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Exhibit # : S9, S11, S12, S14, S15, TEP1

Part 4 of 9

Arizona Corporation Commission
DOCKETED

MAR 13 2013

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BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

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 ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. E-01933A-12-0291

PUBLIC

DIRECT

TESTIMONY

OF

MICHAEL J. MCGARRY, SR.

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

DECEMBER 21, 2012

EXHIBIT
S-9

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EXECUTIVE SUMMARY
TUSCON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291

ENERGY EFFICIENCY RESOURCE PLAN ("EERP")

Tucson Electric Power Company ("TEP" or "Company") is proposing an alternative approach to Energy Efficiency Standard ("EES") compliance. This alternative approach includes a three-year pilot program that the Company maintains will allow them to invest in and deliver cost effective Energy Efficiency ("EE") programs to its customers. The Company would recover the cost of its EE investments, including a return on those costs, through TEP's existing Demand-Side Management ("DSM") Surcharge ("DSMS"). TEP is proposing that the EERP will include the same type of program-related costs that are currently being recovered through the DSMS including the costs of developing, implementing, and administering DSM/EE measures and programs along with a return on TEP's investments in DSM/EE.

TEP's 2011-2012 Energy Efficiency Implementation Plan is currently being litigated in Arizona Corporation Commission Docket No. E-01933A-11-0055. In that case, a resolution of the issues and Commission approval of the plan has not yet occurred as the issue of whether the Company will be able to achieve the efficiency goals for 2012 and 2013 as required by Arizona Administrative Code ("A.A.C.") R14-2-2404 is still outstanding.

The Company maintains that it is undertaking an innovative departure from the way in which they traditionally finance and implement EE programs and measures because they believe that the adoption of cost-effective EE measures significantly enhances the Company's ability to develop a balanced and low cost resource portfolio. They state that their goal is to develop and deploy measures that provide the greatest operating efficiencies to TEP's generation, transmission, and distribution systems; reduce reliance on more costly generating resources; and provide customers with the most cost effective DSM/EE programs.

The Company also argues that its proposal would reduce and stabilize the rate impacts to customers, better synchronize the benefits of EE with their associated costs, provide a base level of certainty to program offerings, and eliminate the need to provide a performance incentive.

The Company is requesting that the Commission approve a three-year forward-looking budget that totals $79,640,355, which includes $24,739,192, $27,044,908, and $27,856,255 for 2014 through 2016, respectively. This results in average annual incremental costs of $26.5 million to TEP's customers. Additionally, TEP is requesting that the Weighted Average Cost of Capital used be based on the debt and capital structure approved by the Commission in this proceeding. The Company is seeking an overall weighted cost of capital of 7.74%, which includes a cost of equity (ROE) of 10.75%. However, the Company is requesting that the ROE should be increased by 200 basis points or 12.75%.

Staff has a number of regulatory and policy concerns that lead them to the conclusion that the Commission should reject the Company's proposed EERP:

(1) The Commission should reject the forward-looking concept proposed by TEP.
(2) The 200-basis-point increase to the ROE is excessive, unnecessary, and should be rejected.
(3) Since cost recovery would be virtually secured, it is unclear that the proposed EERP would provide incentives to maximize the results of the program and, at the same time, provide cost-effective and efficient implementation of the programs.
(4) The Company's proposal would require that the Commission issue one or more waivers of the various requirement of A.A.C. R14-2, including:
    - A.A.C. R14-2-2405 – annual implementation plan
    - A.A.C. R14-2-2410 – monitoring plan
(5) While not specifically mentioned by the Company, the EERP is an apparent attempt by TEP to mitigate the effects of regulatory lag.

In place of the Company's plan, Staff recommends that the Commission adopt the concept of establishing a regulatory asset for approved EE implementation costs that TEP incurs to achieve the Commission's energy efficiency goal. The Commission should allow the Company to earn a return on that investment of no greater than what the Commission approves for the weighted cost of capital in this proceeding. The amortization period for this regulatory asset will be seven years on a rolling basis and will be trued up each year and adjustments made to the Company's DSMS to reflect any under or over recoveries. This seven-year period is based on a composite weighted average of the useful life of the various measures that are included in the Company's proposed EE Implementation Plan.

Over the short term, Staff believes that ratepayers will be burdened less under its recommended plan than under the Company's proposal. At the same time, the Company will have a suitable level of funding to implement cost-effective programs to meet the Commission's goals.

ENVIRONMENTAL COMPLIANCE ADJUSTOR ("ECA")

TEP is proposing the ECA to provide for the recovery of and return on capital investments and associated costs related to environmental investments made by TEP and not already recovered in base rates or recovered through another Commission-approved mechanism. 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 ("CWIP") during the preceding calendar year.

The Company believes the ECA is necessary to allow TEP to recover the significant costs required to meet environmental compliance standards imposed by federal or other governmental agencies. TEP states that the rules to meet compliance standards will require increased capital spending for the installation of additional equipment with corresponding increases in O&M costs associated with the installation and operation of such equipment or implementation of new

environmental protocols at TEP's facilities. The capital investments will reduce the plant capacity because of the increased station power need for the equipment.

Further, the Company believes that it will be likely that most of the compliance-associated expenditures will occur between rate cases. The inability to recover the significant environmental compliance costs as they are incurred, according to TEP, places the Company and its customers in an untenable position. With respect to TEP, these environmental mandates will result in reduced cash flow and increased capital and O&M expenditures without recovery of those costs through increased revenue because of the extended time between the adjudication of TEP rate cases. This will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms. TEP's customers will be negatively impacted by the extended timeframe between rate cases because the accumulated capital costs and increased O&M will result in larger rate increases. The Company believes it is preferable to recover these mandate costs over time and not as established in rate cases, leading to more moderate annual rate increases without causing the Company to suffer any financial harm.

Staff, however, disagrees that a need for a cost-tracker does, in fact, exist. Staff asserts that the Company offers no evidence that its cash flows are unable to sustain the needed capital requirements for the potential mandate compliance. Further, while given the opportunity to do so, the Company did not provide any evidence beyond a hypothetical explanation of financial consequences to the Company should they be required to make the investments for complying with the mandates before recovery of prudently incurred costs are allowed in base rates. Additionally, there is no evidence that the normal regulatory treatment (i.e., Allowance for Funds Used During Construction ("AFUDC") of large capital expenditures such as these would financially harm the Company. Contrary to the Company's claims, the ECA appears to be proposed only as a means to mitigate regulatory lag because the Company has offered no evidence to show that it would, in fact, be substantially harmed from the financial consequences of the needed capital outlays.

Staff recommends that the Commission reject the ECA as currently proposed by the Company as too broad and includes capital investments that are not as of yet mandated or whose compliance date is well outside the timeframe in which the Company is likely to request another base rate increase. Trackers are implicitly an interim measure to provide relief to a utility for costs which are mandated, significant, potentially volatile, and out of the utility's control. A tracker is not intended as a permanent fix to make up for the regulatory lag in the ratemaking process. The Company has not demonstrated a need that warrants the extraordinary action of their proposed ECA tracker.

Since the Company has several major projects that it must meet in the next 2-3 years and to be consistent with the treatment that APS received in Docket No. E-0139A-11-0221, Staff recommends that, if the Commission should decide to order some type of environmental tracker, that tracker should mirror the Environmental Improvement Surcharge ("EIS") granted to Arizona Public Service Company ("APS") in Decision No. 73183 (May 24, 2012). It should include a cap to mitigate ratepayer impacts. Finally, as part of any settlement discussions, the parties should acknowledge that the EIS is a contributing factor to the length of any proposed "stay-out," as was done in the recent APS Decision.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Michael J. McGarry, Sr. I am President and CEO of Blue Ridge Consulting Services, Inc. My business address is 2131 Woodruff Road, Suite 2100, PMB 309, Greenville, SC 29607.

BACKGROUND AND QUALIFICATIONS

Q. Please state your experience and educational background.

A. I have been President of Blue Ridge Consulting Services, Inc. since 2004. In my career, I have overseen or been part of numerous rate case audits, prudency reviews, and management and operational audits. I have worked with clients to manage various aspects of the regulatory and rate case process; prepared supporting analyses and testimony for submission to regulatory bodies and interveners; prepared revenue requirement and cost of service analyses; and developed complex revenue requirement models to present alternative positions to utilities' proposed rate requests. Prior to assuming my present position, I was Vice President of East Coast Operations from July 2003 to June 2004 with Hawks, Giffels & Pullin (HGP), Inc. In that position, I was responsible for developing and overseeing client engagements in utility regulatory affairs, management audits, and rate case management. From August 2001 to July 2003, I was an independent consultant working on a number of different projects, including a renewal/update of delivery service tariffs for Illinois Power and several utility street lighting cost benefit assessment projects. From June 2000 until August 2001, I was a senior consultant with Denali Consulting, Inc., a utility supply chain and e-procurement strategy and implementation firm. From October 1997 through June 2000, I was employed by Navigant Consulting, Inc. and several of its predecessors or acquired firms, working on a number of different projects, including a management audit of Southern Connecticut Gas Company and the original delivery

service tariff filing for Illinois Power. From July 1985 through October 1997, I was employed by the New York State Department of Public Service ("NYSDPS") in its Utility Operational Audit Section in which the staff conducted focused operational audits in many facets of utility operations for all sectors of the utility industry, including gas, electric, telecommunications, and water. Prior to my employment with the NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983) and then with Seminole Electric Cooperative (1983 to 1985). I received my Masters of Business Administration from the State University of New York at Buffalo in 1996 and a Bachelor of Arts in Economics from Potsdam College (SUNY) in 1981.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment MJM-1 provides details concerning my experience and qualifications.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I recently testified in Arizona Public Service Company's base rate filing in Docket No. E-01345A-11-0224, where I proffered testimony on APS's proposed infrastructure tracking mechanism, power supply adjustor, and tariffs.

Q. Have you testified before commissions in other jurisdictions?

A. Yes. I have testified in Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, and Utah. These proceedings included testimony involving revenue requirements, power supply costs, management decisions and prudence impacts, operations and maintenance expenses, capital investments, and project management. A complete list is included in Attachment MJM-1.

I have also presented topics before staff groups from regulatory commissions, NARUC sub-committee groups, and as a program faculty member for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory.

PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am appearing on behalf of the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff").

Q. What is the purpose of the testimony you are presenting?

A. I am presenting the Staff's position with respect to (1) Tucson Electric Power Company's ("TEP" or "Company") proposed Energy Efficiency Resource Plan ("EERP") and (2) Environmental Compliance Adjustor ("ECA").

Q. Was this testimony and the supporting analyses prepared by you or under your direct supervision?

A. Yes, it was.

Q Please briefly describe the information you reviewed in preparation for your testimony.

A. I have reviewed the Company's testimony and exhibits and data request responses provided by the Company to the various parties to this proceeding.

ENERGY EFFICIENCY RESOURCE PLAN ("EERP")

Q. Please describe the EERP proposed by the Company.

A. The Company is proposing what it describes as an alternative and "improved approach to Energy Efficiency Standard ("EES") compliance."[1] This "improved approach" includes a three-year pilot program that the Company maintains will allow them to invest in and deliver cost effective Energy Efficiency ("EE") programs to its customers. The Company would recover the cost of its EE investments, including a return on those costs, through TEP's existing Demand-Side Management ("DSM") Surcharge ("DSMS"). TEP is proposing that the EERP will include the same type of program-related costs that are currently being recovered through the DSMS including the costs of developing, implementing, and administering DSM/EE measures and programs along with a return on TEP's investments in DSM/EE.[2]

Q. Does the EERP include a performance incentive?

A. No. The Company has eliminated the performance incentive in this plan.

Q. **Is there any background information that would be useful to mention for the Commission?**

A. Yes. Arizona Corporation Commission Docket No. E-01933A-11-0055 is where TEP's 2011-2012 Energy Efficiency Implementation Plan is being litigated. The overall goal of that proceeding is for the parties to that proceeding to review and comment on TEP's proposed 2011-2012 EE implementation plan leading to Commission approval. On January 31, 2011, pursuant to A.A.C. R14-2-2405, TEP filed with the Commission its application for approval of the Company's Energy Efficiency Implementation Plan for 2011-2012 ("Implementation Plan"). On August 22, 2011, TEP filed updated information

[1] Hutchens Direct at 15: 4-5.
[2] Hutchens Direct at 15:19-22.

to its Implementation Plan. In the Implementation Plan, the Company proposed, for the 2011-2012 program years, DSM programs and measures with budgets totaling $18,182,475 in 2011 and $24,759,193 for 2012; a modification of the Performance Incentive structure (resulting in payments of $16.4 million for two years); a form of a lost fixed cost recovery mechanism entitled an "Authorized Revenue Requirement True-up" ("ARRT") mechanism which was intended to recover revenue requirement associated with energy efficiency kWh savings; and a DSMS of $0.006343 per kWh.[3] From that timeframe (i.e., January 2011 up to August, 2012), the parties have been litigating the Company's Implementation Plan. However, as of the drafting of this testimony, a resolution of the issues and Commission approval of the plan has not occurred.

Q. Why is not yet having resolution of the plan significant?

A. One of the outstanding issues that is in the Company's proposed plan is whether the Company will be able to achieve the efficiency goals for 2012 and 2013 as required by A.A.C. R14-2-2404. I further address the significance of this later in this testimony.

Q. What does TEP proffer as the benefits of the Company's proposed plan?

A. Company Witness David G. Hutchens states, "TEP's proposal provides an alternative solution for financing the cost of complying with the EE Rules that would reduce and stabilize the rate impacts to our customers, better synchronize the benefits of EE with their associated costs, provide a base level of certainty to program offerings and eliminate the need to provide a performance incentive."[4] The rate that customers would be charged would be based on a three-year planning horizon for TEP's EE programs. The Company is proposing that the DSMS rate would be set in advance and recover the cost of the TEP's investment plus a return, resulting in "moderate, predictable year-over-year increases to

[3] Recommended Opinion & Order at 2, Docket No. E-01933A-11-0055, August 21, 2012.
[4] Hutchens Direct at 16:21-22.

ease customers into the increasing costs of EES compliance."[5] Witness Hutchens argues, "The most efficient way to provide cost-effective EE is to treat it like any other resource in our IRP process."[6] As Witness Hutchens states, "Under TEP's proposal, the Company would determine the most cost-effective EE option appropriate for its particular system, invest its capital to procure that resource, and recover the associated costs – including the amortization expense and an appropriate return on investment – through the DSMS."[7] Witness Hutchens points out that the capital invested in such programs will be considered a regulatory asset and amortized over a four-year term.[8] Witness Hutchens adds that the Company believes that the proposed EERP is "a win-win proposition for all stakeholders."[9] He argues that customers benefit from "a predictable DSMS that allows them to plan for their energy expenses while gaining greater assurance that TEP's EE programs will be available over a multi-year timeframe."[10] Further, he adds that local contractors who manage the various programs will "enjoy greater certainty regarding program funding levels." "The Commission and its Staff would benefit from a reduction in the administrative burden associated with annual reviews of TEP's EE Implementation Plans."[11] Witness Hutchens concludes, "TEP will have more certainty about the energy savings to incorporate into its resource and system planning and will realize a reasonable return from its EE investments."[12]

Q. What are the EE plan costs that are being proposed for inclusion in the plan?

A. As mentioned above, the Company is requesting that the Commission approve a three-year ***forward-looking budget*** that totals $79,640,355, which includes $24,739,192,

[5] Hutchens Direct at 17:1-2.
[6] *Id.* at 17:5-6.
[7] *Id.* at 17: 6-9.
[8] *Id.* at 17:11-12.
[9] Hutchens Direct at 17:16.
[10] *Id.* at 17:16-19.
[11] *Id.* at 17:19-22.
[12] *Id.* at 17: 22-24.

$27,044,908, and $27,856,255 for 2014 through 2016, respectively.[13] This results in average annual incremental costs of $26.5 million to TEP's customers.

Q. What rate of return on EE investments is TEP requesting?

A. TEP is requesting the Weighted Average Cost of Capital used be based on the debt and capital structure approved by the Commission in this proceeding. The Company is seeking an overall weighted cost of capital of 7.74%, which includes a cost of equity (ROE) of 10.75%.[14] However, the Company is requesting that the ROE should be increased by 200 basis points or 12.75% to "reflect the nature of the investment."[15] To support this 200-basis-point increase, Witness Hutchens states:

> Unlike its investments in power plants, buildings, computers and other assets with independent market value, TEP's EE expenditures produce only intangible assets with no value outside of the Commission's rules. That is why the creation of a regulatory asset – the value of which is derived solely from the Commission's authorization – is required to allow TEP to recover and earn a return on its EE investment. The nature of this investment justifies this higher rate of return, since intangible assets do not necessarily provide TEP with the same financial benefits as tangible, saleable assets.[16]

Q. Has the Company provided an estimate of the revenue requirement associated with this forward-looking plan?

A. Yes. Included as Exhibit CAJ-7 to Company Witness Craig A. Jones's Direct Testimony is the Company's proposed Plan of Administration ("POA") for the EERP. Within that document is Attachment D, which shows the revenue requirement calculation for each year for 2014 through 2016 and includes the going-forward portion of recovery of the

[13] Jones Direct at 65, Table 1 – Costs included in DSMS with EE Resource Plan. Note: the 1st year covers the period August 1, 2013 through December 31, 2014 (a 17 month period) while 2015 and 2016 costs are for a calendar year basis.
[14] TEP Application at 6:12-15.
[15] Hutchens Direct at 17:27–18: 3.
[16] *Id.* at 18:3-10.

1 regulatory asset through 2019. I have summarized the incremental impact in Table 1
2 below.
3

Table 1
Total EE Program Expenditures, Revenue Requirement and Cumulative Impact
2014 - 2019

Line No.	Description	2014	2015	2016	2017	2018	2019	Source
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Total EE Program Expenditures ($MM)	$ 24.74	$ 27.04	$ 27.86	$ -	$ -	$ -	
2	Gross Revenue Requirement for 2014 ($MM)	$ 7.97	$ 7.35	$ 6.89	$ 6.42	$ -	$ -	Exhibit CAJ-7 Attachment D
3	Gross Revenue Requirement for 2015 ($MM)	$ -	$ 8.72	$ 8.04	$ 7.53	$ 7.02	$ -	Exhibit CAJ-7 Attachment D
4	Gross Revenue Requirement for 2016 ($MM)	$ -	$ -	$ 8.98	$ 8.28	$ 7.75	$ 7.23	Exhibit CAJ-7 Attachment D
5	Cummulative Impact ($MM) (sum of line 2, 3 & 4)	$ 7.97	$ 16.07	$ 23.90	$ 22.23	$ 14.77	$ 7.23	

Q. Does the Company argue *that its proposed plan* reduce the cost on customer's bills?

A. Yes. Witness Hutchens argues concerning the EERP that, because the costs of the program are amortized over four years, the DMS surcharge would be lower than if each years' full program costs are recovered in the surcharge.[17] Table 2 shows what the Company claims would be the average customer bill impact under the current methodology and the proposed EERP.

Table 2[18]

	Average Residential Bill Impact	
Year	Current	Proposed
2014	$ 2.04	$ 0.81
2015	$ 2.69	$ 1.46
2016	$ 2.74	$ 2.16

[17] Hutchens at 18:13-17.
[18] *Id.* at 18:19-26.

Witness Hutchens provides a chart that shows that to recover the full cost of the first three years of the program, the bill impact to customers continues on from 2017 through 2019 at $1.99, $1.31, and $.064, respectively.[19]

Q. Does the Company provide any support for the 4-year amortization period?

A. The Company provides three reasons that it argues supports the four-year amortization: (1) four years is a balanced approach between needing timely recovery of the costs and customer desires to have moderate rate increases, (2) accounting rules provide criteria for deferring costs so long as those costs are deemed "probable" for recovery, and four years in the Company's opinion meets this accounting criteria, and (3) the Company believes a four-year recovery period is reasonable and appropriate in order to maintain a moderately sized regulatory asset over time. The Company argues that longer amortization periods will produce larger regulatory assets and by inference more costs to customers (presumably by interest costs).[20]

Q. What does the Company conclude regarding its proposed EE Resource Plan?

A. Witness Hutchens makes the following statement:

> TEP is undertaking an innovative departure from the way in which we traditionally finance and implement EE programs and measures, because we believe that the adoption of cost-effective EE measures significantly enhances the Company's ability to develop a balanced and low cost resource portfolio, which is certainly in the best interest of our customers. Our goal is to develop and deploy measures that provide the greatest operating efficiencies to TEP's generation, transmission and distribution systems; reduce reliance on more costly generating resources; and provide customers with the most cost effective DSM/EE programs.

[19] Hutchens Direct at 19, chart.
[20] *Id.* at 20:12-27.

> By "putting our skin in the game" the Company is taking on additional risk by investing in a regulatory asset that derives value only as a result of an order of the Commission authorizing TEP to recover its costs from customers.[21]

Q. Do you agree that the EERP as proposed by the Company is in the best interest of the customer?

A. No.

Q. Please explain your concerns.

A. I have a number of regulatory and policy concerns that I believe the Commission should consider that lead me to the conclusion that the Commission should reject the Company's EERP as proposed.

(1) The Commission should reject the forward-looking concept proposed by TEP.

(2) The 200-basis-point increase to the ROE is excessive, unnecessary, and should be rejected.

(3) Since cost recovery would be virtually secured, it is unclear that the proposed EERP would provide incentives to maximize the results of the program and, at the same time, provide cost-effective and efficient implementation of the programs.

(4) The Company's proposal would require that the Commission issue one or more waivers of the various requirement of Arizona Administrative Code R14-2, including:

- A.A.C. R14-2-2405 – annual implementation plan
- A.A.C. R14-2-2410 – monitoring plan

(5) While not specifically mentioned by the Company, the EERP is an apparent attempt by TEP to mitigate the effects of regulatory lag.

[21] *Id.* at 22:14-25

Q. Please explain each of your concerns and how they lead you to the conclusion that the Commission should reject the Company's proposed EE plan.

A. With respect to the first concern (the Commission should reject the forward-looking concept proposed by TEP), the Company is asking the Commission to approve a three-year budget that would be trued up at the end of the three years and only to the extent that TEP would reconcile the balance in the regulatory asset to true-up for under-recovered costs, which would take place either in a subsequent rate filing or as part of a second EE resource plan filing.[22]

Q. **Why is this a problem?**

A. There are two problems of note. First, if a program proves to be ineffective or not cost beneficial and is terminated or scaled back, the Company will recover the full amount of the program costs that are included in the three-year budget until the true-up in the next rate case or EE resource plan filing. While this concept is no different from other types of expenses that the Company might experience between rate cases (i.e., various O&M accounts can be over or under during the rate effective period from the amounts at which rates were established), the difference here is that those costs will continue to be recovered, are being capitalized and accruing interest at a premium (i.e., the 200-basis-point adder to the ROE). As such, the Company will not only be collecting program costs that are possibly no longer benefiting ratepayers, but TEP will be earning interest on it as well. While the true-up **may** make the ratepayer whole, since no preset time will be established for the next rate case or EE filing, ratepayers absorb the burden for the excess costs. The Company acknowledged that it would earn a return during all periods regardless of whether it underperforms and/or does not meet the EE standards. In

[22] Jones Direct at 67:21 –68: 7.

response to a RUCO data request, the Company stated, "TEP agrees that if the EERP is approved as proposed, that TEP would earn a return on its EE investments."[23]

Second, pre-approving three years of program plans and costs would require that the Commission provide a waiver of certain sections of the Commission's regulations. Specifically, as required by A.A.C. R14-2-2410, sub-section a.1, the Commission must approve a DSM program or DSM measure **before** it is implemented. In response to a data request, the Company acknowledged, "If the Commission approves the Company's proposal as part of the rate case Order, the Commission would have effectively provided a waiver from the specific requirements set forth in A.C.C R14-2-2410, sub-section A.1."[24] Issuing of waivers to this Commission's directives is, in my opinion, not sound regulatory policy.

Q. What are your concerns with the Company's request for a 200-basis-point premium on the ROE that will be used to calculate the return for investors for the regulatory asset that will be used to recover the EE Plan costs?

A. I believe that the Company has provided weak and inconsistent support for it, and, as such, it should be rejected.

Q. Please explain.

A. The Company attempts to position this 200-basis-point premium as necessary because the "investment" in EE is riskier than its investment in more tangible assets such as power plants, buildings, computers, and other assets.[25] The Company states in response to a data request, "Unlike investments in utility plant, such as power plants, buildings, computers and other assets with an independent market value, TEP's EE expenditures produce intangible assets

[23] Exh. 2, RUCO 3.21.
[24] Exh. 3, STF 3.04.
[25] Hutchens Direct at 18: 2-10.

with no external value outside the creation of a regulatory asset by order of the Commission. A 200 basis point increase on these projects, therefore, reflects the increased risk associated with TEP's investment in these intangible assets."[26] In response to a data request, the Company cites a Nevada Decision in which that commission included in its rules a provision that utilities could include an additional 5% (500 basis points) on the authorized rate of return to the Company for conservation and demand management program costs included in a regulatory asset.[27] However, the Company did not provide a complete picture. In 2010, that provision of the Nevada Administrative Code was deleted.[28] In fact, the current language in the Nevada Administrative Code associated with what rate to apply reads, "*The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the unamortized balance in the subaccounts of FERC Account No. 182.3.*"[29] It is interesting that the Company is using as support an administrative code that was removed more than two years ago. Further, the Company's other support for the premium is as lukewarm to the concept as the Nevada Commission apparently was. The Company, in response to a data request, provided a March 2012 Regulatory Assistance Project ("RAP") report titled, "Regulatory Mechanisms to Enable Energy Provider Delivered Energy Efficiency," in which it does mention rate of return premiums as a means to promote energy efficiency and address the possible financial management problems associated with the regulatory asset.[30] While the report acknowledges the Nevada code, it states that this provision was eliminated when the Nevada Commission introduced a net lost revenue adjustment. The report goes on to say, "Few other jurisdictions have offered this type of incentive mechanism."[31] Finally, it is also interesting that the RAP report also makes the

[26] Exh. 4, STF 3.02.
[27] Exh. 5, RUCO 4.01.
[28] Exh. 6, *ADOPTED REGULATION OF THE PUBLIC UTILITIES COMMISSION OF NEVADA*, LCB File No. R042-10, July 22, 2010.
[29] Exh. 7, Nevada Administrative Code § 704.9523 (4)(b).
[30] Exh. 4, Attachment at 38, STF 3.02 RAP Report.
[31] Exh. 4 Attachment at 39, STF 3.02 RAP Report.

following statement: "To ensure that the financial return rewards productive expenditures, regulators should require energy providers to demonstrate that the resulting programs have achieved performance targets."[32] So, the very document that the Company is relying on for support of its 200-basis-point premium calls this mechanism a "reward" and something that could be used to "promote" energy efficiency, yet, conversely, the Company states that its EERP does not include a performance incentive. Also, and at the same time, the Company is seeking approval of a lost fixed cost recovery mechanism which is that with which the Nevada Commission replaced the 5% bonus in its jurisdiction. The Company's support here is very weak. Therefore, the Commission should reject the concept of a premium on the return associated with the regulatory asset for energy efficiency.

Q. What are your concerns with the Company's incentive to implement its energy efficiency plan in a cost efficient and effective manner?

A. As mentioned earlier, I believe that since cost recovery would be virtually secured under the Company proposed plan, it is unclear that the proposed EERP would provide incentives to maximize the results of the program and at the same time provide cost-effective and efficient implementation of the programs. Since the EERP would in essence pre-approve the EE program cost budgets, a certain amount of "good-faith" would have to be assumed that the Company would implement the programs in a cost-effective and efficient manner. One concern would be whether the Company would have incentive to look for ways to improve program implementation and thereby reduce those costs.

[32] Exh. 4, Attachment at 38, STF 3.02 RAP Report.

Q. **What are your concerns with respect to the implementation of the EERP requiring waivers from the Commission?**

A. As a general rule, I believe that waivers from requirements of commission rules should be held to a high standard of review for the necessity of that waiver. I do believe that TEP's proposed EERP rises to that standard. The Commission's rules require a pre-approval of energy efficiency programs for up to two years subject to whether the Commission finds that the proposed plan meets the energy efficiency goals.[33] These rules were carefully crafted to balance the needs of the stakeholders in the process, and any deviation should not be taken lightly. In this case, TEP is proposing at least two waivers. The first is to A.C.C R14-2-2405 which states, "*Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article.*" In response to a data request which asked whether the Company's proposed implementation plan was in compliance with section 2405, the Company responded:

> The purpose of the EERP is to create an alternative mechanism that will fulfill the spirit and objectives of the Electric Energy Efficiency Standard set forth in A.A.C. R14-2-2404. If the Commission approves the Company's proposal as part of the rate case Order, the Commission will have effectively provided a waiver from the specific requirements set forth in A.A.C. R14-2-2405[34]

[33] A.A.C. R14-2-2407.
[34] Exh. 8, STF 3.01.

As such, the Company would only file updates to the existing plan, not a full request for approval of a new plan which identifies how the Company intends to meet the energy efficiency standards as specified in A.C.C. R14-2-2403. In addition, the Company was unclear whether addressing DSM programs or measures which are found not to be cost-effective that need to be modified or terminated in the annual implementation plan filing would be compliant with R14-2-2410 (c). In Exhibit 3 the Company stated:

> Because the program or measure was determined to be cost effective during the planning and implementation stage, all allowable costs incurred for the program up to the actual date of termination will be collected under the DSM surcharge. This satisfies the requirement under A.A.C. R14-2-2410 (c).

This response does not indicate how the DSMS would be adjusted during the three-year plan period.

Q. What do you conclude with respect to these waivers and open issues related to complying with the Commission's rules and regulations and being in the interest of ratepayers?

A. For all the reasons mentioned above, I recommend that the Commission reject the Company's EE Implementation Plan for not being compliant with the Commission's Energy Efficiency rules and regulations and for not being in the public interest.

Q. You mentioned that you believe that the EERP is an attempt to mitigate regulatory lag. Is that correct?

A. Yes.

Q. What leads you to this opinion?

A. The Company does not overtly state that the proposed rate mechanism and upfront collection of costs is being proposed to mitigate regulatory lag. However, these cost recovery mechanisms are intended to provide additional cash flows for costs that the utility is attempting to recover *before* they are reviewed by the Commission in a formal rate case setting. The mechanism is designed to ensure recovery between rate cases, and that would, from the utility's perspective, mitigate regulatory lag.

