Charges ($/kWh)

	Summer (May – September)	Winter (October – April)
Base Power On-Peak	$0.057760	$0.053200
Base Power Off-Peak	$0.024415	$0.020995

~~Base Power Supply Charges ($/kWh)~~

	~~Summer (May – September)~~	~~Winter (October – April)~~
~~On-Peak~~	~~$0.057760045568~~	~~$0.053200029581~~
~~Off-Peak~~	~~$0.024415023985~~	~~$0.020995024352~~

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent ~~kWh~~ adjustment in accordance with Rider-1 ~~PPFAC~~ to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 2:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

~~DETERMINATION OF~~ BILLING DEMAND
The monthly billing demand shall be t~~T~~he greatest of the following:

1. The greatest measured 15-minute interval demand read of the meter during the on-peak hours of the billing period;
2. 75% of the greatest on-peak period billing demand used for billing purposes in the preceding 11 months;
3. The contract capacity or 3,000 kW, whichever is greater
   - ~~1. The maximum 15 minute measured demand during the on-peak period of the billing month;~~
   - ~~2. 75% of the maximum on-peak period billing demand used for billing purposes in the preceding 11 months; or~~
   - ~~3. The contract demand amount, not to be less than 3,000 kW, and~~
   - ~~The greatest measured 15-minute interval demand read of the meter during the on-peak hours of the billing period;~~
   - ~~One-half of the greatest measured 15-minute interval demand read of the meter during the off-peak hours of the billing period;~~
   - ~~The greater of (1) or (2) above during the preceding 11 months; or~~
   - ~~The contract capacity or 3,000 kW, whichever is greater.~~

Additionally, ~~the maximum 15 minute measured demand during the off-peak period of the billing month that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak measured billing demand.~~ the greatest measured 15-minute interval demand read of the meter during the off-peak hours of the billing period that is in excess (i.e. positive incremental amount above) of 150% of that billing month's on-peak ~~billed~~measured demand.

PRIMARY SERVICE
The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of transformers.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than ninety-five percent (95%), an adjustment shall be applied to the bill as follows:

POWER FACTOR ADJUSTMENT

(Maximum Demand / (.05 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

POWER FACTOR

1. The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.
2. In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.
3. If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.
4. Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.
5. Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.

~~POWER FACTOR ADJUSTMENT~~

~~The above rate is subject to charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is below 100%.~~

~~POWER FACTOR~~

~~The Company may require the Customer by written notice to either maintain a specified minimum lagging power factor or the Company may after thirty (30) days install power factor corrective equipment and bill the Customer for the total costs of this equipment and installation.~~

~~In the case of apparatus and devices having low power factor, now in service, which may hereafter be replaced, and all similar equipment hereafter installed or replaced, served under general commercial schedules, the Company may require the Customer to provide, at the Customer's own expense, power factor corrective equipment to increase the power factor of any such devices to not less than ninety (90) percent.~~

~~If the Customer installs and owns the capacitors needed to supply his reactive power requirements, then the Customer must equip them with suitable disconnecting switches, so installed that the capacitors will be disconnected from the Company's lines whenever the Customer's load is disconnected from the Company's facilities.~~

~~Gaseous tube installations totaling more than one thousand (1,000) volt-amperes must be equipped with capacitors of sufficient rating to maintain a minimum of ninety percent (90%) lagging power factor.~~

~~Company installation and removal of metering equipment to measure power factor will be at the discretion of the Company.~~

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

TEP

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 30211-3
Superseding:

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

~~Customer~~Basic Service ~~Charges:~~	
~~Meter Services~~	~~$ 499.63 per month~~
~~Meter Reading~~	~~$ 82.53 per month~~
~~Billing & Collection~~	~~$ 359.51 per month~~
~~Customer Delivery~~	~~$1,058.33 per month~~
~~$2,000.00 per month~~	
~~Demand Charges ($/kW)~~	
~~Delivery Charges~~	
~~Summer & Winter On-peak~~	~~$ 1.69 per kW~~
~~Summer & Winter Off-peak Excess Demand~~	~~$ 1.61 per kW~~
~~Generation Capacity Charges (in $/kW)~~	
~~Summer On-peak~~	~~$12.91 per kW~~
~~Summer Excess Demand~~	~~$ 6.27 per kW~~
~~Winter On-peak~~	~~$ 7.91 per kW~~
~~Winter Excess Demand~~	~~$ 3.77 per kW~~
~~Fixed Must-Run Charges (in $/kW)~~	
~~Fixed Must-Run Charges (in $/kW)Summer & Winter On-peak~~	~~$ 0.97 per kW~~
~~Summer & Winter Off-peak Excess Demand~~	~~$ 0.92 per kW~~
~~Transmission (in $/kW)~~	
~~Summer & Winter On-peak~~	~~$ 3.84 per kW~~
~~Summer & Winter Off-peak Excess Demand (kW)~~	~~$ 2.88 per kW~~

~~Transmission - Ancillary System Control~~
~~Summer & Winter On-peak~~ ~~$ 0.05 per kW~~
~~Summer & Winter Off-peak Excess Demand (kW)~~ ~~$ 0.04 per kW~~

~~Transmission – Ancillary Reactive Supply~~
~~Summer & Winter On-peak~~ ~~$ 0.20 per kW~~
~~Summer & Winter Off-peak Excess Demand (kW)~~ ~~$ 0.15 per kW~~

~~Transmission - Ancillary Frequency Response~~
~~Summer & Winter On-peak~~ ~~$ 0.20 per kW~~
~~Summer & Winter Off-peak Excess Demand (kW)~~ ~~$ 0.15 per kW~~

~~Transmission - Ancillary Spinning Reserve~~
~~Summer & Winter On-peak~~ ~~$ 0.54 per kW~~
~~Summer & Winter Off-peak Excess Demand (kW)~~ ~~$ 0.40 per kW~~

~~Transmission - Ancillary Supplemental Reserve~~
~~Summer & Winter On-peak~~ ~~$ 0.09 per kW~~
~~Summer & Winter Off-peak Excess Demand (kW)~~ ~~$ 0.07 per kW~~
~~Energy Imbalance Service: Currently charged pursuant to the Company's OATT~~

~~Energy Charges ($/kWh)~~
~~Delivery Charges (in $/kWh)~~
~~Summer On-peak~~ ~~$0.006900 per kWh~~
~~Summer Off-peak Excess Demand~~ ~~$0.006500 per kWh~~
~~Winter On-peak~~ ~~$0.007500 per kWh~~
~~Winter Off-peak Excess Demand~~ ~~$0.007100 per kWh~~

~~Base Power Supply Charges:~~
~~Summer~~
~~On-Peak $0.045568 per kWh~~
~~Off-Peak $0.023985 per hWh~~

~~Winter~~
~~On-Peak $0.029581 per kWh~~
~~Off-Peak~~ ~~$0.024352 per kWh~~Basic Service Charge Components (Unbundled):

Description	
Meter Services	$ 77.26 per month
Meter Reading	$ 0.78 per month
Billing & Collection	$ 12.59 per month
Customer Delivery	$1,909.37 per month
Total	$2,000.00 per month

Demand Charges (per kW) (Unbundled):

Component	
Demand Delivery	
Summer On-Peak	$2.73
Summer Off-Peak	$1.40
Winter On-Peak	$1.41
Winter Off-Peak	$0.40
Generation Capacity	
Summer On-Peak	$9.68
Summer Off-Peak	$5.50
Winter On-Peak	$8.00
Winter Off-Peak	$4.00
Fixed Must-run	$1.30
Transmission	$3.34~~2.963.45~~
System Control & Dispatch	$0.05
Reactive Supply & Voltage Control	$0.18
Regulation & Frequency Response	$0.17
Spinning Reserve Service	$0.47
Supplemental Reserve Service	$0.08
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.	

Energy Charges ($/kWh): $0.007100 per kWh

Power Supply Charges:

Component	
Base Power Supply Summer (May – September) On-Peak (per kWh)	$0.057760
Base Power Supply Summer (May – September) Off-Peak (per kWh)	$0.024415
Base Power Supply Winter (October – April) On-Peak (per kWh)	$0.053200
Base Power Supply Winter (October – April) Off-Peak (per kWh)	$0.020995
PPFAC (%) (see Rider-1 for current rate)	Varies

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 501
Superseding:

Traffic Signal and Street Lighting Service (~~PS~~TSL ~~-41~~)

AVAILABILITY
Available for service to ~~the~~ any Public Authority ~~State, a county, city, town, political subdivision, improvement district, or a responsible person or persons for unincorporated communities~~ for Traffic Signal and Street Lighting purposes where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Applicable to Customer owned and maintained traffic signals and public street and highway lighting.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

CHARACTER OF SERVICE
Service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF ~~CUSTOMER AND~~ ENERGY CHARGES

Energy Charges: All energy charges below are charged on a per kWh basis.

Delivery Charge:	$0.060900~~047600~~ per kWh
Base Power Charges:	
Summer (May – September)	$0.037325~~035111~~ per kWh
Winter (October – April)	$0.033801~~031532~~ per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent ~~kWh~~ adjustment in accordance with Rider-1~~-PPFAC~~ to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this rate will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

Filed By:	Kentton C. Grant	Rate:	~~PS-41~~TSL
Title:	Vice President of Finance and Rates	Effective:	~~July 1, 2013~~Pending
District:	Entire Electric Service Area	Decision No.:	~~73912~~Pending

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Energy Charges: All energy charges below are charged on a per kWh basis.

Delivery Charge (in $/kWh)	
All kWh~~Summer~~	$0.027879~~003400~~ per kWh
~~Winter~~	~~$0.003400 per kWh~~
Generation Capacity (in $/kWh)	
~~Summer~~All kWh	$0.0150000~~0200~~ per kWh
~~Winter~~	~~$0.010200 per kWh~~
Fixed Must-Run (in $/kWh)	$0.005908~~14300~~ per kWh
Transmission (in $/kWh)	$0.009450~~015300~~ per kWh
Transmission Ancillary Services (in $/kWh)	
System Control & Dispatch	$0.000128~~000200~~ per kWh
Reactive Supply and Voltage Control	$0.000504~~800~~ per kWh
Regulation and Frequency Response	$0.000489~~800~~ per kWh
Spinning Reserve Service	$0.001325~~2200~~ per kWh
Supplemental Reserve Service	$0.000216~~400~~ per kWh
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.	
Base Power Supply Charge:	
Summer	$0.037325~~5111~~ per kWh
Winter	$0.033801~~31532~~ per kWh

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 502
Superseding:

Lighting Service (L~~P~~S~~-50~~)

AVAILABILITY
At any point where the Company in its judgment has facilities of adequate capacity and suitable voltage available.

APPLICABILITY
Applicable to any Customer for private and public street lighting or outdoor area lighting where this service can be supplied from existing facilities of the Company.

The Company will install, own, operate, and maintain the complete lighting installation including lamp and globe replacements. Not applicable to resale service.

CHARACTER OF SERVICE
Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages. Multiple or series street lighting systems may be installed at the option of Company and at one standard nominal voltage.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

~~BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES~~

Delivery Charge (wattages are for incandescent bulbs or thei~~r~~ equivalent wattage rating for other bulbs):

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Per unit Per month	$11.95~~8.19~~	$11.95	$11.95~~8.19~~	$17.92~~12.29~~	$27.29~~18.70~~	$22.65~~22.65.6015.53~~	$4.17~~2.86~~

Note:
1. *The ~~watt~~ high pressure sodium lamps are charged per unit per month.*
2. *Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.*
3. ~~*Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.*~~

Base Power Supply Charge (based on the actual rated wattage value of each lamp installed per month):

Service	55OH, 55P, 55UG~~55UG~~	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Per unit Per month	$0.87~~85~~	$0.96~~94~~	$1.37~~1.34~~	$3.42~~3.36~~	$5.30~~5.38~~	$0.00	$0.00

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent~~-kWh~~ adjustment in accordance with Rider-1~~-PPFAC~~ to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~.

~~STANDARD LAMP UNITS, OVERHEAD SERVICE~~

~~1. The standard 100 watt lamp unit for overhead service is a 9,500 lumen high pressure sodium unit, mounted on a six (6) foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately twenty-five (25) feet above ground level and is for public and private street lighting and area lighting.~~

~~2. The standard 250 watt lamp unit for overhead service is a 27,500 lumen high pressure sodium unit, mounted on a twelve (12) foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately twenty-seven (27) feet above ground level and is for public and private street lighting.~~

~~3. The standard 400 watt lamp unit for overhead service is a 50,000 lumen high pressure sodium unit, mounted on an eighteen (18) foot mast arm and controlled by a photoelectric cell. This unit will be mounted on a pole approximately thirty-five (35) feet above ground level and is for public and private street lighting.~~

~~4. The standard 100 watt lamp unit for underground service is a 9,500 lumen high pressure sodium post top unit mounted on a pole approximately fifteen (15) feet above ground level and is for public and private street lighting and area lighting.~~

DIRECT ACCESS

A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth herein will be applied to the Customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

CONTRACT PERIOD

All lighting installations will require a contract for service as follows:

Three (3) years initial term for installation on existing facilities.
Four (4) years initial term for installation on new facilities.

After the minimum contract period has expired, this agreement shall be extended from month-to-month. The Company reserves the right to cancel the contract at any time after the initial minimum contract period has expired. It is further understood and agreed that if service is terminated by the Customer prior to the expiration of the term of the agreement, or by the Company due to the Customer's failure to pay the stated monthly service charge when due and payable, the Customer shall pay to the Company said monthly service charge, including any applicable adjustments, multiplied by the number of months remaining under the agreement.

~~SPECIAL PROVISIONS~~TERMS AND CONDITIONS

1. Installation of a light on an existing pole is subject to prior approval of Company.
2. ~~For underground service up to ten (10) feet from the electrical source, the Customer shall be billed at the rates for overhead service.~~

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 502-2
Superseding:

~~3.~~2. Extensions beyond 100 feet and all installations other than those addressed in this rate will require specific agreements providing adequate revenue or arrangements for construction financing.

~~4.~~3. The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

~~5.~~4. If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

~~6.~~5. The Customer is expected to notify the Company when lamp outages occur.

~~7.~~6. The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.

~~8. After the minimum contract period, if any, has expired, this agreement shall be extended from year to year unless written notice of desire to terminate is given by the Customer at least thirty (30) days prior to the end of any such annual extension date. The Company reserves the right not to extend or cancel the lighting agreement at any time after the initial minimum contract period has expired.~~

~~9.~~7. Light installation is subject to the governmental agency approval process.

~~10.~~8. The Customer is responsible for all civil installation requirements as specified by the Company in accordance with the Electrical Service Requirements.

~~11.~~ In the event a public improvement project conflict(s) with existing lighting facilities, the impacted facilities will be removed and the contract terminated.

9.

10. The Company will require a non-refundable contribution for the installation of new construction for facilities of $150.00.

11. A late payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a Customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 502-4
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

55/55P WATT

Local Delivery	$ 10.44
Generation Capacity ($/Unit)	$ 0.52
Fixed Must Run ($/Unit)	$ 0.06
System Benefits ($Unit)	$ 0.01
Transmission	$ 0.71
System Control & Dispatch	$ 0.01
Reactive Supply and Voltage Control	$ 0.04
Regulation and Frequency Response	$ 0.04
Spinning Reserve Service	$ 0.10
Supplemental Reserve Service	$ 0.02
Energy Imbalance Service: currently charged pursuant to the Company's OATT	

70 WATT

Local Delivery	$ 10.03
Generation Capacity ($/Unit)	$ 0.66
Fixed Must Run ($/Unit)	$ 0.08
System Benefits ($/Unit)	$ 0.01
Transmission	$ 0.91
System Control & Dispatch	$ 0.01
Reactive Supply and Voltage Control	$ 0.05
Regulation and Frequency Response	$ 0.~~13~~05
Spinning Reserve Service	$ 0.13
Supplemental Reserve Service	$ 0.02
Energy Imbalance Service: currently charged pursuant to the Company's OATT	

~~Delivery Components:~~
~~50, 70, 100 Watt ($/Unit) $ 0.71 Per Unit~~
~~250 Watt ($/Unit) $ 4.81 Per Unit~~
~~400 Watt ($/Unit) $ 11.22 Per Unit~~

~~Generation Capacity ($/Unit) $ 1.50 Per Unit~~

~~Fixed Must Run ($/Unit) $ 2.84 Per Unit~~

~~Transmission (in $/kWh) $ 2.45 Per Unit~~
~~Transmission Ancillary Services (kn $/kWh)~~
~~System Control & Dispatch $ 0.0300 Per Unit~~
~~Reactive Supply and Voltage Control $ 0.1300 Per Unit~~
~~Regulation and Frequency Response $ 0.1300 Per Unit~~
~~Spinning Reserve Service $ 0.3400 Per Unit~~
~~Supplemental Reserve Service $ 0.0600 Per Unit~~
~~Energy Imbalance Service: currently charged pursuant to the Company's OATT~~

100 WATT

Local Delivery	$ 9.21
Generation Capacity ($/Unit)	$ 0.94
Fixed Must Run ($/Unit)	$ 0.11
System Benefits ($/Unit)	$ 0.02
Transmission	$ 1.30
System Control & Dispatch	$ 0.02
Reactive Supply and Voltage Control	$ 0.07
Regulation and Frequency Response	$ 0.07
Spinning Reserve Service	$ 0.18
Supplemental Reserve Service	$ 0.03
Energy Imbalance Service: currently charged pursuant to the Company's OATT	

250 WATT

Local Delivery	$ 11.08
Generation Capacity ($/Unit)	$ 2.35
Fixed Must Run ($/Unit)	$ 0.28
System Benefits ($/Unit)	$ 0.05
Transmission	$ 3.25
System Control & Dispatch	$ 0.04
Reactive Supply and Voltage Control	$ 0.17
Regulation and Frequency Response	$ 0.17
Spinning Reserve Service	$ 0.46
Supplemental Reserve Service	$ 0.07
Energy Imbalance Service: currently charged pursuant to the Company's OATT	

Local Delivery	$ 16.49
Generation Capacity ($/Unit)	$ 3.71
Fixed Must Run ($/Unit)	$ 0.44
System Benefits ($/Unit)	$ 0.08
Transmission	$ 5.13

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 502-6
Superseding:

System Control & Dispatch	$ 0.07	400 WATT
Reactive Supply and Voltage Control	$ 0.27	
Regulation and Frequency Response	$ 0.26	
Spinning Reserve Service	$ 0.72	
Supplemental Reserve Service	$ 0.12	
Energy Imbalance Service: currently charged pursuant to the Company's OATT		

Base Power Supply Charge:

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Per unit Per month	$0.87~~5~~	$0.964	$1.374	$3.42~~36~~	$5.30~~1038~~

Water Pumping Service (GS-WP~~43~~)

AVAILABILITY
Available for service to the City of Tucson Water Utility and private water Companies where the facilities of the Company are of adequate capacity and are adjacent to the premises.

Available for interruptible service agricultural pumping customers throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

~~The service points being billed under the PS-43 and GS-31 rate classes as of the effective date of this tariff, but do not meet the above criteria, will be allowed to stay on this rate as long as they meet all other requirements specified in the tariff.~~

APPLICABILITY
Applicable for service to booster stations and wells used for domestic water supply. For Interruptible service this is applicable to separately metered interruptible agricultural water pumping service for irrigation purposes of the Customer only.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

CHARACTER OF SERVICE
The service shall be single-phase and three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery approved by the Company. Primary metering may be used by mutual agreement.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF ~~CUSTOMER~~BASIC SERVICE AND ENERGY CHARGES

~~Customer~~Basic Service Charge: $30.00~~15.50~~ per month

Energy Charges:
Firm Service:
Delivery Charge
Summer (May – September) $0.081500~~068000~~ per kWh
Winter (October – April) $0.061500~~048000~~ per kWh

Interruptible Service:
Delivery Charge
Summer (May – September) $0.055500~~042000~~ per kWh
Winter (October – April) $0.040500~~027000~~ per kWh

Base Power Supply Charges:

	Summer (May-September)	Winter (October – April)
Firm Service	$0.037325~~035111~~	$0.033801~~031532~~
Interruptible Service	$0.033500~~031310~~	$0.030700~~028420~~

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a percent ~~kWh~~ adjustment in accordance with Rider-1 ~~PPFAC~~ to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel~~per kWh sold~~.

PRIMARY VOLTAGE DISCOUNT
A discount of 5% will be applied to the Delivery Charges (excluding the ~~Customer~~Basic Service Charge) and Power Supply Charges allowed from the above rates where Customer owns the transformers and service is metered at primary voltage.

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the Customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TERMS AND CONDITIONS OF INTERRUPTIBLE SERVICE

1. Customer must furnish, install, own, and maintain at each point of delivery all necessary Company approved equipment which will enable the Company to interrupt service with its master control station.
2. Service may be interrupted by Company during certain periods of the day not exceeding six hours in any 24-hour period.
3. Company will endeavor to give Customer one hour notice of impending interruption; however, service may be interrupted without notice should Company deem such action necessary.
4. The interruptible load shall be separately served and metered and shall at no time be connected to facilities serving Customer's firm load. Conversely, the firm load shall be separately served and metered and shall at no time be connected to facilities serving Customer's interruptible load.
5. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a Customer based on the type of facilities (e.g., metering) dedicated to the Customer or pursuant to the Customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Firm Service

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~Customer~~Basic Service Charge
Meter Services	$ 3.37~~5.78~~ per month
Meter Reading	$ 0.62~~0.74~~ per month
Billing & Collection	$ ~~3.19~~9.96 per month
Customer Delivery	$ 16.05~~5.79~~ per month
Total	$ 30.00~~15.50~~ per month

Energy Charge Components (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.0370~~321700~~	$0.0170~~321700~~
Generation Capacity	$0.03000~~3900~~	$0.03000~~$0.013900~~
Fixed Must-Run	$0.003970~~3500~~	$0.003970~~$0.003500~~
Transmission	$0.008190~~6800~~	~~$0.006800~~$0.008190
~~Transmission Ancillary Services consists of the following charges:~~		
System Control & Dispatch	$0.00011~~000~~	$0.000110~~$0.000100~~
Reactive Supply and Voltage Control	$0.00044~~000~~	$0.000440~~$0.000400~~
Regulation and Frequency Response	$0.00042~~000~~	$0.000420~~$0.0004~~
Spinning Reserve Service	$0.001150~~000~~	$0.001150~~$0.001000~~
Supplemental Reserve Service	$0.000190~~200~~	$0.000190~~$0.000200~~
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge (per kWh)	$0.03732~~55111~~	$0.03380~~131532~~
PPFAC (%)	In accordance with Rider 1~~– PPFAC~~	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 601-3
Superseding:

Interruptible Service

~~Customer~~Basic Service Charge Components (Unbundled):

Description	~~Customer~~Basic Service Charge
Meter Services	$ 3.37~~5.78~~ per month
Meter Reading	$ 0.62~~0.74~~ per month
Billing & Collection	$ 9.96~~3.19~~ per month
Customer Delivery	$ 16.05~~5.79~~ per month
Total	$ 30.00~~15.50~~ per month

Energy Charge Components (Per kWh) (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.01913~~21700~~	$0.00413~~7900~~
Generation Capacity	$0.021900~~07900~~	$0.021900~~06700~~
Fixed Must-Run	$0.003970~~03500~~	$0.003970~~03500~~
Transmission	$0.008190~~$0.006800~~	$0.008190~~$0.006800~~
~~Transmission Ancillary Services consists of the following charges:~~		
System Control & Dispatch	$0.000110~~$0.000100~~	$0.000110~~$0.000100~~
Reactive Supply and Voltage Control	$0.000440~~$0.000400~~	$0.000440~~$0.000400~~
Regulation and Frequency Response	$0.000420~~$0.000400~~	$0.000420~~$0.000400~~
Spinning Reserve Service	$0.001150~~$0.001000~~	$0.001150~~$0.001000~~
Supplemental Reserve Service	$0.000190~~$0.000200~~	$0.000190~~$0.000200~~
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		
Base Power Supply Charge (per kWh)	$0.033500~~31310~~	$0.030700~~28420~~
PPFAC (%)	In accordance with Rider 1~~ – PPFAC~~	

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 701
Superseding:

Rider-~~R~~-1
Purchased Power and Fuel Adjustment Clause (PPFAC)

APPLICABILITY
The Purchased Power and Fuel Adjustment Clause (PPFAC) will be applied to all Customers taking ~~Standard Offer~~ service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. 70628 (December 1, 2008) ~~Decision No. 73912 dated (June 27, 2013)~~ and as updated and defined in the Company's PPFAC Plan of Administration approved in ACC Decision No. ~~73912~~XXXXX.

RATE
The Customer's monthly bill shall consist of applicable rate charges and adjustments in addition to the PPFAC. The percentage-based PPFAC adjustment, as shown below which reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. The percentage-based PPFAC adjustment will apply to the Customer's Base Power Charge.

~~RATE~~
~~The Customer's monthly bill shall consist of the applicable rate_, charges and adjustments in addition to the PPFAC. The percentage-based PPFAC adjustment ror ate, as shown in the TEP Statement of Charges, reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost of purchased power and fuel. The percentage-based PPFAC adjustment will apply to the Customer's Base Power Charge. is an amount expressed as a Rate per kWh charge to reflect the cost to the Company for energy either generated or purchased.~~

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this ridere ~~above Rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Purchased Power Fuel Adjustment Clause
RIDER 1

APPLICABILITY: To all Company Rates, unless otherwise specified.

Issued: Month Day Year

Effective: Month Day Year

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 702
Superseding:

Rider~~-R~~-2
Demand Side Management Surcharge (DSMS)

APPLICABILITY
The Demand Side Management Surcharge (DSMS) will be applied to all Customers taking ~~Standard Offer~~ service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. ~~73912~~ xxxxx ~~dated (June 27, 2013~~mmm dd. 20xx).

RATE
The DSMS shall be applied to all monthly bills.–The DSMS will be assessed as~~on~~ a ~~per kWh basis for residential Customers and on a~~ percentage of the bill before taxes and assessments~~basis for non-residential Customers~~. The rates and effective date are shown in the TEP Statement of Charges.

~~REQUIREMENTS~~
~~The 2013 TEP DSMS is effective July 1, 2013 and will remain in effect until further order by the ACC.~~

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this rider~~e above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider ~~-~~R-3
Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F

AVAILABILITY

The Market Cost of Comparable Conventional Generation (MCCCG) calculation, Rider-3, is restricted solely to Rider-4, Net Metering for Certain Partial Requirements Service (NM-PRS-F). If for a billing month a Rider-4 NM-PRS-F Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation as described in Rider-4 NM-PRS-F. The excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the positive balance of excess kWhs (if any) after netting against billing period usage. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of Rider-4 NM-PRS-F shall be the simple average of the hourly MCCCG as described below for the applicable year.