Q. Are you recommending an alternative plan?

A. Yes. However, there are components of the Company's plan that I believe are salvageable.

Q. **Please continue.**

A. There are two parts to my recommendation. First, I am recommending that the existing DSMS be eliminated once all unrecovered costs, including any *actual* incentive earned, are accounted for and recovered over a one-year period beginning with the effective date of the Commission approved rates in this proceeding. Second, I am recommending that the Commission adopt the concept of establishing a regulatory asset for approved EE implementation costs that TEP incurs to achieve the Commission's energy efficiency goal. I am also recommending that the Commission allow the Company to earn a return on that investment of no greater than what the Commission approves for the weighted cost of capital in this proceeding. The amortization period for this regulatory asset will be seven years on a rolling basis and will be trued up each year and adjustments made to the Company's DSMS to reflect any under or over recoveries. This seven-year period is based in part on a composite weighted average of the useful life of the various measures

that are included in the Company's proposed EE Implementation Plan and on balancing the interests of stakeholders.

Q. The Company claims that four years is a reasonable period to amortize the regulatory asset. How do you respond?

A. The Company points to U.S. Generally Accepted Accounting Principles ("GAAP") and its own judgment in determining what the amortization period should be and arrives at the conclusion that four years is appropriate. The Company offers no substantive proof that a long amortization period is either riskier or is detrimental to ratepayers. In fact, in response to a staff data request, the Company stated, "Accounting standards do not prohibit the Commission from setting longer (or shorter) amortization periods."[35] I believe that a seven-year period is reasonable and balances the need to recover the principle of the regulatory asset while the EE measures are achieving the savings claimed by the Company and providing the benefits to ratepayers with the need to mitigate rate impacts to customers.

Q. Would your plan include projected costs as proposed by TEP?

A. No. I recommend that the Commission allow only those costs that have been actually incurred and verified to their effectiveness per the Commission's verification regulations as specified in R14-2-2415; Monitoring, Evaluation, and Research.

Q. Please explain the first part of your proposal?

A. At the present, the Company's EE programs are subject to the terms and conditions established in its last base rate case settlement in 2008 as approved in Commission Decision 70628. The Company currently is collecting $0.001294 per kWh for all its

[35] Exh. 9, STF.3.06.

customers except those customers who take service under the Residential Lifeline Discount or Residential Lifeline/Medical Life-Support Discount pricing plans.[36] These revenues are being used to pay for the Company's current EE efforts. The EE plan currently in effect includes costs and a performance incentive that TEP is entitled to collect, assuming the costs are reasonable and prudent. The first part of my proposed plan would allow the Company to recover any unrecovered costs that the current DSMS surcharge does not cover. The Company would be permitted to include the actual unrecovered costs and the actual performance incentive that it earned up through the effective date of the Commission approved rates in this case. This would require a full accounting to be provided as part of the Company's compliance filing with the Commission's order in this case. The existing DSMS surcharge tariff would then be used to collect these funds based on the approved sales forecast in this case for the twelve months of the rate effective period, which is anticipated to be July 1, 2013, to June 30, 2014. While this surcharge is in effect, and assuming a decision in Docket E-01345A-11-0055, the Company would also be incurring its EE Plan costs for the remainder of 2013. On April 1, 2014, the Company would file its proposed EE Plan for 2014 *plus* an accounting of the actual EE program costs for those *actual* costs incurred after July 1, 2013, through the end of the year, December 31, 2013. The Commission's rules allow for the parties to review and comment in a proceeding before the Commission with the Commission making a decision to approve or modify within 180 days of the filing. I would recommend that, to the extent possible, the review process be expedited or even a new rule issued that shortens that period to 120 days, such that the new rate would be effective on or about July 1 of each year. This would be possible in that the prospective part of the plan would be for informational purposes only and that only approved programs would be subject to the accounting for actual costs.

[36] TEP Tariff Rider R-2 - Demand Side Management Surcharge (DSMS) Effective June 1, 2010.

Q. Does this mean that during the first year after approval of your plan that the Company will not have a surcharge in place since the costs have yet to be incurred?

A. No. As I previously mentioned, during the first year of the plan, the Company would be allowed to recover the unrecovered balance of costs from the current DSMS as of the effective date of the rates approved by the Commission in this proceeding. However, my proposal does envision that the Company will incur the program costs **BEFORE** TEP is allowed to recover them in the surcharge. I acknowledge that because of the review and approval process as required by the Commission's rules and regulations, there could be *ten months* between the time the last of the costs are incurred and when recovery is allowed to begin. However, to recognize this lag, I am not opposing the carrying cost rate at the Company's approved weighted cost of capital and would recommend that the Commission allow the Company to accrue the carrying cost from the date the costs are incurred starting with the effective date of the Commission order in this case. In addition, I am recommending that the Commission expedite, to the extent possible, the review and approval schedule with the filings from 180 days to 120 days, as allowed by Commission rules.

Q. Should the Commission accept your recommendation, how would the Company comply with your proposed plan?

A. The Company would be required, as part of its compliance filing for this case, to provide a schedule which shows the unrecovered costs balance as of the anticipated rate effective date including the actual performance incentive earned. Included as Exhibit 15 is an illustrative example of the derivation of the Company DSMS rate for the period July 2013 through June 2014. I have estimated the unrecovered balance at approximately $22.5 million, which is the $4.5 million of unrecovered costs included in Company Witness

Jones's testimony plus $18 million of estimated unrecovered costs[37] for the period since the last rate for DSMS was approved in 2010. This estimate would have to be updated. With this assumption and with applying Staff's recommended cost of capital, I estimate that the DSMS will be $.00XXX per kWh from July 1, 2013, until June 30, 2014.

Q. **Would the current Rider R-2 Demand Side Management Surcharge ("DSMS") stay in place during this period?**

A. Yes. However, it would have to be modified to accommodate the 2nd part of my recommendation.

Q. **Please explain the second part of your recommendation.**

A. According to the requirements of R14-2-2409, on April 1, 2014, the Company will file its annual implementation plan and include the actual expenditures that it incurred from when it begins implementation of the EE Plan as will be ordered in Docket No. E-0139A-11-0055. At present, Staff is recommending in that proceeding that the program costs needed to meet the Commission energy efficiency standards for 2012 and 2013 is $23 million. I defer to Staff Witness Julie McNeely-Kirwan on the specific recommendations concerning the programs that TEP was proposing for 2012 and 2013. In that filing on April 1, 2014, the Company would provide all the requirements of R14-2-2409 showing the **ACTUAL** expenditures and results for July 1 to December 31, 2013.

Modeling the schedules that Company Witness Craig Jones sponsored in Attachment D in the Company's proposed plan of administration, I have prepared Exhibit 15 Staff Derivation of Alternative Plan Revenue Requirement for EERP. My intention is to show this as an illustrative example of what the potential revenue requirement impact will be

[37] Unrecovered costs would be the sum of actual EE Plan expenses plus the actual incentive less the revenues collected from the existing DSMS rate.

along with a comparative analysis to the proposed DSM surcharge rates that are included in the Company filing. I have modified the methodology slightly to simplify the calculation and have eliminated the long-debt component. As mentioned above, I am recommending a regulatory asset similar to that proposed by the Company and I am recommending that asset to accrue interest at the Company's allowed overall rate of return. My analysis reflects the 7.0% overall return proposed by Staff Witness Dr. Berry.

Q. **What were the results of your analysis?**

A. Based on the information contained in Exhibit 15, Table 3 below shows the comparative results for the rate per kWh to customers for my recommended implementation plan versus the Company's plan.

Table 3 – EERP DSMS Rates Comparative Results

Year	Per Company	Per Staff	Difference	Percent
2014	$ 0.000916	$ 0.000565	$ (0.000351)	-38.32%
2015	$ 0.001664	$ 0.000868	$ (0.000796)	-47.84%
2016	$ 0.002454	$ 0.001468	$ (0.000986)	-40.18%
2017	$ 0.002265	$ 0.002044	$ (0.000221)	-9.76%
2018	$ 0.001492	$ 0.001912	$ 0.000420	28.15%
2019	$ 0.000723	$ 0.001589	$ 0.000866	119.78%

Q. What do you conclude from this analysis?

A. Over the short term, ratepayers will be burdened less that under the Company's proposal and, at the same time, the Company will have a suitable level of funding to implement cost-effective programs to meet the Commission's goals.

Q. Does this conclude your testimony on the EERP?

A. Yes, it does.

ENVIRONMENTAL COMPLIANCE ADJUSTOR ("ECA")

Q. Please describe the ECA proposed by the Company.

A. The Company is proposing the ECA to provide for the recovery of and return on capital investments and associated costs related to environmental investments made by TEP and not already recovered in base rates or recovered through another Commission-approved mechanism. 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 ("CWIP") during the preceding calendar year.

Q. Why does the Company believe that an ECA is necessary?

A. Company Witness Hutchens states that the ECA is necessary for the following reason:

> It will allow TEP to recover the significant costs required to meet environmental compliance standards imposed by federal or other governmental agencies. The availability of an adjustor to recover theses costs ***as they are incurred*** would moderate the impact on our customers, avoiding the large rate increases that would result from deferring these costs to a future rate filing.[38]

Further, Witness Hutchens offers why TEP is proposing it in this rate case by stating:

> TEP is proposing the implementation of the ECA in this rate case in response to an ever increasing number of rules creating more stringent environmental standards that require the Company to invest an unprecedented amount of capital in its generation resource portfolio over the next five years. The EPA and other federal agencies (e.g. Office of Surface Mining) recently have mandated through various rulemakings that certain electric utility generating facilities install, upgrade, and revise environmental control measures and practices. These rules include, but are not limited to, EPA final rules and proposed rules that will likely become final in the foreseeable future.39

[38] Hutchens Direct at 23:11-15.
[39] *Id.* at 23: 21 –24:2.

Q. What proposed rules does the Company believe will be enacted that will impact the capital requirements for compliance?

A. Witness Hutchens provides two categories: Final Rules and Proposed Rules. The final rules[40] include the following:

- Regional Haze Best Available Retrofit Technology ("BART") mandates
- Mercury and Air Toxics Standards rule ("MATS")
- Greenhouse Gas New Source Performance Standard ("GHG" "NSPS") for new sources.

The proposed rules[41] include these elements:

- Coal Combustion Residuals ("CCR")
- GHG NSPS for existing sources
- Greenhouse Gas Prevention of Significant Deterioration Permit ("Tailoring Rule")
- Ozone Standards
- 316(b) Cooling Water Intake Structure modification.

Witness Hutchens states that these rules "will require increased capital spending for the installation of additional equipment with corresponding increases in O&M costs associated with the installation and operation of such equipment or implementation of new environmental protocols at TEP's facilities."[42] He provides an approximate breakdown of the possible investments:

- $200 million capital & $3-6 million in O&M for San Juan Generating Station for BART
- $86 million capital & $2-4 million in O&M for Navajo Generating Station for Bart and MATS
- $36 million capital and $2-4 million in O&M for Four Corners Power Plan for BART and MATS

[40] Hutchens Direct at 24: 4-7.
[41] *Id.* at 24:10-15.
[42] *Id.* at 24:17-20.

- $5 million capital and $3 million in O&M for Springerville Generating for MATS[43]

Witness Hutchens states that these capital investments will reduce the plant capacity because of the increased station power need for the equipment. He opines that the total capital outlay could reach $400 million and that TEP "will not be able to phase-in or control the timing of these costs, as the compliance deadlines are mandated exclusively by the EPA and judicial rulings."[44]

Q. What impact does the Company say complying with mandates will have on its customers?

A. Witness Hutchens opines:

> It is likely that most of the expenditures discussed above will occur between rate cases. The inability to recover the significant environmental compliance costs as they are incurred, places TEP and its customers in an untenable position. With respect to TEP, these environmental mandates will result in reduced cash flow and increased capital and O&M expenditures without recovery of those costs through increased revenue because of the extended time between the adjudication of TEP rate cases. This will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms. TEP's customers will be negatively impacted by the extended timeframe between rate cases because the accumulated capital costs and increased O&M will result in larger rate increases.[45]

Witness Hutchens maintains that the Company believes it is "preferable" to recover these mandate costs over time and not as established in rate cases. He argues that this will lead to more moderate annual rate increases and not cause the Company to suffer any financial harm.[46] He concludes that ECA treatment will enable the Company to "meet governmental mandates, especially environmental requirements given their significant impact on TEP and its generation resource portfolio."[47]

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[43] *Id.* at 24: 21 –25:25.
[44] *Id.* at 25:11-15.
[45] *Id.* at 25:19 –26: 2.
[46] *Id.* at 26: 4-7.
[47] *Id.* at 26:13-15.

Q. Do you agree that TEP *needs* a cost-tracker mechanism such as the proposed ECA at this time?

A. No. I do not agree that the Company *needs* a cost-tracker such as the one proposed. The Company offers no evidence that its cash flows are unable to sustain the needed capital requirements for the potential mandate compliance. Further, despite being given the opportunity to do so, the Company did not provide any evidence beyond a hypothetical explanation of financial consequences to the Company should they be required to make the investments for complying with the mandates before recovery of prudently incurred costs are allowed in base rates. In a response to a Staff data request, the Company was asked to fully explain Witness Hutchens's statement in his direct testimony: "*This will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms.*" The Company responded:

> TEP would be investing hundreds of millions of dollars over the course of several years but would be precluded from any recovery of that investment until years later. Investing the equivalent of approximately 30 percent of TEP's rate base for several years without receiving any return on that investment would put pressure on the Company's ability to maintain its current credit ratings.
>
> If TEP's credit ratings were to be lowered due to weakening cash flows resulting from the Company's inability to earn a return on and of the significant amount invested between rate cases, TEP's cost of debt would increase, thus increasing costs to ratepayers. Weakening financial metrics would likely put downward pressure on UNS's stock price, which would also increase the cost of equity financing available to TEP.[48]

However, despite the theoretical claim to the contrary, there is no evidence that the normal regulatory treatment (i.e., AFUDC) of large capital expenditures such as these would financially harm the Company. Contrary to the Company's claims, it is my opinion that the ECA is a mitigation to regulatory lag because the Company has offered no evidence to show that it would, in fact, be substantially harmed from the financial consequences of the

[48] Exh. 10, STF 3.13.

needed capital outlays despite being given the opportunity to do so in Staff 3.13.

Q. The Company claims that its ECA is "similar" to the EIS mechanism recently approved in the Arizona Public Service Company ("APS") base rate proceeding, but TEP tailored it to meet its needs and that of its customers. Do you agree?

A. The Company certainly tailored its proposed ECA. However, I disagree that TEP's ECA is tailored according to the APS EIS. Rather, in my opinion, the ECA is more reflective of what APS originally proposed as its "Environmental and Reliability Account" ("ERA") in Docket No. E-01933A-11-0224.

Q. Please explain.

A. As I testified in the APS case, APS's ERA was designed to recover "both the return ***on*** the capital investment as well as the return ***of*** the investment through depreciation expense. In addition, APS proposed to include the revenue requirement components for the qualified investments, including income and property taxes, deferred taxes, tax credits where appropriate, and operations and maintenance expenses ("O&M")."[49] In the approved settlement in that case, the Company withdrew its ERA proposal and the existing EIS was modified in settlement to include capital carrying costs associated with government-mandated environmental controls, subject to a cap.[50] TEP's proposed ECA does not include a cap and more importantly includes most, if not all, of the categories' cost that APS originally requested in its ERA. Therefore, TEP's proposed ECA is not similar to the approved APS EIS.

[49] Exh. 11 at 6:3-7, McGarry Direct, Docket No. E-01345A-11-0224.
[50] Exh. 14, Decision No. 73183 at 15: 15-19, Docket No. E-01345A-11-0224.

Q. What types of mandates and investments is TEP proposing to include in the ECA?

A. In a data request, TEP provided a list of the projects and the dates that the expected mandates became or would become final and when the Company would be expected to comply. In addition, the Company provided its capital budget for these projects for the period 2013-2019. In response to STF 18.2 (a confidential response),[51] the Company provided a list of dates for both the final rules and proposed rules. [redacted]

[redacted] From this information, some relief may be warranted for those projects that are expected to be in-service in the next 2-3 years.

[51] Exh. 12, STF 18.3 (CONFIDENTIAL).
[52] [redacted]

Q. If adopted as proposed, how will the ECA work?

A. TEP Witness Craig A. Jones sponsored the Plan of Administration ("POA") which describes how the ECA will be implemented and monitored. Each March 1, the POA indicates that TEP will file with the Commission its proposed ECA rate for the previous year and include supporting data and schedules. The Commission Staff and interested parties would then have an opportunity to review the ECA filing and supporting data. The ECA would become effective May 1 unless the Commission acted to suspend the filing by May 1. Once approved, the ECA would be in effect for a twelve-month period.[53]

Q. How would TEP propose to define "Qualified Environmental Compliance Projects"?

A. In a data request, TEP provided a list of the projects and the dates that the expected TEP would define a qualified investment for purposes of inclusion in the ECA as follows:

> 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, but are not limited 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.[54]

TEP would include the follow specific accounts when determining the costs that would flow through the ECA:

Steam Production: FERC Accounts 310 to 316
Other Production: FERC Accounts 340 to 346
Completed Construction not Classified: FERC Account 106
Construction Work In Progress – Electric: FERC Account 107

[53] Jones Direct, Exh. CAJ-6 – Plan of Administration – Environmental Compliance Adjustor.
[54] *Id.*, Exhibit CAJ-6, Environmental Compliance Adjustor ("ECA") Plan of Administration, 2. Definitions Page 1

Q. Does the Company propose to recover just capital costs and the carrying costs associated with those investments?

A. No. The POA includes a full revenue requirements calculation for all the costs for these projects including CWIP. It includes depreciation expense, income taxes, property taxes, deferred taxes and tax credits, and O&M expense.[55]

Q. In your opinion, is the ECA intended as a form of interim rate relief between rate cases?

A. Yes. This rate mechanism is intended to provide additional revenues to the Company that it would otherwise not be entitled to outside the normal litigated rate case process.

Q. Are there circumstances in which the Commission should consider allowing a utility to recover significant capital costs outside the normal regulatory process (i.e., base rate cases)?

A. Yes.

Q. What issues should the Commission consider when deciding whether to approve a cost tracker such as the ERA?

A. As I have previously testified to before the Commission, to allow a cost tracker which provides a utility the opportunity to collect additional revenues outside the normal rate case process should be based on individual utility circumstances and not on a one-plan fits all method. Any utility would want a cost tracker as it avoids and mitigates the impact that the regulatory process, often referred to as regulatory lag, has on a utility's ability to earn its allowed rate of return. A tracker has the ability to provide additional funds for operation, which may reduce the need for short-term debt, thus saving ratepayers interest

[55] *Id.*, CAJ-6, Environmental Compliance Adjustor ("ECA") Plan of Administration, 2. Definitions Page 2

costs. However, these reasons alone are not sufficient to circumvent the regulatory process. There are significant downsides to cost trackers.

Q. What are the downsides of a cost tracker such as the ERA?

A. The disadvantages related to cost tracker overuse include the following:

- Weakening the incentive of a utility to control costs
- Undercutting the positive effects of regulatory lag
- Biasing a utility's technological and investment decisions
- Motivating utilities to shift more costs to functions subject to trackers, diluting frequency and quality of cost reviews
- Having the tendency to be more complicated and burdensome to both the Commission staff and to consumers
- Producing a negative perception by consumers due to more frequent press reports of "rate increase"

Q. Under what circumstances might the Commission approve a tracker such as the ECA?

A. The primary circumstance in which the Commission should consider approving a tracker such as the ECA would be when the utility is mandated to make significant capital expenditures to meet mandates of others on the utility. As such, federal, state, local, tribal, and other mandates involving significant or extraordinary capital investment to meet environmental statutes, rules, and/or regulations that could significantly harm the utility's financial well-being would be one reason for a tracker. However, the Commission should also consider the ability of the utility to fund the investment either by its own internal cash or financing before asking ratepayers to incur the additional hardship a tracker would place on them. Another important variable would be whether the costs are expected to be volatile, unpredictable, and outside the utility's control and thereby potentially causing significant financial harm to the utility and ultimately its ratepayers. The Commission's Power Supply Adjustor ("PSA") fits into this category. The costs are significant and can

be volatile, and price spikes from unforeseen events (such as a major hurricane in the Gulf of Mexico) can have a significant impact on the financial health of a utility while also negatively impacting its ratepayers.

Q. Do you recommend that the Commission approve the ECA proposed by TEP?

A. No. The Commission should reject the ECA as currently proposed by the Company.

Q. Why?

A. The ECA as presented by TEP is too broad and includes capital investments that are not as of yet mandated or whose compliance date is well outside the timeframe in which I believe the Company will request another base rate increase. It also includes other types of costs that are not capital in nature, such as CWIP, O&M and property taxes. Trackers are implicitly an interim measure to provide relief to a utility for costs which are mandated, significant, potentially volatile, and out of the utility's control. A tracker is not intended as a permanent fix to make up for the regulatory lag in the ratemaking process.

Q. Are you aware of any extraordinary events in which the Commission dealt with the possible effects of a federal mandate that could have had considerable negative impact on a group of utilities?

A. Yes. As I testified to in the APS case, such an example is the circumstances surrounding the arsenic water remediation cases in Arizona.[56] It is my understanding that both Staff and ultimately the Commission were concerned that if the water utilities in Arizona were not provided interim rate relief in the form of a tracker, the financial consequences could have been staggering, even to the point of one or more of the utilities filing for bankruptcy. Even worse was the possibility that if a water utility was unable to comply

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Exh. 13, Decision No. 66400, Docket No. W-01445A-00-0962 (October 14, 2003).

with the EPA mandates, the EPA could have shut down the utility forcing its customers to find other sources of water. A tracker was implemented for water utilities to meet the federal mandates associated with water utilities' ability to install the capital equipment necessary to meet the new and more stringent requirements related to arsenic in Arizona wells which were based on specific circumstances and conditions.[57]

Q. What were those conditions?

A. The conditions under which the Commission approved the tracker included the following:

- The tracker was temporary and had a two-step filing process.[58]
- The tracker was focused on only those projects related to arsenic remediation.[59]
- The tracker included limited amounts of O&M with a deferral mechanism set up to recover costs at a later date.[60]
- The Company would set a specific date for the next rate filing.[61]
- The EPA mandates had severe and significant consequences.[62]

Q. Are the proposed ECA and the Arsenic water mandates similar?

A. No. Both are intended to provide the utilities interim relief between rate cases for capital expenditures that are legally mandated. However, TEP's proposed ECA differs significantly in that it may include costs for projects that are not yet mandated (only anticipated) and includes non-capital costs not typically included, such as depreciation, taxes, and O&M. Notably, TEP's tracker would appear to be a permanent tracker updated annually, which is unlike the arsenic water cases which were temporary and included specific timeframes for rate filings. Finally, the ECA does not afford customers any

[57] *Id.*
[58] Id at 21:27-28:28.
[59] Id. at 22:1-2.
[60] Id. at 6:23-25; 7:1-2; and 19:26-28.
[61] Id. at 10:8-10.
[62] *Id.* at 3:26; 4:1-4 .

prescribed protection from substantial rate increases as the result of the tracker and its updates in the form of a cap.

Q Should the Commission approve the ECA as proposed by the Company?

A. No. I recommend that the Commission reject the ECA proposed by TEP as the Company has not demonstrated that circumstances warrant an extraordinary action as was the case with the arsenic problem for water utilities.

Q. What do you recommend?

A. Since the Company has several major projects that it must meet in the next 2-3 years and to be consistent with the treatment that APS received in Docket No. E-0139A-11-0224, I recommend that the Company modify its request and submit a proposal that mirrors the EIS approved by the Commission. This proposal would include a revised plan of administration that would state that the Company would collect only actual capital costs for the environmental mandates that it is required to install plus the carrying costs (at the approved weighted costs of capital). I would recommend that the Company adopt the following language as part of a revised plan of administration:

> *Calculation of EIS Capital Carrying Costs*
>
> EIS capital carrying costs used in calculating the EIS $ per kWh rate will include the following: (1) return on EIS Qualified Investments based on the Company's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. 73183, (2) depreciation expense, (3) income taxes, (4) property taxes, (5) deferred income taxes and tax credits where appropriate, and (6) associated O&M. EIS Qualified Projects and the EIS capital carrying costs calculation will be submitted by the Company to the ACC in the form of Schedule 1 and Schedule 2, as attached to this document.

In addition, any approval for such a mechanism should alleviate the need for frequent base rate increases as a result of these capital outlays. The Company would be recovering the mandated capital investment plus carrying costs before the next base rate proceeding. It is important to note that the parties to the settlement in the APS case acknowledged that the revised EIS was a contributing factor to the length of the "stay-out" provision to which APS agreed.[63] I would expect that any settlement in this case would include a similar recognition. Finally, at the Company's next base rate proceeding, any unrecovered balance of capital investments for this tracker would be moved to base rates and the rate reset to zero.

Q. **The EIS in the APS case included a cap. Do you propose such a cap in this proceeding?**

A. Yes. I believe a cap is a reasonable mechanism to mitigate ratepayer impacts. Absent a similar cap such as that which exists with APS, I believe that a cap that increases the customer and delivery charges portion of the customer's bill by no more than 1% is reasonable.

Q. Does this conclude your testimony related to ECA?

A. Yes. It does

[63] Exh. 14, Decision No. 73183 at 25:25-26.

EXHIBIT 1

Experience and Qualification of Michael J. McGarry, Sr.

Summary

Mr. McGarry's professional experience spans thirty-one years within the private and public sectors. He has conducted over thirty comprehensive management and operational audits of investor-owned energy, telecommunications, and water utilities. These audits have included comprehensive management audits and/or operational audits on most utility functions including corporate governance, strategic planning, internal auditing, capital and operating budget process and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Project Management

Mr. McGarry's experience includes management of multi-discipline teams for a wide range of client engagements, development and implementation of detailed work plans and project schedules. He has analyzed and planned interdivisional resource utilization; supervised, developed and coached interdivisional team members; and created numerous executive reports, briefings, and presentations.

Regulatory and Rate Case Management

Mr. McGarry has worked with clients to manage all aspects of the regulatory and rate case process. He has developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners. He is a seasoned project manager and has analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner. Mr. McGarry has assisted a number of clients in preparing revenue requirement and cost of service analyses. He has also developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports, and annual wholesale rates for member cooperatives. He has developed complex revenue requirement models to present alternative positions to a utility's proposed rate request.

Testimony and Witness Preparation

Mr. McGarry has proffered and/or supported testimony in Arizona, Colorado, Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, Pennsylvania and Utah. These proceedings included testimony involving management decision and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management, and others.

Utility Management and Operational Audits

Mr. McGarry has conducted over thirty comprehensive management and operational audits of investor-owned energy and telecommunications utilities. These audits have included comprehensive management audits and/or operational audits on most functions within the utility environment including corporate governance, strategic planning, internal auditing, capital and operating budget processes and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Restructuring, Unbundling, and Cost Allocation

Mr. McGarry has developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for utilities. This has included detailed studies where the company's plant-in-service and depreciation reserve was allocated to each unbundled function. He has assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services.

Training and Public Speaking

Mr. McGarry has presented topics before Commission staff groups, NARUC sub-committee groups, and as a program faculty member (2010 & 2011) for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, price regulation theory, and cost trackers.

Education

Potsdam College, B.A., Economics, 1981
University at Buffalo School of Management, MBA, 1996

Regulatory Experience

Before the Arizona Corporation Commission (AZCC)
Docket No. 12-0291 *Application of Tucson Electric Power Company for Just and Reasonable rates and charges to realize a reasonable rate of return in Arizona*, before the AZCC. August 2012 - present
Project Manager and Testifying Witness. Oversaw analysis and assessment of the company's proposed cost of service and rate design, cost of capital and return on equity, and energy efficiency mechanisms. Will provide written testimony in support of Staff's position regarding energy efficiency mechanisms and environmental compliance adjustor.

Docket No. 11-0224 *Arizona Public Service Company Rate Case*, before the AZCC. July 2011-March 2012
Project Manager and Testifying Witness. Analyzed the company's proposed Infrastructure Tracking Mechanism, power supply adjustor, and tariffs. Testimony filed November 2011.

Before the Connecticut Public Utilities Regulatory Authority (PURA)

Docket 10-02-13 *Application of Aquarion Water Company to Amend its Rate Schedules*
On behalf of the PURA. April-August 2010
Project Manager. Oversaw rate case analysis and assessment of the company's proposed revenue requirement specifically related to cash working capital and test year expenses. Assisted with analysis of specific issues and preparation of Commission's recommended decision.

Docket 07-07-01 *Diagnostic Management Audit of Connecticut Light & Power Company.*
On behalf of the Staff of the PURA. July 2008-June 2009
Project Manager. Performed overall day to day project management responsibilities to conduct a diagnostic management audit of the Connecticut Light & Power Company (CL&P). Managed a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of all aspects of the company. In addition, managed a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122 million customer information system known as CustomerCentral or C2.

Before the Delaware Public Service Commission (DEPSC)

Docket No. 11-528 *On behalf of the Staff of the DEPSC in the matter of the application Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates.* January-July 2012
Project Manager and Testifying Witness. Oversaw rate case analysis and assessment of the company's proposed inter-company allocations. Provided expert testimony regarding the impact of the sale of Conectiv Energy on inter-company allocations and the resulting impact on revenue requirements.

Docket No. 09-414 *On behalf of the Staff of the DEPSC in the matter of the application of Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates.* September 2009-May 2010
Project Manager. Oversaw rate case analysis and assessment of the company's proposed revenue requirement. Assisted with analysis of specific issues and preparation of witness testimony.

Docket No. 07-239F *On behalf of the Staff of the DEPSC in the matter of the application DPL for approval of modifications to its gas cost rates.* October 2007-April 2008
Project Manager and Testifying Witness. Oversaw review of DPL gas hedging program and testified to the findings and conclusions.

Docket No. 06-287 *On behalf of the Staff of the DEPSC in the matter of Chesapeake Utilities Corporation's implementation of a Gas Hedging program.* June-August 2007
Project Manager. Provided industry expertise and suggestions to the Commission on a proposal plan to implement a gas hedging procurement program at the company.

Docket No. 06-284 *On behalf of the Staff of the DEPSC in the matter of DPL's request for a $15M increase in gas base rates.* October 2006-March 2007
Project Manager and Testifying Witness. Testified on several rate base and revenue requirement issues. Recommended Commission reduce proposed rate increase request to $8.4M (56%).

Before the District of Columbia Public Service Commission (DCPSC)

Formal Case No. 1093 *In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's (WGL) Existing Rates and charges for Gas Service*

On Behalf of the DCPSC. June 2012-present
Project Manager and Lead Consultant. Managed team of consultants providing advisory services to Commissioners and Staff on proposed revenue requirements, rate base, and rate design. Led analysis of revenue requirements, fuel costs, uncollectibles, environmental issues affecting rate base, inventory adjustments, plant in service, construction work in progress, research and development issues, safety initiatives, affiliate allocations, and energy funds.

Formal Case No. 1087 *In the Matter of the Application of the Potomac Electric Power Company (PEPCO) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*

On Behalf of the DCPSC. September 2011-present
Project Manager and Lead Consultant. Advised Commissioners and Staff on proposed revenue requirements, rate base, rate design, reliability projects, and cost recovery mechanism.

Formal Case No. 1076 *In the Matter of the Application of PEPCO for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.*
On Behalf of the DCPSC. July 2009-June 2010
Project Manager. Advised Commission Staff on the company's and intervener's filings and testimony regarding revenue requirements, rate base, cost of service, rate design, bill stabilization, and depreciation.

Formal Case No. 1053 - *Technical consultant for the DCPSC in the matter of PEPCO's request for a $50.4 million increase in base rates.* February 2007-June 2008
Project Manager. Provided technical expertise to Commission in evaluating PEPCO's rate case filing. Commission accepted adjustments which reduced the allowed increase by a significant percentage.

Formal Case No. 1032 *In the Matter of the Investigation into PEPCO's Distribution Service Rates*

On Behalf of the DCPSC. January-March 2005
Project Manager. Review and evaluation of PEPCO compliance filings for class cost of service and revenue requirements for distribution service pursuant to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff on 23 designated issues and 13 company proposed adjustments. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.

Formal Case No. 1016 *In the Matter of the Application of Washington Gas Light Company (WGL), District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service*

On Behalf of the DCPSC. June-December 2003
Project Manager and Consultant to Commissioners and Staff. Project Manager for the analysis of WGL's rate filings. Provided analysis and recommended adjustments to the DCPSC Staff on WGL's proposed increase to base rates. Advised the Commission during deliberations on party positions and possible recommendations.

Before the Hawaii Public Utilities Commission

Docket No. 05-0075 *In the matter of a proceeding to investigate Kauai Island Utility Coop's Proposed Revised Integrated Resource Plan and Demand Side Management Framework.* June 2005-January 2006
Project Manager. Managed a team of consultants responsible for evaluating the impact of the changes proposed by the company.

Before the Illinois Commerce Commission (ILCC)

Case: 05-0597 *On behalf of the Illinois Citizens Utility Board, Cook County States Attorney's Office and City of Chicago.* November 2005-May 2006
Project Manager and Testifying Witness. Provided analysis and recommended adjustments in the general rate increase of 20.1% or $320 million filed by ComEd.

Consultant to Illinois Power Company. Conducted mandated compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the company's controller.

Consultant to Illinois Power Company. Prepared 2001 required update filing for the ILCC compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the company's controller.

Before Maine Public Utilities Commission (MEPUC)

Case No 2008-151 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase II)*

On behalf of Maine Public Advocate. July 2008-July 2010
Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to follow-up on investigation for the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Case No 2004-813 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase I)*

On behalf of Maine Public Advocate. November 2004-March 2005
Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to investigate the need for the program and the company's management of the repair or replacement of its cast iron facilities. Participated in panel testimony regarding cost and risk of the program.

Before the Maryland Public Service Commission

Case No. 9092/9093 (Phase II) *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO and Delmarva Power & Light Company.* December-March 2008
Project Manager and Testifying Witness. Provided rebuttal testimony on behalf of the Commission related to the reasonableness of the costs and charges of Pepco Holdings, Inc. Service Company.

Case No. 9092 *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO.* January-June 2007
Project Manager. Reviewed and analyzed the company's base increase request and all pro formas, adjustments to test year revenue requirement and supported witness testimony. Commission approved less than 20% of the company's original request.

Case No. 9062 *On behalf of the Maryland Office of People's Counsel in the matter of the application of Chesapeake Utilities Corporation for authority to revise its rates and charges for gas service.* May-August 2006
Project Manager. Managed a project team responsible for providing expert witness testimony in the areas of revenue requirements, rate base, cost of service, revenue allocation, rate design, revenue normalization, and cost of capital.

Before the Massachusetts Department of Public Utilities (MADPU)

Case No. D.P.U. 08-110 *On behalf of the MDPU regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company.* February-August 2010
Project Manager. Managed a project team of accountants and industry specialists who were responsible for evaluating the accuracy of the accounting records, practices and procedures used in the development of the company's revenue requirements calculations in the company's base rate request.

Before the Michigan Public Service Commission

Case No. U-16655 *On behalf of the Attorney General of the State of Michigan (MIAG) in the matter of the application of Consumers Energy Company (CECO) for authority to reconcile its renewable energy plan (REP) costs associated with the plan approved in Case No. U-15805 and Case No. U-16543.* September 2012-present
Project Manager and Testifying Witness. Review the company's REP Cost Reconciliation for 2011 to ensure the adherence to approved processes and reasonable and prudent costs. Testified regarding the company's methodology used to calculate its proposed PSCR expense.

Case No. U-16656 *On behalf of the MIAG in the matter of the application of The Detroit Edison Company (DetEd) for authority to reconcile its REP costs associated with the amended plan approved in Case No. U-16582.* September 2012-present
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2011 to ensure the adherence to approved processes and reasonable and prudent costs. Expected to testify at upcoming hearing.

Case No. U-16434-R *On behalf of the MIAG in the matter of the Application of DetEd for reconciliation of its 2011 power supply cost recovery (PSCR) plan.* June 2012-present
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis and testimony concerning prior year under-recovery of power supply costs, over-refund of the company's residual Self-Implementation Refund, the company's claimed credit to PSCR costs related to credit claimed by affiliate, RARS asset and liability balance resulting in over recovery, and Reduced Emissions Fuel (REF) prudency and calculation of REF impacts.

Case No. U-17026 *On behalf of the MIAG in the matter of the application of Indiana Michigan Power Company for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations* June-September 2012
Project Manager. Managed review of certificate of necessity, evaluation of company's prudency in obtaining alternative power supply options, and review of the company's implementation of and prudency in management of its nuclear plant Life Cycle Management project in comparison to industry standards.

Case No. U-16892 *On behalf of the MIAG in the matter of the application of DetEd for reconciliation of its PSCR plan for 2010.* November 2011-May 2012
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-16047-R *On behalf of the MIAG in the matter of the application of DetEd for its PSCR plan for 2011.* August 2011-March 2012
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis and testimony concerning prior year under-recovery of power supply costs, under-recovery of cumulative Pension Equalization Mechanism costs, and the over-refund of the company's residual Self-Implementation Refund.

Case No. U-16432 *On behalf of the MIAG in the matter of CECO's Application to Implement a PSCR Plan for 2011.* February-June 2011
Project Manager. Reviewed cost recovery plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of mercury filter expenses as part of PSCR process.

Case No. U-16434 *On behalf of the MIAG in the matter of DetEd's Application to Implement a PSCR Plan for 2011.* February-June 2011
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of coal refinement expenses as part of PSCR process.

Case No. U-16472 *On behalf of the MIAG in the matter of the application of DetEd for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* February-June 2011
Project Manager and Testifying Witness. Review of Advanced Metering Infrastructure program cost benefits and tariffs filed and testifying witness to same.

Case No. U-16407 *On behalf of the MIAG in the matter of the application of Michigan Consolidated Gas Company (MichCon) for approval of a detailed plan for main renewal, including a long-term plan to significantly reduce the amount of cast iron main in its system.* October 2010-May 2011
Project Manager and Testifying Witness. Reviewed the company's proposed plan with respect to whether a cost recovery mechanism can be designed to minimize the impact on ratepayers. Testified as to the reasonableness of cost benefit of replacements as well as to the capital cost recovery as it affects future rate cases.

Case No. U-16300 *On behalf of the MIAG in the matter of the application of CECO for authority to reconcile its REP costs associated with the plan approved in Case No. U-15805*. November 2010-January 2011
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2009 to ensure the adherence to approved processes and reasonable and prudent costs. Testified as to significant concerns with respect to the transfer price for renewable energy resources proposed by the company.

Case No. U-16356 *On behalf of the MIAG in the matter of the application of DetEd for authority to reconcile its REP costs associated with the plan approved in Case No. U-15806-RPS.* October 2010-March 2011
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2009 to ensure adherence to approved processes and reasonable and prudent costs and testified to those issues.

Case No. U-15675-R *On behalf of the MIAG in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2009.* October 2010-January 2011
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified to transfer price, replacement power costs, and reasonableness of including excess fuel and variable O&M expenses proffered by various intervenors.

Case No. U-15677-R *On behalf of the MIAG in the matter of the application of DetEd for reconciliation of its PSCR plan for the calendar year 2009.* September-December 2010
Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified with respect to the transfer price for renewable energy source flowing into the PSCR proposed by the company.

Case No. U-16047 *On behalf of the MIAG in the matter of the application of DetEd for authority to implement a PSCR Plan in its rate schedules for 2010 metered jurisdictional sales of electricity*. January-May 2010
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-15415-R *On behalf of the MIAG in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2008 and for other relief related to pension and OPEB costs.* May-November 2009
Project Manager and Testifying Witness. Reviewed PSCR reconciliation, provided analysis of potential issues, and developed recommendations including basis, past precedence, and/or industry expertise. Testified regarding Karn 1 outage delay and Rate E-1 discount recovery.

Case No. U-15806/U-15890 *On behalf of the MIAG in the matter of DetEd's and MichCon's compliance with Public Acts 286 and 296 regarding their REP and Energy Optimization Plan (EOP).* March-June 2009
Project Manager and Testifying Witness. Reviewed the EOPs of both companies and provided analysis and testimony regarding issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15805/15889 *On behalf of the MIAG in the matter of CECO to comply with Public Acts 286 and 295 regarding its REP and EOP.* March-June 2009
Project Manager and Testifying Witness. Reviewed the company's EOP and provided analysis and testimony of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15677 *On behalf of the MIAG in the matter of the application of DetEd for authority to implement a PSCR plan in its rate schedules for 2009 metered jurisdictional sales of electricity.* January-June 2009
Project manager. Reviewed PSCR plan requirements for appropriateness of specific components of that factor.

Case No. U-15415 *On behalf of the MIAG in the matter of the application of CECO for approval of a PSCR plan and for authorization of monthly PSCR factors for the year 2008.* January-March 2008
Project Manager. Reviewed PSCR plan requirements and provided summary briefing to Michigan Attorney General.

Case No. U-15320 *On behalf of the MIAG in the matter of the application of Midland Cogeneration Venture Limited Partnership (MCV) for the Commission to eliminate the "availability caps" which limit CECO's recovery of capacity payments with respect to its power purchase agreement with MCV.* October 2007-June 2008
Project Manager. Oversaw project to provide industry expertise to evaluate issue in case and recommend alternative arguments.

Case No. U-15245 *On behalf of the MIAG in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief.* July 2007-April 2008
Project Manager and Testifying Witness. Provided expert testimony on partial and interim rate relief, CECO's decision to acquire Zeeland Power Company from Broadway Gen Funding, LLC. Provided testimony in permanent phase to reduce the company's net operating income to more closely reflect the expected costs in 2008.

Case No U-15244 *On behalf of the MIAG in the matter of the application of DetEd for authority to increase its electric base rates.* September 2007-October 2008
Project Manager and Testifying Witness. Testified regarding revenue requirements.

Case No U-15190 *On behalf of the MIAG in Base Rate Proceeding for CECO.* March-September 2007
Project Manager. Reviewed the revenue decoupling proposal and supported the witness testimony.

Case No U-15040 *On behalf of the MIAG in GCR 2007/08 Plan proceeding of Michigan Gas Utilities Corporation.* March-August 2007
Project Manager and Testifying Witness. Reviewed GCR plan requirements and provided analysis of the potential benefits of gas procurement hedging program. Testified regarding the GCR clause plan 2007-08.

Case No. U-14231 *On behalf of the MIAG in the matter, on the Commission's own motion, to commence an investigation into future capacity requirements.* February-May 2007
Project Manager. Reviewed and provided a formal written report on the Michigan Public Service Commission's 21st Century Energy Plan Report.

Case No. U-15001 *On behalf of the MIAG in PSCR 2007/08 Plan proceeding.* November 2006-August 2007
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified regarding the company's projected PSCR under-recoveries for 2005 and 2006.

Case No. U-14701-R *On behalf of the MIAG in PSCR 2006/07 reconciliation proceeding.* June-November 2007
Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified to eliminate some expenses used in the company's calculation of its under-recovery PSCR reconciliation for 2006.

Case No. U-14547 *On behalf of the MIAG in the matter of the application of CECO for authority to increase rates for the distribution of natural gas and for other relief.* December 2005-April 2006
Expert Witness and Project Manager. Provided analysis, recommended adjustments, and filed testimony for the Attorney General on CECO's proposed increase to base rates.

Case No. U-14347 *On behalf of the MIAG in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief.* April-September 2005.
Project Manager. Managed project team and supported testimony on cost of service, revenue allocation and rate design issues.

Before the Missouri Public Service Commission (MOPSC)

Veolia Energy Company (Veolia) 2011 and 2012 Request for Authority to Increase Electric Rates in Missouri (Case No. HR-2011-0241). July-September 2011
Project Manager and Testifying Witness. Led a team of consultants engaged to review Veolia's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated Veolia's proposed revenue requirement and testified before the MOPSC to proposed adjustments to the revenue requirements filed by the company in its application.

Consultant to Ameren UE. Conducted revenue requirement analysis in preparation of Missouri Public Service Commission compliance filing to un-bundle utility's rate tariffs. Prepared the filing requirements and all support schedules analysis to justify allocations of generation, transmission and distribution.

New Mexico Public Regulation Commission (NMPRC)

Special Case Study: Public Service Company of New Mexico (PNM) NM PRC Docket No. 10-00086-UT. August 2010
Blue Ridge worked with QSI Consulting, Inc. to conduct a training session for the NMPSC Staff and develop training materials for presentation to Staff on the basic elements of future test year proceedings, how those may differ from traditional rate cases, and how to apply and interpret the forecasting methodologies and modeling that will come into play; and analyze the pending PNM rate case and provide an analytic framework for Staff to apply to the forecasting issues in the case.

Before the North Dakota Public Service Commission (NDPSC)

Northern States Power Company (NSP) 2011 and 2012 Request for Authority to Increase Electric Rates in North Dakota (Case No. PU-10-657/PU-11-55). April-Ocotber 2011
Project Manager and Testifying Witness. Led a team of consultants engaged to review NSP's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated NSP's proposed revenue requirement and testified before the NDPSC to proposed adjustments to the revenue requirements filed by the company in its application.

Before the Nova Scotia Utility and Review Board
Case No. P-888 *On behalf of the Consumer Advocate of the Province of Nova Scotia in the base rate proceeding of Nova Scotia Power.* December 2006-March 2007
Project Manager and Testifying Witness. Provided an evaluation of a management audit of Nova Scotia Power and that report's usefulness to assess the company's management performance and operational efficiency within the context of that proceeding.

Before the Public Utilities Commission of Ohio (PUCO)

Case No. 11-5428-EL-RDR *On behalf of the Staff of the Public Utilities Commission of Ohio In the matter of the application of Delivery Capital Recovery (DCR) Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies).* November 2011-April 2012
Project Manager and Expert Witness. Led a team of consultants engaged to audit and attest to the accuracy and reasonableness of the Companies' compliance with their Commission-approved DCR Riders with regard to the return earned on plant-in-service since the Companies' last distribution rate case.

Case No. 08-0917-EL-SSO *On behalf of the Ohio Hospital Association in the matter of the Application of American Electric Power of Ohio for authority to increase rates for distribution of electric service.* (Hired by Ohio Hospital Association's attorney for utility matters, Bricker and Eckler, to provide expertise in negotiating rate with American Electric Power). September 2008-March 2009
Evaluated revenue and rate impact on member hospitals.

On behalf of the Staff of the PUCO:

- Case #08-0072-GA-AIR Columbia Gas of Ohio for an increase in gas rates, April-August 2008
- Case #07-0829-GA-AIR Dominion East Ohio for an increase in gas rates, November 2007-July 2008
- Case #07-0589-GA-AIR Duke Energy Ohio for an increase in gas rates, November 2007-Februrary 2008

Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of the company's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.

Case No. 07-0551-EL-UNC *On behalf of the Ohio Schools Council in the matter of the Application of FirstEnergy Ohio (and its operating companies Ohio Edison, Cleveland Electric and Toledo Edison) for authority to Increase rates for distribution service, modify certain accounting practices and for tariff approval.* August 2007-April 2008
Project Manager. Hired by Ohio Schools Council's attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing FirstEnergy's application with respect to cost of service and rate design and the resulting impact on Council's member school systems' energy costs.

Case No. 06-0986-EL-UNC *On behalf of the City of Cincinnati in the matter of the Application of Duke Energy Ohio, Inc., to modify its market-based Standard service offer.* May-August 2007
Project Manager. Hired by City of Cincinnati's Water and Sewer District attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing the company's proposal and impact on City's project energy costs.

Oregon Public Utility Commission (OPUC)

Docket No UP205 *Examination of NW Natural's Rate Base and Affiliated Interests Issues* Co-sponsored between NW Natural, Staff, Northwest Industrial Gas Users, Citizens Utility Board. August 2005-January 2006
Project Manager. Led a team that conducted a management audit of NW Natural Gas that included an evaluation of rate base issues for Financial Instruments (gas and financial hedging) Deferred Taxes, Tax Credits, Cost for a Distribution System, Security Issuance Costs and AFUDC calculations as well as Affiliate Transactions for Cost Allocations and Transfer Pricing, Labor Loading, Segregation of Regulated Rate Base and Subsidiary Investments and Properties, and validation of tax paid from/to affiliates are proper. Audit was to ensure the company's compliance with orders, rules and regulations of the OPUC, with company policy and with Generally Accepted Accounting Principles.

Utah Division of Public Utilities

Docket No. 09-035-23 *In the Matter of the Application of Rocky Mountain Power (RMP) for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.* June-December 2009
Project Manager and Testifying Witness. Verified the reasonableness of the revenue requirements as provided by the company in its application and testified before the Public Service Commission of Utah.

Docket No. 09-035-15 *In the Matter of the Application of RMP for Approval of its Proposed Energy Cost Adjustment Mechanism (ECAM) - Net Power Cost Evaluation (NPC), RMP 2009 General Rate Case.* July-December 2009
Project Manager and Testifying Witness. Analyzed the reasonableness and technical accuracy of the RMP's NPC request, performed a comprehensive review of the company's NPC estimate and developed recommendations to ensure an accurate baseline for the ECAM, analyzed special issues addressed in the NPC portion of the case, analyzed the company's fuel price hedging policies and provided recommendations appropriate for the ECAM, and reviewed intervener NPC issues as well as analyzing additional issues as raised by the company and testified to hedging issues.

Before the Washington Utilities and Transportation Commission (WUTC)

Independent Third-Party Evaluation of Puget Sound Energy's (PSE) Conservation Incentive Mechanism (ECIM) under the co-direction of PSE and the WUTC Staff. Phase I: July-October 2009; Phase II: October 2009-September 2010
Project Manager. Assess the extent to which the design and implementation of the incentive mechanism addressed key issues and objectives required by the Commission: accuracy of implementation in calculations of incentives or penalties, compliance with the conditions and requirements of the pilot program, proper use of the calculation methodology, and which assumptions or methods were used to calculate and verify the savings report.

Before the Public Utilities Commission of the State of Colorado (COPUC)

Docket No. 04A-050E *Review of the Electric Commodity Trading Operations of Public Service Company of Colorado (PSCo)*
On behalf of the COPUC Staff. March-September 2004
Project Manager. Focused operational audit within the bounds of a litigated proceeding to determine if ratepayers were subsidizing or negatively impacted by PSCo's energy trading function.

South Carolina State Senator

Advised Senator on regulatory process for requesting States Public Service Commission for a comprehensive review of Duke Power Company's storm and restoration and right of way management. Reviewed and advised Senator of results of report finding.

Southern Connecticut Gas

Consultant. As part of a team that conducted a comprehensive management audit of the management and operations of the company, completed the capital budgeting area of the audit.

Before the New York Public Service Commission

Case: 94-C-0657
Commission Staff. Proceeding to evaluate the compliance of NYNEX with Commission rules and orders related to operational support system costs to competitors. Part of staff panel to facilitate discussion between the company and potential competitors (i.e., users of operational support systems) and report back to Commission.

Focused review of the preparedness of Rochester Gas and Electric (RG&E) and Consolidated Edison (ConEd) for competition in the electric industry. Evaluated all aspects of the company's management actions to prepare for competition including strategic planning, goals and objectives and senior management's attention to the company operations in a de-regulated industry.

Case: 97-M-0567
Commission Staff. Litigated proceeding to determine the benefits of a proposed merger of Long Island Lighting Company (LILCO)/Brooklyn Union Gas. Analyzed proposed synergy savings.

Case: 96-E-0132 *Show Cause Proceeding Regarding Rate Relief for Ratepayers of LILCO*
Commission Staff and Testifying Witness. Litigated proceeding where Staff proffered testimony containing a benchmark study showing that LILCO's operations and maintenance expenses were excessive compared to a peer group of 24 utilities. Panel testimony concerning the findings and conclusions resulting from the benchmark study.

Case: 96-M-0858 *Prudence Investigation into the Scrap Handling Practices in the Western Division of Niagara Mohawk Power Company (NIMO)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of allegations of bribery and corruption in company practices related to a specific vendor who purchased company scrap metal. Lead team of 10 staff examiners to quantify the extent to which the company paid excessive rates to this vendor. Testified to the findings of the analysis. Case settled with ratepayers receiving a credit to bills.

Case: 91-C-0613 *Operational Audit of the Outside Plant Construction and Rehabilitation Program of New York Telephone Company*
Commission Staff. Comprehensive operational audit of the company's management and implementation of a $150M capital program to rehabilitate the outside plant distribution network. Served as Staff Examiner responsible for crew supervision, goals monitoring, contractor oversight, and report preparation.

Case: 91-W-0583 *Prudence Proceeding of the Operations and Management of Jamaica Water*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive costs to rate payers. Testified on a Staff panel to the excessive costs associated with management's inattention to sound business practices related to the design, purchase and installation of the company customer information system.

Case: 92-W-0030 *Operational Audit of Jamaica Water Operations and Management*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, and specific topics areas including engineering, contracting, and information technology. Findings led to prudence proceeding.

Case: 92-M-0973 *Management Audit of RG&E*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, supervision of staff and specific topics areas including purchasing and internal controls.

Case: 93-E-0918 *Operational Audit of the Demand Side Management Function at RG&E*
Commission Staff. Comprehensive operational audit of the demand side management function including program planning, management and energy savings verification. Developed and supervised the implementation of the work plan.

Case: 88005 *Operational Audit of Materials and Supply Function at National Fuel Gas*
Commission Staff. Comprehensive operational audit of the materials and supplies function including warehouse operations, inventory control and procurement. Developed and implemented the work plan for this project.

Operational Audit of the Fuel Procurement and Contracting of LILCO
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project.

Operational Audit of the Fuel Procurement and Contracting of ConEd
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Case: 90007 Operational Audit of the Fuel Procurement and Contracting of Central Hudson Gas and Electric
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of Fuel Procurement and Contracting of Orange & Rockland Utilities
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of the Fuel Procurement and Contracting of RG&E
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on nuclear fuel. Provided research and data evaluation expertise.

Case: 88-E-115 *Prudence Proceeding to Investigate the Construction Costs Associated with the Homer City Coal Cleaning Plant (HCCCP)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive construction charges related to the HCCCP. Testified on a Staff panel to the

fuel price differential costs resulting from the failure of the coal cleaning plant to function as designed as well as surrebuttal testimony on the cost of a flu-gas de-sulfurization plant and ancillary equipment and facilities. Case settled. Customers received $125M credit.

Case: 87003 *Operational Audit of the HCCCP*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on the construction of the HCCCP jointly owned by New York State Electric and Gas (NYSEG) and Penelec. Responsible for fuel and construction costs analysis, benchmarking costs and alternative methods for meeting EPA Clean air restrictions, contracting practices and report preparation.

Case: 87003 *Operational Audit of the Fuel Procurement and Contracting of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis, benchmarking costs, contracting practices and report preparation.

Case: 86007 *Operational Audit of the Field Crew Supervision and Utilization of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of field crew utilization and supervision. Staff examiner responsible for verifying supervisor activities, reporting, goals attainment and report preparation.

Case: 86005 *Prudence Proceeding to Investigate the Fuel Procurement and Contracting Practices at NIMO*
Commission Staff. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive fuel charges to customers. Responsible for fuel cost analysis and benchmarking costs, contracting practices, and testimony preparation. Case settled with customers receiving $66M credit.

Case: 86005 *Operational Audit of the Fuel Procurement and Contracting of NIMO*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis and benchmarking costs, contracting practices and report preparation.

Case: 85001 *Operational Audit of the Research and Development Function of ConEd*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on R&D activities. Staff examiner on the project responsible for reviewing projects documentation and control, outside contracting a report preparation.

Testimony filed by Mr. McGarry

Before the Arizona Corporation Commission

- Arizona Public Service Company - Docket No. E-01345A-11-0224

Before the Delaware Public Service Commission

- Delmarva Power and Light Company - Docket No. 11-528
- Delmarva Power and Light Company - Docket No. 07-239F
- Delmarva Power and Light Company - Docket No. 06-284

Before the Illinois Commerce Commission

- Commonwealth Edison - Case: 05-0597

Before Maine Public Utilities Commission

- Northern Utilities Inc. - Case No. 2008-151
- Northern Utilities Inc. - Case No. 2004-813

Before the Maryland Public Service Commission

- PEPCO and Delmarva Power and Light Company - Case No. 9092/9093

Before the Michigan Public Service Commission

- Consumers Energy Company - Case No. U-16655
- Detroit Edison Company - Case No. U-16434-R
- Detroit Edison Company - Case No. U-16047-R
- Detroit Edison Company - Case No. U-16434
- Detroit Edison Company - Case No. U-16892
- Detroit Edison Company - Case No. U-16472
- Michigan Consolidated Gas Company - Case No. U-16407
- Detroit Edison Company - Case No. U-16356
- Consumers Energy Company - Case No. U-16300
- Detroit Edison Company - Case No. U-16047
- Detroit Edison Co. and Michigan Consolidated Gas - Case No. U-15806/U-15890
- Consumers Energy Company - Case No. U-15805/15889
- Detroit Edison Company - Case No. U-15677-R
- Consumers Energy Company - Case No. U-15675-R
- Consumers Energy Company - Case No. U-15415-R
- Consumers Energy Company - Case No. U-15245
- Detroit Edison Company - Case No. U-15244
- Michigan Gas Utilities Corporation - Case No. U-15040
- Consumers Energy Company - Case No. U-15001
- Consumers Energy Company - Case No. U-14701-R
- Consumer Energy Company - Case No. U-14547

Before the Missouri Public Service Commission

- Veolia Energy Company - Case No. HR-2011-0241

Before the New York Public Service Commission

- Long Island Lighting Company - Case: 96-E-0132
- Niagara Mohawk Power Company - Case: 96-M-0858
- Jamaica Water - Case: 91-W-0583
- New York State Electric & Gas Homer City Prudence Review - Case: 88-E-115

Before the North Dakota Public Service Commission

- Northern States Power Company - Case Nos. PU-10-657 and PU-11-55

Before the Nova Scotia Utility and Review Board

- Nova Scotia Power - Case No. P-888

Before the Utah Division of Public Utilities

- Rocky Mountain Power - Docket No. 09-035-23

Speaking Engagements

National Association of Regulatory Utility Commissioners - Before the NARUC sub-committee on Accounting and Finance, CAPEX Trackers, March 28, 2012.

Institute of Public Utilities, Michigan State University, East Lansing, MI; Advanced Regulatory Studies Program, training session on Management Audits and Prudency Reviews; September 27, 2011, and September 30, 2010.

National Association of Regulatory Utility Commissioners - Before the NARUC sub-committee on Accounting and Finance, service company costs and allocations to regulated entities, September 15, 2010.

New Mexico Public Regulation Commission Staff, Santa Fe, NM - In cooperation with QSI Consulting; service companies and related cost allocations, benchmarking, and rate case planning; June 29, 2010.

Colorado Public Utilities Commission Staff – In cooperation with QSI Consulting; future of regulation and deregulation, revenue requirements, rate base, rate of return, cost of service, determining net operating income, cost of capital, staff audits, and affiliate transactions; June 22, 2006.

EXHIBIT 2

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
RUCO'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 25, 2012

RUCO 3.21

Energy Efficiency – If the EERP is approved as proposed, admit that TEP would continue to earn a return on its EE investments during all periods – even years that it underperforms and/or does not meet the EE standard.