The Arizona Corporation Commission (ACC) provided guidance on defining MCCCG in the context of its REST Rules and identified the MCCCG as "the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal and long term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs." R14-2-1801.11.

CALCULATION/METHODOLOGY

For purposes of calculating credits to the Customer for Excess Generation, the unit price paid (Credit for Excess Generation) shall be the simple average of the MCCCG over the 8,760 hours (8,784 in a leap year) ~~hours~~ in the forecasted year. The MCCCG in each hour is based on whether native load requirements will be met by internally owned or contracted generation resources or if market purchases will be required to meet native load requirements. The following table provides a description of the MCCCG methodology. The hourly MCCCG cost determination criteria is based on the Market Condition and Dispatch Type. This method of cost determination is very data intensive and will be calculated annually by running TEP's "Planning and Risk" modeling software, and the rate will be filed with the Commission by February 1 of each year. ~~and its applicability will coincide with the next Purchased Power and Fuel Adjustment Clause (PPFAC) rate effective period.~~

RATE

The customer monthly bill shall consist of the applicable rate charges and adjustments in addition to the Credit for Excess Generation based on the MCCCG. The MCCCG is an amount expressed as a rate per kWh charge that is approved by the ACC on or before April 1 of each year and effective with the first billing cycle in April, as shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TEP Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 703-1
Superseding: __________

MCCCG Cost Determination Matrix

Market Condition and Dispatch Type		
	Selling to Market from In House Real and Contracted Generation Sources	MCCCG Cost Based on Incremental Production/Purchase Cost of Base Load Generation for that hour
	No Market Transactions from/to In House and Contracted Generation Sources	
	Purchasing from Day Ahead Market, but not Spot Market, to meet Native Load Requirements	MCCCG Cost Based on Average Day Ahead Market Price of Purchased Power for that hour
	Purchasing from Spot Market to meet Native Load Requirements	MCCCG Cost Based on Average Spot Market Price of Purchased Power for that hour

Incremental Production / Purchase of Base Load - The cost of the next kWh (incremental) amount of load that has to be provided by TEP generation sources and/or purchased power. This will be dependent on the season, month and time of day.

If Day Ahead Market or Spot Market purchases are being used to provide for reliability support capacity to meet native load requirements by freeing up in house or contracted generation resources for regulation or spinning reserve purposes for support of native load requirements, that would still represent a Market Purchase for purposes of determining which matrix box is applicable.

Tucson Electric Power Company

TEP
Tucson Electric Power

Original Sheet No.: 704
Superseding:

Rider-~~R~~-4
Net Metering for Certain
Partial Requirements Service (NM-PRS-F)

AVAILABILITY

~~Only a~~Available to all existing Net Metering customers interconnected to TEP's system prior to June 1, 2015 and those with completed interconnection applications that were submitted prior to or on June 1, 2015 (and ultimately approved) will stay on the Net Metering Rider R-4 for a period not to exceed twenty years. TEP is proposing that the Rider R-4 expire no later than May 31, 2035.

~~premises receiving service under this rider or having approved applications to receive service under this rider on or before June 1, 2015. This rider expires no later than June 1, 2035.~~

Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources [1], a Fuel Cell [2] or Combined Heat and Power (CHP) [3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this rate, the following notes and/or definitions apply:

[1]Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2]Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3]Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE

The service shall be single-phase or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE

Basic Service~~Customer~~ Charges shall be billed pursuant to the Customer's ~~standard offer~~ rate otherwise applicable under full requirements of service.

Power sales and special services supplied by the Company to the Customer in order to meet the Customer's supplemental or interruptible electric requirements will be priced pursuant to the Customer's ~~standard offer~~ Rate otherwise applicable under full requirements service.

Non-Time-of-Use Rates: For Customers taking service under a ~~Standard Retail Rate~~tariff that is not a time-of-use rate, the Customer Supplied kWh shall be credited against the Company Supplied kWh. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

Time-of-Use Rates: For Customers taking service under a ~~Standard Retail Rate~~tariff that is a time-of-use rate, the Customer Supplied kWh during on-peak hours shall be credited against the Company Supplied kWh during on-peak hours. All Customer Supplied kWh during off-peak hours shall be credited against the Company Supplied kWh during off-peak hours. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

EXCESS GENERATION

If for a billing month the Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation. That is, the excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Customers taking service under a time-of-use rate who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit in the next billing period for the on-peak or off-peak periods in which the kWh were generated by the Customer. Time-of-Use Customer's taking service in the billing month of April shall receive a credit to summer on-peak and summer off-peak usage in the billing month of May for any winter on-peak and/or winter off-peak excess generation for April.

Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the balance of excess kWhs after netting. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of this rate shall be the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) Rider-3 for the applicable year. The MCCCG, as it applies to this rate, is specified in Rider-3 MCCCG - Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F (Net Metering for Certain Partial Requirements Service).

METERING

The Company will install a bi-directional meter at the point of delivery to the Customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the Customer to the metering to allow remote interrogation of the meters at each site. If by mutual agreement between Company and Customer that a phone line is impractical or cannot be provided - the Customer will work with Company to allow for the installation of equipment, on or with customer facilities or equipment to allow remote access to each meter. Any additional cost of communication, such as but not limited to, cell phone service fees will be the responsibility of the Customer.

A Customer that does not install the electrical equipment as specified to provide the verification of the required minimum CHP efficiency will not be eligible for Net Metering.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under this ridere ~~above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider ~~R~~-5
Electric Service Solar Rider
(Bright Tucson Community Solar™)

APPLICABILITY

Rider-5 is for individually metered Customers who wish to participate in the Bright Tucson Community Solar Program. Under Rider-5, Customers will be able to purchase blocks of electricity from solar generation sources. Participation in Rider-5 is limited in the Company's sole discretion to the amount of solar generation available and subscription will be made on a first come, first served basis. In order to maximize subscription under Rider-5, TEP may limit the amount of solar block energy purchased by individual Customers.

Rider-5 available prior to July 1, 2013 is further restricted to Customers being served under one of the following rates in effect at that time:

1) Residential Lifeline Discount, Rate R-06-01
2) Residential Electric Service, Rate R-01
3) Small General Service, Rate GS-10
4) Large General Service, Rate LGS-13
5) Municipal Service, Rate PS-40

Rider-5 effective after July 1, 2013 but before xx,xx, 20xx is further restricted to Customers being served under one of the following rates in effect at that time:

1) Residential Electric Service, Rate R-01
2) Small General Service, Rate GS-10
3) Large General Service, Rate LGS-13
~~3)~~

Rider-5 effective after xx,xx, 20xx is further restricted to Customers being served under one of the following rates in effect at that time:

1) Residential Electric Service, Rate RES
2) Small General Service, Rate SGS
3) Medium General Service, Rate MGS

Customers being served under self-generation riders or plans may not purchase power under Rider-5 (including, but not limited to Rider-4 Net Metering for Certain Partial Requirements Service (NM-PRS-F)~~Rider-4~~ and Rider-15 Net Metering for Certain Partial Requirements Service (NM-PRS), Post June 1, 2015.~~Non-Firm Power Purchase from Renewable Energy Resources and Qualifying Cogeneration Facilities of 100 kilowatts (kW) or Less Capacity Rider-101).~~

RATE

Customers can contract for a portion or up to their average annual usage in solar blocks of 150 kilowatt hours (kWh) each. ~~Transmission and distribution~~Delivery charges will be applied to all energy delivered, including energy delivered under Rider-5. The Customer is responsible for paying (each month) all charges incurred under their applicable rate ~~schedule~~, and the total solar energy contracted for multiplied by the applicable solar block energy rate. Any demand based charges under the Customer's current rate will not be affected by elections under Rider-5. No discounts specified in any of the above-listed ~~standard offer~~ tariffs will apply to this ~~rider~~Rate. The rates are shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES

For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this ~~rate~~rider.

TAX CLAUSE

To the charges computed under this ridere ~~above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMS AND CONDITIONS

1) Customers may contract for a portion or up to their average annual usage in solar blocks of 150 kWh. If Customer's annual average usage is not available, TEP will apply the appropriate class average. This limit can be reviewed annually at the request of the Customer.

2) Each solar block's energy rate will be maintained for twenty years from the date of purchase. For the purposes of the twenty year energy rate, solar blocks will be attributed to the Customer's original service address. Transfer of service under Rider-5 is prohibited. Should the Customer cancel service for any reason, his or her subscription under Rider-5 will expire.

3) Customers may add or delete solar blocks once within a twelve month period. Any addition of solar blocks will be at the then offered solar block energy rate.

4) Solar blocks will be applied to the actual energy usage each month. Electricity used in excess of the purchased solar blocks will be billed at the Customer's regular ~~energy~~ Base Fuel and PPFAC rates. If electricity usage is below the amount covered by the solar block(s), then the excess kWhs will be rolled forward and credited against~~ain~~ the Customer's usage in the following month. The Customer will still be responsible for the full cost of the block(s) each month.

   Customers will be credited for the balance of any excess kWhs annually, or on their final bill should the Customer terminate service under Rider-5. Each year, for the bills produced in October (September usage), TEP will credit Customers their excess kWhs after netting and reset their balance to zero. Credit for excess kWhs will be at the energy rate of the oldest solar block.

5) All contracted solar block kWhs and associated charges in a billing month will be excluded from the calculation of PPFAC and REST charges and/or credits.

Rider-~~R~~-6
Renewable Energy Standard and Tariff (REST) Surcharge
REST-TS1 Renewable Energy Program Expense Recovery

APPLICABILITY
Mandatory, non-bypassable surcharge applied to all energy consumed by all Customers throughout Company's entire electric service area.

RATES
For all energy billed which is supplied by the Company to the Customer. The REST surcharge shall be applied to all monthly bills. The REST rates are shown in the TEP Statement of Charges.

Notes:

1. A Large Commercial Customer is one with monthly demand greater or equal to 200 kW but less than 3,000 kW.
2. An Industrial Customer is one with monthly demand equal to or greater than 3,000 kW.
~~3.~~ For non-metered services, the lesser of the load profile or otherwise estimated kWh required to provide the service in question, or the service's contract
~~4.~~3. kkWh, shall be used in the calculation of the surcharge.

This charge will be a line item on customer bills reading "Renewable Energy Standard Tariff."

Per Decision No. 73637 effective March 21, 2013, any Customer who has received incentives on and after January 1, 2012 under the REST Rules, shall pay the average of the REST surcharge paid by members of their Customer class. Any Customer who has a renewable installation without incentives that is interconnected with TEP's system on and after February 1, 2013 shall pay the average of the REST surcharge paid by members of their Customer class. The average price by class is shown in the TEP Statement of Charges

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

TAX CLAUSE
To the charges computed under this ridere ~~above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 707
Superseding:

Rider ~~-R~~-7
Customer Self-Directed Renewable Energy Option
REST-TS2 Renewable Energy Standard Tariff

AVAILABILITY
Open to all Eligible Customers as defined at A.A.C. R14-02-1801.H.

APPLICABILITY
Any Eligible Customer that applies to the Company under this program and receives approval shall participate at its option.

PARTICIPATION PROCESS
An Eligible Customer seeking to participate shall submit to the Company a written application that describes the Distributed Renewable Energy (DRE) resources or facilities that it proposes to install and the estimated costs of the project. The Company shall have sixty (60) calendar days to evaluate and respond in writing to the Eligible Customer, either accepting or declining the project. If accepted, the Customer shall be reimbursed up to the actual dollar amounts of customer surcharge paid under the REST-TS1 Tariff in any calendar year in which DRE facilities are installed as part of the accepted project. To qualify for such funds, the Customer shall provide at least half of the funding necessary to complete the project described in the accepted application, and shall provide the Company with sufficient and reasonable written documentation of the project's costs. Customer shall submit their application prior to May 1 of a given year to apply for funding in the following calendar year.

FACILITIES INSTALLED
The maintenance and repair of the facilities installed by a Customer under this program shall be the responsibility of the Customer following completion of the project. In order to be accepted by the Company for reimbursement purposes, the project shall, at a minimum, conform to the Company's System Qualification standards on file with the Commission. (REST Implementation Plan, Renewable Energy Credit Purchase Program – RECPP, Distributed Generation Interconnection Requirements, Net Metering Tariff, Company's Interconnection Manual)

PAYMENTS AND CREDITS
All funds reimbursed by the Company to the Customer for installation of approved DRE facilities shall be paid on an annual basis no later than March 30th of each calendar year. All Renewable Energy Credits derived from a project, including generation and Extra Credit Multipliers, shall become the property of the Company and shall be applied towards the Company's Annual Renewable Energy Requirement as defined in A.A.C. R14-2-1801.B.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rider.

RELATED RIDER~~SCHEDULES~~

- REST-TS1 - Renewable Energy Program Expense Recovery

Filed By:	Kentton C. Grant	Rate:	R-7
Title:	Vice President of Finance and Rates	Effective:	~~July 1, 2013~~Pending
District:	Entire Electric Service Area	Decision No.:	~~73912~~Pending

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 708
Superseding:

Rider~~-R~~-8
Lost Fixed Cost Recovery (LFCR)

APPLICABILITY
The Lost Fixed Cost Recovery (LFCR) will be applied to all Customers taking service from the Company other than residential solar – company owned program, traffic signal and street lighting service, lighting service, water pumping service, and large ~~light and~~ power service as defined in the Company's LFCR Plan of Administration (POA). ~~As provided for in the POA, in the event a residential Customer chooses to contribute to this program by paying a fixed charge option, the monthly Customer Charge specified on the appropriate Standard Offer tariff will be charged in lieu of the percentage rate shown in the TEP Statement of Charges.~~

CHANGE IN RATE
The LFCR recovers a portion of the authorized margin approved in the Company's most recent rate case that has been lost as the result of implementing ACC-mandated Energy Efficiency and Distributed Generation programs. Each year, a percentage charge~~s~~ will be placed in effect and charged to the participating Rate classes for the 12-month period the LFCR adjustment is applicable. The total year-on-year adjustment cannot exceed 2~~1~~% of the Company's most recent total combined retail calendar year revenues for all participating rate classes. The LFCR rate is shown in the TEP Statement of Charges.

~~The LFCR adjustments shall be applied to all monthly bills as a percentage of the total bill and are anticipated to become effective on or around July 1, 2014.~~

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission (ACC) see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this rider~~e above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider~~rate~~.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 709
Superseding:

Rider~~-R~~-9
Environmental Compliance Adjustor (ECA)

APPLICABILITY
The Environmental Compliance Adjustor (ECA) will be applied to all Customers taking ~~Standard Offer~~ service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. 73912 dated June 27, 2013 and as modified ~~defined~~ in the Company's ECA Plan of Administration approved in ACC Decision No. xxxxx dated xxx, xx, 20xx.~~.~~

RATE
The Customer's monthly bill shall consist of the applicable rate charges and adjustments including the ECA. The ECA adjustor rate is ~~an amount~~ expressed as a ~~rate per kWh charge~~percentage rate and shall be assessed to the Customer's ~~net b~~bill before taxes and assessments. The rate and effective date are~~, as~~ shown in the TEP Statement of Charges.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the ACC see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under this rider~~e above rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rider.

Rider R–11~~3~~
Partial Requirements Service (PRS)

AVAILABILITY
For all Qualifying Facilities ("QF") that have entered into a Service Agreement with the Company i~~I~~n all territories served by the Company at all points where the adjacent facilities are adequate and suitable~~, for all Qualifying Facilities ("QF") that have entered into a Service Agreement with the Company~~. This rate is not available for temporary or resale service. Customers eligible for taking service under Partial Requirements Service are those customers who are not otherwise subscribed to the Company's approved Net Metering ~~tariff~~Rider.

APPLICABILITY
To QFs operating in Partial Requirements Mode for partial requirements including~~;~~ supplemental power, stand-by power, and maintenance power service.

CHARACTER OF SERVICE
Electric sales to the Company must be single or three phase, 60 Hertz, at a standard voltage subject to availability at the premises. The QF will have the option to sell energy to the Company at a voltage level different from that for purchases from the Company; however, the QF will be responsible for all costs incurred to accommodate such an arrangement.

DEFINITIONS
1. Commission – Arizona ~~Corporate~~ Corporation Commission which has jurisdiction over this Company.

2. Energy - Electric energy which is supplied by the QF and/or Company.

3. Firm Capacity - Capacity available, upon demand, at all times (except for forced outages and scheduled maintenance) during the period covered by the Agreement from the QF with an availability factor of at least 80%, as defined by the North American Electric Reliability Corporation.

4. Full Requirements Service - Any instance whereby the Company provides all the electric requirements

5. Maintenance Power - Electric capacity and energy supplied by the Company during scheduled outages of the QF.

6. Net Energy - The total kilowatt hours ("kWh") sold to the QF by the company less the total kWhs purchased by the Company from the QF.

7. Partial Requirements Mode of Operation - A QF's generation output first goes to supply its own electric requirements with any excess energy (over and above its own requirements) then being sold to the Company. The company supplies the QF's electric requirements not met by the QF's own-generating facilities. This also may be referred to as the "parallel mode" of operation.

8. Purchase Agreement - Agreements for the purchase of electric energy and capacity from and the sale of power to the QF entered into between the Company and QF.

9. Qualifying Facilities - Cogeneration and small power production facilities where the facility's generator(s) and load are located at the same premise and that otherwise meet qualifying criteria for size, fuel use, efficiency and ownership as promulgated in 18 C.F.R., Chapter I, Part 292, Subpart B of Federal Energy Regulatory Commission regulations.

10. Supplemental Power - Electric capacity and energy supplied by the Company regularly used by the QF in addition to that which the facility generates itself.

TEP
Tucson Electric Power

Tucson Electric Power Company

11. Stand-by Power - Electric capacity and energy supplied by the Company to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

RATES FOR SALES TO QFs

Supplemental Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable ~~standard offer~~ tariff but not to be less than $~~15~~25.00 per month.

B. Energy Charge - The energy charge shall be the energy charge (including Base Power Fuel & Purchased Power) using the otherwise applicable ~~standard offer~~ tariff.

C. Demand Charge - The demand charge shall be the demand charge using the otherwise applicable ~~standard offer~~ tariff, or $~~7.50~~12.00 per kW if none is specified in the ~~standard offer~~ tariff, times the higher of the current month's measured demand or the maximum measured Demand in the proceeding ~~11~~ 23 months used to meet only supplemental power and is not applied to total requirements.

Standby Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable ~~standard offer~~ tariff but not to be less than $~~1~~25.00 per month.

B. Energy Charge - The energy charge shall be the energy charge (including Base Fuel & Purchased Power) using the otherwise applicable ~~standard offer~~ tariff plus 50%.

C. Demand Charge - The demand charge shall be the 1.5 times the applicable ~~standard offer~~ tariff with a minimum of $~~11.25~~ 18.00 per kW.

Maintenance Service:

A. Service Charge - The service charge shall be the basic service charge using the otherwise applicable ~~standard offer~~ tariff but not to be less than $~~1~~25.00 per month.

B. Energy Charge - The energy charge shall be the energy charge (including Base Fuel & Purchased Power) using the otherwise applicable ~~standard offer~~ tariff.

C. Demand Charge - The demand charge shall be the demand charge using the otherwise applicable ~~standard offer~~ tariff, or $12.00~~7.50~~ per kW if none is specified in the ~~standard offer~~ tariff, times the maximum measured Demand.

D. Maintenance Service - Must be scheduled with and approved by the Company and may only be scheduled during the period October through April.

Only one service charge will be applied for each billing period.

RATES FOR PURCHASES FROM QFs

Minimum ~~Customer~~ Basic Service Charge per month at $~~15~~25.00 will be assessed each QF selling energy to the Company under this pricing plan. A service charge for purchases from the QF will only be charged if a service charge was not assessed for sales to the QF.

Rates for Energy purchased from the QF shall be priced at short-run avoided cost as provided in the Service Agreement applicable herein and approved by the Commission.

Rates for Firm Capacity purchased from the QF shall be priced at long-run avoided cost based upon deferral of capacity additions indicated in Company's resource plan as provided in the Service Agreement applicable herein and approved by the Commission.

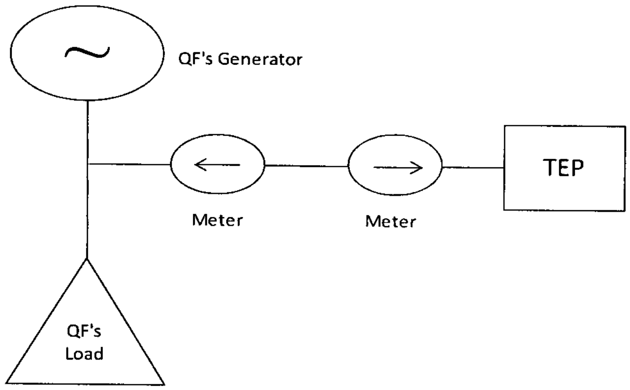
ADJUSTMENTS

All other charges specified in the applicable ~~standard offer~~ tariff apply for all energy purchased from the Company by the QF.

METER CONFIGURATION

As provided for in the Service Agreement. If not otherwise provided for in the Service Agreement then as follows:

If in Partial Requirements mode:



CONTRACT PERIOD

As provided for in the Service Agreement.

TERMS AND CONDITIONS

A Customer that qualifies for service for their full requirements, but now desires to install a generator shall take partial requirements service under the conditions of the tariff herein. In addition to the requirements of the Service Agreement, these conditions include:

1. Must have a demand meter installed and operating before service will be allowed. Any equipment necessary to provide partial requirement service, including equipment to measure the output of the generator(s), that would not otherwise be necessary for full requirements service must meet all Company standards and will be installed at the Customer's expense.

2. The Capacity of the Customer's installed generator(s) must be certified by the Company prior to the receipt of any partial requirements service. This certification will be done by the Company at the Customer's expense. The generating unit cannot be sized at more than 125% of the Customer's connected Capacity. If output of the Customer's generator(s) appears to increase above the certified level, the Company, at its discretion, may require recertification of the equipment. If it is confirmed that the equipment has been expanded or otherwise modified to increase its production ability, the cost of the recertification will be at the Customer's expense. If no changes were found there will be no cost to the Customer for the recertification.

3. Any unpaid balances will be subject to the standard late payment charges as provided for in the currently approved Rules and Regulations.

4. Primary Service and Metering is required for all services that have a certified kW output of the generating unit(s) greater than 300 kW.

5. The Company may require a written contract and a minimum term of contract, at its discretion.

6. Prior to construction, the Customer will contribute to the Company the total amount of the estimated interconnection construction costs directly related to distribution and transmission service. The Customer will furnish, install, and maintain incremental non-distribution system or non-transmission system equipment at their expense. The equipment must meet the standards of the Company's Electric Service Requirements.

TAX CLAUSE

To the charges computed under the above rider~~rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this ~~rate~~rider.

Rider~~-R~~–12
Interruptible Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
Available to Customers qualifying for and receiving electric service ~~under pricing plans applicable to service~~ over 3,000 kW ~~(either Time-of-Use or Non-Time-of-Use)~~ and are willing to subscribe to at least 1,000 kW of interruptible load at a contiguous facility. This rider is not available for standby, temporary, resale or in conjunction with other interruptible rate schedules.

CHARACTER OF SERVICE
Must meet all service requirements for the Customer's applicable ~~Standard Offer~~ tariff.

TERMS AND CONDITIONS OF SERVICE

1. Customers taking service under this rider are eligible for credits in exchange for curtailing load at the request of the Company.
2. Interruptions can be called for economic or non-economic reasons and are to be called at the sole discretion of the Company.
3. The Customer must designate each service point that may be available for interruption with a 30 minute notice. Interruption will be at the discretion of the Company.
4. No more than two interruption events will occur in a given calendar day.
5. A Customer will be limited to no more than two interruptions in a day during the five summer months for a maximum of six (6) hours for each daily interruption event, even if the duration per event is less than 6 hours.
6. To receive service under this Rider–12, the Customer will install, at the Customer's expense, all necessary communication, relay and breaker equipment to qualify for service under this ~~Rate~~Rider-12, subject to Company approval and will pay for associated hardware cost. The Customer must maintain all Company-approved equipment at their service location necessary for the Company to provide interruption notification and to remotely interrupt the Customer from its master control station.
7. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.
8. Nothing herein prevents the Company from interrupting service for emergency circumstances, determined at the Company's sole discretion. Emergency interruptions, as defined by the Company's Rules and Regulations, shall not count as interruption events for purposes of this ~~Rider~~rider.
9. The standard Rules and Regulations of the Company, as on file with the Arizona Corporation Commission, shall apply where not inconsistent with this rider~~Rate schedule~~.
10. The total of all interruption events (excluding Emergency interruptions) will not exceed 120 hours per year.

BID COMMITMENT PERIOD
The Company will post Market Value Capacity Price (MVCP) (defined below) and available Interruptible Credits ($/kW) based on market value capacity for day-ahead dispatch notice for the coming months of May through September by March 15 in the same calendar year.

NOMINATION OF INTERRUPTIBLE LOAD BY CUSTOMER
Nomination will occur before April 15 of the calendar year of each interruption season. Participating Customers shall designate by service point the portion of their load that is Interruptible Load (in kW). A minimum of a thirty minute notice requirement, and a maximum interruption of six hours per event applies to all load nominated at a single service point. Customers with multiple service points may designate different maximum load (kW) for different contiguous service points. If the Customer intends to interrupt a specific activity or function at its operation, the Customer should state this activity or function at the time Interruptible Load is nominated. The minimum nomination of interruptible load summed over a participating Customer's contiguous service points shall be at least 1,000 kW.

INTERRUPTIBLE CREDIT
Customers who elect service under this Rider–12 will receive a monthly Interruptible credit for each of the five summer months in which an interruption may occur. The credit will be calculated by taking the Market Value Capacity Price applicable for the interruptible load season (May through September) times the nominated interruptible load of the individual Customer.

MARKET VALUE CAPACITY PRICE (MVCP)
The Market Value Capacity Price (MVCP) reflects opportunity cost of capacity as revealed through the Company's resource procurement process, adjusted to reflect line losses, and reserves avoided. Resource prices are sensitive and confidential information based on competitive bids; however this information will be made available to the Arizona Corporation Commission Staff and/or an Independent Monitor(s) for review. The MVCP is a price applicable to the five summer months only.

RECOVERY OF PROGRAM COSTS
The cost of the interruptible resource under this Rider–12 (the credits applied to qualifying Customers' bills) shall be treated as "Purchased Power" and shall be recorded in FERC account 555 and appropriately treated through the Purchased Power and Fuel Adjustment Clause (PPFAC) as any other prudent fuel or purchased power cost.