RESPONSE:

TEP agrees that if the EERP is approved as proposed, that TEP would earn a return on its EE investments.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens

EXHIBIT 3

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
September 17, 2012

STF 3.04

Energy Efficiency. Reference David G. Hutchens Direct Testimony, Page 19, Lines 17-22. Please fully explain how the proposed 3 year pilot is consistent with A.C.C R14-2-2410, sub-section A, B & C which state (in part),

a. An affected utility may recover the costs that it incurs in planning, designing, implementing, and evaluating a DSM program or DSM measure if the DSM program or DSM measure is all of the following:
   1. Approved by the Commission before it is implemented,
   2. Implemented in accordance with a Commission-approved program proposal or implementation plan, and
   3. Monitored and evaluated for cost-effectiveness pursuant to R14-2-2415.
b. An affected utility shall monitor and evaluate each DSM program and DSM measure, as provided in R14-2-2415, to determine whether the DSM program or DSM measure is cost-effective and otherwise meets expectations.
c. If an affected utility determines that a DSM program or DSM measure is not cost-effective or otherwise does not meet expectations, the affected utility shall include in its annual DSM progress report filed under R14-2-2409 a proposal to modify or terminate the DSM program or DSM measure.
d. How would the Company's plan comply with Sections A-3, B and C? If a program were deemed not cost effective and terminated, how would the rate treatment be affected during this three year period?

RESPONSE:

The purpose of the EERP is to create an alternative mechanism that will fulfill the spirit and objectives of the Electric Energy Efficiency Standard ("Standard"). If the Commission approves the Company's proposal as part of the rate case Order, the Commission would have effectively provided a waiver from the specific requirements set forth in A.C.C R14-2-2410, sub-section A.1. The Company will continue to monitor and evaluate each DSM program and measure as provided in R14-2-2415, to comply with R14-2-2410, Subsections A.3 and B.

In accordance with the proposed EERP Plan of Administration ("POA"), Exhibit CAJ-7, if an evaluation determines that a previously cost-effective DSM program is no longer cost-effective, the Company will terminate that program and report it in the March 1 DSM progress report, as required under R-14-2-2409. Because the program or measure was determined to be cost effective during the planning and implementation stage, all allowable costs incurred for the program up to the actual date of termination will be collected under the DSM surcharge. This satisfies the requirement under A.A.C. R14-2-2410.C.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens and Craig A. Jones

EXHIBIT 4

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 17, 2012

STF 3.02

Energy Efficiency. Reference David G. Hutchens Direct Testimony, Page 18, lines 2-3. Please explain the basis for selecting 200 basis points for the premium on the return of the EE costs on TEP's ROE. Provide all studies, analysis, and/or industry research that support this level of premium.

RESPONSE:

The 200 basis point addition to the Company's return on equity for EERP projects reflects the increased risk from the EERP investment. Unlike investments in utility plant, such as power plants, buildings, computers and other assets with an independent market value, TEP's EE expenditures produce intangible assets with no external value outside the creation of a regulatory asset by order of the Commission. A 200 basis point increase on these projects, therefore, reflects the increased risk associated with TEP's investment in these intangible assets. It should be noted that Nevada Power has had been granted a 500 basis point increase to its return on equity for EE investments.

Please see STF 3.02 RAP report.pdf, Bates Nos. TEP\019515-019586, from the Regulatory Assistance Project, which illustrates an example of this alternative to a traditional performance incentive. See specifically 6.2.3 on page 38.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens and Craig A. Jones

EXHIBIT 5

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO RUCO'S FOURTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
October 11, 2012, 2012

RUCO 4.01

Energy Efficiency – In regard to the Company's response to STF 3.02, please provide a copy of the Public Utilities Commission of Nevada decision that granted a 500 basis point increase to Nevada Power's return on equity for EE investments.

RESPONSE:

Please see the link below to the original Decision that granted Nevada Power an extra 500 basis points on its return on equity.

http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2001_THRU_2004/2002-5/10716.pdf

The related language that was in the Nevada Administrative Code § 704.9523 (3)(e)(4) is as follows:

> (4) To calculate revenue requirements, the utility must base the rate of return to be applied to the balance in the subaccounts of FERC Account 182.3 for each conservation or demand management program that the utility has carried out on the authorized return of equity plus 5 percent.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens and Craig A. Jones

EXHIBIT 6

ADOPTED REGULATION OF THE

PUBLIC UTILITIES COMMISSION OF NEVADA

LCB File No. R042-10

Effective July 22, 2010

EXPLANATION – Matter in *italics* is new; matter in brackets [~~omitted material~~] is material to be omitted.

AUTHORITY: §§1, 2, 5-14 and 16, NRS 704.741 and 704.785; §§3, 4 and 15, NRS 704.785.

A REGULATION relating to public utilities; prescribing the requirements for electric utilities to recover certain amounts based on the measurable and verifiable effects of the implementation of energy efficiency and conservation programs approved by the Public Utilities Commission of Nevada; amending various provisions concerning the information which an electric utility must include in the resource plan filed with the Commission; and providing other matters properly relating thereto.

Section 1. Chapter 704 of NAC is hereby amended by adding thereto the provisions set forth as sections 2, 3 and 4 of this regulation.

Sec. 2. *"Energy efficiency" means a modification of energy use patterns which results in the greater productive use of energy or a reduction in the consumption of electric power.*

Sec. 3. *1. An electric utility may recover an amount based on the measurable and verifiable effects of the implementation by the electric utility of energy efficiency and conservation programs described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility. The amount recovered must include:*

(a) The costs reasonably incurred by the electric utility in implementing and administering the energy efficiency and conservation programs, which are recovered pursuant to NAC 704.9523; and

(b) The measurable and verifiable effects on the revenue of the electric utility caused or created by the implementation of the energy efficiency and conservation programs, which are recovered pursuant to section 4 of this regulation.

2. Upon the request of an electric utility or intervening party or upon a motion of the Commission, the Commission may authorize an electric utility to include in the amount recovered pursuant to subsection 1 for an individual energy efficiency or conservation program financial incentives to support the promotion of the participation of the customers of the electric utility in the energy efficiency or conservation program.

3. The Commission will consider the effect of any recovery pursuant to this section on the rates of the customers of the electric utility.

Sec. 4. *1. An electric utility may recover an amount based on the measurable and verifiable effects on the revenue of the electric utility which are caused or created by the implementation of energy efficiency and conservation programs described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility.*

2. To recover an amount pursuant to subsection 1, an electric utility must:

(a) Establish and maintain a separate subsidiary record of the subaccounts of FERC Account No. 182.3 (Other Regulatory Assets) for the tracking, calculation and recovery of the lost revenue associated with the energy efficiency and conservation programs that are described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility.

(b) At the time the utility files an annual deferred energy accounting adjustment application pursuant to subsection 3 of NRS 704.187, apply to the Commission to establish the following period-specific rates:

(1) A prospective base lost revenue rate which is determined by allocating lost revenue to each customer class in the manner approved by the Commission in the most recent general rate case of the electric utility. The prospective base lost revenue rate for a customer class is an amount equal to the lost revenue allocated to the customer class pursuant to this subparagraph divided by the projected kilowatt hour sales for that class for the relevant period.

(2) A deferred lost revenue rate to clear the period-specific balance over 12 months. The deferred lost revenue rate is an amount equal to the period-specific balance in the subaccount of FERC Account No. 182.3 for lost revenue associated with energy efficiency and conservation programs for each class of customers divided by the applicable test period kilowatt hour sales.

3. An electric utility shall account for period-specific lost revenue associated with a program for energy efficiency and conservation and revenue received from the period-specific base lost revenue rate in the following manner:

(a) On a monthly basis, the electric utility shall:

(1) Calculate the deferred lost revenue;

(2) Calculate the recorded revenue attributable to the base lost revenue rate; and

(3) Record in the subaccount of FERC Account No. 182.3 the difference between estimated lost revenues and recorded revenue attributable to the base lost revenue rate.

(b) The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the unamortized balance in the lost revenue subaccount of FERC Account No. 182.3.

4. An electric utility shall:

(a) Perform by program by month by class the monitoring and verification of actual kilowatt hour and demand savings required by NAC 704.9522;

(b) Include with the demand side plan submitted by the utility pursuant to NAC 704.934 the information described in paragraph (a) for review and approval by the Commission; and

(c) Make any adjustments to the balancing account for lost revenue, including, without limitation, carrying charges, as are necessary to reflect the results of the review by the Commission of the information submitted pursuant to paragraph (b).

Sec. 5. NAC 704.9057 is hereby amended to read as follows:

704.9057 "Demand side plan" means the programs proposed by a utility to promote *energy efficiency and* conservation . ~~[and demand management.]~~

Sec. 6. NAC 704.9215 is hereby amended to read as follows:

704.9215 1. A utility's resource plan must be accompanied by a summary that is suitable for distribution to the public. The summary must contain easily interpretable tables, graphs and maps and must not contain any complex explanations or highly technical language. The summary must be approximately 30 pages in length.

2. The summary must include:

(a) A brief introduction, addressed to the public, describing the utility, its facilities and the purpose of the resource plan, and the relationship between the resource plan and the strategic plan of the utility for the duration of the period covered by the resource plan.

(b) The forecast of low growth, the forecast of high growth and the forecast of base growth of the peak demand for electric energy and of the annual electrical consumption, for the next 20 years, commencing with the year following the year in which the resource plan is filed, both with and without the impacts of programs for ***energy efficiency and*** conservation ~~[and demand management]~~ and an explanation of the economic and demographic assumptions associated with each forecast.

(c) A summary of the demand side plan listing each program and its effectiveness in terms of costs and showing the 20-year forecast of the reduction of demand and the contribution of each program to this forecast.

(d) A summary of the preferred plan showing each planned addition to the system for the next 20 years, commencing with the year following the year in which the resource plan is filed, with its anticipated capacity, cost and date of beginning service.

(e) A summary of renewable energy showing how the utility intends to comply with the portfolio standard and listing each existing contract for renewable energy and each existing contract for the purchase of renewable energy credits and the term and anticipated cost of each such contract.

(f) A summary of:

(1) The energy supply plan for the next 3 years setting out the anticipated cost, price volatility and reliability risks of the energy supply plan;

(2) The risk management strategy;

(3) The fuel procurement plan; and

(4) The purchased power procurement plan.

(g) A summary of the activities, acquisitions and costs included in the action plan of the utility.

(h) An integrated evaluation of the components of the resource plan which relates the preferred plan to the objectives of the strategic plan of the utility, and any other information useful in presenting to the public a comprehensive summary of the utility and its expected development.

Sec. 7. NAC 704.925 is hereby amended to read as follows:

704.925 1. A utility's resource plan must include forecasts of energy consumption and the peak demand for summer and winter for the system, disaggregated by rate schedule, for the 20-year period beginning with the year following the year in which the resource plan is filed. The utility may combine rate schedules if necessary to protect the confidentiality of individual customers.

2. The utility shall identify components of residential and commercial energy and demand for which initiatives for *energy efficiency and* conservation ~~[and demand management]~~ are applicable. The utility shall include in its forecast an assessment of the impacts of such initiatives on the identified components and on overall levels of energy consumption and demand by residential and commercial customers.

3. The utility's forecast must include:

(a) Estimated annual losses of energy on the system for the 20-year period of the resource plan; and

(b) Estimated annual energy to be used by the utility for the 20-year period of the resource plan.

4. The utility shall consider the impact of applicable new technologies and the impact of applicable new governmental programs or regulations.

5. The utility shall consider the impact of distributed generation and customers who acquire energy pursuant to NRS 704.787 or chapter 704B of NRS.

6. The utility shall provide a reasonable estimate of the demand from interruptible loads and the total demand of each type of interruptible load.

7. The utility shall identify all standby loads and the total demand of each type of standby load and include an analysis of the likelihood and effect of incurring such demands at the time of the system peak of the utility.

8. All forecast values for the entire system of the utility must be reported. The utility shall separately estimate the contribution to peak demand and energy consumption for the components of the system located within the State of Nevada and for the components of the system located outside the State of Nevada.

9. A resource plan must contain a graphical representation of projected load duration curves for the year following the year in which the resource plan was filed and every fifth year thereafter for the remainder of the period covered by the resource plan.

10. To verify and complete the final forecasts, the utility may evaluate the forecasts with the results of alternative forecasting methods.

11. Any change in the methodology of forecasting used by the utility from that used in the utility's previous resource plan must be identified in the current resource plan of the utility.

Sec. 8. NAC 704.934 is hereby amended to read as follows:

704.934 1. As part of its resource plan, a utility shall submit a demand side plan.

2. The demand side plan must include:

(a) An identification of end-uses for programs for *energy efficiency and* conservation . ~~[and demand management]~~

(b) An assessment of savings attributable to technically feasible programs for *energy efficiency and* conservation , ~~[and demand management,]~~ as determined by the utility. The programs must be ranked in a list according to the level of savings in energy or reduction in demand, or both.

(c) An assessment of technically feasible programs to determine which will produce benefits in peak demand or energy consumption. The utility shall estimate the cost of each such program. The methods used for the assessment must be stated in detail, specifically listing the data and assumptions considered in the assessment.

3. In creating its demand side plan, a utility shall consider the impact of applicable new technologies on current and future ~~[demand side]~~ *energy efficiency and conservation* options. The consideration of new technologies must include, without limitation, consideration of the potential impact of advances in digital technology and computer information systems.

4. A utility shall include in its demand side plan an energy efficiency program for residential customers which reduces the consumption of electricity or any fossil fuel. The energy efficiency program must include, without limitation, the use of new solar thermal energy sources.

5. The demand side plan must provide a list of the programs for which the utility is requesting the approval of the Commission. The list must include, without limitation:

(a) An estimate of the reduction in the peak demand and energy consumption that would result from each proposed program, in kilowatt-hours and kilowatts saved. The programs must be listed according to their expected savings and their contribution to a reduction in peak demand

and energy consumption based upon realistic estimates of the penetration of the market and the average life of the programs.

(b) An assessment of the costs of each proposed program and the savings produced by the program. If the program can be relied upon to reduce peak demand on a firm basis, the assessment must include the savings in the costs of transmission and distribution.

(c) An assessment of the impact on the utility's load shapes of each proposed and existing program for ***energy efficiency and*** conservation . ~~[and demand management.]~~

(d) If a program is an educational program, the projected expenses of the utility for the educational program.

6. For any ***energy efficiency or*** conservation ~~[or demand management]~~ program which reduces the consumption of electricity or any fossil fuel, a utility shall include in its demand side plan a complete life-cycle analysis of the costs and benefits of the program using the Total Resource Cost Test.

7. The utility shall include with its demand side plan a report on the status of all programs for ***energy efficiency and*** conservation ~~[and demand management]~~ that have been approved by the Commission. The report must include tables for each such program showing, for each year, the planned and achieved reduction in kilowatt-hours, the reduction in kilowatts and the cost of the program.

8. On or before ~~[August 15]~~ ***July 1*** of each year following the filing of its resource plan, the utility shall file with the Commission a copy of the complete analysis that the utility used in determining for the upcoming year which ***energy efficiency and*** conservation ~~[and demand management]~~ programs are to be continued and which programs are to be cancelled. ~~[The]~~ ***Within 180 days after the analysis is filed, the*** Commission will ~~[process this]~~ ***accept the***

analysis ~~[in the same manner as an amendment filed pursuant to NAC 704.9503.]~~ *as filed, accept the analysis with modification or reject the analysis.*

9. As used in this section:

(a) "New solar thermal energy sources" means energy sources which are installed after the effective date of the utility's energy efficiency program and which reduce the consumption of electricity or any fossil fuel by using solar radiation to heat water or to provide space heating or cooling.

(b) "Total Resource Cost Test" means a method of determining the overall economic efficiency of a demand management program from the perspective of society by measuring the net costs of the program based on its total costs, including, without limitation, the costs to both participants and the utility.

Sec. 9. NAC 704.945 is hereby amended to read as follows:

704.945 1. A utility shall include in its resource plan a table of loads and resources for each supply plan analyzed. The table must include the following data for each year of the resource plan:

(a) The capacity provided by each supply resource;

(b) The total expected capacity of all resources;

(c) The forecasted peak demand;

(d) The estimated impact of new programs for *energy efficiency and* conservation *;* ~~[and demand management;]~~

(e) The expected capacity and energy provided by renewable resources, categorized by type;

(f) The required planning reserves;

(g) The total capacity required;

(h) The excess or deficiency of capacity without additional resources; and

(i) The excess or deficiency of capacity with additional planned resources.

2. A graph must be included for the preferred plan of the utility showing, over the 20-year planning period:

(a) The total resources requirements;

(b) The total demand without new programs for *energy efficiency and* conservation *;* ~~[and demand management;]~~

(c) The total demand with new programs for *energy efficiency and* conservation *;* ~~[and demand management;]~~

(d) The total capacity with additional planned resources; and

(e) The total capacity without additional resources.

3. A graph must be included for the preferred plan that shows, for each year of the 20-year planning period, the excess or required capacity both with and without the additional planned resources.

4. A graph or table must be provided that shows the allocation of the capacity of the transmission system of the utility between bundled retail transmission customers, unbundled retail transmission customers and wholesale transmission customers.

Sec. 10. NAC 704.9475 is hereby amended to read as follows:

704.9475 1. A utility shall conduct an analysis of sensitivity for all major assumptions and estimates used in its resource plan. The analysis must include the:

(a) Forecast of peak demand and energy consumption;

(b) Dates when proposed acquisitions will be in service;

(c) Unit availability;

(d) Costs of power plants;

(e) Prices of fuel;

(f) Amounts of purchased power and corresponding costs;

(g) Schedule, impact and costs of programs for *energy efficiency and* conservation *;* ~~[and demand management;]~~

(h) Capacity of plants in megawatts;

(i) Discount rates;

(j) Rate of inflation;

(k) Cost of capital;

(l) Environmental costs; and

(m) Economic benefit.

2. The utility shall state the ranges and consequences of uncertainty for each of the assumptions and describe methods of combining various uncertainties.

Sec. 11. NAC 704.9489 is hereby amended to read as follows:

704.9489 1. Each resource plan of a utility must include a detailed action plan based on an integrated analysis of the demand side plan and supply plan of the utility. In its action plan, the utility shall specify all its actions that are to take place during the 3 years commencing with the year following the year in which the resource plan is filed. The action plan must contain:

(a) An introductory section that explains how the action plan fits into the longer-term strategic plan of the utility.

(b) A list of actions for which the utility is seeking the approval of the Commission.

(c) A schedule for the acquisition of data, including planned activities to update and refine the quality of the data used in forecasting.

(d) A specific timetable for acquisition of options for the supply of electric energy and for programs for *energy efficiency and* conservation . ~~{and demand management.}~~

(e) If changes in the methodology are being proposed, a description fully justifying the proposed changes, including an analysis of the costs and benefits. Any changes in methodology that are approved by the Commission must be maintained for the period described in the action plan.

(f) A section describing any plans of the utility to acquire additional modeling instruments.

(g) A section for the utility's program for *energy efficiency and* conservation , ~~{and demand management.}~~ including:

(1) A description of continued planning efforts;

(2) A plan to carry out and continue selected measures for *energy efficiency and* conservation ~~{and demand management}~~ that have been identified as desirable; and

(3) Any impacts of imputed debt calculations associated with energy efficiency contracts in the preferred plan.

(h) A section for the utility's program for acquisition of resources for the supply of electric energy for the period covered by the action plan, including:

(1) The immediate plans of the utility for construction of facilities or long-term purchases of power;

(2) The expected time for construction of facilities and acquisition of long-term purchases of power identified in subparagraph (1);

(3) The major milestones of construction; and

(4) Any impacts of imputed debt calculations associated with renewable energy contracts or energy efficiency contracts in the preferred plan.

2. The action plan must contain an energy supply plan.

3. The action plan must contain a budget for planned expenditures suitable for comparing planned and achieved expenditures. Expenses must be listed in a format that is consistent with the categories and periods to be presented in subsequent filings. The budget must be organized in the following categories:

(a) Forecasting of loads;

(b) ~~[Conservation and demand management]~~ *Energy efficiency and conservation;*

(c) Plan for supply; and

(d) Financial plan.

4. The action plan must contain schedules suitable for comparing planned and actual activities and accomplishments. Milestones and points of decision committing major expenditures must be shown.

Sec. 12. NAC 704.9494 is hereby amended to read as follows:

704.9494 1. The Commission will issue an order:

(a) Approving the action plan of the utility as filed; or

(b) If the plan is not approved as filed, specifying those parts of the action plan the Commission considers inadequate.

2. Approval by the Commission of an action plan constitutes a finding that the programs and projects contained in that action plan, other than the energy supply plan, are prudent, including, without limitation, construction of facilities, purchased power obligations, programs for *energy efficiency and* conservation ~~[and demand management]~~ and impacts of imputed debt calculations associated with renewable energy contracts or energy efficiency contracts. If the Commission subsequently determines that any information relied upon when issuing its order approving the

action plan was based upon information that was known or should have been known by the utility to be untrue or false at the time the information was presented, the Commission may revoke, rescind or otherwise modify its approval of the action plan.

3. If, at the time that the Commission approves the action plan of the utility, the Commission determines that the elements of the energy supply plan are prudent, the Commission will specifically include in the approval of the action plan its determination that the elements contained in the energy supply plan are prudent. For the Commission to make a determination that the elements of the energy supply plan are prudent:

(a) The energy supply plan must not contain any feature or mechanism that the Commission finds would impair the restoration of the creditworthiness of the utility or would lead to a deterioration of the creditworthiness of the utility.

(b) The energy supply plan must optimize the value of the overall supply portfolio for the utility for the benefit of its bundled retail customers.

(c) The utility must demonstrate that the energy supply plan balances the objectives of minimizing the cost of supply, minimizing retail price volatility and maximizing the reliability of supply over the term of the plan.

Failure by a utility to demonstrate that its energy supply plan is prudent in accordance with this subsection does not otherwise affect approval of the action plan, including the energy supply plan, and the utility may subsequently seek a determination that the energy supply plan is prudent in the appropriate deferred energy proceeding.

4. A utility may recover all costs that it prudently and reasonably incurs in carrying out an approved action plan in the appropriate separate rate proceeding. A utility may recover all costs that are prudently and reasonably incurred in carrying out the approved energy supply plan.

including deviations pursuant to subsection 1 of NAC 704.9504 approved by the Commission in the appropriate deferred energy application filed pursuant to NAC 704.023 to 704.195, inclusive.

Sec. 13. NAC 704.9498 is hereby amended to read as follows:

704.9498 1. Not earlier than 15 months and not later than 21 months after the date on which the utility files its action plan, the utility shall file a report on the progress of its action plan with the Commission and serve a copy of the progress report on all parties of record. The progress report must include:

(a) Information concerning the status of planned facilities approved by the Commission, including any cost or schedule variances;

(b) Information concerning the status of all programs for *energy efficiency and* conservation , ~~[and demand management,]~~ including planned and achieved reductions in kilowatt-hours and reduction in demand in kilowatt-hours;

(c) A comparison of budgeted and actual costs for the entire action plan;

(d) An identification of and justification for any significant deviation from the approved action plan, including supporting information;

(e) An updated forecast of energy consumption and peak demand; and

(f) An updated table for loads and resources for the remaining years covered by the 20-year plan.

2. The progress report must be in the same form as the action plan and will be assigned a new docket number by the Commission.

3. The utility or any party of record may request a hearing on the progress report, specifying in its request the reason the utility or party believes a hearing is required. Upon a finding of good cause, the Commission will order a hearing on the matter.

Sec. 14. NAC 704.9522 is hereby amended to read as follows:

704.9522 1. A utility provider shall propose a measurement and verification protocol for all energy efficiency ***and conservation*** measures submitted pursuant to NAC 704.9005 to 704.9525, inclusive.

2. The utility provider shall comply with, and shall ensure that all energy efficiency ***and conservation*** contracts entered into by the utility provider comply with, the most recent measurement and verification protocol approved by the Commission . ~~[at the time an energy efficiency measure is implemented.]~~

Sec. 15. NAC 704.9523 is hereby amended to read as follows:

704.9523 1. All costs of implementing programs for ***energy efficiency and*** conservation ~~[and demand management]~~ must be accounted for in the books and records of ~~[a]~~ ***an electric*** utility separately from amounts attributable to any other activity. All accounts must be maintained in a manner that will allow costs attributable to specific programs to be readily identified.

2. ~~[Except as otherwise provided in subsection 4, a]~~ ***An electric*** utility may, pursuant to subsection 3, recover all ~~[prudent and reasonable]~~ ***reasonably incurred*** costs ~~[incurred in]~~ ***of*** implementing programs for ***energy efficiency and*** conservation ~~[and demand management]~~ that have been ***described in the demand side plan of the electric utility and*** approved by the Commission ***pursuant to NAC 704.9494*** as part of the action plan of the ***electric*** utility, including, without limitation, the costs for labor, overhead, materials, incentives paid to customers, advertising, marketing , ***monitoring*** and evaluation. ~~[The utility may recover approved costs associated with monitoring and evaluating these programs through a general rate case.]~~

3. To recover *the reasonably incurred* costs ~~[incurred in]~~ *of* implementing programs for *energy efficiency and* conservation ~~[and demand management, a]~~ *, an electric* utility must:

(a) ~~[Calculate, on a monthly basis, the costs incurred in implementing each program since the end of the test period or period of certification in its last proceeding to change general rates.~~

~~(b) Record the cost of implementing each program, as calculated pursuant to paragraph (a), in c]~~ ***Establish and maintain*** separate ~~[subaccount]~~ ***subsidiary records of the subaccounts*** of FERC Account No. 182.3 (Other Regulatory Assets) for each program ~~[and record an offset in the appropriate subaccount of other FERC accounts.~~

~~(c) Maintain subsidiary records of the subaccounts of FERC Account No. 182.3 for each program.]~~ ***described in the demand side plan of the electric utility and approved by the Commission pursuant NAC 704.9494 as part of the action plan of the electric utility.*** These records must clearly delineate all costs incurred by the *electric* utility in implementing each program approved by the Commission ~~[.~~

~~(d) Apply]~~ ***and be maintained by program by month by rate effective period.***

(b) At the time the electric utility files an annual deferred energy accounting adjustment application pursuant to subsection 3 of NRS 704.187, apply to the Commission to establish the following period-specific rates:

(1) A prospective base program cost rate which is determined by allocating in the manner approved by the Commission in the most recent general rate case of the electric utility the total cost of programs for energy efficiency and conservation that are described in the demand side plan approved by the Commission. The prospective base program cost rate for a customer class is an amount equal to the cost allocated to that customer class pursuant to this

subparagraph divided by the projected kilowatt hour sales for that class for the relevant period.

(2) A deferred program cost rate to clear the period-specific balance over 12 months. The deferred program cost rate is an amount equal to the period-specific balance in the subaccount of FERC Account No. 182.3 for the cost of energy efficiency and conservation programs divided by the applicable test period kilowatt hour sales.

4. An electric utility shall account for period-specific costs incurred to implement a program for energy efficiency and conservation and revenues received from the period-specific prospective base program cost rate in the following manner:

(a) On a monthly basis, the electric utility shall record in a subaccount of FERC Account No. 182.3 the program costs incurred and the revenues received from the prospective base program cost rate for the energy efficiency and conservation program. .

(b) The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the *unamortized* balance in the subaccounts of FERC Account No. 182.3 . ~~[for each program not included in the rate base.~~

~~(c) Clear any balance accumulated in the subaccounts of FERC Account No. 182.3 for each program as a component of an application by the utility to change general rates as follows:~~

~~(1) The Commission will adjust the rate to amortize the balance over a 3-year period, unless otherwise specified by the Commission.~~

~~(2) The utility must begin amortizing costs on the date that the change in general rates becomes effective.~~

~~(3) The utility must include the balance in the subaccounts of FERC Account No. 182.3 for each program, including carrying charges, in the rate base as of the date that as do the rest~~

~~period used in the utility's application to change general rates or as of the date that ends the period of certification, whichever is later.~~

~~(4) To calculate revenue requirements, the utility must base the rate of return to be applied to the balance in the subaccounts of FERC Account No. 182.3 for each conservation or demand management program that the utility has carried out on the authorized return on equity plus 5 percent.~~

~~4. Costs incurred in implementing a dispatchable direct load control program must be recovered pursuant to subsection 3, except for the costs of incentives paid to customers which are treated as fuel and purchased power expense pursuant to NAC 704.023 to 704.195, inclusive.~~

~~5. As used in this section, "dispatchable direct load control program" means a program offered by a utility pursuant to which customers may agree to allow the utility remotely to interrupt or cycle electrical equipment and appliances, including, without limitation, air conditioners, water heaters and space heaters.]~~

Sec. 16. NAC 704.9056 is hereby repealed.

TEXT OF REPEALED SECTION

704.9056 "Demand management" defined. (NRS 703.025, 704.210, 704.741) "Demand management" means a deliberate reshaping of customers' patterns of use to shift the time of use of electric energy and reduce consumption during the period of the utility's peak load.

NOTICE OF ADOPTION OF REGULATION

The Public Utilities Commission of Nevada adopted regulations assigned LCB File No. R042-10 which pertain to Chapter 704 of the Nevada Administrative Code on June 30, 2010. A copy of the regulations as adopted is attached hereto.

LEGISLATIVE REVIEW OF ADOPTED REGULATIONS AS REQUIRED BY NRS 233B.066 LCB FILE R042-10 (DOCKET NO. 09-07016)

The following informational statement is submitted for adopted amendments to Nevada Administrative Code Chapter 704.

1. **A description of how public comment was solicited, a summary of public response, and an explanation how other interested persons may obtain a copy of the summary.**

Copies of the proposed regulations, notice of intent to act upon the regulation and notice of workshop and hearing were sent by U.S. mail and email to persons who were known to have an interest in the subject of electric utility decoupling. These documents were also made available at the website of the Public Utilities Commission ("PUC"), http://puc.nv.gov, mailed to all county libraries in Nevada, published in the following newspapers:

Elko Daily Free Press
Las Vegas Review Journal
Nevada Appeal
Reno Gazette Journal
Tonopah Times-Bonanza,

and posted at the following locations:

Public Utilities Commission
1150 East William Street
Carson City, Nevada 89701

Public Utilities Commission
101 Convention Center Drive, Suite 250
Las Vegas, Nevada 89109

First Judicial District Court
885 East Musser Street
Carson City, Nevada 89701

Second Judicial District Court
75 Court Street
Reno, Nevada 89501

Eighth Judicial District Court
Regional Justice Center
200 Lewis Avenue
Las Vegas, Nevada 89155

Informal workshops were held on October 1, 2009, October 26, 2009, November 24, 2009, and March 12, 2010, at which time the participants discussed potential regulation language

and other issues related to the rulemaking process. Thereafter, the proposed regulation language was sent to LCB on March 16, 2010.

An additional formal workshop was held on June 10, 2010 and a public hearing was held on June 11, 2010. At that workshop and hearing, Nevada Power Company and Sierra Pacific Power Company, d/b/a NV Energy, the Regulatory Operations Staff, MGM/Mirage, Newmont Mining, Barrick Goldstrike Mines and the Attorney General's Bureau of consumer Protection all generally agreed that they were satisfied with the language and that the proposed regulation met the intent of the statute.

A copy of the transcript of the proceedings is available for review at the offices of the PUC, 1150 East William Street, Carson City, Nevada 89701 and 101 Convention Center Drive, Suite 250, Las Vegas, Nevada 89109.

2. **The number of persons who:**
(a) Attended each hearing: June 10, 2010 - 8; June 11, 2010 - 9
(b) Testified at each hearing: June 10, 2010 - 7; June 11, 2010 - 8
(c) Submitted to the agency written comments: 31

3. **A description of how comment was solicited from affected businesses, a summary of their response, and an explanation how other interested persons may obtain a copy of the summary.**

Comments were solicited from affected businesses in the same manner as they were solicited from the public.

The summary may be obtained as instructed in the response to question #1.

4. **If the regulation was adopted without changing any part of the proposed regulation, a summary of the reasons for adopting the regulation without change.**

The permanent regulations were adopted on June 30, 2010. It was not revised as the participants in the Workshop and Hearing and the Commission believed the regulation met the intent of the statute.

5. **The estimated economic effect of the adopted regulation on the businesses which it is to regulate and on the public. These must be stated separately, and each case must include:**
(a) Both adverse and beneficial effects; and
(b) Both immediate and long-term effects.

(a) Both adverse and beneficial effects:

The adopted regulation will have little or no economic impact on the public, aside from informing them of how to dispose of and/or recycle certain electronic waste (such as compact fluorescent light bulbs). Prior to adoption of the regulation, electric utilities

were required to send semi-annual notices to customers containing information on a number of issues. The adopted regulation requires said mailing to include information regarding disposal and/or recycling of certain waste. Including additional information in the previously required mailings, as required by the adopted regulation will not significantly increase the cost to the electric utilities.

(b) Both immediate and long-term effects:

See Item # 5(a).

6. **The estimated cost to the agency for enforcement of the adopted regulation.**

There is no additional cost to the agency for enforcement of these regulations.

7. **A description of any regulations of other state or government agencies which the proposed regulation overlaps or duplicates and a statement explaining why the duplication or overlapping is necessary. If the regulation overlaps or duplicates a federal regulation, the name of the regulating federal agency.**

These regulations do not overlap or duplicate any federal, state, or local regulations.

8. **If the regulation includes provisions that are more stringent than a federal regulation which regulates the same activity, a summary of such provisions.**

N/A

9. **If the regulation provides a new fee or increases an existing fee, the total annual amount the agency expects to collect and the manner in which the money will be used.**

N/A

10. **If the proposed regulation is likely to impose a direct and significant economic burden upon a small business or directly restrict the formation, operation or expansion of a small business? What methods did the agency use in determining the impact of the regulation on a small business?**

The PUC has determined that the proposed regulations do not impose a direct and significant economic burden upon a small business or restrict the formation, operation or expansion of a small business. In making this determination, the PUC adopted the findings of Staff, which conducted a Delphi Method exercise to determine the impacts. The Delphi Method is a systematic, interactive, forecasting method based on independent inputs of selected experts.

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Rulemaking to adopt, amend, or repeal regulations regarding electric utility decoupling and other related utility matters in accordance with Senate Bill 358 (Section 11.3).	)	Docket No. 09-07016

At a general session of the Public Utilities Commission of Nevada, held at its offices on June 30, 2010.

PRESENT: Chairman Sam A. Thompson
Commissioner Rebecca D. Wagner
Commissioner Alaina Burtenshaw
Assistant Commission Secretary Nancy Krassner

ORDER

The Public Utilities Commission of Nevada ("Commission") makes the following findings of fact and conclusions of law:

1. The Public Utilities Commission of Nevada ("Commission") voted to open a rulemaking to adopt, amend, or repeal regulations regarding electric utility decoupling and other related utility matters in accordance with Senate Bill 358 (Section 11.3), passed during the 2009 legislative session. This matter has been designated as Commission Docket No. 09-07016.

2. This matter is being conducted by the Commission pursuant to the Nevada Revised Statutes and the Nevada Administrative Code ("NAC") Chapters 233B, 703, and 704.

3. On September 9, 2009, the Commission issued a Notice of Rulemaking, Request for Comments and Proposed Regulations and Notice of Workshop. Comments, some including suggested regulation language, were filed at various times by the Regulatory Operations Staff ("Staff") of the Commission, Nevada Power Company d/b/a/ NV Energy and Sierra Pacific Power Company d/b/a/ NV Energy (collectively referred to as "NV Energy"), the Attorney

General's Bureau of Consumer Protection ("BCP"), the Southwest Energy Efficiency Project ("SWEEP"), Newmont Mining Corporation ("Newmont"), MGM/Mirage Corporation ("MGM"), and Barrick Goldstrike Mines ("Barrick"). Informal workshops were held on October 1, 2009, October 26, 2009, November 24, 2009 and March 12, 2010.

4. On March 23, 2010, the Commission issued a Procedural Order. The proposed regulations were attached. Staff was directed to conduct an investigation pursuant to NRS 233B.0608 to determine whether the proposed regulations were likely to: (a) impose a direct and significant economic burden upon a small business; or (b) directly restrict the formation, operation or expansion of a small business.

5. On March 16, 2010, the Commission sent the proposed regulations to the Legislative Counsel Bureau ("LCB"). The LCB designated the proposed regulations as LCB File No. R042-10.

6. On April 8, 2010, the LCB returned the proposed regulations to the Commission in revised form. The returned regulation is attached hereto as Attachment No. 1, and incorporated herein by this reference.

7. On April 9, 2010, the Commission issued a Notice of Intent to Act Upon a Regulation, Notice of Workshop and Notice of Hearing.

8. On April 22, 2010, following Staff's recommendation at Agenda 06-10, the Commission issued an Order finding that the proposed regulations do not impose a direct and significant economic burden upon a small business, nor do they directly restrict the formation, operation or expansion of a small business.

9. A duly noticed Workshop and Hearing were held on June 10 and 11, 2010, respectively. Appearances were made by Staff, NV Energy, BCP, Newmont, Barrick and MGM.

10. The participants agreed with the proposed regulation and felt it accomplished the legislative intent of section 11.3 of SB 358.

11. Because the proposed regulations contemplate a new filing establishing collection of a base amount to offset against potential lost revenues, the Commission and the participants discussed the transition phase. NV Energy proposed a plan for the transition phase which was filed on June 11, 2010, a copy of which is attached hereto as Attachment No. 2 and incorporated herein by this reference.

12. The participants agreed that the procedure outlined in Attachment No. 2 was acceptable, and the Commission hereby cites it with approval.

13. The Commission finds that it is in the public interest to adopt as permanent the proposed regulations.

THEREFORE, based on the foregoing findings of fact and conclusions of law, it is hereby ORDERED that:

1. The proposed regulations, attached hereto as Attachment No. 1 are ADOPTED AS PERMANENT pursuant to NRS 233B.063.

2. The Commission retains jurisdiction for the purpose of correcting any errors which may have occurred in the drafting or issuance of this order.

By the Commission,

/s/
SAM A. THOMPSON
Chairman and Presiding Officer

/s/
REBECCA D. WAGNER
Commissioner

/s/
ALAINA BURTENSHAW
Commissioner

Attest: /s/
NANCY KRASSNER,
Assistant Commission Secretary

Dated: Carson City, Nevada
7-2-2010
(SEAL)

EXHIBIT 7

NAC 704.9523 Accounting for and recovery of costs of implementing programs for energy efficiency and conservation. (NRS 703.025, 704.210, 704.785)

1. All costs of implementing programs for energy efficiency and conservation must be accounted for in the books and records of an electric utility separately from amounts attributable to any other activity. All accounts must be maintained in a manner that will allow costs attributable to specific programs to be readily identified.

2. An electric utility may, pursuant to subsection 3, recover all reasonably incurred costs of implementing programs for energy efficiency and conservation that have been described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility, including, without limitation, the costs for labor, overhead, materials, incentives paid to customers, advertising, marketing, monitoring and evaluation.

3. To recover the reasonably incurred costs of implementing programs for energy efficiency and conservation, an electric utility must:

(a) Establish and maintain separate subsidiary records of the subaccounts of FERC Account No. 182.3 (Other Regulatory Assets) for each program described in the demand side plan of the electric utility and approved by the Commission pursuant to NAC 704.9494 as part of the action plan of the electric utility. These records must clearly delineate all costs incurred by the electric utility in implementing each program approved by the Commission and be maintained by program by month by rate effective period.

(b) At the time the electric utility files an annual deferred energy accounting adjustment application pursuant to subsection 3 of NRS 704.187, apply to the Commission to establish the following period-specific rates:

(1) A prospective base program cost rate which is determined by allocating in the manner approved by the Commission in the most recent general rate case of the electric utility the total cost of programs for energy efficiency and conservation that are described in the demand side plan approved by the Commission. The prospective base program cost rate for a customer class is an amount equal to the cost allocated to that customer class pursuant to this subparagraph divided by the projected kilowatt hour sales for that class for the relevant period.

(2) A deferred program cost rate to clear the period-specific balance over 12 months. The deferred program cost rate is an amount equal to the period-specific balance in the subaccount of FERC Account No. 182.3 for the cost of programs for energy efficiency and conservation divided by the applicable test period kilowatt hour sales.

4. An electric utility shall account for period-specific costs incurred to implement a program for energy efficiency and conservation and revenues received from the period-specific prospective base program cost rate in the following manner:

(a) On a monthly basis, the electric utility shall record in a subaccount of FERC Account No. 182.3 the program costs incurred and the revenues received from the prospective base program cost rate for the program for energy efficiency and conservation.

(b) The electric utility shall apply a carrying charge at the rate of 1/12 of the authorized overall rate of return to the unamortized balance in the subaccounts of FERC Account No. 182.3.

(Added to NAC by Pub. Utilities Comm'n by R004-04, eff. 5-25-2004; A by R162-07, 6-17-2008; R051-09, 1-28-2010; R042-10, 7-22-2010)

EXHIBIT 8

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 17, 2012

STF 3.01

Energy Efficiency. Reference David G. Hutchens Direct Testimony, Page 15, lines 4-5, Please fully explain how the Company's 3 year proposal is compliant with A.A.C R14-2-2405 which states, "*Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article.*"

RESPONSE:

The purpose of the EERP is to create an alternative mechanism that will fulfill the spirit and objectives of the Electric Energy Efficiency Standard set forth in A.A.C. R14-2-2404. If the Commission approves the Company's proposal as part of the rate case Order, the Commission will have effectively provided a waiver from the specific requirements set forth in A.A.C. R14-2-2405.

Because the Company will not be filing annual implementation plans, the most recent Commission-approved Energy Efficiency Implementation Plan will be used as the initial document for the EERP. The Company will then file any updates or changes to programs as part of its March 1 DSM progress report required by A.A.C. R-14-2-2409.

RESPONDENT:

Denise Smith

WITNESS:

David Hutchens and Craig A. Jones

EXHIBIT 9

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 17, 2012

STF 3.06

Energy Efficiency. Reference David G. Hutchens Direct Testimony, Page 20, lines 16-22 Assuming that the Commission approves a regulatory asset, specifically identify and fully explain what accounting standards would prohibit the Commission from setting a longer (or shorter amortization period). If the Commission sets a 5 year amortization, would the accounting standards make it such that the regulatory asset was less likely to be fully recovered? Please fully explain your answer.

RESPONSE:

Accounting Standard Codification ("ASC") under U.S. Generally Accepted Accounting Principles ("GAAP") 980-340-25-1 Recognition of Regulatory Assets allows the deferral of costs as long as it is probable that those specific costs are subject to recovery in future revenues. Accounting standards do not prohibit the Commission from setting a longer (or shorter) amortization period. TEP's EERP is a 3-year pilot program. TEP is requesting recovery over 4 years. Recovery periods that extend over a longer time frame should be carefully evaluated, considering the nature of the related cost. If the Commission sets a 5-year amortization period, application of accounting standards could make it such that the regulatory asset is less likely to be fully recovered.

ASC-980-340-25-1 requires a supportable conclusion that the recovery of regulatory assets is probable. Cost of service regulation is based on implicit presumptions that (1) operating expenses should normally be recovered in the period in which the expenses are incurred, and (2) an allowance for a return on investment should normally be recovered in the period during which the investment is used to provide services to customers. Departure from those norms requires professional judgment in the determination of the appropriate recovery period. Subjective decisions regarding a longer recovery period introduces risk and uncertainty about whether past regulatory actions will be upheld due to potential changes in the political or regulatory climate.

RESPONDENT:

Georgia Hale and Annette Candelaria

WITNESS:

Karen Kissinger and David Hutchens

EXHIBIT 10

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO
STAFF'S THIRD SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
September 17, 2012

STF 3.13

Energy Cost Adjustor. Reference David G. Hutchens Direct Testimony, Page 25, lines24-26, please fully explain your statement, *"this will be detrimental to TEP's financial health and may adversely impact its access to capital on reasonable terms."*

RESPONSE:

As stated in Mr. Hutchens' direct testimony, most major compliance projects take a significant time to design, permit and construct. For example, the SCR facilities at San Juan require investments over four to five years before the projects are complete. As a result, TEP would be investing hundreds of millions of dollars over the course of several years but would be precluded from any recovery of that investment until years later. Investing the equivalent of approximately 30 percent of TEP's rate base for several years without receiving any return on that investment would put pressure on the Company's ability to maintain its current credit ratings.

If TEP's credit ratings were to be lowered due to weakening cash flows resulting from the Company's inability to earn a return on and of the significant amount invested between rate cases, TEP's cost of debt would increase, thus increasing costs to ratepayers. Weakening financial metrics would likely put downward pressure on UNS's stock price, which would also increase the cost of equity financing available to TEP.

RESPONDENT:

Jo Smith

WITNESS:

Kevin Larson

EXHIBIT 11

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01345A-11-0224

DIRECT

TESTIMONY

OF

MICHAEL J. MCGARRY, SR.

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

NOVEMBER 18, 2011

service tariff filing for Illinois Power. From July 1985 through October 1997, I was employed by the New York State Department of Public Service ("NYSDPS") in its Utility Operational Audit Section in which the staff conducted focused operational audits in many facets of utility operations for all sectors of the utility industry, including gas, electric, telecommunications, and water. Prior to my employment with the NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983) and then Seminole Electric Cooperative (1983 to 1985). I received my Masters of Business Administration from the State University of New York at Buffalo in 1996 and a Bachelor of Arts in Economics from Potsdam College (SUNY) in 1981.

Q. Have you prepared an attachment summarizing your educational background and regulatory Experience?

A. Yes. Attachment MJM-1 provides details concerning my experience and qualifications.

Q. Have you previously testified before the Arizona Corporation Commission?

A. No.

Q. Have you testified before commissions in other jurisdictions?

A. Yes. I have presented or supported testimony in Colorado, Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, Pennsylvania, and Utah. These proceedings included testimony involving revenue requirements, power supply costs, management decisions and prudence impacts, operations and maintenance expenses, capital investments, and project management. A complete list is included in Attachment MJM-1.

EXHIBIT 12

CONFIDENTIAL

EXHIBIT 13

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MARC SPITZER, Chairman
JIM IRVIN
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
MIKE GLEASON

Arizona Corporation Commission
DOCKETED
OCT 14 2003
DOCKETED BY nR

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS NORTHERN GROUP AND FOR CERTAIN RELATED APPROVALS.

DOCKET NO. W-01445A-00-0962

DECISION NO. 66400

OPINION AND ORDER
PHASE II (ARSENIC TREATMENT COST RECOVERY MECHANISM)

DATES OF HEARING: October 3 and 18, 2002; June 26, 2003

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

APPEARANCES:

Mr. Norman James, FENNEMORE CRAIG, on behalf of Arizona Water Company;

Mr. Daniel W. Pozefksy, Attorney, on behalf of the Residential Utility Consumer Office;

Ms. Kay Bigelow, City Attorney, on behalf of the City of Casa Grande;

Mr. Walter W. Meek, on behalf of the Arizona Utility Investors Association, Inc.; and

Mr. David Ronald, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

I. INTRODUCTION

Arizona Water Company's ("Arizona Water" or "Company") Northern Group serves approximately 16,000 customers under five different sets of rate schedules (Sedona, Pinewood, Rimrock, Lakeside, and Overgaard). In November 2000, Arizona Water filed an application with the Arizona Corporation Commission ("Commission") for rate increases for the five Northern Group systems. In its application, Arizona Water also sought approval to reorganize these systems into two

O&M costs whether the Company leases or operates the facilities itself. Ms. Diaz Cortez testified that RUCO's recommendation could be accomplished by requiring lease payments to be broken out into capital costs and O&M costs, and allowing the Company to recover a return on, and depreciation of, the incremental arsenic plant. However, under RUCO's recommendation, all O&M costs associated with the arsenic treatment facilities would require examination in a full rate case prior to being afforded recovery (RUCO Ex. 2, at 6-7)[7].

After considering the arguments regarding the O&M recovery issue, we believe the modified ACRM proposed by Staff and the Company is a reasonable compromise of the positions previously advocated by those parties. In addition to providing a mechanism for recovery of capital costs incurred by Arizona Water, which costs are not opposed even by RUCO, the modified ACRM offers the Company an opportunity to recover limited verifiable O&M costs in a timely manner. The proposed ACRM also treats leasing and owning arsenic treatment facilities on an equal basis, thereby affording Arizona Water the flexibility to negotiate the least-cost means of complying with federal arsenic limit mandates. However, the recovery of O&M expenses is confined to specific and narrowly defined costs in order to enable Staff and other parties to more easily audit expenditures incurred by the Company for the treatment facilities. The Company also retains the opportunity to file a general rate application.

B. Number of Step Increases

The parties also disagree regarding the number of step increases that should be permitted prior to the Company's next full rate case in 2007. Arizona Water proposed that it should be entitled to three step increases, while Staff and RUCO recommend that each affected system be limited to two step increases (Ex. A-1, at 10; Ex. S-1, at 11, RUCO Ex. 1, at 5). Arizona Water argues that the ability to request three step increases will allow the Company greater flexibility and will enable it to better match operating income with debt service costs. Arizona Water also contends that three step increases will be preferable for customers because the increases will be implemented in smaller increments. The Company claims smaller increases will be even more important if the Commission

[7] RUCO also raised the argument that the modified ACRM exceeds the scope of the Commission's legal authority with respect to approval of automatic adjustment mechanisms. RUCO's legal arguments are addressed below.

EXHIBIT 14

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

Arizona Corporation Commission
DOCKETED
MAY 24 2012
DOCKETED BY TM

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN.

DOCKET NO. E-01345A-11-0224

DECISION NO. 73183

OPINION AND ORDER

DATES OF HEARING: July 18, 2011 (Procedural Conference); October 7, 2011 (Public Comments – Sun City, Arizona); December 16, 2011 (Special Open Meeting); January 19, 2012 (Public Comments – Phoenix, Arizona); January 19, 2012 (Pre-Hearing Conference); January 26, 27, 30, 31, February 1, 2, and 3, 2012.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Lyn Farmer

IN ATTENDANCE: Gary Pierce, Chairman
Bob Stump, Commissioner
Sandra D. Kennedy, Commissioner
Paul Newman, Commissioner
Brenda Burns, Commissioner

APPEARANCES: Ms. Meghan H. Grabel and Mr. Thomas L. Mumaw, Law Department, PINNACLE WEST CAPITAL CORPORATION, on behalf of the Applicant;

Mr. Michael M. Grant, GALLAGHER & KENNEDY, PA, on behalf of Arizona Investment Council;

Mr. Craig A. Marks, CRAIG A. MARKS, PLC, on behalf of AARP;

Mr. Timothy M. Hogan, ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST; on behalf of Southwest Energy Efficiency Project, Western Resource Advocates, Arizona School Boards Association, and Arizona Association of School Business Officials;

updated annually documenting program and measure savings assumptions and incremental costs.

X. Rate Treatment Related to any Acquisition by APS of Southern California Edison's Share of Four Corners Units 4-5 – This Section provides that this docket will remain open until December 31, 2013, for APS to file a request to adjust its rates to reflect the rate base and expense effects associated with (1) the acquisition of Southern California Edison's ("SCE") ownership interest in Four Corners Units 4 and 5, and (2) the retirement of Units 1-3, as well as any cost deferral authorized in the Commission's Decision in the Four Corners acquisition docket; that APS is authorized to request amendments to the PSA Plan of Administration to include the post-acquisition Operations and Maintenance expense associated with Four Corners Units 1-3 as a cost of producing off-system sales until closure of Units 1-3, provided that such costs do not exceed off-system sales revenue in any given year; that any filing seeking a rate adjustment must include specific schedules and any proposed adjustment rider must spread the costs on an equal percentage basis across all rate schedules and will not become effective before July 1, 2013; and that rates are adjusted only if the Commission finds the Four Corners transaction to be prudent.

XI. Modification to Environmental Improvement Surcharge – This Section withdraws the proposed ERA mechanism; revises the existing Environmental Improvement Surcharge ("EIS") to recover the capital carrying costs associated with government-mandated environmental controls, subject to a cap; resets the existing EIS to zero; and revises the EIS Plan of Administration to implement these changes.

XII. Cost Deferral Related to Changes in Arizona Property Tax Rate – This Section allows APS to defer without interest for future recovery: 25 percent of the prorated property tax rate increase in 2012, 50 percent in 2013, and 75 percent each year thereafter, and 100 percent of all property tax rate decreases; recovery will begin after the next general rate case with recovery of a positive balance spread over 10 years and a negative balance over three years; and the signatories may review the deferrals for reasonableness and prudence.

XIII. Transmission Cost Adjustment Mechanism – This Section provides that the current level of transmission costs in base rates will remain in base rates; APS will file its revised TCA tariff and supporting documents by May 15 of each year, and the annual TCA adjustment will become effective

June 1 of each year unless Staff requests review or the Commission orders otherwise; and the TCA Plan of Administration is modified to include the new provisions.

XIV. Low Income Programs – This Section provides that funds remaining in the bill assistance program approved in Decision No. 69663 may be used to assist customers whose incomes are less than or equal to 200 percent of the Federal Poverty Income Guidelines; and that the billing method for low income customers will be simplified by including PSA and the Demand Side Management Adjustor Charge ("DSMAC") charges to their rate schedule and then applying a discount to the total bill, such that there will be no bill impact to low income customers as a result of the billing method change.

XV. Service Schedule 3 (Line Extensions) – This Section provides that Version 12 of Service Schedule 3, as approved in Decision No. 72684 (November 18, 2011), will become effective on the date that rates set herein are effective.

XVI. Bill Presentation – This Section provides that APS will initiate stakeholder meetings within 90 days that will address issues related to making APS' bill easier for customers to understand and requires APS to file an application for any authorization needed to modify its bill presentation and explain how stakeholder input during the process was included.

XVII. Rate Design – This Section provides that APS' proposed Experimental Rate Schedule AG-1, a buy-through rate for large commercial and industrial customers (that does not address the subject of retail competition), should be approved as modified and set forth in Attachment J; that if there are any unmitigated lost fixed generation costs related to the AG-1 Experimental Rate in APS' next rate case, APS should explain why and shall not propose to recover such costs from residential customers; that APS shall file a study in its next rate case to support costs of various charges in Service Schedule 1, taking into account the impact Smart Grid technology may have on the costs; the request to establish Service Schedule 9, an economic development schedule is withdrawn in favor of the use of Commission-approved special contracts; and other rate design issues are resolved in Attachment K.

XVIII. Compliance Matters – This Section provides that within ten days of this Decision, APS shall file compliance schedules for Staff's review and that subject to that review, the schedules

will become effective on the effective date of new rates; that on or before May 31 each year, APS shall file a report with the Commission that identifies the extent of the challenges regarding workforce planning, the specific actions that APS is taking to address the issue, and the progress it is making toward meeting those goals; and provides that the rating agencies communications report filing requirement found in Decision No. 70667 is eliminated.

XIX. Force Majeure Provision – This Section sets out the conditions whereby APS, the Commission, or a signatory may request a change in or review of base rates.

XX. Commission Evaluation of Proposed Settlement – This Section provides that if the Commission fails to issue an order adopting all material terms of the Settlement Agreement, any or all of the signatories may withdraw from the agreement and pursue without prejudice their respective remedies at law; provides that for purposes of the Settlement Agreement, whether a term is material is in the discretion of the signatory choosing to withdraw from the Settlement Agreement, and if a signatory withdraws from the Settlement Agreement and files an application for rehearing, the other signatories except for Staff, shall support the application for rehearing.

XXI. Miscellaneous Provisions – This Section provides that the signatories shall support and defend the Settlement Agreement and shall make reasonable and good faith efforts to obtain a Commission order approving the Settlement Agreement; and that to the extent any provision of the Settlement Agreement is inconsistent with any existing Commission order, rule, or regulation, the Settlement Agreement shall control and that each term is in consideration of all other terms and the terms are not severable.

Benefits of the Settlement Agreement as Identified by the Parties

Staff

Staff finds that the provisions of the proposed Settlement Agreement are in the public interest and that the Commission should approve it. Staff explains that the goal of the 2009 settlement agreement approved by the Commission was to improve APS' standing in the investment community, provide predictability with rate case filings and timing, and establish a strong

commitment to Arizona's energy future.[44] This Settlement Agreement is designed to build upon the progress toward those goals while preserving the Commission's flexibility to implement policy objectives in energy efficiency and renewables. Staff believes that the Settlement Agreement was the product of a transparent and open process involving a diverse group of stakeholders, and that the end result balances APS' financial stability with benefits to customers.

Those benefits include:

- An overall zero dollar base rate increase;
- A zero percent bill impact for the remainder of 2012 (Commission-approved adjustors (including the possibility of a Four Corners rider pursuant to paragraph 10.3 of the Agreement) may increase customer bills after December 31, 2012);
- An increase in rate stability, including a four year period without base rate increases;
- A buy-through rate for industrial and large commercial customers that holds residential customers harmless in the event that there are stranded fixed costs;
- A narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism that supports energy efficiency ("EE") and distributed generation ("DG") at any level or pace set by the Commission;
- An opt-out rate design for residential customers who choose not to participate in the LFCR;
- A process for simplifying customer bills; and
- Bill assistance for additional low income customers at shareholder expense.[45]

Staff explains that the Signatories intended to provide the Commission with maximum flexibility in setting EE and DG policy and therefore, there are no specific EE or RES targets or requirements built into the Settlement Agreement. Staff noted that there are components of the Settlement Agreement that will allow continued improvement in APS' financial standing, including; the settlement itself, which reflects "the positive climate of the Commission's process;"[46] the inclusion of 15 months of post test year plant; a 10 percent return on equity; the LFCR; and the other parts of the Settlement Agreement that support the Company's ability to accept a four year stay out.

[44] Staff's Opening Brief at 5.
[45] Staff Opening Brief at 6.
[46] Tr. at 26, AIC Opening Statement.

Staff argues that the Settlement Agreement appropriately balances consumer and shareholder interests and identifies the following provisions that will benefit consumers:

1) Rate Case Filing Moratorium – Staff believes that the four year stay-out whereby APS will not file its next general rate case before May 31, 2015 and new base rates will not take affect before July 1, 2016, will provide customers with rate stability while also providing APS with sufficient revenue to provide safe and reliable electric service. Staff disagrees with SWEEP's argument that the stay out provision should be shortened to three years, because Staff believes that stay-out provisions encourage utilities to control costs, which can lead to lower rates in future rate cases. Staff also believes that the Settlement Agreement was "crafted to permit maximum flexibility to the Commission in the implementation of new policy while providing a means to make the Company whole."[47]

2) No Base Rate Increase – Staff notes that although APS initially proposed a $95.49 million total rate increase, the proposed Settlement Agreement provides no base rate increase. The change to base rates includes a non-fuel base rate increase of $116.3 million (including post test year plant in service as of March 31, 2012), a fuel base rate decrease of $153.1 million, and a transfer of cost recovery from the RES to base rates in the amount of approximately $36.8 million. The base cost of fuel and purchased power will decrease from $0.037571 per kWh to $0.032071 per kWh. Staff believes that even though adjustor mechanisms may continue to fluctuate and increase bills, "the fact that base rates will remain constant for a four-year period is a significant benefit to customers."[48]

3) A Bill Impact of Zero or Slightly Negative Once New Rates Take Effect for the Remainder of 2012 - APS has agreed to delay recovery of a portion of its fuel and purchased power costs until early 2013 and this delay will allow a zero or slightly negative bill impact until February 1, 2013.[49] This benefits customers by not increasing base rates during the summer when usage is typically higher and by decreasing the frequency of bill impacts associated with the reset of fuel and purchased power costs which would have occurred in July 2012.

4) A Rate of Return on Equity that is 100 Basis Points Below APS' Existing Return on

[47] Staff Opening Brief at 38.
[48] *Id.* at 13.
[49] The PSA reset will occur in February 2013 and true-up its recovery of fuel and purchased power expenses.

5) Rate Treatment Related to APS Proposed Acquisition of Four Corners – Staff explained that APS believes that this provision is essential to the four year rate moratorium, noting that the non-fuel related annual revenue requirement associated with the Four Corners transaction amounts to approximately $70 million annually. Staff also explained that the Settlement Agreement would lower the balance of the cost deferrals, because the costs would begin to be collected sooner.[65] Any recovery of costs would occur only upon a finding by the Commission that the transaction and costs were prudent.