~~DIRECT ACCESS~~
~~A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.~~

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rider~~rate~~, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 712803-2
Superseding:

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rider~~rate~~.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

TEP
Tucson Electric Power

Tucson Electric Power Company

~~First Revised~~Original Sheet No.: 801

Superseding ~~Original Sheet No.~~ : ~~801~~

TEP STATEMENT OF CHARGES

Fee No.	Description	Rate	Effective Date	Decision No.
1.	Service Transfer Fee	$26.00~~20.00~~	~~July 1, 2013~~Pending	~~73912~~ Pending
2.	Customer-Requested Meter Re-read	$26.00~~20.00~~	~~July 1, 2013~~ Pending	~~73912~~ Pending
3.	Special Meter Reading Fee (including Customer Self-Reads)	$26.00~~20.00~~	~~July 1, 2013~~ Pending	~~73912~~ Pending
4.	Service Establishment, ~~and~~ Reestablishment or Reconnection of Service under usual operating procedures During Regulator Business Hours – Single-Phase Service	$38.00~~32.00~~	~~July 1, 2013~~ Pending	~~73912~~ Pending
5.	Service Establishment, ~~and~~ Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Single-Phase Service	$61.00~~57.00~~	~~July 1, 2013~~ Pending	~~73912~~ Pending
6.	Service Establishment, ~~and~~ Reestablishment or Reconnection of Service under usual operating procedures During Regular Business Hours – Three-Phase Service	$129.00~~78.00~~	~~July 1, 2013~~ Pending	~~73912~~ Pending
7.	Service Establishment, ~~and~~ Reestablishment or Reconnection of Service under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Three-Phase Service	$271.00~~216.00~~	~~July 1, 2013~~ Pending	~~73912~~ Pending
8.	Service Reestablishment under other than usual operating procedures (including Automated Meter Opt-Out Set-Up Fee) – Single-Phase Service	$187.00~~150.00~~	~~July 1, 2013~~ Pending	~~73912~~ Pending
9.	Single-Phase Line Extension Charge per Foot	$17.00	~~July 1, 2013~~ Pending	~~73912~~ Pending
10.	Three-Phase Line Extension Charge per Foot	$27.00	~~July 1, 2013~~ Pending	~~73912~~ Pending
11.	Underground Differential Line Extension Charge per Foot	$21.00	~~July 1, 2013~~ Pending	~~73912~~ Pending
12.	PME Switchgear Cabinet	$20,500.00	~~July 1, 2013~~	~~73912~~ Pending

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: Statement of Charges
Effective: ~~July 1, 2013~~Pending
Decision No.: ~~73912~~Pending

Tucson Electric Power

Tucson Electric Power Company

~~First Revised~~Original Sheet No.: 801

Superseding ~~Original Sheet No.~~ : ~~801~~

			Pending	
13.	Meter Test	$211.00~~186.00~~	~~July 1, 2013~~ Pending	~~73912~~ Pending
14.	Returned Payment Fee	$10.00	~~July 1, 2013~~ Pending	~~73912~~ Pending
15.	Late Payment Finance Charge	1.5%	~~July 1, 2013~~ Pending	~~73912~~ Pending
16.	Residential Solar – Company Owned Program Processing Fee	$250.00	~~Dec. 31, 2014~~ Pending	~~74884~~ Pending
17	Consumption History Request and Interval History Request	$65.00 an hour	Pending	Pending

Tucson Electric Power

Tucson Electric Power Company

~~Fifth Revised~~ Original Sheet No.: 801-1

Superseding ~~Third Substitute Fourth Revised Sheet No.: 801-1~~

TEP STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-1 – Purchased Power and Fuel Adjustment Clause (PPFAC)	Varies – See Rider-1 ~~$0.006820 per kWh~~	~~April 1, 2015~~ Pending	~~74974~~Pending
Rider R-2 – Demand Side Management Surcharge (DSMS) ~~RESIDENTIAL:~~ ~~NON-RESIDENTIAL:~~ ~~FREEPORT-MCMORAN COPPER AND GOLD (25 MW and above):~~	~~$0.002311 per kWh~~Pending ~~2.466%~~ ~~Exempt~~	~~January 6, 2015~~Pending	~~74885~~Pending
Rider R-3 – Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS-F	$0.028653 per kWh	April 1, 2015	74973
Rider R-5 – Electric Service Solar Rider (Bright Tucson Community Solar™) Solar Block Energy Rate for Residential Lifeline Discount, Rate R-06-01 Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for General Service, Rate GS-10 Solar Block Energy Rate for Large General Service, Rate LGS-13 Solar Block Energy Rate for Municipal Service, Rate PS-40	$0.050198 per kWh $0.050324 per kWh $0.048475 per kWh $0.049371 per kWh $0.049086 per kWh	February 1, 2011 Through June 30, 2013	71835[1]
Rider R-5 – Electric Service Solar Rider (Bright Tucson Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate R-01 Solar Block Energy Rate for Small General Service, Rate GS-10 Solar Block Energy Rate for Large General Service, Rate LGS-13	$0.053463 per kWh $0.053274 per kWh $0.053227 per kWh	July 1, 2013 Through Pending	73912
Rider R-5 – Electric Service Solar Rider (Bright Tucson Community Solar™) Solar Block Energy Rate for Residential Electric Service, Rate RES Solar Block Energy Rate for Small General Service, Rate SGS Solar Block Energy Rate for Medium General Service, Rate MGS	Pending	Pending	Pending
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Monthly Cap For Residential Customers: For Small General Service Customers: For Large General Service Customers: For Large ~~Light & Power~~ Service Customers: For Lighting Customers:	$0.008000 per kWh Monthly Cap $ 3.76 per month $ 100.00 per month $1,015.00 per month $8,000.00 per month $ 100.00 per month	January 1, 2015	74884

Filed By:	Kentton C. Grant	Rate:	Statement of Charges
Title:	Vice President of Finance and Rates	Effective:	~~July 1, 2013~~Pending
District:	Entire Electric Service Area	Decision No.:	~~73912~~Pending

[1] ~~The Rider R-5 approved by Decision No. 71835 is closed for new enrollment as of July 1, 2013~~

Tucson Electric Power

Tucson Electric Power Company

~~Fifth Revised~~Original Sheet No.: ~~—~~801-2

Superseding ~~Fourth Revised Sheet No.~~: ~~801-2~~

TEP STATEMENT OF CHARGES

Description	Rate	Effective Date	Decision No.
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Average price by class: Average Rate ~~Monthly Cap~~ For Residential Customers: For Small General Service Customers: For Large General Service Customers: For Large ~~Light &~~ Power Service Customers: For Lighting Customers:	Average Rate~~Monthly Cap~~ $ 3.19 per month $ 20.77 per month $ 779.66 per month $8,000.00 per month $ 11.71 per month	January 1, 2015	74884
Rider R-8 Lost Fixed Cost Recovery (LFCR) Mechanism ~~– Energy Efficiency~~ ~~Lost Fixed Cost Recovery (LFCR) Mechanism – Distributed Generation~~	~~0.4149%~~Pending ~~0.3126%~~	~~August 1, 2014~~Pending	~~74593~~Pending
Rider R-9 – Environmental Compliance Adjustor (ECA)	~~$0.000191 per kWh~~Pending	~~May 1, 2015~~Pending	~~73912~~Pending
Rider R-16 – Renewable Credit Rate (RCR)	Pending	Pending	Pending

Filed By:	Kentton C. Grant	Rate:	Statement of Charges
Title:	Vice President of Finance and Rates	Effective:	~~July 1, 2013~~Pending
District:	Entire Electric Service Area	Decision No.:	~~73912~~Pending

Bill Estimation Methodologies

Tucson Electric Power Company (TEP) regularly encounters situations in which TEP cannot obtain a complete and valid meter read. No matter the cause of the need to estimate the read, the following methods are used depending on the circumstances.

PREVIOUS YEAR FORMULA

SAME CUSTOMER WITH AT LEAST ONE YEAR OF HISTORY

TEP would generate a bill based on customer usage from the previous year using the "PREVIOUS YEAR" formula as follows:

If last year's usage was estimated, see Previous Month Formula:

LAST YEAR'S USAGE FOR SAME MONTH / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR "TIME OF USE" (TOU) THIS WOULD BE APPLIED TO EACH PERIOD)

PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

PREVIOUS MONTH FORMULA

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY

TEP would generate a bill based on customer usage from the previous month using the "PREVIOUS MONTH" formula as follows:

If last month's usage was estimated, see Trend Formula:

LAST MONTHS USAGE / NUMBER OF DAYS IN BILLING PERIOD = PER DAY USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)
PER DAY USAGE X NUMBER OF DAYS IN THIS MONTH'S CYCLE = ESTIMATED USAGE
(FOR TOU THIS WOULD BE APPLIED TO EACH PERIOD)

TREND FORMULA

NEW CUSTOMER AT SAME PREMISE

TEP would generate a bill using the "TREND" formula, based on customer's usage trend as described below:

TEP's customer information system (CIS) would generate a bill based on trend. Customers are assigned to a Trend area which differentiate consumption based on different geographic areas. Secondly, the customer is assigned to a Trend class which is used to differentiate consumption trends based on the type of service and type of property. An example of this would be residential, commercial, and industrial usage. Thirdly, all consumption is identified using unit of measure code and a time of use code. Within TEP's CIS, a trend record is created from each billed service. This record becomes part of a trend table. During estimation, consumption from three prior bill cycles is compared to the consumption from the same cycle in the previous month to determine a trend. This trend, plus a tolerance, is used to create a usage amount for bill estimation.

CUSTOMER'S USAGE IN PREVIOUS PERIOD/ AVERAGE CUSTOMER'S USAGE IN PREVIOUS PERIOD X AVERAGE CUSTOMER'S USAGE IN CURRENT PERIOD = ESTIMATED CONSUMPTION FOR REGISTER READ

NO HISTORY

TEP would not generate a bill until a good meter read was acquired then use known consumption to estimate previous bills.

Demand Estimate

For accounts that have a demand billing component TEP collects interval data. This interval data is used to manually estimate demands using the following methodologies:

SAME CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous year using the following formula:

LAST YEAR'S DEMAND FOR SAME MONTH = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH AT LEAST ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

SAME CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NEW CUSTOMER AT SAME PREMISE WITH LESS THAN ONE YEAR OF HISTORY
TEP would generate a bill based on customer usage from the previous month using the following formula:

LAST MONTHS DEMAND = ESTIMATED DEMAND

NO HISTORY
TEP would not generate a bill until a good demand read was acquired then use known demand to estimate previous bills.

Residential Lifeline/Senior Discount (R-04-01F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase or three-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must be 65 years of age, or older, and reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard
Customer Charge, single-phase service and minimum bill — $ 6.90 per month
Customer Charge, three-phase service and minimum bill — $11.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh — $ 9.40 per month
Customer Charge, three-phase with usage less than 2,000 kWh — $14.40 per month

Customer Charge, single-phase with usage of 2,000 kWh or more — $13.40 per month
Customer Charge, three-phase with usage of 2,000 kWh or more — $18.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
Summer (May – September)	$0.0611	$0.033198	*varies*	$0.094298
Winter (October – April)	$0.0570	$0.025698	*varies*	$0.082698

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0 - 300 kWh	35%
301 - 600 kWh	30%
601- 1,000 kWh	25%
1001- 1,500 kWh	15%
Over 1,500 kWh	0%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 103-2
Superseding:

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
Total	**$6.90 per month**	**$11.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$2.50 per month	$2.50 per month
Total	**$9.40 per month**	**$14.40 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$6.50 per month	$6.50 per month
Total	**$13.40 per month**	**$18.40 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 103-3
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Component	**Summer** (May – September)	**Winter** (October - April)
Local Delivery-Energy	$0.013800	$0.011300
Generation Capacity	$0.032700	$0.031100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge:

	Summer (May – September)	**Winter** (October - April)
Base Power Component	$0.033198	$0.025698
PPFAC	In accordance with Rider 1 - PPFAC	

CANCELED

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-04-01F
Effective: July 1, 2013
Decision No.: 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 104
Superseding:

Residential Lifeline/Senior Discount (R-04-21F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must be 65 years of age, or older, and reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, single-phase service and minimum bill $ 8.86 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh $11.36 per month
Customer Charge, single-phase with usage of 2,000 kWh or more $15.36 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	Power Supply Charges[2] PPFAC	Total[3]
On-Peak	$0.0788	$0.053198	*varies*	$0.131998
Off-Peak	$0.0301	$0.023198	*varies*	$0.053298

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	Power Supply Charges[2] PPFAC	Total[3]
On-Peak	$0.0652	$0.040698	*varies*	$0.105898
Off-Peak	$0.0330	$0.020698	*varies*	$0.053698

Filed By:	Kentton C. Grant	Rate:	R-04-21F
Title:	Vice President of Finance and Rates	Effective:	July 1, 2013
District:	Entire Electric Service Area	Decision No.:	73912

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.
2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.
3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0 - 300 kWh	35%
301 - 600 kWh	30%
601 - 1000 kWh	25%
1001 - 1500 kWh	15%
Over 1500 kWh	0%

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
Total	**$8.86 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$2.50 per month
Total	**$11.36 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$6.50 per month
Total	**$15.36 per month**

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.052900	$0.004200
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Summer (May – September)	**On-Peak**	**Off-Peak**
Base Power Component	$0.053198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.039300	$0.007100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	**On-Peak**	**Off-Peak**
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 105
Superseding:

Residential Lifeline/Senior Discount (R-04-70F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must be 65 years of age, or older, and reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, single-phase service and minimum bill $ 8.78 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh $11.28 per month
Customer Charge, single-phase with usage of 2,000 kWh or more $15.28 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.139300	$0.055698	*varies*	$0.194998
Shoulder	$0.074000	$0.048198	*varies*	$0.122198
Off-Peak	$0.037900	$0.023198	*varies*	$0.061098

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.092500	$0.040698	*varies*	$0.133198
Off-Peak	$0.024900	$0.020698	*varies*	$0.045598

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.
2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.
3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0- 300 kWh	35%
301- 600 kWh	30%
601- 1,000 kWh	25%
1001- 1,500 kWh	15%
Over 1,500 kWh	0%

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m. Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
Total	**$8.78 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$2.50 per month
Total	**$11.28 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 105-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$6.50 per month
Total	**$15.28 per month**

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300	$0.011300
Generation Capacity	$0.113400	$0.048100	$0.012000
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Base Power Component	$0.055698	$0.048198	$0.023198
PPFAC	In accordance with Rider 1 – PPFAC		

CANCELED

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.010200	$0.010200
Generation Capacity	$0.067700	$0.000100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	**On-Peak**	**Off-Peak**
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

CANCELED

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 106
Superseding:

Residential Lifeline Discount (R-05-01F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase and three-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase and three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated in this rate:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard
Customer Charge, single-phase service and minimum bill — $ 6.90 per month
Customer Charge, three-phase service and minimum bill — $11.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh — $ 9.40 per month
Customer Charge, three-phase with usage less than 2,000 kWh — $14.40 per month

Customer Charge, single-phase with usage of 2,000 kWh or more — $13.40 per month
Customer Charge, three-phase with usage of 2,000 kWh or more — $18.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
Summer (May – September)	$0.061100	$0.033198	varies	$0.094298
Winter (October – April)	$0.057000	$0.025698	varies	$0.082698

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-05-01F
Effective: July 1, 2013
Decision No.: 73912

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0- 300 kWh	25%
301- 600 kWh	20%
601- 1,000 kWh	15%
Over 1,000 kWh	0%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

	Standard	
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
Total	**$6.90 per month**	**$11.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$2.50 per month	$2.50 per month
Total	**$9.40 per month**	**$14.40 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 106-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$6.50 per month	$6.50 per month
Total	**$13.40 per month**	**$18.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	**Summer** (May – September)	**Winter** (October - April)
Local Delivery-Energy	$0.013800	$0.011300
Generation Capacity	$0.032700	$0.031100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge:

	Summer (May – September)	**Winter** (October - April)
Base Power Component	$0.033198	$0.025698
PPFAC	In accordance with Rider 1 - PPFAC	

CANCELED

Residential Lifeline Discount (R-05-21F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, single-phase service and minimum bill — $ 8.86 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh — $11.36 per month
Customer Charge, single-phase with usage of 2,000 kWh or more — $15.36 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.078800	$0.053198	*varies*	$0.131998
Off-Peak	$0.030100	$0.023198	*varies*	$0.053298

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.065200	$0.040698	*varies*	$0.105898
Off-Peak	$0.033000	$0.020698	*varies*	$0.053698

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.
2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.
3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0 - 300 kWh	25%
301 - 600 kWh	20%
601 - 1000 kWh	15%
Over 1000 kWh	0%

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
Total	**$8.86 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$2.50 per month
Total	**$11.36 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$6.50 per month
Total	**$15.36 per month**

Energy Components of Delivery Services (Unbundled):

Summer (May – September)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.052900	$0.004200
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Summer (May – September)	**On-Peak**	**Off-Peak**
Base Power Component	$0.053198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.039300	$0.007100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	**On-Peak**	**Off-Peak**
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 108
Superseding:

Residential Lifeline Discount (R-05-70F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments. The applicant must reside at the premise to qualify.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, single-phase service and minimum bill — $ 8.78 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh — $11.28 per month
Customer Charge, single-phase with usage of 2,000 kWh or more — $15.28 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC	
On-Peak	$0.139300	$0.055698	*varies*	$0.194998
Shoulder	$0.074000	$0.048198	*varies*	$0.122198
Off-Peak	$0.037900	$0.023198	*varies*	$0.061098

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC	
On-Peak	$0.092500	$0.040698	*varies*	$0.133198
Off-Peak	$0.024900	$0.020698	*varies*	$0.045598

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.
2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.
3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0-300 kWh	25%
301-600 kWh	20%
601-1,000 kWh	15%
Over 1,000 kWh	0%

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m. Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
Total	**$8.78 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$2.50 per month
Total	**$11.28 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$6.50 per month
Total	**$15.28 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 108-3
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300	$0.011300
Generation Capacity	$0.113400	$0.048100	$0.012000
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Base Power Component	$0.055698	$0.048198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC		

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.010200	$0.010200
Generation Capacity	$0.067700	$0.000100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	**On-Peak**	**Off-Peak**
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 109
Superseding:

Residential Lifeline Discount (R-05-201AF)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To single-phase (subject to availability at point of delivery) electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this rate requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this rate. Not with standing the above, the customer's use of solar energy for any purpose shall not preclude subscription to this rate.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard
Customer Charge, single-phase service and minimum bill — $ 6.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh — $ 9.40 per month

Customer Charge, single-phase with usage of 2,000 kWh or more — $13.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
Mid-Summer (June – August)	$0.0611	$0.033198	*varies*	$0.094298
Remaining-summer (May & September)	$0.0436	$0.033198	*varies*	$0.076798
Winter (October – April)	$0.0413	$0.027198	*varies*	$0.068498

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0 - 300 kWh	25%
301 - 600 kWh	20%
601 - 1000 kWh	15%
Over 1000 kWh	0%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single-Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
Total	**$6.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$2.50 per month
Total	**$9.40 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$6.50 per month
Total	**$13.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	Mid Summer (June -August)	Remaining Summer (May & September)	Winter (October – April)
Local Delivery-Energy	$0.020600	$0.003100	$0.006800
Generation Capacity	$0.025900	$0.025900	$0.019900
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge:

	Mid Summer (June -August)	Remaining Summer (May & September)	Winter (October – April)
Base Power Component	$0.033198	$0.033198	$0.027198
PPFAC	In accordance with Rider 1 - PPFAC		

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 110
Superseding:

Residential Lifeline Discount (R-06-01F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase and three-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

ELIGIBILITY
1. The TEP account must be in the customer's name applying for a lifeline discount.
2. Applicant must be a TEP residential customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:

Standard

Customer Charge, single-phase service and minimum bill	$ 6.90 per month
Customer Charge, three-phase service and minimum bill	$11.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, single-phase with usage less than 2,000 kWh	$ 9.40 per month
Customer Charge, three-phase with usage less than 2,000 kWh	$14.40 per month
Customer Charge, single-phase with usage of 2,000 kWh or more	$13.40 per month
Customer Charge, three-phase with usage of 2,000 kWh or more	$18.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	Power Supply Charges[2] PPFAC[2]	Total[3]
Summer (May – September)	$0.061100	$0.033198	varies	$0.094298
Winter (October – April)	$0.057000	$0.025698	varies	$0.082698

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT:
The monthly bill shall be in accordance to the rate above except that a discount up to $9.00 per month shall be applied to the Standard Customer Charge, Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the bill to less than zero.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

Tucson Electric Power Company

Tucson Electric Power

Original Sheet No.: 110-2
Superseding:

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
Total	**$6.90 per month**	**$11.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$2.50 per month	$2.50 per month
Total	**$9.40 per month**	**$14.40 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$6.50 per month	$6.50 per month
Total	**$13.40 per month**	**$18.40 per month**

CANCELLED

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 110-3
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Component	**Summer** (May – September)	**Winter** (October - April)
Local Delivery-Energy	$0.013800	$0.011300
Generation Capacity	$0.032700	$0.031100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge:

	Summer (May – September)	**Winter** (October - April)
Base Power Component	$0.033198	$0.025698
PPFAC	In accordance with Rider 1 - PPFAC	

CANCELED

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 111
Superseding:

Residential Lifeline Discount (R-06-21F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

ELIGIBILITY
1. The TEP account must be in the customer's name applying for a lifeline discount.
2. Applicant must be a TEP residential customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, single-phase service and minimum bill — $ 8.86 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh — $11.36 per month
Customer Charge, single-phase with usage of 2,000 kWh or more — $15.36 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.078800	$0.053198	*varies*	$0.131998
Off-Peak	$0.030100	$0.023198	*varies*	$0.053298

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.065200	$0.040698	*varies*	$0.105898
Off-Peak	$0.033000	$0.020698	*varies*	$0.053698

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The monthly bill shall be in accordance to the rate above except that a discount up to $9.00 per month shall be applied to the Standard Customer Charge, Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the bill to less than zero.

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
Total	**$8.86 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$2.50 per month
Total	**$11.36 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$6.50 per month
Total	**$15.36 per month**

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.052900	$0.004200
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Summer (May – September)	**On-Peak**	**Off-Peak**
Base Power Component	$0.053198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.039300	$0.007100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	**On-Peak**	**Off-Peak**
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 112
Superseding:

Residential Lifeline Discount (R-06-70F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to three-phase service, resale, breakdown, temporary, standby, or auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

ELIGIBILITY
1. The TEP account must be in the customer's name applying for a lifeline discount.
2. Applicant must be a TEP residential customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, single-phase service and minimum bill $ 8.78 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh $11.28 per month
Customer Charge, single-phase with usage of 2,000 kWh or more $15.28 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.139300	$0.055698	*varies*	$0.194998
Shoulder	$0.074000	$0.048198	*varies*	$0.122198
Off-Peak	$0.037900	$0.023198	*varies*	$0.061098

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.092500	$0.040698	*varies*	$0.133198
Off-Peak	$0.024900	$0.020698	*varies*	$0.045598

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The monthly bill shall be in accordance to the rate above except that a discount up to $9.00 per month shall be applied to the Standard Customer Charge, Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the bill to less than zero.

TIME-OF-USE TIME PERIODS

The Summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m. Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES

For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
Total	**$8.78 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$2.50 per month
Total	**$11.28 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$6.50 per month
Total	**$15.28 per month**

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300	$0.011300
Generation Capacity	$0.113400	$0.048100	$0.012000
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Base Power Component	$0.055698	$0.048198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC		

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.010200	$0.010200
Generation Capacity	$0.067700	$0.000100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	**On-Peak**	**Off-Peak**
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

Residential Lifeline Discount (R-06-201AF)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To single-phase (subject to availability at point of delivery) electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this rate requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this rate. The customer's use of solar energy for any purpose shall not preclude subscription to this rate.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

ELIGIBILITY
1. The TEP account must be in the customer's name applying for a lifeline discount.
2. Applicant must be a TEP residential customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard

Customer Charge, single-phase service and minimum bill	\$ 6.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, single-phase with usage less than 2,000 kWh	\$ 9.40 per month
Customer Charge, single-phase with usage of 2,000 kWh or more	\$13.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
Mid-Summer (June – August)	$0.061100	$0.033198	*varies*	$0.094298
Remaining-Summer (May & September)	$0.043600	$0.033198	*varies*	$0.076798
Winter (October – April)	$0.041300	$0.027198	*varies*	$0.068498

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT:
The monthly bill shall be in accordance to the rate above except that a discount up to $9.00 per month shall be applied to the Standard Customer Charge, Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the bill to less than zero.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 113-2
Superseding:

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:
Customer Charge Components (Unbundled):

	Standard
Description	**Single-Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
Total	**$6.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$2.50 per month
Total	**$9.40 per month**

CANCELED

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 113-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$6.50 per month
Total	**$13.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	Mid Summer (June -August)	Remaining Summer (May & September)	Winter (October – April)
Local Delivery-Energy	$0.020600	$0.003100	$0.006800
Generation Capacity	$0.025900	$0.025900	$0.019900
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge:

	Mid Summer (June -August)	Remaining Summer (May & September)	Winter (October – April)
Base Power Component	$0.033198	$0.033198	$0.027198
PPFAC	In accordance with Rider 1 - PPFAC		

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 114
Superseding:

Residential Lifeline Discount (R-06-201BF)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To single-phase (subject to availability at point of delivery) electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this rate requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this rate. The customer's use of solar energy for any purpose shall not preclude subscription to this rate.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

ELIGIBILITY
1. The TEP account must be in the customer's name applying for a lifeline discount.
2. Applicant must be a TEP residential customer residing at the premise.
3. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard

Customer Charge, single-phase service and minimum bill	$ 8.78 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, single-phase with usage less than 2,000 kWh	$ 11.28 per month
Customer Charge, single-phase with usage of 2,000 kWh or more	$ 15.28 per month

Energy Charges ($/kWh)

Mid-Summer (June – August)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-Peak	$0.136900	$0.055698	*varies*	$0.192598
Shoulder-Peak	$0.074700	$0.048198	*varies*	$0.122898
Off-Peak	$0.038300	$0.023198	*varies*	$0.061498

Remaining Summer (May & Sept)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-Peak	$0.099500	$0.055698	*varies*	$0.155198
Shoulder-Peak	$0.048600	$0.048198	*varies*	$0.096798
Off-Peak	$0.025300	$0.023198	*varies*	$0.048498

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-Peak	$0.065200	$0.040698	*varies*	$0.105898
Off-Peak	$0.015300	$0.020698	*varies*	$0.035998

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

TIME-OF-USE TIME PERIODS

The Mid-summer and Remaining-summer On-Peak period: 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods: 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

MONTHLY DISCOUNT:

The monthly bill shall be in accordance to the rate above except that a discount up to $9.00 per month shall be applied to the Standard Customer Charge, Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the bill to less than zero.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Standard	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
Total	**$8.78 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$2.50 per month
Total	**$11.28 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$6.50 per month
Total	**$15.28 per month**

Energy Charge Components (Unbundled)

Components Mid-Summer (June – August)	On-Peak	Shoulder-Peak	Off-Peak
Delivery-Energy	$0.091400	0.030900	$0.018100
Generation Capacity	$0.030900	0.029200	$0.005600
Fixed Must-Run	$0.003000	0.003000	$0.003000
Transmission	$0.009000	0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT:			
	On-Peak	Shoulder-Peak	Off-Peak
Base Power Supply Charge	$0.055698	$0.048198	$0.023198
PPFAC		In accordance with Rider 1 – PPFAC	

Components Remaining Summer (May & September)	On-Peak	Shoulder-Peak	Off-Peak
Delivery-Energy	$0.054000	0.025000	$0.001700
Generation Capacity	$0.030900	0.009000	$0.009000
Fixed Must-Run	$0.003000	0.003000	$0.003000
Transmission	$0.009000	0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT:			
	On-Peak	Shoulder-Peak	Off-Peak
Base Power Supply Charge	$0.055698	$0.048198	$0.023198
PPFAC		In accordance with Rider 1 – PPFAC	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 114-5
Superseding:

Components Winter (October-April)	On-Peak	Off-Peak
Delivery-Energy	$0.028200	$0.000500
Generation Capacity	$0.022400	$0.000200
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT:		
	On-Peak	Off-Peak
Base Power Supply Charge	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 – PPFAC	

CANCELED

Residential Lifeline/Medical Life-Support Discount (R-08-01F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase and three-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

ELIGIBILITY
1. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.
2. The applicant must provide documentation to the company that the regular use of a medical life-support device is essential to maintain the life of a full-time resident of the household; or a full-time resident of the household is a paraplegic, quadriplegic or hemiplegic, or a multiple sclerosis or scleroderma patient.
3. A Physician's Verification Form must be completed by the doctor documenting the patient's critical need for electrically powered appliances and describing the needed devices.

CHARACTER OF SERVICE
The service shall be single-phase or three-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:

Standard

Customer Charge, single-phase service and minimum bill	\$ 6.90 per month
Customer Charge, three-phase service and minimum bill	\$11.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, single-phase with usage less than 2,000 kWh	\$ 9.40 per month
Customer Charge, three-phase with usage less than 2,000 kWh	\$14.40 per month
Customer Charge, single-phase with usage of 2,000 kWh or more	\$13.40 per month
Customer Charge, three-phase with usage of 2,000 kWh or more	\$18.40 per month

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
Summer (May – September)	$0.061100	$0.033198	varies	$0.094298
Winter (October – April)	$0.057000	$0.025698	varies	$0.082698

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0 – 1000 kWh	35%
1001 – 2000 kWh	30%
Over 2000 kWh	10%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE

A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

	Standard	
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
Total	**$6.90 per month**	**$11.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$2.50 per month	$2.50 per month
Total	**$9.40 per month**	**$14.40 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more		
Description	**Single-Phase**	**Three-Phase**
Meter Services	$1.20 per month	$2.07 per month
Meter Reading	$0.81 per month	$1.39 per month
Billing & Collection	$3.48 per month	$6.00 per month
Customer Delivery	$1.41 per month	$2.44 per month
LFCR	$6.50 per month	$6.50 per month
Total	**$13.40 per month**	**$18.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	**Summer** (May – September)	**Winter** (October - April)
Local Delivery-Energy	$0.013800	$0.011300
Generation Capacity	$0.032700	$0.031100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge:

	Summer (May – September)	**Winter** (October - April)
Base Power Component	$0.033198	$0.025698
PPFAC	In accordance with Rider 1 - PPFAC	

Residential Lifeline/Medical Life-Support Discount (R-08-21F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

ELIGIBILITY
1. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.
2. The applicant must provide documentation to the company that the regular use of a medical life-support device is essential to maintain the life of a full-time resident of the household; or a full-time resident of the household is a paraplegic, quadriplegic or hemiplegic, or a multiple sclerosis or scleroderma patient.
3. A Physician's Verification Form must be completed by the doctor documenting the patient's critical need for electrically powered appliances and describing the needed devices.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard

Customer Charge, single-phase service and minimum bill	$ 8.86 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, single-phase with usage less than 2,000 kWh	$11.36 per month
Customer Charge, single-phase with usage of 2,000 kWh or more	$15.36 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.078800	$0.053198	*varies*	$0.131998
Off-Peak	$0.030100	$0.023198	*varies*	$0.053298

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.065200	$0.040698	*varies*	$0.105898
Off-Peak	$0.033000	$0.020698	*varies*	$0.053698

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0 – 1000 kWh	35%
1001 – 2000 kWh	30%
Over 2000 kWh	10%

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 10:00 a.m. to 10:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 116-2
Superseding:

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:
Customer Charge Components (Unbundled):

Standard	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
Total	**$8.86 per month**

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-08-21F
Effective: July 1, 2013
Decision No.: 73912

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$2.50 per month
Total	**$11.36 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.54 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.47 per month
Customer Delivery	$1.82 per month
LFCR	$6.50 per month
Total	**$15.36 per month**

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.052900	$0.004200
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Summer (May – September)	**On-Peak**	**Off-Peak**
Base Power Component	$0.053198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC	

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 116-4
Superseding:

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.039300	$0.007100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	**On-Peak**	**Off-Peak**
Base Power Component	$0.040698	$0.0020698
PPFAC	In accordance with Rider 1 - PPFAC	

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-08-21F
Effective: July 1, 2013
Decision No.: 73912

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 117
Superseding:

Residential Lifeline/Medical Life-Support Discount (R-08-70F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To all single-phase (subject to availability at point of delivery) residential electric service in individual private dwellings and individually metered apartments when all service is supplied at one point of delivery and energy is metered through one meter.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

ELIGIBILITY
1. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.
2. The applicant must provide documentation to the company that the regular use of a medical life-support device is essential to maintain the life of a full-time resident of the household; or a full-time resident of the household is a paraplegic, quadriplegic or hemiplegic, or a multiple sclerosis or scleroderma patient.
3. A Physician's Verification Form must be completed by the doctor documenting the patient's critical need for electrically powered appliances and describing the needed devices.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charges:
Standard
Customer Charge, single-phase service and minimum bill — $8.78 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option
Customer Charge, single-phase with usage less than 2,000 kWh — $11.28 per month
Customer Charge, single-phase with usage of 2,000 kWh or more — $15.28 per month

Energy Charges ($/kWh):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC	
On-Peak	$0.139300	$0.055698	*varies*	$0.194998
Shoulder	$0.074000	$0.048198	*varies*	$0.122198
Off-Peak	$0.037900	$0.023198	*varies*	$0.061098

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.092500	$0.040698	*varies*	$0.133198
Off-Peak	$0.024900	$0.020698	*varies*	$0.045598

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT
The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0 – 1000 kWh	35%
1001 – 2000 kWh	30%
Over 2000 kWh	10%

TIME-OF-USE TIME PERIODS
The Summer On-Peak period is 1:00 p.m. to 6:00 p.m., Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day). The summer Shoulder period is 6:00 p.m. to 8:00 p.m. Monday through Friday (excluding Memorial Day, Independence Day, and Labor Day).

The Winter On-Peak periods are 7:00 a.m. - 11:00 a.m. and 6:00 p.m. - 9:00 p.m., Monday through Friday (excluding Thanksgiving Day, Christmas Day, and New Year's Day).

All other hours are Off-Peak. If a holiday falls on Saturday, the preceding Friday is designated Off-Peak; if a holiday falls on Sunday, the following Monday is designated Off-Peak.

LOST FIXED COST RECOVERY (LFCR) – RIDER 8
For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

	Standard
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
Total	**$8.78 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage less than 2, 000 kWh	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$2.50 per month
Total	**$11.28 per month**

TEP
Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 117-3
Superseding:

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option – usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.52 per month
Meter Reading	$1.03 per month
Billing & Collection	$4.43 per month
Customer Delivery	$1.80 per month
LFCR	$6.50 per month
Total	**$15.28 per month**

Energy Charge Components of Delivery Services (Unbundled):

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Local Delivery-Energy	$0.011300	$0.011300	$0.011300
Generation Capacity	$0.113400	$0.048100	$0.012000
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge

Summer (May – September)	**On-Peak**	**Shoulder-Peak**	**Off-Peak**
Base Power Component	$0.055698	$0.048198	$0.023198
PPFAC	In accordance with Rider 1 - PPFAC		

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: R-08-70F
Effective: July 1, 2013
DecisionNo.: 73912

Energy Charge Components of Delivery Services (Unbundled):

Winter (October – April)	**On-Peak**	**Off-Peak**
Local Delivery-Energy	$0.010200	$0.010200
Generation Capacity	$0.067700	$0.000100
Fixed Must-Run	$0.003000	$0.003000
Transmission	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:		
System Control & Dispatch	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT		

Power Supply Charge

Winter (October – April)	**On-Peak**	**Off-Peak**
Base Power Component	$0.040698	$0.020698
PPFAC	In accordance with Rider 1 - PPFAC	

Residential Lifeline/Medical Life-Support Discount (R-08-201AF)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

APPLICABILITY
To single-phase (subject to availability at point of delivery) electric service in individual residences as described in current program details when all service is supplied at one point of delivery and energy is metered through one meter. Additionally, this rate requires that the customer use exclusively the Company's service for all space heating and all water heating energy requirements except as provided below and that the customer's home conform to the standards of the Heating, Cooling and Comfort Guarantee program as in effect at the time of subscription to this rate. The customer's use of solar energy for any purpose shall not preclude subscription to this rate. The discount is also available to tenants of master metered mobile home parks and apartments.

Not applicable to resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

ELIGIBILITY
1. Applicant must have a combined household income at or below 150% of the federal poverty level. See Income Guidelines Chart on TEP's website at www.tep.com or contact a TEP customer care representative.
2. The applicant must provide documentation to the company that the regular use of a medical life-support device is essential to maintain the life of a full-time resident of the household; or a full-time resident of the household is a paraplegic, quadriplegic or hemiplegic, or a multiple sclerosis or scleroderma patient.
3. A Physician's Verification Form must be completed by the doctor documenting the patient's critical need for electrically powered appliances and describing the needed devices.

CHARACTER OF SERVICE
The service shall be single-phase, 60 Hertz, and at one standard nominal voltage as mutually agreed and subject to availability at point of delivery.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:
Standard

Customer Charge, single-phase service and minimum bill	$ 6.90 per month

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option

Customer Charge, single-phase with usage less than 2,000 kWh	$ 9.40 per month
Customer Charge, single-phase with usage of 2,000 kWh or more	$13.40 per month

CANCELED

Energy Charges ($/kWh)

	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
Mid-Summer (June-August)	$0.061100	$0.033198	*varies*	$0.094298
Remaining-summer (May & September)	$0.043600	$0.033198	*varies*	$0.076798
Winter (October – April)	$0.041300	$0.027198	*varies*	$0.068498

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission/Ancillaries), Generation Capacity, Fixed Must-Run, Transmission and Ancillary Services.

2. The Power Supply Charge is the sum of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause (PPFAC), a per kWh adjustment in accordance with Rider-1-PPFAC. PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

3. Total is calculated above for illustrative purposes (PPFAC varies over time pursuant to Rider-1 PPFAC).

MONTHLY DISCOUNT

The following monthly discount applies to the rate incorporated herein:

For Bills with Usage of:	Monthly Discount will be applied to the Standard Customer Charge, Delivery Charges, and Power Supply Charges:
0 – 1000 kWh	35%
1001 – 2000 kWh	30%
Over 2000 kWh	10%

LOST FIXED COST RECOVERY (LFCR) – RIDER 8

For those Customers who choose not to participate in the percentage based recovery of lost revenues associated with energy efficiency and distributed generation, a higher monthly Customer Charge will apply and the percentage based LFCR will not be included on the bill. All other Customers will pay the Standard monthly Customer Charge and the percentage based LFCR. Customers can choose the fixed charge option one (1) time per calendar year. Once the Customer chooses to contribute to the LFCR through a fixed charge they must pay the higher monthly Customer Charge for a complete twelve (12) month period. During the first twelve (12) months subsequent to the effective date of the LFCR, the Customer may choose to change back to the percentage based option without being on the fixed option for a full twelve (12) months. After one full year of the LFCR in effect, a Customer must remain on an option for a full twelve (12) months.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

	Standard
Description	**Single-Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
Total	**$6.90 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage of 2,000 kWh or more	
Description	**Single-Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$6.50 per month
Total	**$13.40 per month**

Lost Fixed Cost Recovery (LFCR) Fixed Charge Option - usage less than 2,000 kWh	
Description	**Single-Phase**
Meter Services	$1.20 per month
Meter Reading	$0.81 per month
Billing & Collection	$3.48 per month
Customer Delivery	$1.41 per month
LFCR	$2.50 per month
Total	**$9.40 per month**

Energy Charge Components of Delivery Services (Unbundled):

Component	**Mid Summer** (June -August)	**Remaining Summer** (May & September)	**Winter** (October – April)
Local Delivery-Energy	$0.020600	$0.003100	$0.006800
Generation Capacity	$0.025900	$0.025900	$0.019900
Fixed Must-Run	$0.003000	$0.003000	$0.003000
Transmission	$0.009000	$0.009000	$0.009000
Transmission Ancillary Services consists of the following charges:			
System Control & Dispatch	$0.000100	$0.000100	$0.000100
Reactive Supply and Voltage Control	$0.000500	$0.000500	$0.000500
Regulation and Frequency Response	$0.000500	$0.000500	$0.000500
Spinning Reserve Service	$0.001300	$0.001300	$0.001300
Supplemental Reserve Service	$0.000200	$0.000200	$0.000200
Energy Imbalance Service: Currently charged pursuant to the Company's OATT			

Power Supply Charge:

	Mid Summer (June -August)	**Remaining Summer** (May & September)	**Winter** (October – April)
Base Power Component	$0.033198	$0.033198	$0.027198
PPFAC	In accordance with Rider 1 - PPFAC		

Large Light and Power Service (LLP-14)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To all large general power and lighting service on an optional basis when all energy is supplied at one point of delivery and through one metered service. The minimum monthly billing demand hereunder is 3,000 kW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

CHARACTER OF SERVICE
Service shall be three-phase, 60 Hertz, Primary Service, and shall be supplied directly from any 46,000 volt, or higher voltage, system at a delivery voltage of not less than 13,800 volts and delivered at a single point of delivery unless otherwise specified in the contract.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$1,800 per month
Demand Charge:	$21.98 per kW
Energy Charges:	
Summer (May – September)	$0.003200 per kWh
Winter (October – April)	$0.002100 per kWh
Base Power Charges:	
Summer (May – September)	$0.031611 per kWh
Winter (October - April	$0.028388 per kWh

Purchased Power and Fuel Adjustment Clause (PPFAC): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with Rider-1 PPFAC to reflect any increase or decrease in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold.

BILLING DEMAND
The monthly billing demand shall be the greatest of the following:

1. The maximum 15 minute measured demand in the billing month;
2. 75 % of the maximum demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 3,000 kW.

PRIMARY SERVICE
The above rate is subject to Primary Service and Metering. The Customer will provide the entire distribution system (including transformers) from the point of delivery to the load. The energy and demand shall be metered on primary side of the transformer.

POWER FACTOR ADJUSTMENT
The above rate is subject to a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is below 100%

DIRECT ACCESS
A Customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

FOR DIRECT ACCESS: ARIZONA INDEPENDENT SCHEDULING ADMINISTRATOR (AZISA) CHARGE
A charge per kWh shall, subject to FERC authorization, be applied for costs associated with the implementation of the AZISA in Arizona.

TEP STATEMENT OF CHARGES
For all additional charges and assessments approved by the Arizona Corporation Commission see the TEP Statement of Charges which is available on TEP's website at www.tep.com.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this rate.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$ 449.66 per month
Meter Reading	$ 74.29 per month
Billing & Collection	$ 323.56 per month
Customer Delivery	$ 952.49 per month
Total	$1,800.00 per month
Demand Charges:	
Delivery Charge (in $/kW)	$ 1.69 per kW
Generation Capacity Charges (in $/kW)	$14.40 per kW
Fixed Must-Run Charges (in $/kW)	$ 0.97 per kW

Transmission (in$/kW)	$ 3.84 per kW
Transmission Ancillary Services (in $/kW)	
System Control & Dispatch	$ 0.05 per kW
Reactive Supply and Voltage Control	$ 0.20 per kW
Regulation and Frequency Response	$ 0.20 per kW
Spinning Reserve Service	$ 0.54 per kW
Supplemental Reserve Service	$ 0.09 per kW
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	
Energy Charges: (in $/kWh)	
Delivery Charges	
Summer	$0.003200 per kWh
Winter	$0.002100 per kWh
Base Power Supply Charges:	
Summer	$0.031611 per kWh
Winter	$0.028388 per kWh

CANCELED

Rider R-11
Schedule MGC-2 Market Generation Credit (MGC) Calculation for Partial Requirements Services

INTRODUCTION

The purpose of the Market Generation Credit (MGC) for Partial Requirements Services is to establish a price at which TEP's partial requirements customers will purchase backup/standby and supplemental energy for applicable Partial Requirements Service tariff customers. The Market Generation Credit for Partial Requirements Services is consistent with the MGC methodology per TEP's Settlement Agreement, Section 2.1(d), as amended March 20, 2003.

The monthly MGC amount shall be calculated in advance and stated as both an on-peak value and an off-peak value. The monthly on-peak MGC component shall be equal to the Market Price multiplied by one plus the appropriate line loss (including unaccounted for energy ("UFE")) amount. The Market Price shall be equal to the Tullett Liberty Long-Term Forward Assessment for the Palo Verde Forward price, except when adjusted for the variable cost of TEP's must-run generation. The Market Price shall be determined fifteen (15) days prior to each calendar month using the average of the most recent three (3) business days of Tullett Liberty Long-Term Forward Assessment for Palo Verde settlement prices. The off-peak MGC component shall be determined in the same manner as the on-peak component, except that the Tullett Liberty Long-Term Forward Assessment for the Palo Verde Forward price will be adjusted by the ratio of off-peak to on-peak prices from the Dow Jones Palo Verde Index of the same month from the preceding year.

CALCULATIONS

The Customer will be charged adjusted on-peak MGC multiplied by kWh consumption for On-peak hours, and adjusted off-peak MCG multiplied by kWh consumption for Off-peak hours. Three steps are outlined below for the calculation of the MGC. None of the steps are excludable for any customer type. Acronyms are defined in the Glossary at the end of this document.

1. Calculating the on-peak MGC

Fifteen (15) days prior to each calendar estimation month, the Platts Long-Term Forward Assessment for Palo Verde Forward prices for the three (3) most recent business days are used. The simple average (or arithmetic mean) is calculated for these three (3) days for the estimation month.

$$MGC_{ON,j} = \frac{\sum(TULLETT)_i}{3} \qquad \text{(Equation 1)}$$

The calculation is illustrated in the table below.

Forward Prices per MWh	Apr 2002
3/13/2002	$25.80
3/14/2002	$26.90
3/15/2002	$27.75
Average	$26.82

2. Calculating the off-peak MGC

The off-peak MGC is determined by multiplying the on-peak MGC value by the off-peak price weighting factor (WEIGHT). The WEIGHT is equal to the simple average of all off-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year, divided by the simple average of all on-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$\mathrm{MGC}_{\mathrm{OFF,i}} = \mathrm{MGC}_{\mathrm{ON,i}} * \mathrm{WEIGHT}_{\mathrm{i}} \qquad \text{(Equation 2)}$$

where

$$WEIGHT_i = \frac{DJPVI_{OFF,i}}{DJPVI_{ON,i}} \qquad \text{(Equation 3)}$$

3. Loss-adjusting the MGC

The on-peak MGC and the off-peak MGC must be adjusted for line losses. The appropriate line loss adjustment factor (LLAF) for the large industrial customer class is 1.0515; for all other customer classes, the appropriate factor is 1.0919.

$$MGC_{LOSS-ON,i} = MGC_{ON,i} * LLAF \qquad \text{(Equation 4)}$$

$$MGC_{LOSS-OFF,i} = MGC_{OFF,i} * LLAF \qquad \text{(Equation 5)}$$

This calculation produces the final value for the on-peak and off-peak Market Generation Credits.

GLOSSARY

$\mathrm{DJPVI}_{\mathrm{OFF}}$ Simple average of off-peak prices on the Dow Jones Palo Verde Index.

$\mathrm{DJPVI}_{\mathrm{ON}}$ Simple average of on-peak prices on the Dow Jones Palo Verde Index.

Dow Jones Palo Verde Index Daily calculation of actual firm on-peak and firm off-peak weighted average prices for electricity traded at Palo Verde, Arizona switchyard.

LLAF	Line-loss adjustment factor.
MGC	Market Generation Credit.
MGC_{OFF}	MGC_{ON} weighted by the ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.
MGC_{ON}	Average of the Tullett Liberty prices on days appropriate for the calculation of the MGC.
$MGC_{LOSS\text{-}ON}$	MGC_{ON} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
$MGC_{LOSS\text{-}OFF}$	MGC_{OFF} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
NERC	North American Electric Reliability Council. A voluntary not-for-profit organization established to promote bulk electric system reliability and security. Membership include investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.
Off-Peak Hours	Number of total monthly off-peak hours as defined by NERC. Off-peak hours are hour ending 0100 – hour ending 0600 and hour ending 2300 – hour ending 2400, Monday through Saturday, Pacific Prevailing Time (PPT). All Sunday hours are considered off-peak. PPT is defined as the current clock time in the Pacific time zone.
On-Peak Hours	Number of total monthly on-peak hours as defined by NERC. On-peak hours are hour ending 0700 – hour ending 2200 Monday through Saturday, Pacific Prevailing Time (PPT). PPT is defined as the current clock time in the Pacific time zone.
TULLETT	Tullett Liberty - a provider of independent real-time price information from the wholesale inter-dealer brokered commodity markets, from which the on-peak Long Term Forward Assessment of market prices of electricity at the Palo Verde, Arizona switchyard are obtained. The forward product is "6 x 16," power is for 16 hours a day for six days a week (Monday through Saturday) for the delivery period, excluding NERC holidays.
Stranded Costs	The difference between revenues under competition and the costs of providing service, including the inherited fixed costs from the previous regulated market.
TEP	Tucson Electric Power Company, a subsidiary of UNS Energy Corp.
TEP Settlement Agreement	An agreement between TEP, the Arizona Residential Utility Consumer Office, members of the Arizonans for Electric Choice and Competition, and Arizona Community Action Association regarding TEP's implementation of retail electric competition, implementation of unbundled tariffs, and recovery of stranded costs.
WEIGHT	Ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.

Exhibit CAJ-5

CLEAN

TUCSON ELECTRIC POWER COMPANY
LOST FIXED COST RECOVERY MECHANISM ("LFCR")
PLAN OF ADMINISTRATION

Table of Contents

1. General Description

This document describes the plan of administration for the LFCR mechanism approved for Tucson Electric Power Company ("TEP" or "Company") by the Arizona Corporation Commission ("Commission") in Decision No. xxxxx (xxx, xx, xxxx). The LFCR mechanism provides for the recovery of lost fixed costs, as measured by a reduction in non-fuel revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the non-fuel energy costs included in base rates and the demand rates in effect, plus any amount quantified in the Balancing Account.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Balancing Account – A mechanism to track the difference between allowed Lost Fixed Cost Revenue and actual amounts billed by the Company through the LFCR adjustment. The balancing account will be reflected in Schedule 2 of the LFCR Compliance Report and shall be calculated by taking the Total Lost Fixed Cost Revenue from Prior Period less the amount billed through the LFCR for the most recent collection period at the time of filing.

Current Period – The most recent calendar year used to determine lost sales for purposes of LFCR recovery.

Delivery Revenue – The amount of revenue determined at the conclusion of a rate case by multiplying each participating rate class' adjusted test year billing determinants (kWh or kW) by their approved non-fuel energy and demand charges.

DG Savings – The amount of kWh or kW sales reduced by DG. TEP will use meter data for determining the kWh or kW lost through the implementation of DG systems unless a rare circumstance occurs where the meter data is not available at which time the lost sales will be quantified using statistical verification or output profile or other Commission authorized methods. Each year, TEP will use actual data through December to calculate the savings. The calculation of DG Savings will consist of the following by class:

1. Current Period: The total kWh or kW reduction metered during the period less the total kWh or kW reduction metered in TEP's most recent general rate case test year.

2. The only DG Savings that will be excluded from the Lost Fixed Cost Revenue calculation are those kWh or kW that were lost as the result of actions by customers on the Excluded Rate Schedules.
3. The annual kW capacity of the cumulative total of DG installations since the end of the test year used in TEP's most recent general rate case. For solar systems only, the actual kW capacity used to calculate lost revenues for applicable demand metered customers will be the actual solar generation measured by the Solar production meter coincident with the customer's maximum fifteen minute demand for the billing period.

<u>EE Programs</u> - Any program approved in TEP's Energy Efficiency/Demand Side Management ("EE/DSM") implementation plan or defined in the Commission's Electric Energy Efficiency Rules.

<u>EE Savings</u> - The amount of sales, expressed in kWh or kW, reduced by Energy Efficiency activities as demonstrated by the Measurement, Evaluation, and Research Report ("MER") conducted for TEP's EE Programs. The Company's EE activities are being reviewed as part of the MER evaluation and will determine the total kWh or kW lost as a result of those activities. As part of this filing the Commission Staff will have the option of reviewing any portion of the filing they deem necessary to verify the filing's accuracy. EE Savings shall be quantified based on the cumulative lost kWh or kW occurring starting July 1, 2015 and shall reset as of the end of the test year in each rate case. The calculation of EE Savings will consist of the following by class:

1. Current Period: The annual EE related sales reductions (kWh or kW). Each year, TEP will use actual MER data through December to calculate savings.
2. Prior Period: The cumulative total kWh or kW reduction reported in the previous year's LFCR filing, recognizing that the cumulative total is reset (to zero) at the end of each of TEP's most recent general rate case. The first such reset was on January 1, 2012, (the end of the Test Year in Decision No. 73912.) Recovery of LFCR revenues quantified in the initial LFCR will continue until the first LFCR resulting from the current general rate case results in the specified reset to zero. With the approval of this rate case (Decision No. xxxxx) the cumulative total kWh and kW will be reset as of July 1, 2015 (the end of the test year) for calculations of the LFCR performed until reset in the Company's next general rate case.
3. Excluded kWh reduction: The reduction of recoverable EE Savings calculated by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules if included in the total reported in the annual EE/DSM filing.

<u>Effective Period</u> – The twelve month period beginning with July 1 of each year, when the LFCR will be charged.