6) Elimination of the 90/10 Sharing Is In the Public Interest – Staff believes that the elimination of the 90/10 sharing provision and two new PSA provisions will produce benefits for customers when there are lower fuel prices and will provide incentives for APS to manage its PSA balance. The PSA is "a cost tracking mechanism designed to allow APS to recover costs associated with obtaining power supplies in a more effective manner due to the short-term volatility in power costs" and tracks how much actual fuel and purchased power costs deviate from the amount recovered through APS' base cost of fuel and purchased power collected in base rates.[66] The 90/10 sharing provision splits the over or under collection of fuel costs between ratepayers and the Company. When actual fuel costs exceed base fuel rates, APS can collect 90 percent of those costs, and when actual fuel costs are less than base fuel rates, APS can keep 10 percent of those savings. The PSA sharing mechanism is designed to give APS a financial incentive to prudently plan for and acquire its purchased power and fuel. Under the Settlement Agreement, the 90/10 sharing provision is replaced with periodic audits of APS' fuel and power procurement, with the first audit for calendar year 2014; and with the application of interest rates that vary depending upon whether there is an under or over collection of the PSA balance. Staff believes that these provisions will produce benefits for customers when fuel prices are lower and will provide incentives for APS to better manage its PSA balances.

7) The EIS and Property Tax Deferrals Were Important In Achieving A Longer Stay-Out And Are In the Public Interest As Well - Staff believes that the changes to the EIS are in the public

[65] Staff Opening Brief at 27.
[66] Staff Ex. 4, Solganick November 18, 2011 Direct Testimony at 17.

interest because now APS will invest its own funds to pay for government-mandated environmental controls, and the EIS will only collect the capital carrying costs, subject to a cap equal to the charge currently in place for the EIS. The EIS will be reset to zero on the effective date of new rates adopted in this Decision. The property tax deferral was an important component of APS' ability to agree to a four year stay out, and as Staff explains, the amount to be deferred is limited and any positive balance will be recovered over 10 years while any negative balance will be refunded over 3 years.

Staff believes that the Settlement Agreement results in just and reasonable rates and that the impact on customers' bills will be reasonable. Staff notes the following bill impacts from adopting the Settlement Agreement, and also from various adjustors and surcharges:

- A modest reduction across customer classes, generally around one percent on the effective date of the new rates, expected to be July 1, 2012, resulting from delaying the reset of the existing PSA to reflect new base fuel rates;
- In early 2013 when the PSA resets, average residential customer bills will increase by approximately 6.4 percent;
- If the Four Corners transaction closes in 2012, there would be a reduction in the PSA forward component, resulting in a negative 2.9 percent PSA impact, and the February 2013 PSA reset would be approximately 3.5 percent instead of 6.4 percent;
- When the first LFCR adjustment is approved by the Commission, a 0.2 percent adjustment to bills would occur on March 1, 2013;
- If the Four Corners transaction closes, then no earlier than July 2013, a 3 percent nonfuel increase to the average residential customer bill is possible if approved by the Commission; and
- Other adjustor charges could impact customer bills, including the DSMAC, the TCA, and the RES.[67]

. . .

[67] Staff Opening Brief at 31-32. These are estimates and not rates adopted in this Decision.

EXHIBIT 15

Exhibit____MJM-13 - Staff Derivation of Alternative plan Revenue Requirement for EERP

Line	Description	Amount	Comment
1	Original Cost	$11,500,000.00	Estimate - Actual amount would be recorded here. Used Staff proposed budget from E-01933A-11-0055 for 6 months
2	Asset Life	7	Based on average usefulful life of measures - see Exhibit____ MJM-XX, Line 4
3	Income Tax Rate	39.57%	
4	Nominal Return	7.0000%	Per Staff Witness S.Keith Berry, Ph.D
5	Gross Conversion Factor	1.659	TEP Schedule C-3

		Comment	2014 **	2015	2016	2017	2018	2019	2020	2021	2022	2023
6	Regulatory Assest Amortization	Original Cost ÷ Years	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ -	$ -	$ -
7	Tax Depreciation	Original Cost	$ 11,500,000									
8	Net Book basis (end of year)	Line 7 minus Line 6	$ 9,857,143	$ 8,214,286	$ 6,571,429	$ 4,928,571	$ 3,285,714	$ 1,642,857	$ -	$ -	$ -	$ -
9	Tax basis (end of year)											
10	ADIT (end of year) Book basis minus tax basis) times tax rate)	Line 8 * income tax rate (line 3)	$ 3,900,471	$ 3,250,393	$ 2,600,314	$ 1,950,236	$ 1,300,157	$ 650,079	$ -	$ -	$ -	$ -
11	Rate Base, end of year											
12	Regulatory Asset	Line 1	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000	$ 11,500,000
13	Accumulated Amortization	Sum Line 6 to 2014 to YTD	$ (1,642,857)	$ (3,285,714)	$ (4,928,571)	$ (6,571,429)	$ (8,214,286)	$ (9,857,143)	$ (11,500,000)	$ (11,500,000)	$ (11,500,000)	$ (11,500,000)
14	ADIT	Line 10	$ (3,900,471)	$ (3,250,393)	$ (2,600,314)	$ (1,950,236)	$ (1,300,157)	$ (650,079)	$ -	$ -	$ -	$ -
15	Unamortized ITC		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Rate Base, end of year	Sum lines 12-15	$ 5,956,671	$ 4,963,893	$ 3,971,114	$ 2,978,336	$ 1,985,557	$ 992,779	$ (0)	$ (0)	$ (0)	$ (0)
17	Revenue Requirement											
18	Carrying Costs	Line 16 * Nominal Return	$ 416,967	$ 347,473	$ 277,978	$ 208,484	$ 138,989	$ 69,495	$ (0)	$ (0)	$ (0)	$ (0)
19	O&M		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Revenue Requirement before Taxes	Sum lines 18+19	$ 416,967	$ 347,473	$ 277,978	$ 208,484	$ 138,989	$ 69,495	$ (0)	$ (0)	$ (0)	$ (0)
21	Gross Up Conversion	Line 5	$ 691,748	$ 576,457	$ 461,166	$ 345,874	$ 230,583	$ 115,291	$ (0)	$ (0)	$ (0)	$ (0)
22	Amortization	Line 6	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ 1,642,857	$ -	$ -	$ -
23												
24	Total Revenue Requirement -2014 Plan Costs	Sum lines 20-23	$ 2,334,605	$ 2,219,314	$ 2,104,023	$ 1,988,731	$ 1,873,440	$ 1,758,149	$ 1,642,857	$ (0)	$ (0)	$ (0)
25	Total Revenue Requirement -2015 Plan Costs	Tab 2015	$ -	$ 5,022,283	$ 4,774,264	$ 4,526,245	$ 4,278,226	$ 4,030,208	$ 3,782,189	$ 3,534,170	$ (0)	$ (0)
26	Total Revenue Requirement -2016 Plan Costs	Tab 2016	$ -	$ -	$ 5,490,364	$ 5,219,230	$ 4,948,096	$ 4,676,961	$ 4,405,827	$ 4,134,693	$ 3,863,558	$ -
27	Total Revenue Requirement -2017 Plan Costs	Tab 2017	$ -	$ -	$ -	$ 5,655,075	$ 5,375,807	$ 5,096,538	$ 4,817,270	$ 4,538,002	$ 4,258,733	$ 3,979,465
28	Total Revenue Requirement	Sum Line 24-27	$ 2,334,605	$ 7,241,597	$ 12,368,651	$ 17,389,281	$ 16,475,569	$ 15,561,856	$ 14,648,143	$ 12,206,865	$ 8,122,292	$ 3,979,465
29	Forecast Sales (MWhrs)	CAJ-8, 2014 annualized from amount shown o 2021 thru 2023 estimated based on growth rate trend 2014 to 2020	4,790,031	9,658,045	9,739,655	9,813,955	9,902,221	10,002,707	11,045,242	11,102,686	11,140,265	11,163,859
30	DSMS Rate per kWh	Line 28 ÷ Line 29	$ 0.0004870	$ 0.0007500	$ 0.0012700	$ 0.0017720	$ 0.0016640	$ 0.0015560	$ 0.0013260	$ 0.0010990	$ 0.0007290	$ 0.0003560
31	Current DSMS Rate (per TEP Tariffs)	Previous years rate	$ 0.0012490	$ 0.0004870	$ 0.0007500	$ 0.0012700	$ 0.0017720	$ 0.0016640	$ 0.0015560	$ 0.0013260	$ 0.0010990	$ 0.0007290
32	Change	Line 30 minus line 31	$ (0.0007620)	$ 0.0002630	$ 0.0005200	$ 0.0005020	$ (0.0001080)	$ (0.0001080)	$ (0.0002300)	$ (0.0002270)	$ (0.0003700)	$ (0.0003730)
33	TEP Proposed Rate	Exhibit CAJ-8 TEP EERP POA Attachm	$ 0.0009160	$ 0.0016640	$ 0.0024540	$ 0.0022650	$ 0.0014920	$ 0.0007230	NA	NA	NA	NA
34	Change Staff versus Company	line 30 minus line 33	$ (0.0004290)	$ (0.0009140)	$ (0.0011840)	$ (0.0004930)	$ 0.0001720	$ 0.0008330	NA	NA	NA	NA
35	Percent Change	line 34 ÷ line 35	$ (0.4683406)	$ (0.5492788)	$ (0.4824776)	$ (0.2176600)	$ 0.1152815	$ 1.1521438	NA	NA	NA	NA

Exhibit____MJM-13 - Staff Derivation of Alternative plan Revenue Requirement for EERP

2015

Line	Description	Amount	Comment
1	Original Cost	$ 24,739,192.00	Estimate - Actual amount would be recorded here. Used Staff proposed budget from E-01933A-11-0055 for 6 months
2	Asset Life	7	Based on average usefulful life of measures - see Exhibit____ MJM-XX, Line 4
3	Income Tax Rate	39.57%	
4	Nominal Return	7.0000%	Per Staff Witness S.Keith Berry, Ph.D
5	Gross Conversion Factor	1.659	TEP Schedule C-5

		Comment	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
6	Regulatory Assest Amortization	Original Cost ÷ Years		$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ -	$ -
7	Tax Depreciation	Original Cost		$ 24,739,192								
8	Net Book basis (end of year)	Line 7 minus Line 6	$ -	$ 21,205,022	$ 17,670,851	$ 14,136,681	$ 10,602,511	$ 7,068,341	$ 3,534,170	$ -	$ -	$ -
9	Tax basis (end of year)											
10	ADIT (end of year) Book basis minus tax basis) times tax rate	Line 8 * income tax rate (line	$ -	$ 8,390,827	$ 6,992,356	$ 5,593,885	$ 4,195,414	$ 2,796,942	$ 1,398,471	$ -	$ -	$ -
11	Rate Base, end of year											
12	Regulatory Assest	Line 1		$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192
13	Accumulated Amortization	Sum Line 6 to 2014 to YTD	$ -	$ (3,534,170)	$ (7,068,341)	$ (10,602,511)	$ (14,136,681)	$ (17,670,851)	$ (21,205,022)	$ (24,739,192)	$ (24,739,192)	$ (24,739,192)
14	ADIT	Line 10	$ -	$ (8,390,827)	$ (6,992,356)	$ (5,593,885)	$ (4,195,414)	$ (2,796,942)	$ (1,398,471)	$ -	$ -	$ -
15	Unamortized ITC											
16	Rate Base, end of year	Sum lines 12-15	$ -	$ 12,814,195	$ 10,678,496	$ 8,542,796	$ 6,407,097	$ 4,271,398	$ 2,135,699	$ (0)	$ (0)	$ (0)
17	Revenue Requirement											
18	Carrying Costs	Line 16 * Nominal Return	$ -	$ 896,994	$ 747,495	$ 597,996	$ 448,497	$ 298,998	$ 149,499	$ (0)	$ (0)	$ (0)
19	O&M											
20	Revenue Requirement before Taxes	Sum lines 18+19	$ -	$ 896,994	$ 747,495	$ 597,996	$ 448,497	$ 298,998	$ 149,499	$ (0)	$ (0)	$ (0)
21	Gross Up	Line 5	$ -	$ 1,488,112	$ 1,240,094	$ 992,075	$ 744,056	$ 496,037	$ 248,019	$ (0)	$ (0)	$ (0)
22	Amortization	Line 6	$ -	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ 3,534,170	$ -	$ -
23	Prior Years Unrecovered Costs											
24	Total Revenue Requirement -2015 Plan Costs	Sum lines 21+22+23	$ -	$ 5,022,283	$ 4,774,264	$ 4,526,245	$ 4,278,226	$ 4,030,208	$ 3,782,189	$ 3,534,170	$ (0)	$ (0)

Exhibit____MJM-13 - Staff Derivation of Alternative plan Revenue Requirement for EERP

2016

Line	Description	Amount	Comment
1	Original Cost	$ 27,044,908.00	Estimate - Actual amount would be recorded here. Used Staff proposed budget from E-01933A-11-0055 for 6 months
2	Asset Life	7	Based on average usefulful life of measures - see Exhibit____ MJM-XX, Line 4
3	Income Tax Rate	39.57%	
4	Nominal Return	7.0000%	Per Staff Witness S.Keith Berry, Ph.D
5	Gross Conversion Factor	1.659	TEP Schedule C-8

		Comment	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
6	Regulatory Assest Amortization	Original Cost ÷ Years		$ -	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ -
7	Tax Depreciation	Original Cost		$ -	$ 27,044,908							
8	Net Book basis (end of year)	Line 7 minus Line 6	$ -	$ -	$ 23,181,350	$ 19,317,791	$ 15,454,233	$ 11,590,675	$ 7,727,117	$ 3,863,558	$ -	$ -
9	Tax basis (end of year)											
10	ADIT (end of year) Book basis minus tax basis) times tax rate)	Line 8 * income tax rate (line 3)	$ -	$ -	$ 9,172,860	$ 7,644,050	$ 6,115,240	$ 4,586,430	$ 3,057,620	$ 1,528,810	$ -	$ -
11	Rate Base, end of year											
12	Regulatory Assest	Line 1			$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908	$ 27,044,908
13	Accumulated Amortization	Sum Line 6 to 2014 to YTD	$ -	$ -	$ (3,863,558)	$ (7,727,117)	$ (11,590,675)	$ (15,454,233)	$ (19,317,791)	$ (23,181,350)	$ (27,044,908)	$ (27,044,908)
14	ADIT	Line 10	$ -	$ -	$ (9,172,860)	$ (7,644,050)	$ (6,115,240)	$ (4,586,430)	$ (3,057,620)	$ (1,528,810)	$ -	$ -
15	Unamortized ITC											
16	Rate Base, end of year	Sum lines 12-15	$ -	$ -	$ 14,008,490	$ 11,673,741	$ 9,338,993	$ 7,004,245	$ 4,669,497	$ 2,334,748	$ (0)	$ (0)
17	Revenue Requirement											
18	Carrying Costs	Line 16 * Nominal Return	$ -	$ -	$ 980,594	$ 817,162	$ 653,730	$ 490,297	$ 326,865	$ 163,432	$ (0)	$ (0)
19	O&M											
20	Revenue Requirement before Taxes	Sum lines 18+19	$ -	$ -	$ 980,594	$ 817,162	$ 653,730	$ 490,297	$ 326,865	$ 163,432	$ (0)	$ (0)
21	Gross Up	Line 5	$ -	$ -	$ 1,626,806	$ 1,355,672	$ 1,084,537	$ 813,403	$ 542,269	$ 271,134	$ (0)	$ (0)
22	Amortization	Line 6	$ -	$ -	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ 3,863,558	$ -
23	Prior Years Unrecovered Costs		$ -									
24	Total Revenue Requirement -2016 Plan Costs	Sum lines 21+22+23	$ -	$ -	$ 5,490,364	$ 5,219,230	$ 4,948,096	$ 4,676,961	$ 4,405,827	$ 4,134,693	$ 3,863,558	$ (0)

Exhibit____MJM-13 - Staff Derivation of Alternative plan Revenue Requirement for EERP

2017

Line	Description	Amount	Comment
1	Original Cost	$ 27,856,255.00	Original Cost
2	Asset Life	7	Asset Life
3	Income Tax Rate	39.57%	Income Tax Rate
4	Nominal Return	7.0000%	Nomial Return
5	Gross Conversion Factor	1.65900	Gross Conversion

		Comment	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
6	Regulatory Assest Amortization	Original Cost ÷ Years		$ -	$ -	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465
7	Tax Depreciation	Original Cost		$ -	$ -	$ 27,856,255						
8	Net Book basis (end of year)	Line 7 minus Line 6	$ -	$ -	$ -	$ 23,876,790	$ 19,897,325	$ 15,917,860	$ 11,938,395	$ 7,958,930	$ 3,979,465	$ -
9	Tax basis (end of year)											
10	ADIT (end of year) Book basis minus tax basis) times tax ra	Line 8 * income tax rate (line 3)	$ -	$ -	$ -	$ 9,448,046	$ 7,873,372	$ 6,298,697	$ 4,724,023	$ 3,149,349	$ 1,574,674	$ -
11	Rate Base, end of year											
12	Regulatory Assest	Line 1			$ -	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255
13	Accumulated Amortization	Sum Line 6 to 2014 to YTD	$ -	$ -	$ -	$ (3,979,465)	$ (7,958,930)	$ (11,938,395)	$ (15,917,860)	$ (19,897,325)	$ (23,876,790)	$ (27,856,255)
14	ADIT	Line 10	$ -	$ -	$ -	$ (9,448,046)	$ (7,873,372)	$ (6,298,697)	$ (4,724,023)	$ (3,149,349)	$ (1,574,674)	$ -
15	Unamortized ITC											
16	Rate Base, end of year	Sum lines 12-15	$ -	$ -	$ -	$ 14,428,744	$ 12,023,953	$ 9,619,163	$ 7,214,372	$ 4,809,581	$ 2,404,791	$ -
17	Revenue Requirement											
18	Carrying Costs	Line 16 * Nominal Return	$ -	$ -	$ -	$ 1,010,012	$ 841,677	$ 673,341	$ 505,006	$ 336,671	$ 168,335	$ -
19	O&M											
20	Revenue Requirement before Taxes	Sum lines 18+19	$ -	$ -	$ -	$ 1,010,012	$ 841,677	$ 673,341	$ 505,006	$ 336,671	$ 168,335	$ -
21	Gross Up	Line 5	$ -	$ -	$ -	$ 1,675,610	$ 1,396,342	$ 1,117,073	$ 837,805	$ 558,537	$ 279,268	$ -
22	Amortization	Line 6	$ -	$ -	$ -	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465	$ 3,979,465
23	Prior Years Unrecovered Costs		$ -									
24	Total Revenue Requirement -2017 Plan Costs	Sum lines 21+22+23	$ -	$ -	$ -	$ 5,655,075	$ 5,375,807	$ 5,096,538	$ 4,817,270	$ 4,538,002	$ 4,258,733	$ 3,979,465

	Tariff (per kWh)		Avg. Res. Bill	
Year	Current	Proposed	Current	Proposed
2014	$ 0.002315	$ 0.000916	$ 2.04	$ 0.81
2015	$ 0.003052	$ 0.001664	$ 2.69	$ 1.46
2016	$ 0.003117	$ 0.002454	$ 2.74	$ 2.16

Line No.	Description	2014	2015
	(a)	(b)	(c)
1	Total EE Program Expenditures ($MM)	$ 24.74	$ 27.04
2	Gross Revenue Requirement for 2014 ($MM)	$ 7.97	$ 7.35
3	Gross Revenue Requirement for 2015 ($MM)	$ -	$ 8.72
4	Gross Revenue Requirement for 2016 ($MM)	$ -	$ -
5	Cummulative Impact ($MM) (sum of line 2, 3 & 4)	$ 7.97	$ 16.07

2016	2017	2018	2019	Source
(d)	(e)	(f)	(g)	
$ 27.86	$ -	$ -	$ -	
$ 6.89	$ 6.42	$ -	$ -	Exhibit CAJ-7 Attachment D
$ 8.04	$ 7.53	$ 7.02	$ -	Exhibit CAJ-7 Attachment D
$ 8.98	$ 8.28	$ 7.75	$ 7.23	Exhibit CAJ-7 Attachment D
$ 23.90	$ 22.23	$ 14.77	$ 7.23	

Exhibit____MJM-12 - Staff Derivation of DSMS July 2013 through June 2014

Line No.	Month	Unrecovered Balance (1)	1/12th	Carrying Charge	monthly	Carrying Costs	Recovered amount	Cummulative
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	7/1/2013	$ 22,452,182	$ 1,871,015	7.0000%	0.5833%	$ 130,971.06	$ 2,001,986.23	$ 2,001,986.23
2	8/1/2013	$ 20,581,167	$ 1,871,015			$ 120,056.81	$ 1,991,071.97	$ 3,993,058.20
3	9/1/2013	$ 18,710,152	$ 1,871,015			$ 109,142.55	$ 1,980,157.72	$ 5,973,215.92
4	1-Oct	$ 16,839,137	$ 1,871,015			$ 98,228.30	$ 1,969,243.46	$ 7,942,459.38
5	11/1/2013	$ 14,968,121	$ 1,871,015			$ 87,314.04	$ 1,958,329.21	$ 9,900,788.59
6	12/1/2013	$ 13,097,106	$ 1,871,015			$ 76,399.79	$ 1,947,414.95	$ 11,848,203.54
7	1/1/2014	$ 11,226,091	$ 1,871,015			$ 65,485.53	$ 1,936,500.70	$ 13,784,704.24
8	2/1/2014	$ 9,355,076	$ 1,871,015			$ 54,571.28	$ 1,925,586.44	$ 15,710,290.68
9	3/1/2014	$ 7,484,061	$ 1,871,015			$ 43,657.02	$ 1,914,672.19	$ 17,624,962.87
10	1-Apr	$ 5,613,046	$ 1,871,015			$ 32,742.77	$ 1,903,757.93	$ 19,528,720.80
11	5/1/2014	$ 3,742,030	$ 1,871,015			$ 21,828.51	$ 1,892,843.68	$ 21,421,564.48
12	6/1/2014	$ 1,871,015	$ 1,871,015			$ 10,914.26	$ 1,881,929.42	$ 23,303,493.90
13	Total		$ 22,452,182			$ 851,312	$ 23,303,494	
14	Forecast Retail Sales (MWhrs) (2)						9,580,062	
15	Estimated DSMS Rate per kWh (July 1, 2013 - June 30, 2014)						$ 0.00243	

Notes:

(1) Unrecovered Beginning Balance at 7/1/2013 estimated at $4,452,182 included in filing plus $18M expected program plan expenses in 2013

(2) Forecast Retail Sales based on 13,571,755 for period 8/13 to 12/14 annualized

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

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 ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. E-01933A-12-0291

DIRECT

TESTIMONY

OF

HOWARD SOLGANICK

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

DECEMBER 21, 2012

EXHIBIT
9-11

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291

My testimony reviews the Tucson Electric Power Company's ("Company") Lost Fixed Cost Recovery ("LFCR") proposal. Mr. Solganick is also providing a Rate Design Direct Testimony that will be filed on January 11, 2013.

Mr. Solganick's testimony presents Staff's recommendations based on a review of the Company's application and responses to Staff data requests. Staff recommends that the Commission modify the Company's LFCR proposal to (1) allow the Company to recover only distribution (delivery) service fixed charges, (2) cap the increased revenue allowed for each year at 1 percent, (3) recover the lost fixed cost revenue on a percentage of revenue basis, and (4) make the LFCR mechanism effective beginning with the rate effective date for this rate case.

INTRODUCTION

Q. **Please state your name, position and business address.**

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc.

Q. **Please summarize your qualifications and experience.**

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning submetering and billing. I also previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 35 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony in utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand side management, capacity and system planning, and regulatory issues.

I have also led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects

focused on the marketing, sale and delivery of retail energy, energy related products and services, and support services provided to utilities and retailers.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and have advised the Board of Directors of a public power utility consortium. For a period of four years I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and the Public Utilities Commission of Ohio. I also provide (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric and gas rate cases.

I have also been engaged (as a subcontractor) to review utility performance before, during and after outages resulting from major storms including Hurricane Ike and the two 2011 storms that affected New Jersey.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998, I was a Managing Consultant for AT&T Solutions. From 1990 to 1994, I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held progressively increasing positions of responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice and implementation in both New Jersey and Pennsylvania.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies.

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio

- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

PURPOSE AND SUMMARY OF TESTIMONY

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Staff of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. What is the purpose of your testimony?

A. My testimony analyzes Lost Fixed Cost Recovery ("LFCR") proposal of the Tucson Electric Power Company ("Company").

Based on my review of the Company's application, supporting testimony, and responses to data requests, I make the following recommendations:

- The Commission should modify the Company's LFCR proposal to
  - Allow the Company to receive recovery for only distribution and transmission (delivery) service fixed costs
  - Cap the increased revenue allowed for each year at 1%
  - Recover the lost fixed cost revenue on a percentage of revenue basis
  - Make the LFCR mechanism effective beginning with the rate effective date for this case

Q. What is revenue decoupling?

A. Decoupling is the term used to define a rate design that is designed to disconnect a utility's earnings or revenue from sales of energy or commodity. Decoupled rates can be

designed to eliminate or reduce the utility's disincentive to encourage energy conservation, impacts of the business cycle and/or the effects of weather.

Q. Have you reviewed specific decoupled rate design proposals in other jurisdictions?

A. I have reviewed proposals for decoupled electric and gas rate designs in Delaware for the Staff of the Delaware Public Service Commission where I also assisted in the pre-implementation education process. I have also reviewed decoupling proposals by gas utilities and offered testimony in Maryland for the People's Counsel and in Michigan for the Attorney General. In addition, I assisted the Staff of the District of Columbia Public Service Commission in the evaluation and implementation of a decoupled rate design for delivery of electricity. For Staff I also sponsored a LFCR mechanism in the recent APS case (Docket No. E-01345A- 11-0224).

Q. Please describe the Company's LFCR proposal.

A. The Company's proposal is to establish an LFCR mechanism focused on recovering its estimate of the fixed costs that are unrecovered due to energy efficiency and distributed generation. The Company's LFCR mechanism would exclude fuel and purchased power charges because those areas are already subject to an adjustment mechanism or annual formula.[1] Customer charges and 50% of demand-based charges would also be excluded.[2]

The Company's LFCR is proposed to include all customer classes except for street lighting and water pumping.[3] For calculation purposes the LFCR proposal uses four classes, residential, small general service, large general service and large light and power, which I call "super" classes for identification.

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[1] Exhibit CAJ-5 – LFCR Plan of Administration, page 1, Delivery Revenue
[2] Exhibit CAJ-5 – LFCR Plan of Administration, page 1, Delivery Revenue
[3] Exhibit CAJ-5 – LFCR Plan of Administration, page 2, Excluded Rate Schedules and STF 1.087

The calculation of any lost fixed costs by class is based on the actual kWh metered (or estimated) at the distributed generation facilities (or sites)[4] and the estimated kWh not consumed based on an independent Measurement Evaluation and Research ("MER") of the Company's energy efficiency program[5].

To determine the Total Lost Fixed Cost Revenue the Company's LFCR mechanism uses a Lost Fixed Cost Rate ($/kWh)[6] multiplied by the Total Recoverable Energy Efficiency (or Distributed Generation) Savings (kWh).[7] This calculation is made individually for each of the four "super" classes. The LFCR mechanism would lump together all amounts from the "super" classes[8] add in any past over or under recovery[9] and recover the amount from all classes covered by the Company's LFCR on a per kWh basis.[10]

Although the Company's LFCR Plan of Administration refers to Delivery Revenue[11] and Delivery Charge[12] as inputs into the Company's LFCR mechanism and therefore might be interpreted as focusing on lost distribution costs, the Company's testimony[13] focuses on costs other than customer charge and power purchase and fuel.

The Company's LFCR mechanism annual cap would be 2%[14] (except during the initial period)[15] with the remaining balance plus interest carried to the next period.[16] Subject to

[4] Jones Direct 59:21
[5] Jones Direct 59:18
[6] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 4
[7] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 3
[8] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 2, line 4
[9] Jones Direct 57:23
[10] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 1, line3
[11] Exhibit CAJ-5 – LFCR Plan of Administration, page 1, Delivery Revenue
[12] Exhibit CAJ-5 – LFCR Plan of Administration, Schedule 5
[13] Jones Direct 57:19
[14] Jones Direct 58:1 and Data Response STF 1.087
[15] Jones Direct 61:14

the annual cap, the Company's LFCR mechanism aggregates all underrecovery or overrecovery on an annual basis and recovers or repays those sums over the following twelve-month period beginning July 1st.[17]

The Company is also proposing a fixed charge alternative for residential customers that may want a cost certain option. This alternative has a monthly cost of either $2.50 or $6.50 depending on whether the monthly consumption is less than 2,000 kWh or more than 2,000 kWh.[18] A gap (at exactly 2,000 kWh) exists on the proposed residential tariffs R-01, R-80, R-201AN and R-201BN.[19] This minor item will need to be addressed at implementation if the Company's LFCR mechanism is approved as proposed.

Q. Is the Company's LFCR mechanism the same as the LFCR mechanism approved by the Commission in Decision No. 73183?

A. No. The Company's testimony characterized the LFCR as "...very similar to the Commission-approved mechanisms in the APS and UNS Gas rate cases that were decided earlier this year."[20]

In response to a Staff data request, the Company further defined the differences as:[21]

- Recovery of lost revenues through a kWh charge instead of a percentage-based charge
- Use of a annual true-up mechanism
- A 2 percent cap
- Exclusion of the water pumping and lighting rate classes

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[16] Jones Direct 58:20
[17] Jones Direct 58:14
[18] Jones Direct 59:14
[19] Exhibit CAJ-10
[20] Jones Direct 57:9
[21] STF 1.087

In another response to a data request the Company further defined the difference as:[22]

- No reduction in the generation component in rates

Q. Are there other differences that were not enumerated by the Company?

A. Yes, there are:

- Lost revenue would be based on tail-block revenue[23] that includes generation costs
- An effective date at the end of the Test Year (1/1/12)[24] rather than the beginning of the rate effective period

Q. Has the Company estimated the impact of the LFCR mechanism?

A. The Company initially estimated the impact of its LFCR mechanism at approximately $36.6 million for 2012 and 2013.[25] In its initial response to a Staff data request, the Company estimated subsequent years at around $19 million.[26] To better understand the impact of the Company's LFCR mechanism, Staff and the Company had an informal technical conference and I had several telephone conferences with Mr. Jones. These communications focused on understanding and refining the definition of the Company's LFCR mechanism.