<u>Excluded Rate Schedules</u> – The LFCR mechanism shall not apply to Traffic Signal and Street Lighting Service (TSL), Lighting Service (LS), Water Pumping Service (GS-WP), or the Large Power Services (LPS-TOU and LPS-138) rate schedules, or the Residential Solar – Company Owned Program.

LFCR Adjustment – An amount calculated by dividing Lost Fixed Cost Revenue by the Applicable Company Revenues. This percentage-based LFCR Adjustment will be applied to all customer bills, excluding those on Excluded Rate Schedules.

Lost Fixed Cost Rate – A rate determined at the conclusion of a rate case by taking the sum of allowed Delivery Revenue (which excludes the Basic Service Charge and purchased power and fuel) for each rate class and dividing each by their respective class adjusted test year kWh and/or kW billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE Savings and DG Savings during the Current Period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable kWh or kW Savings, by rate class.

Prior Period – The calendar year preceding the Current Period.

Recoverable kWh or kW Savings – The EE Savings and DG Savings by applicable rate class.

3. *LFCR Annual Incremental Cap*

The total LFCR Adjustment will be subject to an annual 2% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR Adjustment results in a surcharge in excess of 2%, in total, of Applicable Company Revenues, any amount in excess of the 2% cap will be deferred for collection until the next year its inclusion does not result in the 2% year-over-year cap being exceeded. Any deferred amounts, plus any amount quantified in the Balancing Account, will be collected in a subsequent year or rolled into the next rate case, whichever occurs first. Where the 2% cap limits the recovery of deferrals in any program year, and thus moves their recovery to the following year, a first-in, first-out ("FIFO") approach will be applied. In connection therewith, the new surcharges billed in the following year will first recover any such carried-over deferrals, as well as any Balancing Account balance, and then recover new deferrals arising in that following year. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

4. *Filing and Procedural Deadlines*

TEP will file the calculated Annual LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by May 15th of each year. Staff will use its best efforts to process the matter based on the results of the Company's annual EE/DSM and Renewable Energy Standard Tariff ("REST") filings such that a new LFCR Adjustment may go into effect by July 1st of each year. However, the new LFCR Adjustment will not go into effect until approved by the Commission.

5. *Compliance Reports*

TEP will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office by May 15th of each year. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1 : LFCR Annual Percentage Adjustment Rate
- Schedule 2: LFCR Annual Incremental Cap Calculation

- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: Delivery Revenue Calculation

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Percentage Adjustment Rates

Line No.	(A) Annual Percentage Adjustment	(B) Reference		(C) Totals
	~~Energy Efficiency Related Adjustment~~			
1	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15, Column C ~~(Sch 2, Line 15, Col C * Sch 3, Line 55, Col E)~~	$	#DIV/0!
2	20_ _ Applicable Company Revenues	Schedule 2, Line 1, Column C	$	-
3	Percentage Adjustment Applied to Customer's Bills ~~for EE~~	(Line 1 / Line 2)		0.0000%
	~~Distributed Generation Related Adjustment~~			
~~4~~	~~Total Lost Fixed Cost Revenue for Current Period~~	~~(Sch 2, Line 15, Col C * Sch 3, Line 56, Col E)~~	~~$~~	~~#DIV/0!~~
~~5~~	~~20_ _ Applicable Company Revenues~~	~~Schedule 2, Line 1, Column C~~	~~$~~	~~-~~
~~6~~	~~Percentage Adjustment Applied to Customer's Bills for DG~~	~~(Line 4 / Line 5)~~		~~0.0000%~~

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	20_ _ Applicable Company Revenues		$	-
2	Allowed Cap %			2.00% 3.00%
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	#VALUE!
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 83, Column C	$	#DIV/0!
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
6	Annual Interest Rate			0.00%
7	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	$	-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	#DIV/0!
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10	Lost Fixed Cost Revenue - Billed[1]		$	-
11	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	#DIV/0!
13	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	#DIV/0!
14	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.0000%
15	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	#DIV/0!

[1] Amount billed to customers for the collection period of 20_ _

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting
	Residential - Delivery Revenue - Demand					
	Energy Efficiency Savings					
1	Current Period			-	kW	
2	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 3, Column C		-	kW	
3	Cumulative Recoverable kW savings	(Line 1 + Line 2)		-	kW	
4	Total Recoverable EE Savings	Line 3		-	kW	
5	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW	
6	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 4 * Line 5)	$	#DIV/0!		
	Distributed Generation					
7	Current Period			-	kW	
8	Total Recoverable DG Savings	Line 7			kW	
9	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW	
10	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 8 * Line 9)	$	#DIV/0!		
	Residential - Delivery Revenue					
	Energy Efficiency Savings					
11	**Current Period**			-	**kWh**	
12	~~[illegible]~~			[illegible]		
13	~~[illegible] kWh [illegible]~~	~~[illegible]~~			~~[illegible]~~	
14	~~Net Current [illegible]~~	~~[illegible]~~			~~[illegible]~~	
12	**Prior Period kWh EE losses**	**Previous Filing, Schedule 3, Line 13, Column C**		-	**kWh**	
13	**Cumulative Recoverable kWh savings**	~~[illegible]~~ **(Line 11 + Line 12)**		-	**kWh**	
14	**Total Recoverable EE Savings**	**Line 13**		-	**kWh**	
15	**Residential - Lost Fixed Cost Rate**	**Schedule 4, Line 3, Column C**	**$**	**#DIV/0!**	**$/kWh**	
16	**Residential - Lost Fixed Cost Revenue Relating to EE**	**(Line 14 * Line 15)**	**$**	**#DIV/0!**		
	Distributed Generation					
17	**Current Period**			-	**kWh**	
18	~~# of Residential Customers choosing fixed option~~			[illegible]		
19	~~Exclude [illegible] kWh reduction~~	~~(Line [illegible] * Line [illegible])~~			~~kWh~~	
20	~~Net Current Period~~	~~(Line 19 - Line 13)~~			~~kWh~~	
21	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line 15, Column C~~			~~kWh~~	
22	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line 15, Column C + Line 13)~~			~~kWh~~	
18	**Total Recoverable DG Savings**	**Line 17**		-	**kWh**	
19	**Residential - Lost Fixed Cost Rate**	**Schedule 4, Line 3, Column C**	**$**	**#DIV/0!**	**$/kWh**	
20	**Residential - Lost Fixed Cost Revenue Relating to DG**	**(Line 18 * Line 19)**	**$**	**#DIV/0!**		
	Small General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
21	Current Period				kW	
22	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 23, Column C			kW	
23	Cumulative Recoverable kW savings	(Line 21 + Line 22)			kW	
24	Total Recoverable EE Savings	Line 23			kW	
25	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
26	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 24 * Line 25)	$	[illegible]		
	Distributed Generation					
27	Current Period			-	kW	
28	Total Recoverable DG Savings	Line 27		-	kW	
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) [illegible]
	Small General Service - Delivery Revenue					
	Energy Efficiency Savings					
31	Current Period			-	kWh	
32	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kWh	
33	Cumulative Recoverable kWh savings	([illegible] Line 31 + Line 32)		-	kWh	
34	Total Recoverable EE Savings	Line 33		-	kWh	
35	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh	
36	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 34 * Line 35)	$	#DIV/0!		
	Distributed Generation					
37	Current Period			-	kWh	
[illegible]	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line [illegible], Column C~~			~~kWh~~	
[illegible]	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line 37, Column C + Line 37)~~			~~kWh~~	
38	Total Recoverable DG Savings	Line 37		-	kWh	
39	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh	
40	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 38 * Line 39)	$	#DIV/0!		
	Medium General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
41	Current Period			-	kW	
42	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 43, Column C		-	kW	
43	Cumulative Recoverable kW savings	(Line 41 + Line 42)			kW	
44	Total Recoverable EE Savings	Line 43			kW	
45	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 19, Column C	$	#DIV/0!	$/kW	
46	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 44 * Line 45)	$	#DIV/0!		
	Distributed Generation					
	[illegible]				[illegible]	
[illegible]	[illegible]	[illegible]			[illegible]	
[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	
[illegible]	[illegible]	[illegible]	$	#DIV/0!		
	Medium General Service - Delivery Revenue					
	Energy Efficiency Savings					
51	Current Period			-	kWh	
52	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 53, Column C		-	kWh	
53	Cumulative Recoverable kWh savings	(Line 51 + Line 52)		-	kWh	
54	Total Recoverable EE Savings	Line 53		-	kWh	
55	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
56	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 54 * Line 55)	$	#DIV/0!		
	Distributed Generation					
57	Current Period			-	kWh	
58	Total Recoverable DG Savings	Line 57		-	kWh	
59	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
60	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 58 * Line 59)	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting	
	Large General Service - Delivery Revenue - Demand						
	Energy Efficiency Savings						
61	Current Period			-	kW		
62	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 63, Column C		-	kW		
63	Cumulative Recoverable kW savings	~~(Previous Filing, Schedule 3, Line 63, Column C~~ Line 61+ Line 62)		-	kW		
64	Total Recoverable EE Savings	Line 63		-	kW		
65	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW		
66	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 64 * Line 65)	$	#DIV/0!			
	Distributed Generation						
67	Current Period			-	kW		
68	[illegible]	[illegible]		[illegible]	[illegible]		
69	[illegible]	[illegible]		[illegible]	[illegible]		
[illegible]	Total Recoverable DG Savings	Line [illegible]		-	kW		
[illegible]	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line [illegible], Column C	$	#DIV/0!	$/kW		
	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line [illegible] * Line [illegible])	$	#DIV/0!			
	Large General Service - Delivery Revenue						
	Energy Efficiency Savings						
71	Current Period			-	kWh		
72	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 73, Column C		-	kWh		
73	Cumulative Recoverable kWh savings	~~(Previous Filing, Schedule 3, Line 45, Column C~~ Line 71+ Line 72)		-	kWh		
74	Total Recoverable EE Savings	Line 73		-	kWh		
75	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 23, Column C	$	#DIV/0!	$/kWh		
76	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 74 * Line 75)	$	#DIV/0!			
	Distributed Generation						
77	Current Period			-	kWh		
78	[illegible]	[illegible]		[illegible]	[illegible]		
79	[illegible]	[illegible]		[illegible]	[illegible]		
[illegible]	Total Recoverable DG Savings	Line 77		-	kWh		
79	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 23, Column C	$	#DIV/0!	$/kWh		
80	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 78 * Line 79)	$	#DIV/0!		Percent of Total	
81	Total Lost Fixed Cost Revenue Related to Energy Efficiency	Sum Line 6 + 16 + 26 + 36 + 46 + 56 + 66 + 76	$	#DIV/0!		#DIV/0!	[illegible]
82	Total Lost Fixed Cost Revenue Related to Distributed Generation	Sum Line 10 + 20 + 30 + 40 + 50 + 60 + 70 + 80	$	#DIV/0!		#DIV/0!	[illegible]
83	Total Lost Fixed Cost Revenue	(Line 81 + Line 82)	$	#DIV/0!			

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Percentage Adjustment Rate

Line No.	(A) Annual Percentage Adjustment	(B) Reference		(C) Totals
1	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15, Column C	$	#DIV/0!
2	20_ _ Applicable Company Revenues	Schedule 2, Line 1, Column C	$	-
3	Percentage Adjustment Applied to Customer's Bills	(Line 1 / Line 2)		0.0000%

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	20_ _ Applicable Company Revenues		$	-
2	Allowed Cap %			2.00%
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	-
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 83, Column C	$	#DIV/0!
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
6	Annual Interest Rate			0.00%
7	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	$	-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	#DIV/0!
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10	Lost Fixed Cost Revenue - Billed[1]		$	-
11	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	#DIV/0!
13	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	#DIV/0!
14	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.0000%
15	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	#DIV/0!

[1] Amount billed to customers for the collection period of 20_ _

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Residential - Delivery Revenue - Demand				
	Energy Efficiency Savings				
1	Current Period			-	kW
2	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 3, Column C		-	kW
3	Cumulative Recoverable kW savings	(Line 1 + Line 2)		-	kW
4	Total Recoverable EE Savings	Line 3		-	kW
5	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW
6	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 4 * Line 5)	$	#DIV/0!	
	Distributed Generation				
7	Current Period			-	kW
8	Total Recoverable DG Savings	Line 7		-	kW
9	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW
10	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 8 * Line 9)	$	#DIV/0!	
	Residential - Delivery Revenue				
	Energy Efficiency Savings				
11	Current Period			-	kWh
12	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 13, Column C		-	kWh
13	Cumulative Recoverable kWh savings	(Line 11 + Line 12)		-	kWh
14	Total Recoverable EE Savings	Line 13		-	kWh
15	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	#DIV/0!	$/kWh
16	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 14 * Line 15)	$	#DIV/0!	
	Distributed Generation				
17	Current Period			-	kWh
18	Total Recoverable DG Savings	Line 17		-	kWh
19	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	#DIV/0!	$/kWh
20	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 18 * Line 19)	$	#DIV/0!	
	Small General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
21	Current Period			-	kW
22	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 23, Column C		-	kW
23	Cumulative Recoverable kW savings	(Line 21 + Line 22)		-	kW
24	Total Recoverable EE Savings	Line 23		-	kW
25	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW
26	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 24 * Line 25)	$	#DIV/0!	
	Distributed Generation				
27	Current Period			-	kW
28	Total Recoverable DG Savings	Line 27		-	kW
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	#DIV/0!	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Small General Service - Delivery Revenue				
	Energy Efficiency Savings				
31	Current Period			-	kWh
32	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kWh
33	Cumulative Recoverable kWh savings	(Line 31 + Line 32)		-	kWh
34	Total Recoverable EE Savings	Line 33		-	kWh
35	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh
36	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 34 * Line 35)	$	#DIV/0!	
	Distributed Generation				
37	Current Period			-	kWh
38	Total Recoverable DG Savings	Line 37		-	kWh
39	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh
40	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 38 * Line 39)	$	#DIV/0!	
	Medium General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
41	Current Period			-	kW
42	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 43, Column C		-	kW
43	Cumulative Recoverable kW savings	(Line 41 + Line 42)		-	kW
44	Total Recoverable EE Savings	Line 43		-	kW
45	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 18, Column C	$	#DIV/0!	$/kW
46	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 44 * Line 45)	$	#DIV/0!	
	Distributed Generation				
47	Current Period			-	kW
48	Total Recoverable DG Savings	Line 47		-	kW
49	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 18, Column C	$	#DIV/0!	$/kW
50	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 48 * Line 49)	$	#DIV/0!	
	Medium General Service - Delivery Revenue				
	Energy Efficiency Savings				
51	Current Period			-	kWh
52	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 53, Column C		-	kWh
53	Cumulative Recoverable kWh savings	(Line 51 + Line 52)		-	kWh
54	Total Recoverable EE Savings	Line 53		-	kWh
55	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh
56	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 54 * Line 55)	$	#DIV/0!	
	Distributed Generation				
57	Current Period			-	kWh
58	Total Recoverable DG Savings	Line 57		-	kWh
59	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh
60	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 58 * Line 59)	$	#DIV/0!	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Large General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
61	Current Period			-	kW
62	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 63, Column C		-	kW
63	Cumulative Recoverable kW savings	(Line 61+ Line 62)		-	kW
64	Total Recoverable EE Savings	Line 63		-	kW
65	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW
66	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 64 * Line 65)	$	#DIV/0!	
	Distributed Generation				
67	Current Period			-	kW
68	Total Recoverable DG Savings	Line 67		-	kW
69	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW
70	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 68 * Line 69)	$	#DIV/0!	
	Large General Service - Delivery Revenue				
	Energy Efficiency Savings				
71	Current Period			-	kWh
72	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 73, Column C		-	kWh
73	Cumulative Recoverable kWh savings	(Line 71+ Line 72)		-	kWh
74	Total Recoverable EE Savings	Line 73		-	kWh
75	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh
76	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 74 * Line 75)	$	#DIV/0!	
	Distributed Generation				
77	Current Period			-	kWh
78	Total Recoverable DG Savings	Line 77		-	kWh
79	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh
80	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 78 * Line 79)	$	#DIV/0!	
81	Total Lost Fixed Cost Revenue Related to Energy Efficiency	Sum Line 6 + 16 + 26 + 36 + 46 + 56 + 66 + 76	$	#DIV/0!	
82	Total Lost Fixed Cost Revenue Related to Distributed Generation	Sum Line 10 + 20 + 30 + 40 + 50 + 60 + 70 + 80	$	#DIV/0!	
83	Total Lost Fixed Cost Revenue	(Line 81 + Line 82)	$	#DIV/0!	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation

Line No.	(A) LFCR Fixed Cost Calculation		(B) Reference		(C) Totals
	Residential Customers				
1		Delivery Revenue	Schedule 5, Line 9, Column E	$	-
2		kWh Billed	Schedule 5, Line 9, Column B		-
3		Lost Fixed Cost Rate	(Line 1 / Line 2)	$	#DIV/0!
	Residential Customers				
4		Delivery Revenue - Demand	Schedule 5, Line 24, Column E	$	-
5		kW Billed	Schedule 5, Line 24, Column B		-
6		Lost Fixed Cost Rate	(Line 4 / Line 5)	$	#DIV/0!
	Small General Service				
7		Delivery Revenue	Schedule 5, Line 14, Column E	$	-
8		kWh Billed	Schedule 5, Line 14, Column B		-
9		Lost Fixed Cost Rate	(Line 7 / Line 8)	$	#DIV/0!
	Small General Service				
10		Delivery Revenue - Demand	Schedule 5, Line 27, Column E	$	-
11		kW Billed	Schedule 5, Line 27, Column B		-
12		Lost Fixed Cost Rate	(Line 10 / Line 11)	$	#DIV/0!
	Medium General Service				
13		Delivery Revenue	Schedule 5, Line 17, Column E	$	-
14		kWh Billed	Schedule 5, Line 17, Column B		-
15		Lost Fixed Cost Rate	(Line 13 / Line 14)	$	#DIV/0!
	Medium General Service				
16		Delivery Revenue - Demand	Schedule 5, Line 30, Column E	$	-
17		kW Billed	Schedule 5, Line 30, Column B		-
18		Lost Fixed Cost Rate	(Line 16 / Line 17)	$	#DIV/0!
	Large General Service				
19		Delivery Revenue	Schedule 5, Line 20, Column E	$	-
20		kWh Billed	Schedule 5, Line 20, Column B		-
21		Lost Fixed Cost Rate	(Line 19 / Line 20)	$	#DIV/0!
	Large General Service				
22		Delivery Revenue - Demand	Schedule 5, Line 33, Column E	$	-
23		kW Billed	Schedule 5, Line 33, Column B		-
24		Lost Fixed Cost Rate	(Line 22 / Line 23)	$	#DIV/0!

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation

Line No.	(A) Rate Schedule	(B) Adjusted Test Year Billing Determinants	(C) Units	(D) Delivery Charge	(E) B x D Total Delivery Revenue
	kWh related				
1	Residential Service (RES)	-	kWh	$ -	$ -
2	Residential Service (RES-TOU)	-	kWh	$ -	$ -
3	Residential Service (RES-P-TOU)	-	kWh	$ -	$ -
4	Residential Service (RES-S)	-	kWh	$ -	$ -
5	Residential Service (RES-S-TOU)	-	kWh	$ -	$ -
6	Residential Service (RES-D)	-	kWh	$ -	$ -
7	Residential Service (RES-D-TOU)	-	kWh	$ -	$ -
8	Prepay Energy Service (PES)	-	kWh	$ -	$ -
9	Subtotal - kWh	-	kWh		$ -
10	Small General Service (SGS)	-	kWh	$ -	$ -
11	Small General Service (SGS-TOU)	-	kWh	$ -	$ -
12	Small General Service (SGS-D)	-	kWh	$ -	$ -
13	Small General Service (SGS-D-TOU)	-	kWh	$ -	$ -
14	Subtotal - kWh	-	kWh		$ -
15	Medium General Service (MGS)	-	kWh	$ -	$ -
16	Medium General Service (MGS-TOU)	-	kWh	$ -	$ -
17	Subtotal - kWh	-	kWh		$ -
18	Large General Service (LGS)	-	kWh	$ -	$ -
19	Large General Service (LGS-TOU)	-	kWh	$ -	$ -
20	Subtotal - kWh	-	kWh		$ -
21	Total kWh	-	kWh		$ -
	kW related				
22	Residential Service (RES-D)	-	kW	$ -	$ -
23	Residential Service (RES-D-TOU)	-	kW	$ -	$ -
24	Subtotal - kW	-	kW		$ -
25	Small General Service (SGS-D)	-	kW	$ -	$ -
26	Small General Service (SGS-D-TOU)	-	kW	$ -	$ -
27	Subtotal - kW	-	kW		$ -
28	Medium General Service (MGS)	-	kW	$ -	$ -
29	Medium General Service (MGS-TOU)	-	kW	$ -	$ -
30	Subtotal - kW	-	kW		$ -
31	Large General Service (LGS)	-	kW	$ -	$ -
32	Large General Service (LGS-TOU)	-	kW	$ -	$ -
33	Subtotal - kW	-	kW		$ -
34	Total kW	-	kW		$ -

REDLINE

TUCSON ELECTRIC POWER COMPANY
LOST FIXED COST RECOVERY MECHANISM ("LFCR")
PLAN OF ADMINISTRATION

Table of Contents

1. General Description

This document describes the plan of administration for the LFCR mechanism approved for Tucson Electric Power Company ("TEP" or "Company") by the Arizona Corporation Commission ("Commission~~ACC~~") in Decision No. xxxxx~~73912~~ (xxx. xx, xxxx~~June 27, 2013~~). The LFCR mechanism provides for the recovery of lost fixed costs, as measured by a reduction in non-fuel revenue, associated with the amount of energy efficiency ("EE") savings and distributed generation ("DG") that is authorized by the Commission and determined to have occurred. Costs to be recovered through the LFCR include the ~~portion of transmission and distribution~~ non-fuel energy costs included in base rates ~~exclusive of the Customer Charge~~ and ~~50% of~~ the demand rates in effect, plus any amount quantified in the Balancing Account.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules~~, less the amount attributable to sales to those residential customers who chose the Fixed Cost Option~~.

Balancing Account – A mechanism to track the difference between allowed Lost Fixed Cost Revenue and actual amounts billed by the Company through the LFCR adjustment. The balancing account will be reflected in Schedule 2 of the LFCR Compliance Report and shall be calculated by taking the Total Lost Fixed Cost Revenue from Prior Period less the amount billed through the LFCR for the most recent collection period at the time of filing.

Current Period – The most recent ~~adjustment~~ calendar year used to determine lost sales for purposes of LFCR recovery~~measurement year~~.

~~Demand Stability Factor – Fifty percent of Demand-based revenue (excluding any purchased power and fuel costs) produced by base rates.~~

~~Distribution and Transmission~~Delivery Revenue – The amount of revenue determined at the conclusion of a rate case by multiplying each participating rate class' adjusted test year billing determinants (kWh or kW) by their approved non-fuel energy and demand~~distribution and transmission related~~ charges.~~ This will be determined by reducing each class' total retail revenue~~

~~by the customer charge revenue, generation related revenue, purchased power and fuel costs and the Demand Stability Factor.~~

DG Savings – The amount of kWh or kW sales ~~or kW of capacity~~ reduced by DG. TEP will use meter data for determining the kWh or kW lost through the implementation of DG systems unless a rare circumstance occurs where the meter data is not available at which time the lost sales will be quantified using statistical verification or output profile or other Commission authorized methods. Each year, TEP will use actual data through December to calculate the savings. The calculation of DG ~~s~~Savings will consist of the following by class:

~~1.~~ ~~Cumulative Verified~~Current Period: The total kWh or kW reduction ~~as~~ metered ~~each year~~during the ~~measurement year~~period less the total kWh or kW reduction metered in TEP's most recent general rate case test year ~~(2011). The initial Cumulative Verified term of this LFCR will begin on January 1, 2013~~.

~~2.~~1. ~~Current Period: The annual kWh or kW produced by the cumulative total of DG installations since the end of the test year used in TEP's most recent general rate case.~~

~~3.~~ The only DG Savings that will be excluded from the ~~calculated~~ Lost Fixed Cost Revenue calculation are those kWh or kW that were lost as the result of actions by customers ~~in~~on the ~~e~~Excluded ~~r~~Rate Schedules~~classes~~.

2.

~~4.~~3. The annual kW capacity of the cumulative total of DG installations since the end of the test year used in TEP's most recent general rate case. For solar systems only, the actual kW capacity used to calculate lost revenues for applicable demand metered customers will be the actual solar generation measured by the Solar production meter coincident with the customer's maximum fifteen minute demand for the billing period.

~~Fixed Cost Option – The rate schedule choice for residential customers who prefer contributing to the recovery of Lost Fixed Cost Revenue in the form of an optional fixed rate added as an incremental charge to the Customer Charge in the applicable residential tariff rate. The total dollars paid as an incremental amount added to the otherwise effective Customer Charge will be accumulated over the Current Period and used to reduce the total Lost Fixed Cost Revenue recovered as part of the LFCR adjustment. The variable LFCR adjustment shall not be applied to residential customers who choose the Fixed Cost option. This rate will be reflected as an incremental addition to the customer charge on the otherwise effective tariff and made available to customers at the time of the first LFCR adjustment. Customers choosing this fixed option within the first twelve months subsequent to the initial effective date of the LFCR will be allowed to change back to the volumetric option one time without any penalties. After the initial twelve month period, customers will be required to stay on which ever option they choose for twelve full months before a change can be made.~~

EE Programs - Any program approved in TEP's Energy Efficiency/Demand Side Management ("EE/DSM") implementation plan or defined in the Commission's Electric Energy Efficiency Rules. ~~or Energy Efficiency Resource Plan.~~

EE Savings - The amount of sales, expressed in kWh or kW, reduced by Energy Efficiency activities as demonstrated by the Measurement, Evaluation, and Research Report ("MER") conducted for TEP's EE Programs. The Company's EE activities are being reviewed as part of the MER evaluation and will determine the total kWh or kW lost as a result of those activities.

As part of this filing the Commission Staff will have the option of reviewing any portion of the filing they deem necessary to verify the filing's accuracy. EE Savings shall be quantified based on the cumulative lost kWh or kW occurring starting ~~January~~ July 1, ~~2013~~ 2015 and shall reset as of the end of the test year in each ~~subsequent~~ rate case. The calculation of EE Savings will consist of the following by class:

1. Current Period: The annual EE related sales reductions (kWh or kW). Each year, TEP will use actual MER data through December to calculate savings.
2. ~~Cumulative Verified~~Prior Period: The cumulative total kWh or kW reduction reported in the previous year's LFCR filing. ~~as determined by the MER~~ recognizing that the cumulative total is reset (to zero) at the end of each of TEP's most recent general rate case. The first such reset ~~will~~ was on ~~be~~ January 1, 2012, (the end of the Test Year in Decision No. 73912.) Recovery of LFCR revenues quantified in the initial LFCR will continue until the first LFCR resulting from the current general rate case results in the specified reset to zero. With the approval of this rate case (Decision No. xxxxx) the cumulative total kWh and kW will be reset as of July 1, 2015 (the end of the test year) for calculations of the LFCR performed until reset in the Company's next general rate case. ~~The initial Cumulative Verified term of the LFCR will begin on January 1, 2013.~~
~~2. Current Period: The annual EE related sales reductions (kWh or kW). Each year, TEP will use actual MER data through December to calculate savings.~~
3. Excluded kWh reduction: The reduction of recoverable EE Savings calculated by subtracting the amount of EE ~~s~~Savings actually achieved by customers on Excluded Rate Schedules if included in the total reported in the annual EE/DSM filing.

Effective Period – The twelve month period beginning with July 1 of each year, when the LFCR will be charged.

Excluded Rate Schedules – The LFCR mechanism shall not apply to Traffic Signal and Street Lighting Service (TSL~~PS-41~~), Lighting Service (LS~~GS-50~~), Water Pumping Service (GS-WP~~43~~), or the Large ~~Light and~~ Power Services (~~LLP-14 and LLP-90~~LPS-TOU and ~~LLP~~LPS-138) rate schedules, or the Residential Solar – Company Owned Program ~~(R-10)~~.

LFCR Adjustment – An amount calculated by dividing Lost Fixed Cost Revenue ~~(As reduced by the total incremental fixed cost option dollars paid by the residential customers who have chosen the Fixed Cost Option and will be based on the incremental increase in the customer charge they have paid over the twelve months during the Current Period.)~~ by the Applicable Company Revenues. ~~Current period's retail revenue (less the estimated sales to the residential customers who chose the Fixed Cost Option) during the Effective Period for the participating rate classes. This percentage based LFCR Adjustment will be presented on the customer's bills as two separate charges. These two charges will be developed by applying the weighted average proportion of the Energy Efficiency related lost revenues and the Distributed Generation related lost revenues as a proportion of total lost revenues falling under the 1% cap referenced herein. The weighted average proportions will be shown on Schedule 3 of this Plan of Administration.~~

~~These two separate percentage adjustment rates~~ This percentage-based LFCR Adjustment will be applied to all customer bills, excluding those ~~of~~on Excluded Rate Schedules.

Lost Fixed Cost Rate – A rate determined at the conclusion of a rate case by taking the sum of allowed ~~Distribution and Transmission~~Delivery Revenue (which excludes the ~~customer~~Basic Service ~~c~~Charge~~, the generation component~~ and purchased power and fuel) for each rate class and dividing each by their respective class adjusted test year kWh and/or kW billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE Savings and DG Savings during the Current Period~~measurement period~~. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable kWh or kW Savings, by rate class.

Prior Period – The ~~twelve months in the~~ calendar year preceding the Current Period.

Recoverable kWh or kW Savings – The ~~sum of~~ EE Savings and DG Savings by applicable rate class.

3. *LFCR Annual Incremental Cap*

The total LFCR Adjustment will be subject to an annual ~~1~~2% year-over-year cap based on Applicable Company Revenues. If the annual incremental LFCR Adjustment results in a surcharge in excess of ~~1~~2%, in total, of Applicable Company Revenues, any amount in excess of the ~~1~~2% cap will be deferred for collection until the next year its inclusion does not result in the 2% year-over-year cap being exceeded. Any deferred amounts, plus any amount quantified in the Balancing Account, will be collected in a subsequent year or rolled into the next rate case, whichever occurs first. Where the ~~1~~2% cap limits the recovery of deferrals in any program year, and thus moves their recovery to the following year, a first-in, first-out ("FIFO") approach will be applied. In connection therewith, the new surcharges billed in the following year will first recover any such carried-over deferrals, as well as any Balancing Account balance, and then recover new deferrals arising in that following year. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

~~The initial LFCR filing will reconcile unrecovered lost revenues from January 1, 2013 through December 31, 2013.~~

4. *Filing and Procedural Deadlines*

TEP will file the calculated Annual LFCR Adjustment~~s~~, including all Compliance Reports, with the Commission for the previous year by May 15th of each year. Staff will use its best efforts to process the matter based on the results of the Company's annual EE/DSM and Renewable Energy Standard Tariff ("REST") filings such that a new LFCR ~~a~~Adjustment~~s~~ may go into effect by July 1st of each year. However, the new LFCR Adjustment will not go into effect until approved by the Commission.

5. *Compliance Reports*

TEP will provide comprehensive compliance reports to Staff and the Residential Utility Consumer Office by May 15th of each year. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1 : LFCR Annual Percentage Adjustment Rates
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Test Year Rate Calculation
- Schedule 5: ~~Distribution and Transmission~~Delivery Revenue Calculation

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Percentage Adjustment Rate~~s~~

Line No.	(A) Annual Percentage Adjustment	(B) Reference		(C) Totals
	~~Energy Efficiency Related Adjustment~~			
1	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15, Column C ~~(Sch 2, Line 15, Col C * Sch 3, Line 55, Col E)~~	$	#DIV/0!
2	20__ Applicable Company Revenues	Schedule 2, Line 1, Column C	$	-
3	Percentage Adjustment Applied to Customer's Bills ~~for EE~~	(Line 1 / Line 2)		0.0000%
	~~Distributed Generation Related Adjustment~~			
~~4~~	~~Total Lost Fixed Cost Revenue for Current Period~~	~~(Sch 2, Line 15, Col C * Sch 3, Line 56, Col E)~~	~~$~~	~~#DIV/0!~~
~~5~~	~~20__ Applicable Company Revenues~~	~~Schedule 2, Line 1, Column C~~	~~$~~	~~-~~
~~6~~	~~Percentage Adjustment Applied to Customer's Bills for DG~~	~~(Line 4 / Line 5)~~		~~0.0000%~~

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 2: LFCR Annual Incremental Cap Calculation

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	20_ _ Applicable Company Revenues		$	-
2	Allowed Cap %			2.00% 4.00%
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	#VALUE!
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 34, Column C	$	#DIV/0!
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
6	Annual Interest Rate			0.00%
7	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	$	-
8	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 5 + Line 7)	$	#DIV/0!
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	$	-
10	Lost Fixed Cost Revenue - Billed[1]		$	-
11	LFCR Balancing Account	(Line 9 - Line 10)	$	-
12	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	$	#DIV/0!
13	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	$	#DIV/0!
14	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]		0.0000%
15	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	$	#DIV/0!

[1] Amount billed to customers for the collection period of 20_ _

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting
	Residential - Delivery Revenue - Demand					
	Energy Efficiency Savings					
1	Current Period			-	kW	
2	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 3, Column C		-	kW	
3	Cumulative Recoverable kW savings	(Line 1 + Line 2)		-	kW	
4	Total Recoverable EE Savings	Line 3		-	kW	
5	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW	
6	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 4 * Line 5)	$	#DIV/0!		
	Distributed Generation					
7	Current Period			-	kW	
8	Total Recoverable DG Savings	Line 7		-	kW	
9	Residential - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	#DIV/0!	$/kW	
10	Residential - Lost Fixed Cost Revenue Relating to DG	(Line 8 * Line 9)	$	#DIV/0!		
	Residential - Delivery Revenue					
	Energy Efficiency Savings					
11	**Current Period**			-	**kWh**	
[illegible]	[illegible]			[illegible]		
[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	
[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	
12	**Prior Period kWh EE losses**	**Previous Filing, Schedule 3, Line 1., Column C**		-	**kWh**	
13	**Cumulative Recoverable kWh savings**	~~(Previous Filing, Schedule 3, Line 6, Column C~~ + **Line** 11 + Line 12)		-	**kWh**	
14	**Total Recoverable EE Savings**	**Line 13**		-	**kWh**	
15	**Residential - Lost Fixed Cost Rate**	**Schedule 4, Line 3, Column C**	**$**	**#DIV/0!**	**$/kWh**	
16	**Residential - Lost Fixed Cost Revenue Relating to EE**	**(Line 14 * Line 15)**	**$**	**#DIV/0!**		
	Distributed Generation					
17	**Current Period**			-	**kWh**	
18	~~% of Residential Customers choosing fixed option~~			~~0.0%~~		
19	~~Excluded kWh reduction~~	~~(Line 10 * Line 11)~~			~~kWh~~	
20	~~Net - Current Period~~	~~(Line 10 - Line 12)~~			~~kWh~~	
21	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line 15, Column C~~			~~kWh~~	
22	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line 15, Column C + Line 13)~~			~~kWh~~	
18	**Total Recoverable DG Savings**	**Line 17**		-	**kWh**	
19	**Residential - Lost Fixed Cost Rate**	**Schedule 4, Line 3, Column C**	**$**	**#DIV/0!**	**$/kWh**	
20	**Residential - Lost Fixed Cost Revenue Relating to DG**	**(Line 18 * Line 19)**	**$**	**#DIV/0!**		
	Small General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
21	Current Period			-	kW	
22	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 23, Column C			kW	
23	Cumulative Recoverable kW savings	(Line 21 + Line 22)			kW	
24	Total Recoverable EE Savings	Line 23			kW	
25	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
26	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 24 * Line 25)	$	#DIV/0!		
	Distributed Generation					
27	Current Period			-	kW	
28	Total Recoverable DG Savings	Line 27		-	kW	
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	#DIV/0!	$/kW	
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E)
	Small General Service - Delivery Revenue					
	Energy Efficiency Savings					
31	Current Period			-	kWh	
32	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line [illegible], Column C		-	kWh	
33	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line [illegible], Column C + Line 31 + Line 32)		-	kWh	
34	Total Recoverable EE Savings	Line 33		-	kWh	
35	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh	
36	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 34 * Line 35)	$	#DIV/0!		
	Distributed Generation					
37	Current Period			-	kWh	
38	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line 27, Column C~~			~~kWh~~	
39	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line 27, Column C + Line 25)~~			~~kWh~~	
38	Total Recoverable DG Savings	Line 37		-	kWh	
39	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	#DIV/0!	$/kWh	
40	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 38 * Line 39)	$	#DIV/0!		
	Medium General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
41	Current Period				kW	
42	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 43, Column C		-	kW	
43	Cumulative Recoverable kW savings	(Line 41 + Line 42)		-	kW	
44	Total Recoverable EE Savings	Line 43			kW	
45	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 18, Column C	$	#DIV/0!	$/kW	
46	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 44 * Line 45)	$	#DIV/0!		
	Distributed Generation					
47	Current Period				kW	
48	Total Recoverable DG Savings	Line 47		-	kW	
49	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kW	
50	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 48 * Line 49)	$	#DIV/0!		
	Medium General Service - Delivery Revenue					
	Energy Efficiency Savings					
51	Current Period				kWh	
52	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 53, Column C		-	kWh	
53	Cumulative Recoverable kWh savings	(Line 51 + Line 52)		-	kWh	
54	Total Recoverable EE Savings	Line 53		-	kWh	
55	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
56	Medium General Service - Lost Fixed Cost Revenue Relating to EE	(Line 54 * Line 55)	$	#DIV/0!		
	Distributed Generation					
57	Current Period			-	kWh	
58	Total Recoverable DG Savings	Line 57		-	kWh	
59	Medium General Service - Lost Fixed Cost Rate	Schedule 4, Line 15, Column C	$	#DIV/0!	$/kWh	
60	Medium General Service - Lost Fixed Cost Revenue Relating to DG	(Line 58 * Line 59)	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units	(E) Weighting
	Large General Service - Delivery Revenue - Demand					
	Energy Efficiency Savings					
61	**Current Period**			-	kW	
62	**Prior Period kW EE losses**	Previous Filing, Schedule 3, Line 63, Column C		-	kW	
63	**Cumulative Recoverable kW savings**	~~(Previous Filing, Schedule 3, Line 63, Column C~~ Line 61+ Line 62)		-	kW	
64	**Total Recoverable EE Savings**	Line 63		-	kW	
65	**Large General Service - Lost Fixed Cost Rate**	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW	
66	**Large General Service - Lost Fixed Cost Revenue Relating to EE**	(Line 64 * Line 65)	$	#DIV/0!		
	Distributed Generation					
67	**Current Period**			-	kW	
68	~~Prior Period kW DG losses~~	~~Previous Filing, Schedule 3, Line [illegible], Column C~~			~~kW~~	
69	~~Cumulative Recoverable kW savings~~	~~(Previous Filing, Schedule 3, Line [illegible], Column C + Line 67)~~			~~kW~~	
[illegible]	**Total Recoverable DG Savings**	Line 67		-	kW	
69	**Large General Service - Lost Fixed Cost Rate**	Schedule 4, Line 24, Column C	$	#DIV/0!	$/kW	
70	**Large General Service - Lost Fixed Cost Revenue Relating to DG**	(Line [illegible] * Line 69)	$	#DIV/0!		
	Large General Service - Delivery Revenue					
	Energy Efficiency Savings					
71	**Current Period**			-	kWh	
72	**Prior Period kWh EE losses**	Previous Filing, Schedule 3, Line 73, Column C		-	kWh	
73	**Cumulative Recoverable kWh savings**	~~(Previous Filing, Schedule 3, Line 45, Column C~~ Line 71+ Line 72)		-	kWh	
74	**Total Recoverable EE Savings**	Line 73		-	kWh	
75	**Large General Service - Lost Fixed Cost Rate**	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh	
76	**Large General Service - Lost Fixed Cost Revenue Relating to EE**	(Line 74 * Line 75)	$	#DIV/0!		
	Distributed Generation					
77	**Current Period**			-	kWh	
78	~~Prior Period kWh DG losses~~	~~Previous Filing, Schedule 3, Line 51, Column C~~			~~kWh~~	
79	~~Cumulative Recoverable kWh savings~~	~~(Previous Filing, Schedule 3, Line 51, Column C + Line 49)~~			~~kWh~~	
78	**Total Recoverable DG Savings**	Line 77		-	kWh	
79	**Large General Service - Lost Fixed Cost Rate**	Schedule 4, Line 21, Column C	$	#DIV/0!	$/kWh	
80	**Large General Service - Lost Fixed Cost Revenue Relating to DG**	(Line 78 * Line 79)	$	#DIV/0!		
[illegible]	**Total Lost Fixed Cost Revenue Related to Energy Efficiency**	Sum Line [illegible]	$	#DIV/0!		[illegible]
[illegible]	**Total Lost Fixed Cost Revenue Related to Distributed Generation**	Sum Line [illegible]	$	#DIV/0!		[illegible]
[illegible]	**Total Lost Fixed Cost Revenue**	(Line [illegible] + Line [illegible])	$	#DIV/0!		

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation

Line No.	(A) LFCR Fixed Cost Calculation	(B) Reference		(C) Totals
	Residential Customers			
1	Delivery Revenue	Schedule 5, Line 9, Column E	$	-
2	kWh Billed	Schedule 5, Line 9, Column B		-
3	Lost Fixed Cost Rate	(Line 1 / Line 2)	$	#DIV/0!
	Residential Customers			
4	Delivery Revenue - Demand	Schedule 5, Line 24, Column E	$	-
5	kW Billed	Schedule 5, Line 24, Column B		-
6	Lost Fixed Cost Rate	(Line 4 / Line 5)	$	#DIV/0!
	Small General Service			
7	Delivery Revenue	Schedule 5, Line 14, Column E	$	-
8	kWh Billed	Schedule 5, Line 14, Column B		-
9	Lost Fixed Cost Rate	(Line 7 / Line 8)	$	#DIV/0!
	Small General Service			
10	Delivery Revenue - Demand	Schedule 5, Line 27, Column E	$	-
11	kW Billed	Schedule 5, Line 27, Column B		-
12	Lost Fixed Cost Rate	(Line 10 / Line 11)	$	#DIV/0!
	Medium General Service			
13	Delivery Revenue	Schedule 5, Line 17, Column E	$	-
14	kWh Billed	Schedule 5, Line 17, Column B		-
15	Lost Fixed Cost Rate	(Line 13 / Line 14)	$	#DIV/0!
	Medium General Service			
16	Delivery Revenue - Demand	Schedule 5, Line 30, Column E	$	-
17	kW Billed	Schedule 5, Line 30, Column B		-
18	Lost Fixed Cost Rate	(Line 16 / Line 17)	$	#DIV/0!
	Large General Service			
19	Delivery Revenue	Schedule 5, Line 20, Column E	$	-
20	kWh Billed	Schedule 5, Line 20, Column B		-
21	Lost Fixed Cost Rate	(Line 19 / Line 20)	$	#DIV/0!
	Large General Service			
22	Delivery Revenue - Demand	Schedule 5, Line 33, Column E	$	-
23	kW Billed	Schedule 5, Line 33, Column B		-
24	Lost Fixed Cost Rate	(Line 22 / Line 23)	$	#DIV/0!
	~~Large General Service~~			
~~10~~	~~Delivery Revenue~~	~~Schedule 5, Line 14, Column E~~	$	
~~11~~	~~kWh Billed~~	~~Schedule 5, Line 14, Column B~~		
~~12~~	~~Lost Fixed Cost Rate~~	~~(Line 10 / Line 11)~~	$	#DIV/0!

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation

Line No.	(A) Rate Schedule	(B) Adjusted Test Year Billing Determinants	(C) Units	(D) Delivery Charge	~~(E)~~ ~~Demand Stability Factor~~	(E) ~~(F)~~ B x D ~~x E~~ Total Delivery Revenue
	kWh related					
1	**Residential Service (RES-~~01~~)**	-	kWh	$ -	~~100%~~	$ -
2	**Residential Service (RES-TOU~~90~~)**	-	kWh	$ -	~~100%~~	$ -
3	Residential Service (RES-P-TOU)	-	kWh	$		$
4	**Residential Service (RES-~~S2016N~~)**	-	kWh	$ -	~~100%~~	$ -
5	**Residential Service (RES-~~S-TOU2016N~~)**	-	kWh	$ -	~~100%~~	$ -
6	Residential Service (RES-D)	-	kWh	$ -		$
7	Residential Service (RES-D-TOU)	-	kWh	$ -		$
8	Prepay Energy Service (PES)	-	kWh	$ -		$ -
9	**Subtotal - kWh**	-	kWh			$ -
10	**Small General Service (SGS-~~10~~)**	-	kWh	$ -	~~100%~~	$ -
11	**Small General Service (SGS-TOU~~76~~)**	-	kWh	$ -	~~100%~~	$ -
12	Small General Service (SGS-D)	-	kWh	$ -		$ -
13	Small General Service (SGS-D-TOU)	-	kWh	$ -		$ -
14	**Subtotal - kWh**	-	kWh			$ -
15	Medium General Service (MGS)	-	kWh	$ -		$ -
16	Medium General Service (MGS-TOU)	-	kWh	$ -		$ -
17	Subtotal - kWh	-	kWh			$ -
18	Large General Service (LGS)	-	kWh	$ -		$ -
19	Large General Service (LGS-TOU)	-	kWh	$ -		$ -
20	Subtotal - kWh	-	kWh			$ -
21	Total kWh	-	kWh			$ -
	kW related					
22	Residential Service (RES-D)	-	kW	$ -		$ -
23	Residential Service (RES-D-TOU)	-	kW	$ -		$
24	Subtotal - kW	-	kW			$
25	Small General Service (SGS-D)	-	kW	$		$
26	Small General Service (SGS-D-TOU)		kW	$ -		$
27	Subtotal - kW		kW			$
28	Medium General Service (MGS)	-	kW	$		$ -
29	Medium General Service (MGS-TOU)	-	kW	$		$ -
30	Subtotal - kW	-	kW			$ -
31	**Large General Service (LGS-~~13~~) ~~- kW~~**	-	kW	$ -	~~50%~~	$ -
32	**Large General Service (LGS-TOU~~85~~) ~~- kW~~**	-	kW	$ -	~~50%~~	$ -
33	**Subtotal - kW ~~- Demand~~**	-	kW			$ -
34	Total kW	-	kW			$ -
~~43~~	~~Large General Service (LGS-13)~~		~~kWh~~	~~$~~	~~100%~~	~~$~~
~~45~~	~~Large General Service (LGS-85)~~		~~kWh~~	~~$~~	~~100%~~	~~$~~
~~44~~	~~Subtotal - kWh - Delivery~~		~~kWh~~			~~$~~

Exhibit CAJ-6

CLEAN

Plan of Administration

Environmental Compliance Adjustor ("ECA")

Table of Contents

1. GENERAL DESCRIPTION

This document describes the plan of administration for the Environmental Compliance Adjustor ("ECA") approved for Tucson Electric Power Company ("TEP") by the Arizona Corporation Commission ("Commission") in Decision No. xxxxx [DATE]. The ECA provides for the recovery of capital carrying costs and incremental O&M costs related to environmental investments made by TEP and not already recovered in base rates approved in Decision No. xxxxx or recovered through another Commission approved adjustment. The ECA will be calculated annually based on the ECA Qualified Investments closed to plant-in-service and ECA Qualified Investments included in Construction Work in Progress during the preceding calendar year.

2. DEFINITIONS

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

ECA Qualified Investments - Investments in Qualified Environmental Compliance projects. Each ECA Qualified Investment shall: 1) be classified in one or more of the FERC plant or Construction Work in Progress accounts listed in Section 3 of this document, or any other successor FERC account, upon going into service, and 2) be tracked by a specific project number.

Qualified Environmental Compliance Projects - Qualified ECA investments include those projects designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws and regulations. In general, these environmental standards apply to the following: sulfur dioxide, nitrogen oxide, carbon dioxide, ozone, particulate matter, volatile organic compounds, mercury and other toxics, coal ash and other combustion residuals and water intake.

Total kWh Sales – The total prior calendar kWh sales served under applicable ACC jurisdictional electric rate schedules as reported in the Company's FERC Form No. 1.

3. ECA QUALIFIED INVESTMENTS - FERC ACCOUNTS

Steam Production:

- FERC Account 310 – Land and Land Rights
- FERC Account 311 – Structures and Improvements
- FERC Account 312 – Boiler Plant Equipment
- FERC Account 313 – Engines and Engine-Driven Generators
- FERC Account 314 – Turbogenerator Units
- FERC Account 315 – Accessory Electric Equipment
- FERC Account 316 – Miscellaneous Power Plant Equipment

Other Production:

- FERC Account 340 – Land and Land Rights
- FERC Account 341 – Structures and Improvements
- FERC Account 342 – Fuel Holders, Products and Accessories
- FERC Account 343 – Prime Movers
- FERC Account 344 – Generators
- FERC Account 345 – Accessory Electric Equipment
- FERC Account 346 – Miscellaneous Power Plant Equipment

Construction Work In Progress – Electric

- FERC Account 107

Please note this list may expand to include other accounts approved by the Commission in the future.

4. CALCULATION OF ECA REVENUE REQUIREMENT

The recoverable ECA costs will be subject to an annual 0.5% year-over-year cap based on Applicable Company Revenues. The costs used in calculating the ECA Percentage Rate will include:

- Return on ECA Qualified Investments (Plant in Service and CWIP) based on TEP's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. XXXXX;
- For plant in-service:
    - Depreciation expense;
    - Income Taxes;
    - Property taxes;
    - Deferred taxes and tax credits where applicable; and
    - Operation and Maintenance costs.

The ECA Qualified Projects and the ECA recoverable costs calculation will be submitted by the company to the Commission in the form of Schedule 1 and Schedule 2 as attached to this document.

5. CALCULATION OF ECA PERCENTAGE RATE

The ECA rate to be applied to customers' bills will be calculated by dividing the total ECA recoverable costs by Applicable Company Revenues.

6. FILING AND PROCEDURAL DEADLINES

TEP will file the calculated ECA rate including all supporting data with the Commission for the previous year on or before March 1. See schedules 1 and 2, attached.

The Commission staff and interested parties shall have the opportunity to review the ECA filing and supporting data. Unless the Commission has otherwise acted or Commission Staff has filed an objection by May 1, the new ECA rate proposed by TEP will go into effect with the first billing cycle in May (without proration) and will remain effect for the following 12-month period.

Schedule 1: Qualified Investments for ECA

Electric Plant in Service

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Environmental Improvement Projects					
1.	XXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
2.	XXXX	Project B	Project B Purpose Description	MM/YY	$ -	$ -
3.	XXXX	Project C	Project C Purpose Description	MM/YY	$ -	$ -
4.		Total			$ -	$ -

Construction Work In Progress - Electric

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) Expected In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Environmental Improvement Projects					
5.	XXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
6.	XXXX	Project B	Project B Purpose Description	MM/YY	$ -	$ -
7.	XXXX	Project C	Project C Purpose Description	MM/YY	$ -	$ -
8.		Total			$ -	$ -
9.		Total Qualified Investments (Line 4 + Line 8)			$ -	$ -

Billing Period XX/XX/20XX - XX/XX/20XX

Line No.	ECA Rate Calculation		
	Qualified Net Plant		
1.	Environmental Improvement Projects (Schedule 1 - Total Line Column F)	$	-
2.	Accumulated Depreciation	$	-
3.	Cumulative Deferred Tax/Tax Credits	$	-
4.	Qualified Net Plant (Line 1 - Line 2 - Line 3)	$	-
5.	Pre-Tax Weighted Average Cost of Capital		0.00%
	Capital Carrying Costs		
6.	Composite Return on ECA Net Plant (Line 4 * Line 5)	$	-
7.	Annual Depreciation of Plant in Service	$	-
8.	Applicable Property Tax	$	-
9.	Associated O&M Expense	$	-
10.	Total ECA Capital Carrying Costs (Line 6 + Line 7 + Line 8 + Line 9)	$	-
11.	Applicable Company Revenues		-
12.	Calculated ECA Rate as Percentage (Line 10 / Line 11)		0.0000%
13.	Prior Year's Calculated ECA Rate as a Percentage (Line 16, prior year)		0.0000%
14.	Year over Year increase (Limited to 0.5%)		0.0000%
15.	Amount in excess of 0.5% (Line 14 less .05%)		0.0000%
16.	Current Year's ECA Rate (Line 12 - line 15)		0.0000%

REDLINE

Plan of Administration

Environmental Compliance Adjustor ("ECA")

Table of Contents

1. GENERAL DESCRIPTION

This document describes the plan ~~for~~ of ~~administering~~ administration for the Environmental Compliance Adjustor ("ECA") ~~the Arizona Corporation Commission ("Commission")~~ approved for Tucson Electric Power Company ("TEP") by the Arizona Corporation Commission ("Commission") in Decision No. xxxxx [DATE]. The ECA provides for the recovery of capital carrying costs and incremental O&M costs related to environmental investments made by TEP and not already recovered in base rates approved in Decision No. xxxxx or recovered through another Commission approved adjustment. The ECA will be calculated annually based on the ECA Qualified Investments closed to plant-in-service and ECA Qualified Investments included in Construction Work in Progress during the preceding calendar year.