The Company worked collaboratively to develop a model that better answered the Staff data request and this information was provided to all parties as an update of STF 1.092 on December 5, 2012. The Company's estimate is attached as Exhibit HS-2. The Company's estimate of the impact of its LFCR mechanism is approximately $8.9 million in 2014, $10.3 million in 2015 and $11.8 million in 2016. The Company's proposed

[22] TEP Response to VSI 2.39
[23] Jones Direct 60:2
[24] Jones Direct 60:23
[25] Jones Direct 61:14
[26] STF 1.092

LFCR mechanism differentiates between lost fixed costs before and after the rate effective date by recognizing the different tail block rates effective before and after the expected rate change.

Q. Do you have a concern with STF 1.092?

A. Yes. The spreadsheet contains a note "Staff's APS position of using 50% of generation". Staff's position was that no generation component was appropriate in the LFCR mechanism.[27] The APS LFCR does not include a generation component.[28]

Q. Do you support the adoption of the Company's LFCR mechanism?

A. No. The Company's LFCR mechanism appears to have started with the recent Commission approved LFCR for APS but then adds on items that significantly raise costs to customers.

Q. What areas of the Company's revenue do not require some form of revenue decoupling to deal with the impact of energy efficiency programs and distributed generation?

A. The following cost areas do not require decoupling protection in whole or in part:

- Generation
- Energy
- Distribution *(partial)*
- Customer Management
    - Customer Accounts and Sales
    - Metering

[27] Direct Testimony of Howard Solganick (Docket No. E-01345A-11-0224) 11:8 dated November 18, 2011
[28] AZCC Decision No. 73183 13:6, 22:1 and 40:3

- Billing
- Meter Reading

Q. Is some form of revenue decoupling needed for transmission charges?

A. Absent an adjustment mechanism to true-up transmission charges some form of limited decoupling is appropriate.

Q. Is decoupling needed for distribution revenue?

A. Distribution costs are not as fungible, and some distribution assets cannot serve other customers within the short term. Therefore, a reduction in per customer sales may result in a shortfall in revenues to cover fixed costs. Decoupling is needed to recapture the portion of distribution costs that are collected on a volumetric (per kWh) basis. Some of the Company's rate schedules collect distribution costs using demand charges, which will remain constant or change slower than a straight volumetric rate.

Q. Why is revenue decoupling not necessary for the Customer Charges?

A. As a customer takes advantage of energy efficiency or distributed generation the Customer Charge is collected regardless of the customer's usage.

Q. Is the Company subject to an energy efficiency goal?

A. The rules[29] (the "Rules") set cumulative (and incremental) savings (based on prior year sales) as follows:

Year	Cumulative Savings %[30]	Incremental Savings %
2011	1.25	1.25
2012	3.00	1.75
2013	5.00	2.00
2014	7.25	2.25
2015	9.50	2.25

Q. Is energy efficiency cost effective for customers?

A. Yes. The analyses explored during the decoupling workshop proceedings forecast cost savings for customers as a result of a well designed, long-term energy efficiency program.

Q. Has the Company developed an energy efficiency forecast?

A. Yes. Exhibit HS-2 contains the Company's estimate of the results of its energy efficiency efforts under the title "EE related KWh".

Q. Has the Company developed a forecast of the impact of distributed generation?

A. Yes. Exhibit HS-2 contains the Company's estimate of the impact of distributed generation under the title "DG related KWh".

[29] Arizona Administrative Code R14-2-2401, et seq (effective January 1, 2011)
[30] Arizona Administrative Code R14-2-2404, Table 1 (effective January 1, 2011)

Q. Without some mechanism would the Company's Plan have a measureable impact on the Company's revenue?

A. Yes. The Rules require reductions in the Company's sales compared to each prior year. If the Company meets those goals then a portion of the Company's transmission and distribution revenue could be impacted.

Q. After reviewing the Company's LFCR mechanism what changes would you recommend?

A. I recommend changes to the Company's LFCR mechanism as follows:

- Remove the Company's recovery of generation charges
- Change the recovery basis from a $/kWh basis to a percentage of revenue basis
- Ensure that any transmission costs included in the LFCR mechanism are not double counted within a transmission adjustment
- Make the LFCR mechanism effective on the rate effective date of this case
- Reduce the annual cap to 1 percent
- Modify the Company's proposed fixed price option
- Develop and execute a customer education program

Q. Why is decoupling not necessary for generation?

A. The output of the Company's generating system is fungible. The generating system is not affected if energy is delivered to a new customer, an existing customer using slightly more energy, non-ACC jurisdictional customers or sold off-system. Therefore, the Company has many opportunities to sell the output of its generating system.

Q. What is the Company's forecast for sales?

A. The Company's Load Forecast shows a trend of increasing total sales to retail customers (without the effects of Energy Efficiency ("EE") and Distributed Generation ("DG")) and a generally level series of wholesale sales until current contract expiration.[31]

Year	Retail Sales (GWh)	Off System Sales (GWh)
2012	9,686	775
2013	10,033	772
2014	10,259	764
2015	10,477	745
2016	10,698	208

Q. What is a projection of net sales over that period?

A.

Year	Unrestricted Sales (GWh)	LFCR related Reductions (GWh)	Net Sales (GWh)
2012	10,461	222	10,239
2013	10,805	307	10,498
2014	11,023	419	10,604
2015	11,222	560	10,662
2016	10,906	721	10,185

Based on the Company's projected sales and its estimates of EE and DG for the period, the net sales still result in an increasing trend with the exception of 2016, which is driven by the Company's off-system sales situation.

Q. Does the LFCR approved for APS include generation costs?

A. No.

[31] TEP 2012 Integrated Resource Plan Table 7 (page 57)

Q. Why do you recommend that the LFCR mechanism collect the lost fixed costs on a percentage of base rate revenue basis?

A. The LFCR approved for APS and the Company's proposed LFCR mechanism require the same data and/or estimates. Lost fixed costs include both energy and demand impacts. The use of revenue-based recovery (rather than a per kWh basis) preserves the relationship between customer, demand and energy revenues collected from customers and therefore does not shift the LFCR impact towards high load factor customers.

Q. How should PPFAC costs be treated?

A. If the PPFAC is approved as the Company requested, then there is a separate mechanism to recover and adjust for the changes in the Company's sales and energy production. However, if the Company's request for full costs within the PPFAC is rejected then the "Delivery Charge" must be reduced by the amount of fuel and purchased power in base rates. The net effect is zero on the calculations made and impact to the Company.

Q. What concerns do you have about including transmission costs within the LFCR?

A. To avoid potential double recovery of lost transmission costs any changes to the transmission rate mechanism must recognize that a LFCR mechanism that includes transmission costs will protect the Company from cumulative lost sales.

Q. Is the Company's use of tail block rates appropriate?

A. No. Tail block rates are reasonable for the customers that use enough energy to reach their respective tail block. However, there are a significant number of customers that do not reach that point. Therefore, the "Delivery Charge" to be used should be a bill weighted average of each individual rate schedule. The cumulative bill information needed to make this calculation exists in the Company's bill frequency data. Using data

for Rate R-01 as an example ~~22.8~~ 28.8 percent of the summer bills and 45.6% of the winter bills are priced within the initial 0-500 kWh rate block,[32] which is significantly lower than the tailblock. Without adjusting the Company's proposed "Delivery Charge" the Company will receive a windfall.

Q. Why are you recommending that the LFCR mechanism be implemented starting on the rate effective date of this case?

A. The Company's proposal to start the LFCR mechanism at the end of the Test Year recognizes the impact of only a single issue (cost or revenue item) rather than updating all inputs. For example, any labor or process productivity increases that the Company achieves after the end of the Test Year will flow to the stockholders; costs will change in both directions after a Test Year but the ratemaking formula does not usually include an adjustment mechanism, therefore singling out just the LFCR would be inappropriate. Additionally, as the Company has identified, the LFCR would need to have two different "Delivery Charges" to reflect rates before and after the rate effective date. Also, the LFCR approved for APS begins on the rate effective date.

Q. Why are you suggesting that the annual cap be reduced to 1%?

A. Using the information developed by the Company and provided in STF 1.092 the Company is now forecasting incremental impacts of less than 1.25%.[33]

I removed the recovery of generation costs and corrected the implementation point to reflect the rate effective date. With those changes I have calculated the impact of the LFCR and there is no need for a 2% cap and a 1% cap is more appropriate. An

[32] TEP file R-01 BF update for Howard 10-24-12.xls
[33] Exhibit HS-2 "Total LFCR $" and "% of Total Revenue"

appropriate calculation of the rate to be used in the LFCR rather than the suggested single tailblock will reduce this level further. My results are shown in Exhibit HS-3.

Q. What changes do you recommend for the proposed fixed charge option?

A. The Company has proposed a single break point for the fixed charge option. In the APS implementation there are multiple steps to the fixed price alternative. The Company apparently chose its two points using a bill impact methodology rather than a relationship to expected costs.[34]

I suggest a methodology be developed to determine the fixed price option for various steps. The methodology should use the midpoint of consumption for each of the steps and assume the number of years that the LFCR may be in effect. The amount should be based upon the expected LFCR over that period. The goal is to approximate the LFCR mechanism's expected results in the fixed charge.

Q. Do you recommend a customer education plan for the LFCR?

A. Yes. If an LFCR mechanism is approved for implementation, the Company should submit a plan to Staff and other parties for customer education. In my experience, this helps to make a significant rate change understandable and acceptable to customers. It is important to highlight the long-term benefits of EE and DG and the LFCR's short-term support for the Company to ensure that all parties are focused on cost-effective EE and DG as proscribed by the Rules.

[34] STF 1.090

The Company has indicated its willingness to receive input from all parties and I support that attitude.[35] Any customer education plan should use a variety of methods to deliver information to customers, as customers may be more receptive to one form or another. Some of the methods might include bill inserts, customer service representatives, energy advisors, website explanations and calculations as the Company suggests. I recommend additional approaches such as print and TV (both in paid advertisements and articles or features written by reporters), meeting with customers in small groups (Speaker's Bureau) and educating community leaders and organizations to further explain the concept.

Q. How would all of the changes that need to be accomplished to implement an LFCR be finalized?

A. At the resolution of any rate case, unless the Company was to receive its exact request, the Company has to file rates that conform to the Commission's decision. If a settlement occurs this calculation process occurs before the settlement is presented to the Commission. In either event, the Company has to prepare new rates for approval by the Staff as the result of a Commission decision or acceptance by the parties to the settlement document.

At present, the generation estimates in the Company's response to STF 1.092 appear inconsistent between residential and commercial and before and after the rate effective, date and this open issue should be resolved. Further, the Company's estimate of generation costs at $0.021 per kWh from STF 1.092 is not supported by the calculation of residential Production Demand divided by Total Throughput from STF 21.1 Unit Costs of $0.0407 per kWh.

[35] STF 1.086

Additionally, as the Company has noted for simplicity it has used Rate 10 for the commercial impact[36] although there are multiple rates for commercial customers and similar issues arise for the other classes. The filing should include both the new rates and all of the inputs needed to calculate the LFCR except the MER results and the DG metered data.

The Company's technical conferences have helped to set the stage for this final effort by opening the lines of communication.

Q Does the LFCR ensure that the Company cannot earn above its allowed rate of return?

A. An LFCR mechanism is designed to recoup the lost fixed costs for sales that no longer occur due to mandated energy efficiency and/or distributed generation. As shown above, the Company's sales forecast adjusted for its EE and DG efforts continues to growth through 2015. Positive economic conditions and/or above normal weather could increase sales during the rate effective period and potentially lead to an over earning situation. Further, as the positive effects of EE and DG take place future capital requirements should decline. Therefore the Company should still be subject to reviews of its financial performance at least annually even with the approval of an LFCR mechanism.

Q. **Does this conclude your testimony?**

A. Yes.

[36] Email dated November 21, 2012

Exhibit HS-1
Testimony - Howard Solganick

Arizona Corporation Commission
Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation

Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.
Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)

Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days

EXHIBIT HS-2

EE related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial	EE or DG Goal	Total Lost kWh	Lost kWh as % of 9,285 GWh
Cummulative	2011	47,637,346	10,301,531	7,646,868	163,289	16,246	11,887	1.02%	65,749,033	0.7081%
Annual		47,637,346	10,301,531	7,646,868	163,289	16,246	11,887			
Cummulative	2012	106,381,459	22,438,136	16,663,305	959,822	37,285	44,330	2.44%	154,442,721	1.6649%
Annual		58,744,113	12,138,545	19,016,437	796,533	21,038	32,443			
Cummulative	2013	144,166,349	23,939,871	25,328,933	1,077,257	38,342	45,562	4.15%	197,412,510	2.1261%
Annual		37,784,890	1,401,336	1,665,628	117,436	1,058	1,232			
Cummulative	2014	211,410,864	57,673,577	38,372,988	1,508,898	61,534	62,102	6.11%	284,566,327	3.1122%
Annual		67,244,515	14,033,606	10,044,055	231,641	23,172	16,540			
Cummulative	2015	296,024,972	80,812,174	64,127,444	2,435,599	98,215	103,940	7.21%	426,088,780	4.5566%
Annual		84,617,708	22,738,597	25,754,455	1,006,701	36,701	41,838			
Cummulative	2016	384,620,273	86,357,055	94,546,051	3,389,979	142,802	152,859	9.22%	571,153,358	6.1514%
Annual		88,841,701	27,724,881	30,418,608	1,084,380	44,587	48,919			

DG related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial	EE or DG Goal	Total Lost kWh	Lost kWh as % of 9,285 GWh
Existing	2011	28,774,143	12,781,691	4,000,000			8,000	0.35%	43,555,834	0.4691%
Incremental		28,774,143	12,781,691	4,000,000	-		8,000			
Existing	2012	34,056,137	25,375,000	6,625,000			16,000	0.70%	66,056,137	0.7114%
Incremental		7,281,994	12,593,309	2,625,000			8,000			
Existing	2013	47,565,612	38,125,000	27,125,000			35,000	1.05%	109,215,612	1.1763%
Incremental		13,909,475	8,750,000	20,500,000			19,000			
Existing	2014	54,860,008	48,125,000	27,125,000			43,000	1.40%	130,130,008	1.4015%
Incremental		6,914,396	14,000,000	-			8,000			
Existing	2015	61,570,040	48,125,000	27,125,000			43,000	1.75%	136,820,040	1.4736%
Incremental		6,690,032	-	-			-			
Existing	2016	74,508,361	48,125,000	27,125,000			43,000	2.10%	149,758,361	1.6129%
Incremental		12,938,321	-	-			-			

EE and DG percentage changes reflect adjustments for allowed credits

LFCR related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
Existing	2011	74,411,489	23,083,257	11,646,868	163,289	16,246	19,887
Incremental		74,411,489	23,083,257	11,646,868	163,289	16,246	19,887
Existing	2012	140,437,596	47,813,136	39,288,305	959,822	37,285	60,930
Incremental		66,026,107	24,729,864	27,641,437	796,533	21,038	40,443
Existing	2013	191,131,961	57,964,971	95,453,933	1,077,257	38,342	40,562
Incremental		51,694,365	10,151,836	22,165,628	117,436	1,058	20,232
Existing	2014	266,290,872	85,996,577	65,497,988	1,308,898	61,534	105,102
Incremental		74,158,911	28,033,606	10,044,055	231,641	23,172	24,840
Existing	2015	357,598,612	108,737,174	91,252,444	1,415,599	98,215	148,940
Incremental		91,307,740	22,738,597	25,754,455	1,006,701	36,701	41,838
Existing	2016	459,378,834	136,462,055	121,671,051	2,399,979	142,802	195,859
Incremental		101,780,022	27,724,881	30,418,608	1,084,380	44,587	48,919

Choose 1 for Company's position and 2 for Staff's APS position of using 50% of Generation

1

LFCR Rates	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
	2011	$ 0.065106	$ 0.077833	$ 0.024882	$ 0.065106		$ 19.02
	2012	$ 0.065106	$ 0.077833	$ 0.024882	$ 0.065106		$ 19.02
	2013	$ 0.065106	$ 0.077833	$ 0.024882	$ 0.065106		$ 19.02
	2014	$ 0.078100	$ 0.087900	$ 0.008500	$ 0.078100		$ 21.00
	2015	$ 0.078100	$ 0.087900	$ 0.008500	$ 0.078100		$ 21.00
	2016	$ 0.078100	$ 0.087900	$ 0.008500	$ 0.078100		$ 21.00

Generation Component in Rates	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
	2011	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2012	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2013	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2014	$ 0.021000	$ 0.031800	$ -	$ 0.021000		$ 8.25
	2015	$ 0.021000	$ 0.031800	$ -	$ 0.021000		$ 8.25
	2016	$ 0.021000	$ 0.031800	$ -	$ 0.021000		$ 8.25

LFCR Revenues	Year	Residential	Commercial	Industrial	Other	Commercial	Industrial
Cummulative	2011	$ 4,844,634	$ 1,796,699	$ 284,797	$ 10,631	$ -	$ 378,244
Annual		$ 4,844,634	$ 1,796,699	$ 284,797	$ 10,631	$ -	$ 378,244
Cummulative	2012	$ 9,145,330	$ 3,721,440	$ 828,280	$ 62,490	$ -	$ 1,147,472
Annual		$ 4,298,696	$ 1,924,801	$ 543,482	$ 51,859	$ -	$ 769,228
Cummulative	2013	$ 12,503,943	$ 4,511,588	$ 1,379,805	$ 70,136	$ -	$ 1,932,283
Annual		$ 3,358,613	$ 790,148	$ 551,525	$ 7,646	$ -	$ 384,811
Cummulative	2014	$ 20,757,317	$ 7,559,275	$ 506,733	$ 102,425	$ -	$ 2,297,140
Annual		$ 8,281,811	$ 2,464,154	$ 85,874	$ 18,591	$ -	$ 515,345
Cummulative	2015	$ 27,923,452	$ 9,557,903	$ 775,846	$ 180,848	$ -	$ 3,695,737
Annual		$ 7,131,135	$ 1,998,723	$ 218,934	$ 78,523	$ -	$ 878,594
Cummulative	2016	$ 35,877,471	$ 11,995,015	$ 1,034,204	$ 265,538	$ -	$ 4,113,031
Annual		$ 7,949,020	$ 2,437,017	$ 258,558	$ 84,690	$ -	$ 1,027,296

Total LFCR $	Incremental	% of Total Rev Assume $950 mil	Total Accum lost revenues	Incremental Recovery rate	Accum Recovery rate per kWh
$ 7,319,945					
$ 7,319,945					
$ 14,905,012					
$ 7,585,066	7,585,066	0.80%			
$ 20,007,755					
$ 5,099,743	$ 5,099,743	0.54%	$20,265,876	$ 0.000549	$ 0.002183
$ 31,222,630					
$ 8,874,775	$ 8,874,775	0.93%	$41,813,461	$ 0.000556	$ 0.004504
$ 41,528,481					
$ 10,305,931	$ 10,305,931	1.08%	$73,487,016	$ 0.001110	$ 0.007836
$ 52,285,282					
$ 11,756,581	$ 11,756,581	1.24%	$117,307,193	$ 0.001266	$ 0.012634

notes: Initial filed rate and total dollars (revenues sales of 9,285,000,000 kwh)

-2011 lost revenues are excluded from recovery amount , but included in accumulated lost kWh

The volumetric rates calculated for Res, Comm and Ind above are using the tariffbick revenues for both summer and winter divided by the combined kWh, resulting in a weighted average price.

This calculation was made for both the existing rates and the proposed rates. (Example, TY revenues for all usage >500 kWh was $81,431,764 + $7,268,564 summer and $14,390,624+$423,195 winter divided by regulbl(ist combined volumes (sales) for 1,820,129,613 KWh)

This data can be found in the individual classes data provided in the file named "6. 2012 TEP Proposed Rates - Corrected". For Residential standard reference Columns E, G and Lines 5, 6, 9 and 10.

EXHIBIT HS-3

EE related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
Commulative	2011	47,637,346	10,801,581	7,646,868	163,269	16,246	11,887
Annual		47,637,346	10,801,581	7,646,868	163,269	16,246	11,887
Commulative	2012	106,381,459	22,438,126	16,683,305	959,822	37,285	24,330
Annual		58,744,113	12,136,545	19,016,437	796,553	21,038	12,443
Commulative	2013	164,266,349	23,639,971	28,926,933	1,077,257	58,342	45,562
Annual		57,784,890	1,503,846	1,866,628	117,436	3,058	1,232
Commulative	2014	211,410,864	37,873,577	38,372,988	1,308,898	61,514	62,102
Annual		67,244,515	14,033,606	10,044,055	231,641	23,172	16,540
Commulative	2015	256,028,572	50,612,174	64,127,444	2,315,598	98,215	108,940
Annual		44,617,708	12,738,597	25,754,455	1,006,701	36,701	41,838
Commulative	2016	334,870,273	88,537,655	94,540,051	3,359,979	142,802	152,859
Annual		88,841,701	37,724,891	30,418,608	1,064,380	44,587	48,919

EE or DG Goal	Total Lost kWh	Lost kWh as % of 9,285 GWh
1.02%	65,749,093	0.7081%
2.44%	156,442,721	1.6849%
4.15%	197,412,510	2.1261%
6.31%	288,964,327	3.1123%
7.21%	423,082,789	4.5566%
9.25%	571,153,359	6.1514%

DG related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
Existing	2011	25,774,143	12,781,663	4,000,000			8,000
Incremental		26,774,143	12,781,663	4,000,000	-		8,000
Existing	2012	53,056,137	25,125,000	6,625,000			16,000
Incremental		7,281,994	12,593,389	2,625,000			8,000
Existing	2013	47,965,812	34,125,000	27,125,000			35,000
Incremental		12,909,475	6,730,000	20,900,000			19,000
Existing	2014	54,880,008	48,125,000	27,125,000			43,000
Incremental		6,914,396	14,000,000	-			8,000
Existing	2015	61,570,040	48,125,000	27,125,000			48,000
Incremental		6,690,032	-	-			-
Existing	2016	75,508,361	48,125,000	27,125,000			43,000
Incremental		12,938,321	-	-			-

0.15%	43,555,804
0.70%	66,050,137
1.05%	108,215,612
1.40%	130,130,008
1.75%	136,820,040
2.10%	149,758,861

EE and DG percentage changes reflect adjustments for allowed credits

LFCR related KWh	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
Existing	2011	74,411,489	23,083,352	11,646,868	163,269	16,246	11,887
Incremental		74,411,489	23,083,352	11,646,868	163,269	16,246	11,887
Existing	2012	140,437,996	47,813,136	33,788,305	959,822	37,285	61,430
Incremental		66,026,107	24,729,884	21,641,437	796,553	21,038	40,443
Existing	2013	192,131,461	57,964,971	55,455,938	1,077,257	58,342	80,562
Incremental		51,694,465	10,151,836	22,169,628	117,436	1,058	20,237
Existing	2014	266,290,872	85,998,577	65,497,988	1,308,898	61,514	105,102
Incremental		74,159,911	28,033,606	30,044,055	231,641	23,172	24,540
Existing	2015	357,598,412	108,737,174	91,252,444	2,315,598	98,215	146,940
Incremental		91,307,740	12,738,597	25,754,455	1,006,701	36,701	41,838
Existing	2016	459,376,634	136,462,055	121,673,051	3,359,979	142,802	190,859
Incremental		101,786,021	37,724,891	30,418,608	1,064,380	44,587	48,919

169,304,897	
322,495,558	
306,626,143	
419,096,335	
559,493,829	
720,911,720	

Choose 1 to retain Company's start position and 5 for Staff's start position

$

Choose 1 for Company's position and 3 for Staff's position of using 0% of Generation

$

LFCR Rates	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
	2011	$ -	$ -	$ -	$ -	$ -	$ -
	2012	$ -	$ -	$ -	$ -	$ -	$ -
	2013	$ 0.028550	$ 0.028650	$ 0.004250	$ 0.028550		$ 6.48
	2014	$ 0.057100	$ 0.056100	$ 0.006500	$ 0.057100		$ 12.75
	2015	$ 0.057100	$ 0.056100	$ 0.006500	$ 0.057100		$ 12.75
	2016	$ 0.057100	$ 0.056100	$ 0.006500	$ 0.057100		$ 22.00

Generation Component in Rates	Year	Residential	Commercial	Industrial	Other	Demand KW Commercial	Demand KW Industrial
	2011	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2012	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2013	$ 0.031605	$ 0.027224	$ -	$ 0.031605		$ 12.83
	2014	$ 0.021000	$ 0.021600	$ -	$ 0.021000		$ 8.25
	2015	$ 0.021000	$ 0.021600	$ -	$ 0.021000		$ 8.25
	2016	$ 0.021000	$ 0.021600	$ -	$ 0.021000		$ 8.25

LFCR Revenues	Year	Residential	Commercial	Industrial	Other	Commercial	Industrial
Commulative	2011	$ -	$ -	$ -	$ -	$ -	$ -
Annual		$ -	$ -	$ -	$ -	$ -	$ -
Commulative	2012	$ -	$ -	$ -	$ -	$ -	$ -
Annual		$ -	$ -	$ -	$ -	$ -	$ -
Commulative	2013	$ 5,485,367	$ 1,025,917	$ 235,579	$ 30,750	$ -	$ 519,581
Annual		$ 1,475,874	$ 284,258	$ 94,204	$ 3,359	$ -	$ 126,379
Commulative	2014	$ 15,205,509	$ 4,824,529	$ 556,733	$ 74,736	$ -	$ 1,940,069
Annual		$ 4,234,474	$ 1,572,685	$ 85,174	$ 13,227	$ -	$ 312,888
Commulative	2015	$ 20,416,881	$ 8,190,155	$ 775,646	$ 152,721	$ -	$ 1,673,463
Annual		$ 5,213,672	$ 1,275,625	$ 218,913	$ 57,483	$ -	$ 585,434
Commulative	2016	$ 26,290,520	$ 7,655,521	$ 1,034,204	$ 194,139	$ -	$ 4,113,088
Annual		$ 5,811,639	$ 1,055,366	$ 258,558	$ 41,418	$ -	$ 1,027,296

Total LFCR $	Incremental	% of Total Rev Assume $950 mil	Total Accum lost revenues	Incremental Recovery rate	Accum Recovery rate per kWh
$ -					
$ -					
$ -					
$ -	-	0.00%			
$ 7,891,301					
$ 1,987,168	$ 1,987,168	0.21%	$ 1,987,168	$ 0.000214	$ 0.000214
$ 22,001,939					
$ 6,218,608	$ 6,218,608	0.65%	$ 10,192,985	$ 0.000670	$ 0.001098
$ 29,300,386					
$ 7,289,137	$ 7,289,137	0.77%	$ 25,007,938	$ 0.000786	$ 0.002768
$ 39,227,417					
$ 8,714,777	$ 8,714,777	0.92%	$ 42,917,693	$ 0.000938	$ 0.005576

notes: -Initial fixed rate and total dollars (assumes sales of 9,285,000,000 kwh)

2011 lost revenues are excluded from recovery amount, but included in accumulated lost kWh

The volumetric rates calculated for Res, Comm and Ind above are using the tail block revenues for both summer and winter divided by the combined kwh, resulting in a weighted average price.

This calculation was made for both the existing rates and the proposed rates. (Example, EE revenues for all usage >500 kWh was $81,431,769 + $1,266,385 summer and $14,390,824 + $423,195 winter divided by equivalent combined volumes totaling 1,820,323,633 kWh)

This data can be found in the individual classes data provided in the file named "6. 2012 TEP Proposed Rates - Corrected", for Residential Standard reference Columns E, G and cells 5, 6, 9 and 10.

Staff has retained the Company's tailblock rate concept SOLELY for the purposes of calculations see testimony for Staff's position.

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER-SMITH
Commissioner

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 ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. E-01933A-12-0291

(RATE DESIGN)

DIRECT

TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 11, 2012

EXHIBIT
S-12

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291

Mr. Solganick's testimony reviews and analyzes Tucson Electric Power Company's ("Company") jurisdictional allocation, class cost of service study ("CCOSS") and the various rate design proposals of the Company. Mr. Solganick also previously filed testimony on the Company's Lost Fixed Cost Recovery proposal on December 21, 2012.

Mr. Solganick's testimony presents Staff's recommendations based on a review of the Company's application and responses to Staff's and other parties' data requests.

Staff recommends that the Company's jurisdictional allocation is appropriate to use to develop the CCOSS and that the CCOSS can be used as a general guideline for the relative positions of the six customer/rate classes. Mr. Solganick's testimony also describes the economic, social, historical and other factors that may affect customers and be the basis of the Commission's determination of the allocation of an increase in revenue.

Staff recommends that the Company's proposals to consolidate and redesign its rates be modified after full analysis of the impacts on customers. Mr. Solganick recommends that the residential rates have a common customer charge and an additional block be added to the standard residential rate. For non-residential rates Mr. Solganick's analysis highlights the impact of the Company's proposal to increase the customer charge and add the charge to rates not presently including the customer charge (municipal and water pumping customers).

Staff recommends that the Company's proposals for a 100% demand ratchet, partial service requirements and a PPFAC that includes all energy costs be rejected due to the other wide ranging changes that may result from this case and the customer education needed.

Staff recommends that the Company's proposal for an extended summer On-Peak period within its Time of Use rates be replaced by an On-Peak period not to exceed five hours in order to encourage greater participation by residential and non-residential customers. Mr. Solganick recommends that a customer education program be developed for time of use rates and that a 12 month no risk test period be available to residential customers.

Staff recommends that the Company's lifeline proposal be modified to retain the level of support and to minimize the impact on certain customer subclasses due to the change in structure proposed by the Company.

Staff recommends that the tariff provision covering non-residential deposits be changed to require that deposits be analyzed after 24 months and if the customer's payment performance over the past 12 months is satisfactory that the deposit be returned.

Staff recommends that a door hanger fee proposed by the Company not be approved.

Staff recommends that the Company plan and perform research to support its rate design efforts.

Staff recommends that the final rate design be developed through a cooperative process among the parties.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc.

Q. Please summarize your qualifications and experience.

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning submetering and billing. I also previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 35 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony in utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand side management, capacity and system planning, and regulatory issues.

I have also led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects

focused on the marketing, sale and delivery of retail energy, energy related products and services, and support services provided to utilities and retailers.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and have advised the Board of Directors of a public power utility consortium. For a period of four years I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and the Public Utilities Commission of Ohio. I also provided (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric and gas rate cases.