2. DEFINITIONS

Applicable Company Revenues – The amount of revenue generated by sales to retail customers for all applicable rate schedules.

ECA Qualified Investments - Investments in Qualified Environmental Compliance projects. Each ECA Qualified Investment shall: 1) be classified in one or more of the FERC plant or Construction Work in Progress accounts listed in Section 3 of this document, or any other successor FERC account, upon going into service, and 2) be tracked by a specific project number.

Qualified Environmental Compliance Projects - Qualified ECA investments include those projects designed to comply with current or prospective environmental standards required by federal, state, tribal, or local laws and regulations. In general, these environmental standards apply to the following: sulfur dioxide, nitrogen oxide, carbon dioxide, ozone, particulate matter, volatile organic compounds, mercury and other toxics, coal ash and other combustion residuals and water intake.

Total kWh Sales – The total prior calendar kWh sales served under applicable ACC jurisdictional electric rate schedules as reported in the Company's FERC Form No. 1.

3. ECA QUALIFIED INVESTMENTS - FERC ACCOUNTS

Steam Production:

- FERC Account 310 – Land and Land Rights
- FERC Account 311 – Structures and Improvements
- FERC Account 312 – Boiler Plant Equipment
- FERC Account 313 – Engines and Engine-Driven Generators
- FERC Account 314 – Turbogenerator Units
- FERC Account 315 – Accessory Electric Equipment
- FERC Account 316 – Miscellaneous Power Plant Equipment

Other Production:

- FERC Account 340 – Land and Land Rights
- FERC Account 341 – Structures and Improvements
- FERC Account 342 – Fuel Holders, Products and Accessories
- FERC Account 343 – Prime Movers
- FERC Account 344 – Generators
- FERC Account 345 – Accessory Electric Equipment
- FERC Account 346 – Miscellaneous Power Plant Equipment

Construction Work In Progress – Electric

- FERC Account 107

Please note this list may expand to include other accounts approved by the Commission~~ACC~~ in the future.

4. CALCULATION OF ECA REVENUE REQUIREMENT

The recoverable ECA costs will be subject to an annual ~~2~~0.5% year-over-year cap based on Applicable Company Revenues. The costs used in calculating the ECA ~~used in calculating the ECA $ per kWh~~ Percentage R~~r~~ate will include:

- Return on ECA Qualified Investments (Plant in Service and CWIP) based on TEP's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. XXXXX~~xx~~;
- For plant in-service:
  - Depreciation expense;
  - -Income Taxes;
  - Property taxes;
  - Deferred taxes and tax credits where applicable; and
  - Operation and Maintenance costs.

The ECA Qualified Projects and the ECA recoverable costs calculation will be submitted by the company to the Commission~~ACC~~ in the form of Schedule 1 and Schedule 2 as attached to this document.

5. CALCULATION OF ECA ~~$ PER KWH~~PERCENTAGE RATE

The ECA rate to be applied to customers' bills will be calculated by dividing the total ECA recoverable costs by ~~Total kWh Sales~~Applicable Company Revenues.

Formatted: Normal, Indent: Left: 0"

6. FILING AND PROCEDURAL DEADLINES

TEP will file the calculated ECA rate including all supporting data with the Commission for the previous year on or before March 1. See schedules 1 and 2, attached.

The Commission staff and interested parties shall have the opportunity to review the ECA filing and supporting data. Unless the Commission has otherwise acted or Commission Staff has filed an objection by May 1, the new ECA rate proposed by TEP will go into effect with the first billing cycle in May (without proration) and will remain effect for the following 12-month period.

Schedule 1: Qualified Investments for ECA

Electric Plant in Service

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Environmental Improvement Projects					
1.	XXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
2.	XXXX	Project B	Project B Purpose Description	MM/YY	$ -	$ -
3.	XXXX	Project C	Project C Purpose Description	MM/YY	$ -	$ -
4.		Total			$ -	$ -

Construction Work In Progress - Electric

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) Expected In-Service Date	(E) Total Cost	(F) ACC Jurisdictional Total Cost
	Environmental Improvement Projects					
5.	XXXX	Project A	Project A Purpose Description	MM/YY	$ -	$ -
6.	XXXX	Project B	Project B Purpose Description	MM/YY	$ -	$ -
7.	XXXX	Project C	Project C Purpose Description	MM/YY	$ -	$ -
8.		Total			$ -	$ -
9.		Total Qualified Investments (Line 4 + Line 8)			$ -	$ -

Schedule 2: Capital Carrying Costs and Adjustor Calculation
Plant in Service for Calendar Year 20XX
Billing Period ~~4/1/20XX-3/30/XX~~XX/XX/20XX - XX/XX/20XX

Line No.	ECA Rate Calculation		
	Qualified Net Plant		
1.	Environmental Improvement Projects (Schedule 1 - Total Line Column F)	$	-
2.	Accumulated Depreciation	$	-
3.	Cumulative Deferred Tax/Tax Credits	$	-
4.	Qualified Net Plant (Line 1 - Line 2 - Line 3)	$	-
5.	Pre-Tax Weighted Average Cost of Capital		0.00%
	Capital Carrying Costs		
6.	Composite Return on ECA Net Plant (Line 4 * Line 5)	$	-
7.	Annual Depreciation of Plant in Service	$	-
8.	Applicable Property Tax	$	-
9.	Associated O&M Expense	$	-
10.	Total ECA Capital Carrying Costs (Line 6 + Line 7 + Line 8 + Line 9)	$	-
11.	~~Total Company Retail Sales (kWh)~~Applicable Company Revenues		-
12.	Calculated ECA Rate as Percentage ~~($/kWh)~~ (Line 10 / Line 11)		0.0000%
13.	Prior Year's Calculated ECA Rate as a Percentage (Line 16, prior year)		0.0000%
14.	Year over Year increase (Limited to 0.5%)		0.0000%
15.	Amount in excess of 0.5% (Line 14 less .05%)		0.0000%
16.	Current Year's ECA Rate (Line 12 - line 15)		0.0000%

IBEW - X1

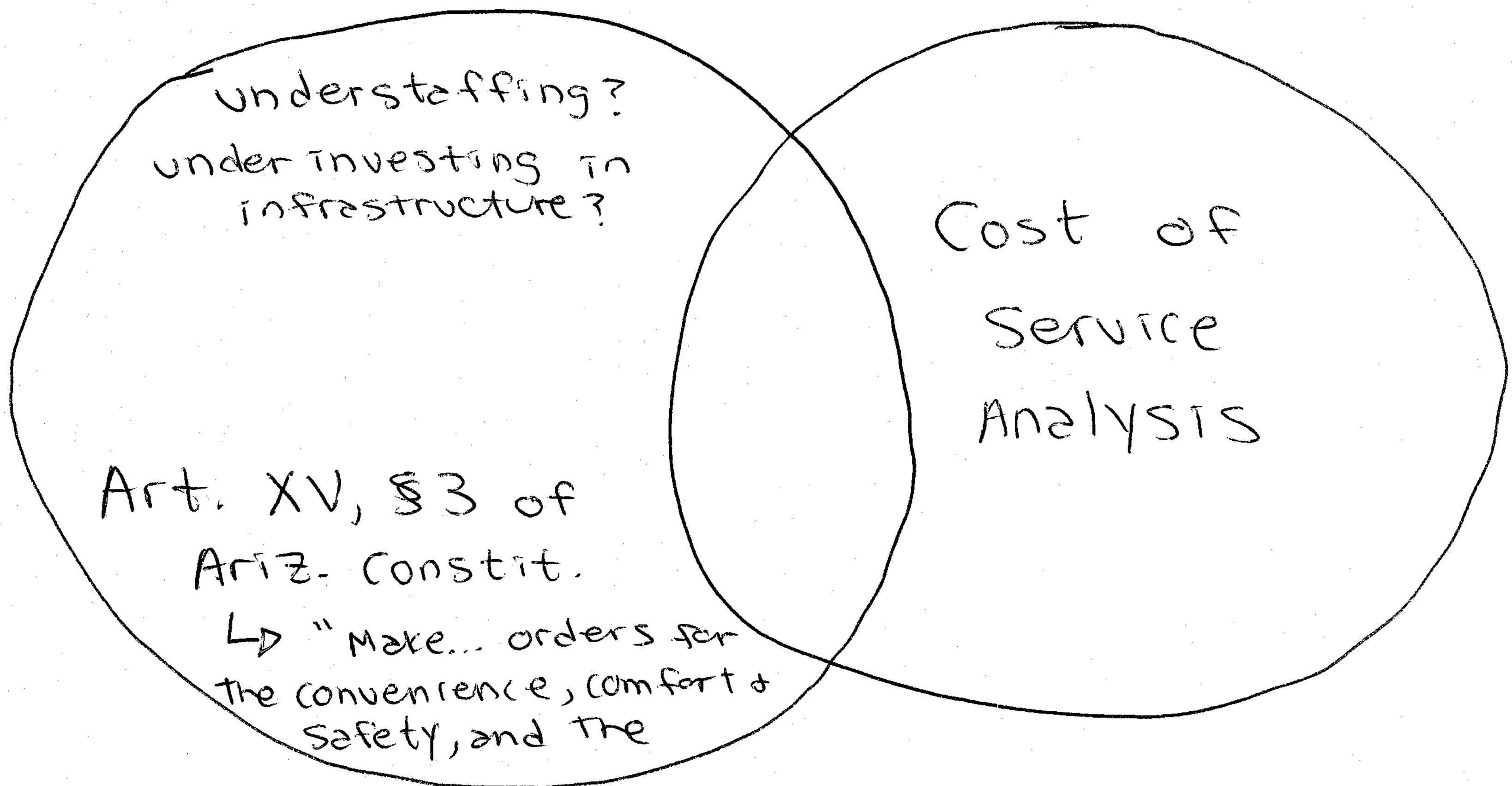


EXHIBIT
IBEW-1
ADMITTED

ORIGINAL

EXHIBIT
IBEW-2
ADMITTED

0000170738

RECEIVED

2016 JUN -3 P 4: 06

AZ CORP COMMISSION
DOCKET CONTROL

LUBIN & ENOCH, P.C.
Nicholas J. Enoch
State Bar No. 016473
Jarrett J. Haskovec
State Bar No. 023926
Emily A. Tornabene
State Bar No. 030855
349 North Fourth Avenue
Phoenix, Arizona 85003
Telephone: (602) 234-0008
Facsimile: (602) 626-3586
Email: Nick@lubinandenoch.com
Jarrett@lubinandenoch.com
Emily@lubinandenoch.com

Attorneys for Intervenor IBEW Local 1116

BEFORE THE ARIZONA CORPORATION COMMISSION

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 E-01933A-15-0239 **INTERVENOR IBEW LOCAL 1116'S NOTICE OF FILING DIRECT TESTIMONY OF SCOTT NORTHRUP**

Pursuant to the Administrative Law Judge's Rate Case Procedural Order and Notification of Intervention dated December 14, 2015 (p. 2), Intervenor Local Union 1116 of the International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 1116"), by and through undersigned counsel, hereby provides notice of its filing of the attached Direct Testimony of Scott Northrup in this docket.

///

///

///

Arizona Corporation Commission
DOCKETED

JUN - 3 2016

DOCKETED BY

RESPECTFULLY SUBMITTED this 3rd day of June, 2016.

LUBIN & ENOCH, P.C.

Nicholas J. Enoch, Esq.
Attorney for Intervenor IBEW Local 1116

CERTIFICATE OF SERVICE

I hereby certify that I have this day filed an original and thirteen (13) copies of Intervenor IBEW Local 1116's Notice of Filing Direct Testimony with:

Arizona Corporation Commission
Docket Control Center
1200 West Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing e-mailed or mailed this same date to all parties included on the attached service list dated June 3, 2016.

Steve Chriss
WAL-MART STORES, INC.
2011 S.E. 10th Street
Bentonville, Arkansas 72716

Michael Hiatt
EARTHJUSTICE
633 17th ST Suite #1600
Denver, Colorado 80202

Ken Wilson
WESTERN RESOURCE ADVOCATES
2260 Baseline Road, Suite 200
Boulder, Colorado 80302

Rick Gilliam
THE VOTE SOLAR INITIATIVE
1120 Pearl St, Ste 200
Boulder, Colorado 80302

Timothy Hogan
ARIZONA CENTER FOR LAW IN THE
PUBLIC INTERST
514 W. Roosevelt St.
Phoenix, Arizona 85003

Nicholas Enoch
LUBIN & ENOCH, PC
349 N. Fourth Ave.
Phoenix, Arizona 85003

Cynthia Zwick
ARIZONA COMMUNITY ACTION
ASSOCIATION
2700 N. Third St. - 3040
Phoenix, Arizona 85004

Gary Yaquinto
ARIZONA INVESTMENT COUNCIL
2100 North Central Avenue, Suite 210
Phoenix, Arizona 85004

Michael Patten
SNELL & WILMER, LLP
One Arizona Center
400 East Van Buren Street, 19th Floor
Phoenix, Arizona 85004

Jason Gellman
SNELL & WILMER, LLP
Michael Patten
400 East Van Buren Street
Phoenix, Arizona 85004

Kevin Hengehold
ARIZONA COMMUNITY ACTION
ASSOCIATION
2700 N 3rd St., Suite 3040
Phoenix, Arizona 85004

Camila Alacron
GAMMAGE & BURNHAM, PLC
Two N. Central Avenue, 15 th Floor
Phoenix, Arizona 85004

Thomas Broderick
1200 W. Washington St.
Phoenix, Arizona 85007

Janice Alward
1200 W. Washington
Phoenix, Arizona 85007

Daniel Pozefsky
RUCO
1110 West Washington, Suite 220
Phoenix, Arizona 85007

Arizona Corporation Commission
Dwight Nodes
1200 W. Washington
Phoenix, Arizona 85007-2927

Meghan Grabel
OSBORN MALADON, PA
2929 N. Central Avenue Suite 2100
Phoenix, Arizona 85012

Scott Wakefield
HIENTON & CURRY, PLLC
5045 N 12th Street, Suite 110
Phoenix, Arizona 85014-3302

C. Webb Crockett
FENNEMORE CRAIG, PC
2394 E. Camelback Rd, Ste 600
Phoenix, Arizona 85016

Michele Van Quathem
LAW OFFICES OF MICHELE VAN
QUATHEM, PLLC
7600 N 15th St, Suite 150-30
Phoenix, Arizona 85020

Tom Harris
ARIZONA SOLAR ENERGY INDUSTRIES
ASSOCIATION
2122 W. Lone Cactus Dr. Suite 2
Phoenix, Arizona 85027

Craig Marks
CRAIG A. MARKS, PLC
10645 N. Tatum Blvd.
Suite 200-676
Phoenix, Arizona 85028

Thomas Loquvam
PINNACLE WEST CAPITAL
CORPORATION
P.O. Box 53999, MS 8692
Phoenix, Arizona 85072

Kerri Carnes
ARIZONA PUBLIC SERVICE COMPANY
P.O. Box 53072, MS 9712
Phoenix, Arizona 85072-3999

Court Rich
ROSE LAW GROUP, PC
7144 E. Stetson Drive, Suite 300
Scottsdale, Arizona 85251

Lawrence Robertson, Jr.
PO Box 1448
Tubac, Arizona 85646

Bradley Carroll
TUCSON ELECTRIC POWER COMPANY
88 E. Broadway Blvd. MS HQE910
P.O Box 711
Tucson, Arizona 85701

Barbara LaWall
PIMA COUNTY ATTORNY'S OFFICE
c/o Charles Wesselhoft
32 North Stone Avenue, Suite 2100
Tucson, Arizona 85701

Jeff Schlegel
SWEEP ARIZONA REPRESENTATIVE
1167 W. Samalayuca Dr.
Tucson, Arizona 85704-3224

Kevin Koch
P.O. Box 42103
Tucson, Arizona 85733

Bryan Lovitt
3301 West Cinnamon Drive
Tucson, Arizona 85741

Briana Kobor
VOTE SOLAR
360 22nd St. Suite 730
Oakland, California 94602

Travis Ritchie
SIERRA CLUB ENVIRONMENTAL LAW PROGRAM
2101 Webster Street, Suite 1300
Oakland, California 94612

Ellen Zuckerman
SWEEP SENIOR ASSOCIATION
1627 Oak View Ave.
Kensington, California 94707

Q1. Please state your name and business address.

A1. Scott Northrup. My business address is 4601 South Butterfield Drive, Tucson, Arizona 85714.

Q2. Please describe your present position, background, and experience.

A2. I am the Business Manager/Financial Secretary for Intervenor, Local Union 1116 of the International Brotherhood of Electrical Workers, AFL-CIO, CLC ("IBEW Local 1116"). The position of Business Manager/Financial Secretary is an elected union position, but due to the recent retirement of my predecessor, Frank Grijalva, I was appointed by our Executive Board to my present position on February 1, 2016.

Because all IBEW Local Unions also have a President, persons outside of our organization commonly believe that the President is the principal officer of the Local. This is not the case. Article 17, §§ 4 and 8 of the Constitution of the IBEW, AFL-CIO, provides that the Business Manager/Financial Secretary is the "principal officer" of any IBEW Local Union.

Prior to becoming Business Manager/Financial Secretary, I was employed by the Applicant, Tucson Electric Power Company ("TEP") for sixteen years in various positions, most recently as a Training Specialist. While employed at TEP, I was an active member of IBEW Local 1116, and previously served as the Local's President for eight (8) years.

Q3. Have you testified in other matters before the Arizona Corporation Commission?

A3. Yes. I recently testified *In the Matter of the Commission's Investigation of Value and Costs of Distributed Generation*, ACC Docket No. E-00000J-14-0023.

Q4. What is IBEW Local 1116?

A4. IBEW Local 1116 is a labor organization that serves as the exclusive representative for approximately seven-hundred (700) non-managerial TEP employees, including, by way of example, linemen/cablemen, substation electricians, electronics technicians, equipment servicemen, field technicians, designers, heavy equipment and transport operators, maintenance electricians, maintenance mechanics, meter repairmen and customer care representatives. Even a cursory review of this illustrative list reveals that such represented employees are among those who contribute daily, directly, and significantly to TEP's efforts to provide safe and reliable electric service to its customers.

IBEW Local 1116 and TEP's series of collective bargaining agreements ("CBA") date back to November 16, 1937, and its two current CBAs – one covering the

Springerville Generation Power Plant and the other covering the rest of the company — extends to December 31, 2018. IBEW Local 1116 was a party to the 2008 TEP Rate Case Settlement Agreement, approved in Decision No. 70628, and to the 2012 TEP Rate Case Settlement Agreement, approved in Decision No. 73912. IBEW Local 1116 was also a party to the May 16, 2014 Settlement Agreement *In the Matter of the Reorganization of UNS Energy Corporation*, later approved in Decision No. 74689.

Q5. Do you believe that TEP is a responsible corporate citizen?

A5. For the most part, yes. While the relationship between IBEW Local 1116 and TEP is by no means perfect, it is mature and stable. It is clear that this stability has inured to the benefit of TEP, its employees, and its customers. In my opinion, the importance of the relationship between a public service corporation and its employees cannot be overstated. I believe that others share my opinion in this regard. In fact, Article I, § 1.3 of our CBA states:

> The Company and the Union have a common and sympathetic interest in the utility industry and harmonious relations are necessary to improve the relationship between the Company, the Union and the public. Progress in industry demands a

> mutuality of confidence between the Company and the Union. All will benefit by continuous peace and adjusting any difference by rational, commonsense methods. To these ends this Agreement is made.

Q6. What is the purpose of your testimony?

A6. As you know, Article XV, § 3 of the Arizona Constitution expressly states that the interests of public service employees are on par with those of patrons. It reads as follows:

> The corporation commission shall have full power to, and shall... make reasonable rules, regulations, and orders, by which such [public service] corporations shall be governed in the transaction of business within the State, and... make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the ***employees*** and patrons of such corporations[.]

In its 1984 decision in *Cogent Pub. Serv. v. Arizona Corp. Comm'n*, 142 Ariz. 52, 56-57, 688 P.2d 698, 702-03 (Ariz. Ct. App. 1984), Division One expressly, and in my opinion, correctly, held that "the jurisprudence of our State made it plain long ago that the interests of public-service corporation stockholders must not be permitted to overshadow those of the public served." In support of this quite unremarkable proposition, our Court of Appeals relied upon a series of U.S. and Arizona Supreme Court decisions dating back to 1896. Beyond that, I would also point out that while Article XV, § 3 of the Arizona Constitution mentions "employees and patrons" as key stakeholders, it does not mention shareholders as such. Further, it certainly does not mention the shareholders and/or owners of rooftop solar companies.

On behalf of its own members as well as several hundred thousand patrons of TEP, IBEW Local 1116 believes this proceeding provides a unique and timely opportunity for it to express to this Commission its growing concern regarding what it believes to be a marked deterioration in the reliability and safety of TEP's operations and the primary causes of said deterioration, *to wit*, TEP's shaky financial situation.

Q7. You assert that there has been a marked deterioration in the reliability and safety of TEP's operations. Can you provide the Commission with some specific examples?

A7. Certainly. The following are just some illustrations of the problems we have recently encountered and the concerns that we have moving forward:

1. While TEP's sister company, Central Hudson Gas & Electric Corporation ("Central Hudson"), has over 100,000 fewer customers than TEP, the former has approximately three (3) times the number of linemen as TEP. I am aware of some of these numbers based on the publically available information contained on the companies' websites, *to wit*, www.centralhudson.com/about_us/facts.aspx and www.tep.com/about/overview. I also know the number of linemen at Central Hudson based on my conversations with the officers of IBEW Local 320 in Poughkeepsie, New York, the certified representative of Central Hudson.

2. Due to the low number of customer care representatives and chronic understaffing issues, TEP has, at times, subjected its customers to extreme delays in responding to non-emergency, billing-related inquires. In an apparent, but flawed, response to this problem, on April 21, 2016 TEP announced that it "will be working with Staff Members to recruit and identify approximately 20-25 individuals who will assist us on a temporary part time basis." Time will tell what is meant by "a temporary part time basis[.]"

3. Due to apparent budget constraints, TEP is not currently maintaining records for non-CIP (Critical Infrastructure Protection) breakers.

4. TEP has hired two (2) (so-called) designers to be trained in design work. Since April, they have said that they were going to endure designer apprentices, but that has not been the case. TEP desperately needs more designers because there is a disruption in the Company's workflow inasmuch as some crews do not actually have sufficient work to stay busy. This very real problem is alluded to on page 17 of Susan M. Gray's prefiled direct testimony dated November 5, 2015.

5. TEP also continues to spend more money on out of state contractors to do work that TEP employees can do for a lot less. For example, TEP has four Sturgeon crews on site working fifty hours per week on busy work instead of using bargaining unit employees to do the same work. TEP also just bid two (2) transmission jobs out that could have been performed by TEP employees. TEP should be required to show the Commission invoices for work that TEP Substation Journeyman had to fix due to the contractors' substandard and unsatisfactory work. An example of this would be at the North Loop Substation.

6. IBEW Local 1116 has significant concerns related

to TEP's workforce planning moving forward and, in particular, the "aging workforce" problem that so many utilities, including TEP, face and will continue to face in the coming years. Paragraph 18.2 of the January 6, 2012 Proposed Settlement Agreement in Arizona Public Service Company's ("APS") last general rate case, adopted in relevant part in Decision No. 73183, highlights these concerns and serves to focus the parties' and the Commission's attention on these important matters – both now and going forward. While Conditions 27, 30 and 41(ii) of ACC Decision No. 74689 touch on these same sorts of concerns, IBEW Local 1116 believes that something along the lines of what APS has agreed to should be required in this case to ensure that TEP makes an effort to actually maintain a staff capable of doing safe and reliable work instead of subcontracting the work to out of state contractors. An annual review and assessment of its workforce planning for critical positions would shed light on these challenges and would force consideration of what sorts of recruitment and hiring efforts TEP must undertake to meet these challenges ahead of anticipated retirements. I can say, without exaggeration or hyperbole, that I firmly believe TEP's ability to provide safe and reliable electric power in southern Arizona in the years to come largely depends on the steps the Company takes to meet these impending challenges to hire, train, and maintain a highly skilled work force.

Q8. Can you identify any specific measures that ought to be taken in order to bolster TEP's financial situation?

A8. Yes, I can. First, IBEW Local 1116 strongly supports the proposed *pro forma* adjustments to the payroll and payroll tax expense associated with TEP's unionized workforce. In as much as those contractually agreed to expenses are certain and easily calculated, they should be considered in conjunction with the instant rate case. This proposal is set forth on page 31 of Frank P. Marino's prefiled direct testimony dated November 5, 2015. IBEW Local 1116 does not support, however, the proposed *pro forma* adjustments to the payroll and payroll tax expense associated with TEP's non-unionized workforce. By definition, those workers are employed at-will and, as such, the terms and conditions of their employment are subject to change at any time and in any direction. That being the case, it would not be sound rate making to include that particular adjustment on a prospective basis.

Second, on behalf of its own members as well as several hundred thousand patrons of TEP, IBEW Local 1116 believes this proceeding provides it with a unique and timely opportunity to express to this Commission its growing concern regarding what it believes to be a marked deterioration in the reliability and safety of TEP's operations and a primary cause of that deterioration, *to wit*, TEP's cross-subsidization of UNS Energy Corporation.

To be clear, IBEW Local 1116 fully believes that TEP should and must receive a fair rate of return on the fair value of ***its*** property and we fully support its efforts to achieve that goal. In calculating what that is, however, IBEW Local 1116 strongly urges this Commission to truly focus its attention on the issue of TEP's cross-subsidization of UNS. Only by doing so with much more detail than has been explored in previous proceedings can this Commission ever really come to terms with what a fair rate of return for TEP actually is.

IBEW Local 1116 recognizes that any public service corporation is entitled to a fair rate of return on the fair value of its property, no more and no less. It goes without saying that it costs a substantial amount of money for a public service corporation to hire, train, and maintain a highly skilled workforce. Similarly, it costs a great deal of money for any public service corporation to preserve the safety and health of its employees and patrons. IBEW Local 1116 believes that the Commission should provide TEP with whatever rate relief and structure that is necessary to ensure that TEP will be able to meet its commitments to its employees and customers to hire, train, and maintain a highly skilled workforce in the years to come. In so doing, however, the Commission should pay special attention to whether UNS is being inappropriately enriched at the expense of TEP and, in turn, its patrons.

Third, I would like to point out that TEP compensates solar customers for their surplus electricity at full retail value. Thus, solar customers are excused from paying their fair share of the costs derived from their use of the grid, including its maintenance and the transmission and distribution it facilitates. Solar customers are compensated for the energy that they generate, but that compensation does not account for the fact that less than half of the cost of providing energy comes from generating it. In fact, thirty-seven cents of every dollar charged by utilities goes toward building and maintaining the grid. Regardless of much solar grows, TEP will still need workers to build and maintain the grid. The fact that TEP will not receive a fair price for its services jeopardizes job stability for its workers, and reduces TEP's ability to provide a safe and efficient workplace for these workers. This is obviously an unfavorable outcome for the members of IBEW Local 1116. The IBEW Locals also posit that this outcome should concern the Arizona Corporation Commission, which is bound by Article XV, § 3 of the Arizona Constitution to protect the employees of public service corporations, as notably opposed to the interests of distributed-solar companies, many of which are actually from out-of-state.

Distributed generation solar power promises to dramatically change the grid in the near future. How that change occurs will impact the jobs and futures of our workers at TEP. IBEW Local 1116's principal concern is that solar customers use and rely on the grid without contributing a fair share to the cost of its maintenance, thereby requiring utilities to either absorb or shift the cost to other users, and fundamentally destabilizing the environment in which utility workers do their jobs. At best, this is grossly unfair and imprudent and, at worst, it is patently unconstitutional. As explained by Division Two in its 1987 decision in *Marco Crane & Rigging v. Ariz. Corp. Comm'n*, 155 Ariz. 292, 297, 746 P.2d 33, 38 (Ariz. Ct. App. 1987):

> A public service corporation must treat all similarly situated customers alike[.]

> A public service corporation is impressed with the obligation of furnishing its service to each patron at the same price it makes to every other patron for the same or substantially the same or similar service. It must be equal in its dealings with all. It must treat the members of the general public alike. There must be equality of rights to all and special privileges to none.

Under this line of reasoning, why, and upon what sound constitutional basis, should residential solar customers be afforded the special privilege of using TEP's infrastructure without having to pay their fair share for its use?

As I previously stated in response to question 3, I recently testified at length about this subject *In the Matter of the Commission's Investigation of Value and Costs of Distributed Generation*, ACC Docket No. E-00000J-14-0023. My direct testimony in that matter was filed on January 29, 2016 and my rebuttal testimony was filed on February 25, 2016. I also testified in person at the hearing on April 19, 2016 and my verbal testimony starts on page 221 of the hearing transcript. In lieu of repeating all of my previous testimony again herein, I would invite the ALJ to take official notice of it pursuant to A.A.C. R14-3-103(T)(4) and/or (U).

Q9. Is IBEW Local 1116 concerned about the regressive social costs currently imposed by net-metering?

A9. Yes. In many cases, the costs that solar customers are excused from paying are reallocated to non-solar customers. Solar customers typically must be able to pay many thousands of dollars for a solar unit, have a single-family home, and possess a good credit score. Those without these abilities, including those living in apartments or multi-unit low-income housing, cannot access rooftop solar power for their home. Thus, the cost shift from solar users to non-solar users is actually a cost shift from affluent families to low-income families. As the bargaining representative for utilities workers supporting working class families in non-managerial jobs, this strikes IBEW Local 1116 as especially unjustifiable.

Q10. Does this conclude your testimony?

A10. Yes.

F:\Law Offices\client directory\IBEW L. 1116\044\Pleadings\2016-6-3 (1575-044) Northrup direct testimony.wpd

ORIGINAL

RECEIVED
AZ CORP COMMISSION
DOCKET CONTROL

2016 AUG 25 P 3: 52

00000172881

EXHIBIT
IBEW-3
ADMITTED

LUBIN & ENOCH, P.C.
Nicholas J. Enoch, State Bar No. 016473
Jarrett J. Haskovec, State Bar No. 023926
Emily A. Tornabene, State Bar No. 030855
349 North Fourth Avenue
Phoenix, Arizona 85003
Telephone: 602-234-0008
Facsimile: 602-626-3586
Email: nick@lubinandenoch.com

Attorneys for Intervenors IBEW Local 1116

BEFORE THE ARIZONA CORPORATION COMMISSION

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 E-01933A-15-0239 **INTERVENOR IBEW LOCAL 1116'S NOTICE OF FILING SURREBUTTAL TESTIMONY OF SCOTT NORTHRUP AND SARITA MORALES**

Pursuant to the Administrative Law Judge's Rate Case Procedural Order and Notification of Intervention dated December 14, 2015 (p. 3), Intervenor, the International Brotherhood of Electrical Workers, AFL-CIO, CLC Local Union 1116 by and through undersigned counsel, hereby provide notice of their filing of the attached Surrebuttal Testimony of Scott Northrup and Sarita Morales in this docket.

///

Arizona Corporation Commission
DOCKETED
AUG 25 2016
DOCKETED BY

///

RESPECTFULLY SUBMITTED this 25th day of August, 2016.

LUBIN & ENOCH, P.C.

E A Tornabene

Emily A. Tornabene, Esq.
Attorneys for Intervenors

Original and thirteen (13 copies) of IBEW 1116's Surrebuttal Testimony filed this 25th of August, 2016, with:

Arizona Corporation Commission
Docket Control Center
1200 W. Washington Street
Phoenix, Arizona 85007-2996

Copies of the foregoing transmitted
Via mail or email this same date to:

Jeffrey Shinder

CONSTANTINE CANNON LLP
335 Madison Avenue, 9th Floor
New York New York 10017

Richard O. Levine

CONSTANTINE CANNON LLP
1001 Pennsylvania Ave, NW
Suite 1300 North
Washington District of Columbia 20004

David Bender

EARTHJUSTICE
1625 Massachusetts Ave., NW
Suite 702
Washington District of Columbia 20036-2243

Kyle J Smith

9275 Gunston Rd
Fort Belvoir Virginia 22060
kyle.j.smith124.civ@mail.mil

Consented to Service by Email

Stephen J Baron

KENNEDY & ASSOCIATES
570 Colonial Park Dr. Ste 305
Roswell Georgia 30075

Karen White

AFLOA/JACL-ULT
139 Barnes Drive, Suite 1
Tyndall Air Force Base Florida 32403
karen.white.13@us.af.mil

Consented to Service by Email

Kurt Boehm

BOEHM, KURTZ & LOWRY
36 E. Seventh St. Suite 1510
Cincinnati Ohio 45202

The Kroger Co.

Att: Corporate Energy Manager
1014 Vine St
Cincinnati Ohio 45202

Steve W. Chriss

WAL-MART STORES, INC.
2011 S.E. 10th Street
Bentonville Arkansas 72716

Michael Hiatt

EARTHJUSTICE
633 17th ST Suite #1600
Denver Colorado 80202
mhiatt@earthjustice.org

Consented to Service by Email

Rick Gilliam

THE VOTE SOLAR INITIATIVE
1120 Pearl St, Ste 200
Boulder Colorado 80302
rick@votesolar.org

Consented to Service by Email

Ken Wilson

WESTERN RESOURCE ADVOCATES
2260 Baseline Road, Suite 200
Boulder Colorado 80302

Kevin C. Higgins

ENERGY STRATEGIES, LLC
215 South State Street, Ste. 200
Salt Lake City Utah 84111

Nicholas J. Enoch

LUBIN & ENOCH, PC
349 N. Fourth Ave.
Phoenix Arizona 85003

Timothy M. Hogan

ARIZONA CENTER FOR LAW IN THE PUBLIC INTERST
514 W. Roosevelt St.
Phoenix Arizona 85003
thogan@aclpi.org

Consented to Service by Email

Michael Patten

SNELL & WILMER, LLP
One Arizona Center
400 East Van Buren Street
Phoenix Arizona 85004

mpatten@swlaw.com
bcarroll@tep.com
jhoward@swlaw.com
docket@swlaw.com

Consented to Service by Email

Cynthia Zwick

ARIZONA COMMUNITY ACTION ASSOCIATION
2700 N. Third St. - 3040
Phoenix Arizona 85004

Gary Yaquinto

ARIZONA INVESTMENT COUNCIL
2100 North Central Avenue, Suite 210
Phoenix Arizona 85004

gyaquinto@arizonaic.org

Consented to Service by Email

Camila Alacron

GAMMAGE & BURNHAM, PLC
Two N. Central Avenue, 15 th Floor
Phoenix Arizona 85004

Janice Alward

ARIZONA CORPORATION COMMISSION
1200 W. Washington
Phoenix Arizona 85007

rmitchell@azcc.gov
Wvancleve@azcc.gov
cfitzsimmons@azcc.gov
legaldiv@azcc.gov

Consented to Service by Email

Daniel Pozefsky

RUCO
1110 West Washington, Suite 220
Phoenix Arizona 85007

Thomas Broderick

ARIZONA CORPORATION COMMISSION
1200 W. Washington St.
Phoenix Arizona 85007

Greg Patterson

MUNGER CHADWICK
916 W. Adams Suite 3
Phoenix Arizona 85007

Dwight Nodes

ARIZONA CORPORATION COMMISSION
1200 W. Washington
Phoenix Arizona 85007-2927

HearingDivision@azcc.gov

Consented to Service by Email

Meghan H. Grabel

OSBORN MALADON, PA
2929 N. Central Avenue Suite 2100
Phoenix Arizona 85012

mgrabel@omlaw.com

Consented to Service by Email

Scott S. Wakefield

HIENTON & CURRY, PLLC
5045 N 12th Street, Suite 110
Phoenix Arizona 85014-3302

Jeffrey Crockett

CROCKETT LAW GROUP, PLLC
2198 E. Camelback Rd., Suite 305
Phoenix Arizona 85016

Garry D Hays

LAW OFFICES OF GARRY D. HAYS, PC
2198 East Camelback Road, Suite 305
Phoenix Arizona 85016

C. Webb Crockett

FENNEMORE CRAIG, PC
2394 E. Camelback Rd, Ste 600
Phoenix Arizona 85016

wcrocket@fclaw.com
pblack@fclaw.com

Consented to Service by Email

John William Moore, Jr.

MOORE BENHAM & BEAVER, PLC
7321 N. 16th Street
Phoenix Arizona 85020

Michele Van Quathem

LAW OFFICES OF MICHELE VAN QUATHEM, PLLC
7600 N 15th St, Suite 150-30
Phoenix Arizona 85020

Tom Harris

ARIZONA SOLAR ENERGY INDUSTRIES ASSOCIATION
2122 W. Lone Cactus Dr. Suite 2
Phoenix Arizona 85027

Tom.Harris@AriSEIA.org

Consented to Service by Email

Craig A. Marks

CRAIG A. MARKS, PLC
10645 N. Tatum Blvd.
Suite 200-676
Phoenix Arizona 85028

Craig.Marks@azbar.org

Consented to Service by Email

Thomas A Loquvam

PINNACLE WEST CAPITAL CORPORATION
P.O. Box 53999, MS 8695
Phoenix Arizona 85072

Thomas.Loquvam@pinnaclewest.com

Consented to Service by Email

Kerri A Carnes

ARIZONA PUBLIC SERVICE COMPANY
P.O. Box 53072, MS 9712
Phoenix Arizona 85072-3999

Kerri.Carnes@aps.com

Consented to Service by Email

Court S. Rich

ROSE LAW GROUP, PC
7144 E. Stetson Drive, Suite 300
Scottsdale Arizona 85251

crich@roselawgroup.com

Consented to Service by Email

Patrick Quinn

QUINN AND ASSOCIATES, LLC
ARIZONA UTILITY RATEPAYER ALLIANCE
5521 E. Cholla St.
Scottsdale Arizona 85254

Lawrence V. Robertson, Jr.

PO Box 1448
Tubac Arizona 85646

Barbara LaWall

PIMA COUNTY ATTORNY'S OFFICE
c/o Charles Wesselhoft
32 North Stone Avenue, Suite 2100
Tucson Arizona 85701

charles.wesselhoft@pcao.pima.gov

Consented to Service by Email

Jeff Schlegel

SWEEP ARIZONA REPRESENTATIVE
1167 W. Samalayuca Dr.
Tucson Arizona 85704-3224

Bruce Plenk

2958 N. St. Augustine Pl
Tucson Arizona 85712

Kevin M. Koch

P.O. Box 42103
Tucson Arizona 85733

Bryan Lovitt

3301 West Cinnamon Drive
Tucson Arizona 85741

Travis Ritchie

SIERRA CLUB ENVIRONMENTAL LAW PROGRAM
85 Second St, 2nd Floor
San Francisco California 94105

Travis.ritchie@sierraclub.org

Consented to Service by Email

Briana Kobor

VOTE SOLAR
360 22nd St. Suite 730
Oakland California 94602

briana@votesolar.org

Consented to Service by Email

Ellen Zuckerman

SWEEP SENIOR ASSOCIATION
1627 Oak View Ave.
Kensington California 94707

Q1. Please state your name and business address.

A1. Scott Northrup. My business address is 4601 South Butterfield Drive, Tucson, Arizona 85714.

Q2. Are you the same Scott Northrup whose direct testimony was filed in this docket on June 3, 2016.

A2. Yes.

Q3. On whose behalf are you filing your Surrebuttal Testimony?

A3. My Surrebuttal Testimony is filed on behalf of IBEW Local 1116 ("IBEW" or the "Union").

Q4. What is the purpose of your testimony?

A4. My Surrebuttal Testimony addresses the Rebuttal Testimony filed on behalf of TEP. In particular, I will respond to Susan Gray, Kenton Grant, and Frank Marino. In addition, I will address IBEW's position on the Settlement Agreement Regarding Revenue Requirement filed by TEP.

Q5. In her Rebuttal Testimony, Susan Gray states that "TEP has maintained an exemplary safety and reliability record for the past several years" and that she "absolutely disagree[s]" that there has been a marked deterioration in the reliability and safety of TEP's operations. Do you have any examples that would support your position?

A5. Yes. I have several examples that are illustrative of IBEW's safety and reliability concerns. To begin, TEP is utilizing an antiquated and obsolete 4kV distribution system. This type of equipment is nearly identical to what was used in the 1800's, not 2016. In fact, Thomas Edison's first installations were very similar to the system that TEP is operating. In addition, there is not a fuse on the transformer; rather, it is connected directly to the main line. What this means is that when it does fail, an employee will have to open the circuit breaker at the substation to clear the fault, thereby causing a much greater outage. Thus, not only is the outdated system unsafe, it directly impacts TEP's ability to deliver reliable service.

Another example involves an old, rotted electrical pole. Typically, when a bad or rotted pole is replaced, the old pole has to be removed or 'pulled.' The picture attached as Exhibit A shows a rotted pole and a new pole side-by-side. The date on the new pole is 2012, which means that in all likelihood the rotted pole has been sitting for 4 years without having been pulled. This rotted pole presents a significant danger as it could fall at any time. It needs to be removed.

There is a transformer that is well over 40 years old at Warehouse Substation 2029 E. 20th St. This transformer has been leaking oil for many years, if not decades. Rather than fix the leak or replace the transformer, TEP placed a piece of plywood down so that people would not sink into the soil. This oil leak is dangerous; it presents serious environmental issues; and the transformer should have been replaced years ago. A picture of this transformer is attached as Exhibit B.

Attached hereto as Exhibit C is a picture of a 13.8 feeder riser that is connected to the substation bus. Industry standards call for this to be protected by a 600A breaker below the main breaker in the switch gear. When this cable fails, the fault will have to be cleared by first traveling through, and possibly damaging, the substation transformer and tripping the 138kV breaker on the primary side.

Also, TEP is using cables that are well over 20 years old – the industry standard. In fact, some cables appear to be 40 years old. In one incident an old cable was shielded with a separate neutral so fault indicators were used. The shielding was in such a degraded condition that the fault indicators did not go off and actually gave a false reading.

According to the fault indicators, the bad section was between the transformer and the riser. When the employee isolated that section of the cable and closed at the normal condition to restore power, an arc flash occurred. The 'B' positon elbow and bushing failed catastrophically which resulted in a second 8000-volt arc flash. This could have caused the employees involved to suffer severe burns or even a fatality. A picture of the elbow is attached as Exhibit D.

TEP has many substation transformers that are at 60% of rated capacity. Industry standards are to build a new feeder line when a current one is at 60% capacity. Outdated and overloaded equipment create serious safety and reliability problems. The most recent example of this was the massive outage at Hart Substation in Green Valley.

Finally, in Susan Gray's Rebuttal Testimony a Total Recordable Incident Rate chart is included to demonstrate the number of recordable injuries. The number of injuries that occurred throughout the entire year during 2012 was 0.08 per 100 workers. The number of injuries that occurred in the first six months of 2016 was 1.59 per 100 workers. This is nearly double the amount of injuries in half the amount of time. An increase in numbers of this magnitude is alarming.

Q6. Susan Grey states that you contradict yourself in your Direct Testimony when you assert that TEP does not have enough linemen per customer as Central Hudson and later state that crews do not have enough work to stay busy. Do you believe that these statements are contradictory?

A6. No. The reason crews do not have enough work to stay busy is because TEP is assigning the work to subcontractors like Sturgeon and Adkins. These subcontractors are completing enough work to staff three crews. While TEP claims that the use of subcontractors is due to the inconsistent nature of the work, this has not been the case. Over the past three years the amount of subcontracted work has not declined.

Q7. In her Rebuttal Testimony, Susan Grey claims that TEP maintains records for all substation breakers. Has the Union ever requested these records?

A7. Yes. The Union requested breaker maintenance records for the northeast substation after an incident occurred there. TEP could not provide any records in response to the Union's request. Additionally, substation employees have stated that TEP does not maintain records unless it is a "CIP" critical breaker. Finally, because the Journeyman Substation Electrician position is insufficiently staffed, it is impossible for TEP to properly maintain all of the breakers.

Q8. Susan Grey does not agree with your statement that Designers and Designer Apprentices are not qualified. Do you have any further explanation for this statement?

A8. Yes. The Design Department at TEP is critically low on Designers, and historically TEP has been dangerously slow on replacing Designers who have left or retired. The two Distribution Design contractors that TEP recently hired have no training on TEP's system, tools or standards. Though they have been working for several months, they have produced no work. This is disconcerting.

Q9. In your Direct Testimony you expressed concerns about TEP subcontracting work. Do you have any specific examples of how subcontracting work has caused problems at TEP?

A9. Recently, there was an incident in Kingman where a Sturgeon crew was working in a substation, and the crew violated the Lock Out/ Tag Out procedure. The crew did not get clearance from TEP and only had it from APS. This is extremely dangerous.

A10. You express concerns regarding the "aging workforce" problem and TEP's workforce planning initiatives in your Direct Testimony. Do you have anything else that you would like to add to explain your concerns?

A10. Yes. TEP gave a presentation to the Union regarding its workforce planning for the Transmission & Distribution group. A summary of this process is below:

1. TEP looks at the past three years' worth of work, overtime, outages, retirees, apprentice levels, storm outages and repairs, contracted out work, Priority A, B, and C work, and several other factors.
2. TEP looks at the following items for the next two to three years: employees who could retire, improvement projects, apprentice levels, expected Operation & Maintenance, estimates of storm damage, Priority A, B, and C. TEP then sets the goals based on this information.

TEP runs all of this information through a formula that indicates how many employees to hire to meet all of the criteria it set.

The flaw in this planning process is that it generally takes 5 years to turn out an apprentice to a Journeyman. After that, a Journeyman typically needs 3-5 years of experience before being fully trained. TEP does not hire apprentices or any new bargaining employees until someone retires. Sometimes they do not replace the position at all. This prohibits any passing on of knowledge in the areas that do not have apprenticeships. There have been employees with 30 plus years of experience who have departed from TEP without passing any knowledge along.

Q11. In their Rebuttal Testimony, Frank Marino and Kenton Grant state that they are not aware of any cross-subsidization of UNS by TEP. Do you have an example of the cross-subsidization you reference?

A11. Yes. A simple example occurs in the customer service department. Even though TEP and UNS maintain two separate telephone lines for their customers, UNS customers frequently phone the TEP line. These customers are assisted by TEP representatives.

Q12. Do you believe that a 2% union increase for 2017 is reasonable like Kenton Grant states in his Direct Testimony?

A12. Yes. While the Union believes that TEP should have requested a larger revenue requirement, the Union is in accord with TEP regarding the 2% union increase. The Union does not agree with a 2% non-union increase due to the instability inherent in being at-will employees. The Union was not a signatory to the Settlement Agreement Regarding Revenue Requirement, and it is unclear from that agreement how TEP is treating this increase.

Q13. Why do you believe that TEP should have requested a larger revenue requirement?

A13. Given the express concerns about the aged infrastructure coupled with the overall safety and reliability issues TEP has experienced, the Union believes that TEP is entitled to a larger amount. Maintaining the status quo is not in the best interest of TEP patrons, TEP employees, and the overall public.

Q14. Does this conclude your Surrebuttal Testimony?

A14. Yes.

Q1. Please state your name and business address.

A1. Sarita Morales. My business address is 4601 South Butterfield Drive, Tucson, Arizona 85714.

Q2. Have you previously filed testimony in this docket?

A2. No.

Q3. What is your position with IBEW Local 1116?

A3. My title is Business Representative. In that capacity, *inter alia*, I work directly with the customer service representatives in the call center.

Q4. On whose behalf are you filing your Surrebuttal Testimony?

A4. My Surrebuttal Testimony is filed on behalf of IBEW Local 1116

Q5. What is the purpose of your testimony?

A5. My Surrebuttal Testimony addresses the Rebuttal Testimony filed by Denise Smith.

Q6. In her Rebuttal Testimony, Denise Smith states that the part-time customer service representatives have significantly contributed to the customer service TEP provides. Do you agree?

A6. No. The part-time customer service representatives have created havoc in the customer service department.

Q7. In what way have the part-time customer service representatives created havoc?

A7. These part-time customer service representatives are quite limited in the types of calls they can take. For some reason, they are only allowed to handle calls related to billing. However, billing issues can be some of the most involved calls that a customer service representative handles. The part-time representatives only receive two weeks of training and are unequipped to handle these calls. Because they are given such limited training, the part-time representatives require a great deal of hands on training from core employees. The result is that the core employees are pulled away from the phones to conduct this training, but they are not given any credit for this time.

Also, when the part-time representatives cannot successfully handle a call, the assistance of a core employee is required. What generally happens is that a core employee will take over the call (usually an irate or highly confused customer) and resolve the issues. This takes a great deal of time. The core employee does not get credit for talk time related to the call, or even for being on the call itself. The credit goes to the part-time representative who failed to resolve the issue. Not only is this unfair, but it is forcing core employees off the phones and seriously impacting their ability to meet their performance goals. Additionally, core employees are spending much of their time cleaning up the errors that the part-time representatives caused.

There are safety implications as well. Despite being so limited in their duties, the part-time representatives answer all of TEP's calls. TEP and UNS have two separate telephone numbers. Notwithstanding this fact, customers frequently use both numbers interchangeably. It is not uncommon for a customer experiencing a gas emergency to call the TEP number. If a part-time representative receives one of these calls, the call must be put back into the cue, getting bounced around the system, until it reaches an employee who can handle it. Not only is this inefficient, it is extremely dangerous.

All of these issues have caused a marked decrease in morale in the customer service department.

Q8. Does this conclude your Surrebuttal Testimony?

A8. Yes.

EXHIBIT A

EXHIBIT B

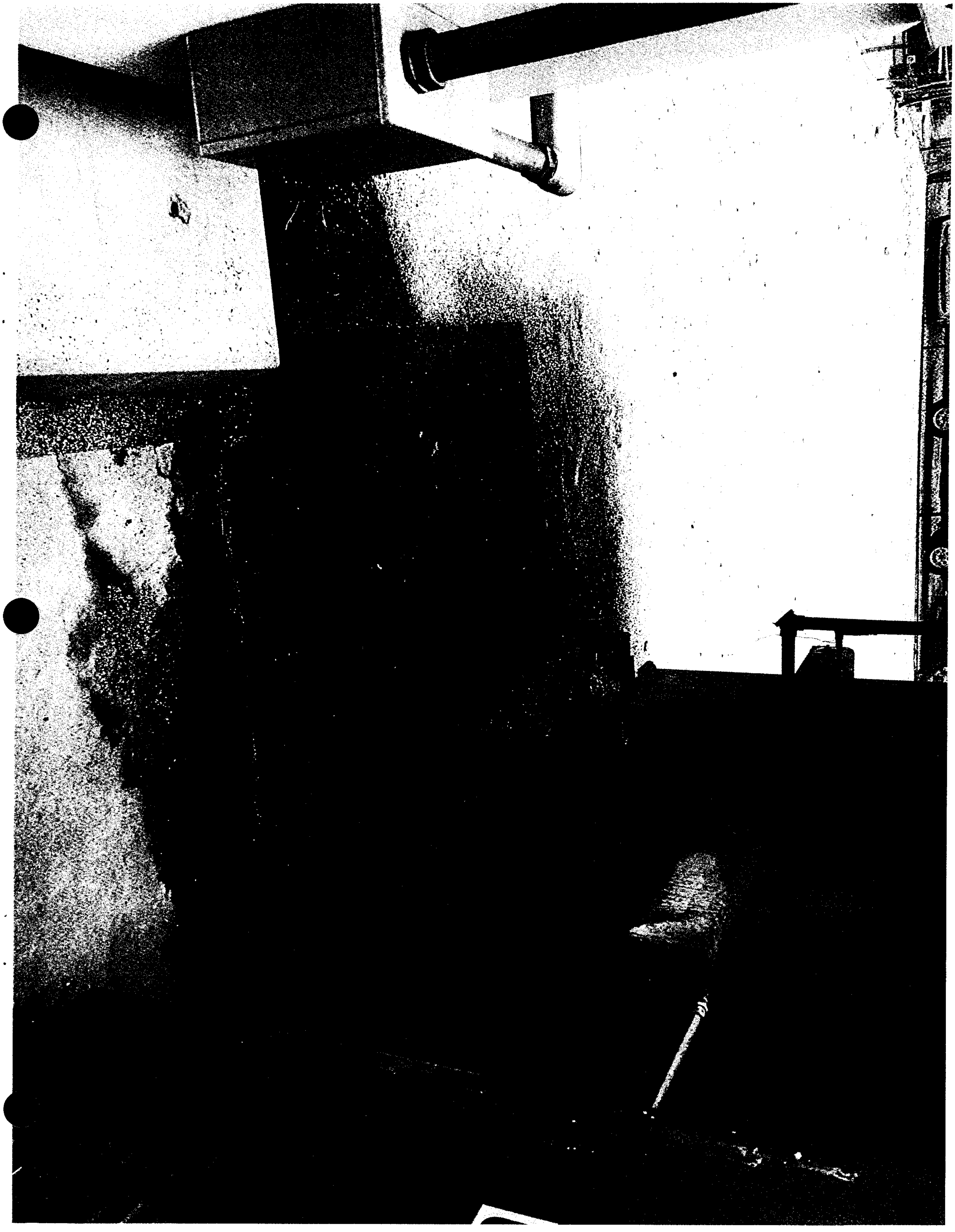


EXHIBIT C

EXHIBIT D