I have also been engaged to review utility performance before, during and after outages resulting from major storms including Hurricane Ike and the two 2011 storms that affected New Jersey.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998, I was a Managing Consultant for AT&T Solutions. From 1990 to 1994, I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held progressively increasing positions of responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice and implementation in both New Jersey and Pennsylvania.

Q. **Have you previously submitted testimony in regulatory proceedings?**

A. Yes. In this proceeding I submitted testimony in regard to Lost Fixed Cost Recovery on December 21, 2012.

I have also testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies.

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission

- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

II. DIRECT TESTIMONY

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission").

Q. What is the purpose of your testimony?

A. My testimony analyzes Tucson Electric Power Company's ("Company") jurisdictional and class cost of service studies ("CCOSS") and the Company's proposed rate design. I recommend changes to the proposed rate design, time of use periods, the lifeline rates and various tariff changes.

Based on my review of the Company's application, supporting testimony, and responses to data requests, I make the following recommendations:

- The Commission should direct the Company to retain its existing blocks and to revise its proposed Residential rate design by adding an additional block.
- The Commission should direct the Company to revise its general service rate design as proposed including adjusting for the impacts on lower usage customers.
- The Commission should direct the Company to revise its Time of Use rate design as proposed including changing the proposed Summer period to encourage greater participation.

- The Commission should direct the Company to revise its lifeline (low-income and medical) rate design as proposed to continue the existing level of benefits, adjusting for the impacts on lower usage customers and encouraging conservation and consolidate the lifeline rates within the residential rates.
- The Commission should reject the implementation of proposed changes to Partial Requirements Service, the PPFAC and the definition of demand ratchet at this time due to breadth of other rate design changes and needed customer education.
- The Commission should direct the Company to revise its deposit policy for general service customers.
- The Commission should revise the Company's proposed miscellaneous service charge charges.
- The Commission should not adopt the door hanger fee proposed by the Company.
- The Commission should direct the Company to plan and perform customer and rate research.

Jurisdictional Allocation

Q. Why is jurisdictional allocation important?

A. The Company provides services to a number of entities commonly called sale for resale. The Federal Energy Regulatory Commission ("FERC") regulates wholesale transactions. In developing its revenue requirements and before performing any allocation of those requirements among retail rate classes, the costs (capital and expenses) and revenues from the wholesale customers must be removed or excluded from the jurisdictional revenue requirements process.

Q. Are there differences between the Company's jurisdictional allocation and the allocation within the CCOSS?

A. Yes. The most significant difference is the use of a 4CP (four coincident peaks for June, July, August and September)[1] allocator for production plant and related items as compared to the use of an Average and Peaks (A&P) demand allocator[2] within the CCOSS.

Q. Is the application of the 4CP method appropriate?

A. The FERC has used a three part methodology[3] to determine if a production allocator should focus on a season or the entire year. I performed this test for the years 2009 through 2011 based on information provided by the Company.[4] Based on this methodology, the use of a 4CP allocator at this level is appropriate as compared to a 12CP allocator.

Q. Is the allocator difference between retail and wholesale jurisdictions appropriate?

A. The FERC has required the use of the 4CP allocator[5] and the Company has complied with this requirement. The Company's position is appropriate because it is responding to two different regulatory bodies.

Q. Did you review other aspects of the jurisdictional allocation?

A. I performed a review of the allocations, developed and reviewed the answers to Staff Data Requests and discussed items as needed with the Company to understand certain aspects of the jurisdictional allocation.

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[1] Jones Direct 13:8
[2] Jones Direct 18:11
[3] FERC Docket Nos. EL05-19-002 and ER05-168-001, paragraph 76
[4] DoD 1.03 Revised
[5] TEP Response to STF 1.020

Q. Is the Company's jurisdictional allocation appropriate for its use to develop the CCOSS?

A. Yes it is.

Class Cost of Service

Q. Has the Company provided a class cost of service study?

A. The Company provided an updated CCOSS based on the Test Year (twelve month period ended December 31, 2011).[6] This schedule provides the individual class returns for the Company's six major customer classes. No subclass or rate class information was presented.

Q. What is the purpose of a fully allocated cost of service study?

A. Just as the rate case process studies each element of the Company's operations to determine the overall cost to operate the Company efficiently and effectively, a fully allocated cost of service study attempts to determine the individual cost to serve each customer class and subclass. A fully allocated cost of service study is intended to assist a Commission to allocate revenue requirements among customer classes.

Q. How does a regulator use the cost of service study?

A. Because customer classes use the utility's system on an interrelated or shared basis, regulators have historically used a fully allocated cost of service study as a guideline to allocate revenue among classes. Additionally, when determining revenue allocation, regulators have a responsibility to consider not only the utility's financial condition and requirements, but also economic, social, historical and other factors that may affect customers.

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[6] TEP Filing Schedule G revised on 10/5/12

Q. Are there limitations to a cost of service study?

A. Yes, a cost of service study involves judgment and decisions on the part of the practitioner in making allocations among customer classes. In some situations, decisions are made to use a particular allocation factor for a particular account. In other situations, data used to develop an allocation factor are not always complete and/or timely and the practitioner must deal with the resulting uncertainty. Therefore, the cost of service study acts as a guide to revenue allocation and can be used to assist rate design.

Q. Did the Company adjust or normalize its revenues?

A. The Company used a 2011 Test Year and then adjusted it to reflect more normal or appropriate (from the Company's viewpoint) conditions. The Company made revenue adjustments for weather normalization and customer annualization.[7]

Q. Have you reviewed the CCOSS presented by the Company?

A. Yes. The CCOSS was provided as Schedules G-1 through 7. I performed a review of the allocations, developed and reviewed the answers to Data Requests by Staff and other parties and conducted an informal technical conference with the Company to understand certain aspects of the CCOSS.

Q. Is the application of A&P allocator appropriate within the CCOSS?

A. The Company expects to make substantial environmental investments to retain its coal generation capability, which indicates a focus on energy costs.[8] Additionally, the Company is forecasting the need for peaking investments.[9] This combination of expected

[7] Jones Direct 6:14 and 10:1
[8] DeConcini Direct 29:21
[9] 2012 TEP IRP pages 20, 28, 30

investments for both energy and peak supports the use of an A&P methodology for the allocation of generation as opposed to either a peak or energy focused allocator.

Q. Does the CCOSS provide unit cost information to support rate design?

A. The Company provided Schedule G-6-1 labeled Revenues and Unit Cost. After my initial review I was concerned that the "unit costs" shown for residential customer costs were only $5.11. The Company's response to DoD 2.2 indicated "There is not a return component included in Schedule 6 for Unit Cost". Staff then asked for unit cost data including a return component at the overall rate of return. The Company's response was provided and the inclusion of the return component has raised customer related costs to $6.33.[10]

Q. How did the Company allocate income taxes?

A. The Company indicated that it allocated income taxes to reflect an equalized return on plant.[11] The calculation of income taxes on class net income would provide the same general positioning between classes but result in larger differences among classes.

Q. Did the Company perform a loss study for use in the CCOSS?

A. The Company indicated that it had not completed an engineering study on line losses over the last two rate cases.[12] Further, the Company indicated that "losses" also includes an allocation of variance amounts resulting from load research data.[13]

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[10] TEP Response to STF 21.1
[11] TEP Response to AECC 3.5 a
[12] TEP Response to STF 1.032 and AECC 3.1 c
[13] TEP Response to AECC 6.1 b (i)

Q. Is the Company's CCOSS appropriate for its use as a guideline to develop a revenue allocation proposal?

A. The results of the CCOSS should be used as a general guideline for the relative positions of the six cost of service classes. The items I have summarized above should cause some concern about the use of precise results from the CCOSS.

Q. What are the relative positions of the various classes?

A. As a high level indicator I use the Rate of Return on Rate Base as shown in Schedule G-1 (line 33). Compared to the overall return for the Company at 1.90%, the Small General Service class at 20.43% is providing an above average return, the Residential Service class at -0.40% and Large General Service class at 0.52% are providing a return below the average and the Large Light & Power class at -9.02%, Mining class at -12.98% and Lighting class at -11.43% are providing returns well below the average.

Revenue Allocation

Q. What non-cost considerations should the Commission consider?

A. The Commission should consider the relative positions of the classes along with the qualitative issues such as economic conditions for consumers, the business climate and past practices when deciding what portion of a revenue increase is allocated to each class. Also the size of the classes limits how much the Commission can move a class at the conclusion of any single rate case. For example, the Large General Service, Large Light & Power, Mining and Lighting classes together are still smaller than the Small General Service class. The Residential class is more than 50% larger than the Small General Service class.[14]

[14] TEP Schedule G-1 line 20 Total Electric Revenue From Sales

Q. Based upon the CCOSS results what revenue allocation concept do you recommend?

A. In concept the revenue allocation should assign a larger percentage increase (compared to the overall increase allowed for the Company) to classes earning less than the system average and a smaller percentage increase to classes that provide returns greater than the system average return.

Further, all classes should earn a positive return. This goal may not be able to be achieved within this case as the required increase may be judged too high in regard to the factors stated above, but it is a long-term goal that should be considered by the Commission.

Rate Design

Q. What underlying principles do you use for rate design?

A. For residential and small general service customers, I lean towards simplicity where possible. This would include a limited number of rate schedules and riders. I recognize that one rate schedule does not fit all customers and that schedules that encourage limiting or shifting peak consumption have real value both for customers, for system planners and longer term cost reduction.

For delivery (distribution) rates, I recommend gradually shifting from volumetric to customer and demand charges as supported by cost of service principles. This recognizes that delivery services are not generally based on volumetric (energy) parameters but vary based on the number of customers and their demand.

Q. Does the implementation of advanced metering infrastructure ("AMI") have a rate design impact?

A. Yes. In recognition of the penetration of automated meter reading ("AMR")[15] and the potential implementation of AMI, I recommend that the customer charge for similar customers in the same class but on different rate schedules should be the same. This recognizes that costs are the same for AMI regardless of whether the customer chooses a standard rate or a time of use ("TOU") rate. Smart meters have the capability to report consumption by interval and then the usage by periods is determined by data analysis rather than by meter readings. Thus the same meter and software can be used to provide meter reading for most rate forms at approximately equal cost.

Q. Please summarize the Company's rate design proposal.

A. The Company is proposing to make a wide variety of changes to its existing rates along with the addition of a rate for electric vehicles. The Company's rate design objectives are to consolidate, simplify, and modernize these rates for several key reasons including that many rates are only nominally different and the sheer number of rates can create unnecessary confusion for customers.[16] Additionally, there are rates that are frozen (no longer available to new customers) that require time and costs to maintain and these rates are considered by the Company to be below the cost of providing service.[17] The Company also wishes to better align the Commission's policies with the Company's need for fixed cost recovery.[18]

[15] TEP Response to VSI 3.02
[16] Jones Direct 22:7
[17] Jones Direct 24:21
[18] Jones Direct 25:7

Q. What was the Company's primary concern in developing its rate design proposals?

A. As I understand the Company's approach, the focus was on evaluating the potential impacts on customers by developing a complete understanding of how these changes would affect revenues.[19] The Company describes its efforts to determine the appropriate level of billing determinants[20] and its efforts to approach a revenue neutral impact on each class[21].

Q. Is this focus on revenue impact sufficient to support a wide range of rate design changes?

A. Evaluating the revenue impact is not the only concern when rate design is substantially changed. There are impacts on the customers' behavior and operations that should be considered during the rate design process to minimize unintended consequences. While the following list is not exhaustive it includes a range of sources of information about customers that should be considered.

- Customer Alternatives
  - Competitive Fuel Forecasting[22]
  - End Use Forecasting[23]
  - Cost of Load Shifting for TOU[24]
- Customer Information
  - Formal Commercial & Industrial Survey Process[25]
  - Appliance Saturation Study[26]

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[19] Jones Direct 25:16
[20] Jones Direct 25:20
[21] Jones Direct 26:4
[22] TEP Response to STF 1.008
[23] TEP Response to STF 1.006
[24] TEP Response to STF 1.079
[25] TEP Response to STF 1.005
[26] TEP Response to STF 1.007

1 ○ Consumption versus Income[27]
2 • Rate Studies
3 ○ Non-Coincident Peak ("NCP") Data[28]
4 ○ System Losses[29]
5 ○ Marginal Cost[30]
6 ○ Seasonal Energy[31]
7
8 **Q. Did the Company perform any of the above studies or have such information?**
9 A. In response to Staff data requests the Company indicated that these items were not readily
10 available, or were not forecast for future years (2012 -2014), or backcast information was
11 not available, or only limited information was available. [The above footnotes provide
12 references.]
13
14 **Q. Are these items essential to accomplish the scope of the rate design envisioned by the**
15 **Company?**
16 A. Having all of the items is not essential but each item provides information about customer
17 options and potential reactions to a new or modified rate. The lack of this information
18 increases the possibility that some important aspect will be overlooked or cannot be
19 readily evaluated by all parties.
20

[27] TEP Response to STF 1.041
[28] TEP Response to STF 1.031
[29] TEP Response to STF 1.032, 1.077, AECC 3.1
[30] TEP Response to STF 1.037
[31] TEP Response to STF 1.076

Q. Should the Company's proposal to make rate design changes be rejected?

A. No, but some items should be delayed or modified until supporting information is available. Also, the sheer magnitude of the changes should be gaged and the range of proposed changes placed into perspective and chosen carefully.

Q. Is the Company proposing any overall or wide reaching rate design changes?

A. Yes, the Company is focusing on decreasing the proportion of revenue that is collected from energy charges.[32] This leads to the Company's proposal to increase the monthly Customer Charge.[33]

Q. What rate changes does the Company propose for the non-TOU Residential Service subclass?

A. The Company is requesting an increase in the customer charge from $7.00 to $12.00 .[34]

The Company is also requesting the elimination of the third tier (over 3,500 kWh) for Rate R-01[35]; the shift of all Rate R-02F load to Rate R-01[36]; the elimination of Rate R-201 AF and moving those customers to Rate R-201 AN[37].

Q. What rate changes does the Company propose for the TOU Residential Service subclass?

A. The Company is requesting an increase in the customer charge from $8.00 to $15.00 for TOU customers.[38]

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[32] Jones Direct 28:10
[33] Jones Direct 28:4
[34] Jones Direct 33:14
[35] Jones Direct 36:12
[36] Jones Direct 36:13
[37] Jones Direct 36:14

The Company also is requesting the creation of a new TOU Rate R-80 that would shift customers presently served by Rates R-21F, 70F, 70NB, 70NC and 70ND.[39]

Similarly the Company is requesting the consolidation into TOU Rate R-201BN of customers presently served by Rates R-201BF, 201CF and 201CN.[40]

Q. Do you support the changes to the standard residential rate? A. I suggest the following modifications of the Company's proposal:

- The existing rate design including the first tier (up to 500 kWh) and the upper tier (over 3,500 kWh) should be retained.
- A new tier for the Rate R-01 at 1,000 kWh should be developed to offer a breakpoint that includes approximately 58% of all summer bills and over 80% of winter bills.[41]. The Rate R-02 usage can then be combined into the Rate R-01, as this new block would decrease the impact on some water-heating customers. Ideally customer load research by strata and unit costs would help develop the relationships between the tiers but the Company has indicated that it does not have this type of load research.[42]
- The existing inverted rate structure should be retained for the Rate R-01.

Q. Are residential customer charges interrelated?

A. Yes. The customer charge for the TOU rate should equal the customer charge for non-TOU rates to reflect the eventual implementation of advanced meters.

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[38] Jones Direct 33:14
[39] Jones Direct 36:15
[40] Jones Direct 36:20
[41] TEP worksheet – R-01 BF update for Howard 10-24-12.xls
[42] Company email dated October 19, 2012

Q. What are the residential customer costs?

A. The Company's information shows that direct customer costs are $6.33.[43] This amount includes meters, billing and collection meter reading costs and the service.[44] The Company has indicated that it does not use either a minimum sized system or zero intercept methodology to allocate portions of the distribution system (such as poles, wires, transformers) to the customer component.

Q. Please discuss the Company's basis for the Residential Customer Charge?

A. The Company is requesting a Customer Charge of $12 per month, which it characterizes as 22% of the $55.00 (now $68.39[45]) of customer and demand charges identified by the CCOSS. It is inappropriate to consider in the basis for the monthly Customer Charge shared costs such as production and transmission that do vary with the demand the customer places on the system and those costs should be collected in a charge that varies with usage (absent a demand charge). Even the costs of Demand Distribution that are equivalent to $10.69[46] would be excessive as that value includes facilities that are below 138,000 V.[47]

Q. What increase in the Residential Customer Charge do you propose?

A. Without information provided by a minimum sized system or zero intercept analysis, I recommend a Residential Customer Charge of $10.00,subject to review of customer impact at various usage levels. This provides coverage for direct customer costs and a portion of distribution costs.

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[43] TEP Response to STF 21.1
[44] Schedule G, Functionalization_RES Q44 Account 369 Services
[45] TEP Response to STF 21.1
[46] TEP Response to STF 21.1
[47] TEP Response to AECC 11.4

Q. What is the Company's opt-out option for those customers that do not want an AMR meter that uses radio frequency for meter reading?

A. The Company has proposed to add language to the Rate R-01 to charge the Special Meter Reading fee each month and a one-time Meter Change-out fee.[48] The charges proposed by the Company are both $20.00, an increase from the existing $13.50.[49]

Q. Is the Company's Opt-Out proposal appropriate?

A. In this situation, a customer is requesting non-standard service and should pay for the incremental cost of providing service, otherwise all other customers have to pay for the additional work requested by a single customer. However, the Company's proposal assumes that each customer served in this manner is separate and that no economies of scale exist even though this customer's request may be able to be scheduled with other work.

Q. What process do you propose for Opt-Out customers?

A. I recommend that the additional meter reading services requested by Opt-Out customers be priced to encourage the Company to productively handle Opt-Out service. For example, the Company's tariff describes an existing process for customers that require special meter reading.[50] One productivity measure that could be encouraged would be the use of meter reading by customers that would support a lower monthly charge. As described in the tariff, the Company would read the meter at least once every six months. Under either type of meter reading the Company still has costs for special data entry.

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[48] Jones Direct 38:11 and Exhibit CAJ-11
[49] Exhibit CAJ-9 - Tariff Original Sheet 801
[50] TEP Tariff Section 10 Meter Reading

Q. What charges do you propose for Opt-Out services?

A. I recommend that monthly readings made by the Opt-Out customer should be priced at 25% of the Special Meter Reading fee. Readings made by the Company for the Opt-Out service should be priced at 50% of the Special Meter Reading fee. The Company should be allowed to vary the monthly period by up to plus or minus five days (rather than a quasi meter reading cycle) to allow for scheduling efficiency. If the customer already has an analog meter in place, the one-time Meter Charge-out fee should not be assessed if the existing meter can be used.

Q. Is the Company's increase in the customer charge for Small General Service customers (GS-10) appropriate?

A. Some customers using this rate may have characteristics similar to a residential customer and this rate also does not include a demand charge. The Company is proposing to increase the customer charge to $18.00 from $8.00. Also the municipal customers served under Rate PS-40 have no customer charge at present. The proposed increase is too large when placed in this prospective and the impact will be disproportionate on low usage customers. The unit cost information in Schedule G-6-1 indicates that customer costs for the Small General Service Class are $18.25.[51] Based on this information the Company's proposed Customer Charge is numerically appropriate if the Company receives its fully requested increase. As this outcome is unlikely, the Small General Service Customer Charge should be reduced to eliminate the disproportionate impact.

Q. Is the Company's proposed consolidation of Rate PS-40 into GS-10 appropriate?

A. The Company has recognized the impact of its proposal to eliminate Rate PS-40 (Municipal Service) and proposes a mechanism (a 16.5% discount) to shield municipal

[51] TEP Response to STF 21.1

customers from extraordinary impact. This "rate blocker" is a concept used in this type of situation. However, the consolidation would now subject these accounts to a proposed $18.00 customer charge when presently there is no customer charge.

The Company has calculated impacts of 22% (summer) and 17% (winter) for usage at 10,000 through 20,000 kWh.[52] However, in summer almost 75% and in winter 79.5% of all bills are lower than 10,000 kWh.[53] Calculating the impacts for the governmental entities at more realistic levels shows significant impacts such as over a one third of the bills will have increases of 40%, and 15% of the bills will have increases of 200%. While the 200% increase amounts to essentially the proposed new Customer Charge of $18.00, this impact should have been known and/or disclosed. The proposed Customer Charge should be reduced to lower the dollar impact for lower usage customers.

Q. What rate changes does the Company propose for the Water Pumping rates?

A. The Company proposes to consolidate water-pumping rates (GS-31 and PS-43) into a single rate schedule GS-43 that includes an interruptible option. GS-31 presently serves agricultural customers. At present GS-31 applies to only pumping load that must be interruptible, while PS-43 applies to water utilities. As proposed by the Company the tariff language for the new GS-43 would not apply to agricultural pumping. The Company did confirm that this should to be corrected.[54] Schedule H-4[55] also must be updated as the calculation of the Proposed Rate for "C-31" Interruptible Agricultural Pumping does not match the value for "PS-45" Interruptible Municipal Pumping by the value of the $18 customer charge.

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[52] Schedule H-4 pages 24 and 25
[53] Schedule H-5 pages 28 and 29
[54] Email dated October 23, 2012
[55] Schedule H-4 Page 26

Q. Are the changes proposed for the water-pumping rate appropriate?

A. I am concerned that the consolidation has not been completely analyzed. The Company has calculated impacts of 22% (summer) and 12% (winter) for usage at 16,000 through 21,000 kWh for PS-43 customers choosing firm service.[56] However, in summer 60%, and in winter 69%, of all bills are lower than 10,000 kWh.[57] Calculating the impacts for the municipal pumping customers at more realistic levels shows significant impacts such as one quarter of the bills will have increases of 57% and 13% of the bills will have increases of 200%. While the 200% increase amounts to essentially the proposed new Customer Charge of $18, this impact should have been known and/or disclosed. The proposed Customer Charge should be reduced to lower the dollar impact for lower usage customers.

Q. Is the Company's change to the demand ratchet appropriate?

A. The change to a 100% demand ratchet is not appropriate at this time. The Company is embarking on a series of rate consolidations that will require individual customers to analyze the impact and then if needed make changes in their operations. Changing the demand ratchet will at best confuse those customers' demand history and make the customers' analysis more difficult. Therefore, I recommend that the Commission not implement the 100% demand ratchet at this time. In preparation for this future change the Company should consider how to accumulate and make demand ratchet data available to customers.

[56] Schedule H-4 page 25
[57] Schedule H-5 pages 28 and 29

Q. What rate changes does the Company propose for the Large General Service and Large Light & Power Rates?

A. The Company is requesting the consolidation into Rate LGS-85N of customers presently served by Rates LGS-85F and LGS-85AF.[58] The Company also is requesting the consolidation into Rate LLP-90N of customers presently served by Rates LLP-90F and LLP-90AF.[59]

The Company is proposing to set the demand ratchet at 100% and eliminating the 50% or 66% levels.[60]

Q. Do you support the changes to the Large General Service and Large Light & Power Rates?

A. I support the consolidation of the rates with the proviso that the impact be analyzed at a finer level than the average customer as shown in Schedules H-1, H-2-2 and H-4. The Company's response to STF 1.042, 1.043, 1.044 and 1.045 demonstrate that the analysis can be made at a finer (more customer focused) level and these analyses are now in the record for those customers to analyze. Specifically, the Company's analysis should consider the impact by load factor and overall usage. Additionally, as I stated above the change to the 100% demand ratchet should not be implemented in this case.

Q. How is the Company proposing to change its TOU rates?

A. The Company is proposing to reduce the number of TOU rates significantly. The Company also has highlighted that there has been limited participation in TOU rates and that reducing complexity will increase participation and help reduce peak demand and

[58] Jones Direct 37:4
[59] Jones Direct 37:7
[60] Jones Direct 40:6

over the long term reduce the costs of rate administration.[61] The Company is proposing a summer On-Peak period of 10 AM to 9 PM and two Winter On-Peak periods of 6 AM to 10 AM and 5 PM to 9 PM.

Q. Have you mapped out the Company's proposed changes to the TOU rate periods?

A. To visualize the changes proposed I have generated Exhibit HS-4.

Q. Do you support the changes to the residential TOU rate?

A. Yes and no. I agree with the Company proposal to have no On-Peak periods on the weekend and to eliminate Shoulder periods as confusing to customers.

As detailed above I recommend a residential customer charge that is equal to the R-01 charge.

Although the Company has provided its rationale for the development of system wide TOU On-Peak periods, I have concerns about the imposition of the broad hours proposed for residential customers.

Q. What are your concerns about the Company's TOU proposal?

A. Only the R-21 customers (approximately 2,400) are presently subject to a Summer On-Peak period as long (11 hours) as that proposed by the Company and similar periods in the winter. It is unclear whether these customers have adapted to the frozen Rate R-21 or they have stayed there due to inertia or the perceived frozen lower rate.

[61] Jones Direct 41:23

The Rate R-70 and R-201 customers (approximately 1,400 and 4,200 respectively) are presently subject to a significantly shorter On-Peak period (5 hours in the summer).

Q. What parameters do you recommend to encourage customers to adopt TOU rates?

A. In light of this situation and the limited information available[62] about existing residential TOU customers including the costs they may incur to deal with broad On-Peak periods, I recommend that:

- The residential Summer On-Peak period should be set at a maximum period of 6 hours. Staff suggests 2:00 PM to 8:00 PM.
- The Company should offer existing Rate R-01 and R-201AN customers the option to try the TOU rate with a six-month "money back" trial that allows them to return and recover any costs above the corresponding R-01 or R-201AN rate. This concept is included in Rates R-70F, R-201BF and R-201CF but has not been retained by the Company in its proposed Residential Time-of-Use rate R-80.
- To assist the customer to make the transition to TOU rates, the Company should provide a tool for the customer to perform a TOU analysis as part of a TOU customer education program.
- The Company should develop a customer education program to retain the existing residential TOU customers.
- The Company should develop a research program to understand the benefits of TOU rates for the customer and the Company, including potential capacity and energy savings.

[62] TEP Response to STF 1.079, STF 1.083 and STF 1.003

These recommendations are made to increase participation, understand why customers choose and stay on the TOU rate and measure the impact on energy costs and peak demand.

Q. Does the Company's proposal provide for a Critical Peak rate?

A. No.

Q. What are the advantags of a Critical Peak Rate?

A. A critical peak rate can offer advantages to the Company and customers by targeting periods of high energy costs and/or capacity needs. I recommend that the Commission order the Company to file a critical peak rate proposal within six months of the effective date of this case including a plan to implement the rate before summer 2014.

Q. The Company has proposed an Electric Vehicle rate, do you have any comments?

A. The Company has proposed an Electric Vehicle rate to be included as an option on the two residential TOU rates.[63] Based on my review it seems to be an inconsistency about the level of the discount as the tariff sheets (102-1 and 104-1) and the Company's response to STF 1.068 show a discount of 5%, while Table 5 of Mr. DesLauriers' testimony[64] shows a discount of 10% off the Off-Peak (low voltage) rate.

Q. Has the Commission previously addressed this issue?

A. Yes. The Commission has reviewed this issue in Decision No. 72582.[65] This decision supports the concept of a "whole house" rate, as does the Company's version, thus

[63] Jones Direct 50:14
[64] DesLauriers Direct 35:6
[65] *In the Matter of the Application of Arizona Public Service Company for Approval of Proposed Electric Vehicle Demonstration Project*, Docket No. E-01345A-10-0123

eliminating the need for additional metering and billing. The decision goes further and sets up a "Super Off-Peak" time period during weekdays to encourage cost effective charging from both the customer's and the Company's perspective. I recommend that the Company modify its proposal to conform to the decision and resolve the difference between the 5% and 10% discounts proposed.

Q. Do you support the changes to the non-residential TOU rate?

A. Yes. The Company is proposing a summer On-Peak period of 10 AM to 9 PM and two Winter On-Peak periods of 6 AM to 10 AM and 5 PM to 9 PM. I agree with the Company proposal to have no On-Peak periods on the weekend and to eliminate Shoulder periods as confusing to customers.

As shown on Exhibit HS-4 the Company's proposal for the new TOU is at variance with the existing summer TOU periods even when the shoulder periods are included. The Company does not have a formal process for obtaining input from its C&I customers.[66] Absent supporting information, extending the TOU period could reduce participation rather than increase the desired savings in energy costs and peak load reduction.

Q. What parameters do you recommend to encourage non-residential customers to adopt TOU rates?

A. I recommend that:

- The consolidation of non-residential TOU rates should be accepted.
- The non-residential Summer On-Peak period should be set at a maximum of 5 hours. The Company should reanalyze its data and customer experience to determine the On-Peak period subject to input from the parties. Although they

[66] TEP Response to STF 1.005

could be the same, there is no compelling reason that the non-residential and residential TOU periods need to be the same if participation, customer experience or feedback is different.

- The Company should develop a customer education program to retain the existing non-residential TOU customers and encourage new TOU customers. This may require training for its C&I representatives and/or the engagement of outside consultants.
- The Company should develop a research program to understand the operational impact of TOU rates on C&I customers and the Company, including potential capacity and energy savings.

These recommendations are made to increase participation, understand why customers choose and stay on the TOU rates and measure the impact on energy costs and peak demand.

Q. Why do you recommend Summer On-Peak time periods that do not match the period suggested by the Company?

A. The Company's work focused on its costs, however the goal is to obtain savings on energy costs and long-term peak load demand reductions. The Company's proposed On-Peak time period may fit the Company's operations but it may not encourage customers to shift to the new rates and may reduce the existing participation rates.

Q. Will a change in the On-Peak period change the rates charged to customers?

A. Yes, and only the Company has access to the billing determinants for different periods to calculate rates for the shorter period.

Q. Why have you not recommended changes in the Company's proposed Winter On-Peak period?

A. The Company's proposal is substantially the same as the existing TOU rates and the split periods offer customers multiple opportunities to shift load.

Q. Do you agree with the conceptual rate changes that the Company has proposed for the Lighting Service class?

A. Yes.

Q. Do you support the proposed changes to the Partial Requirements Service Rates?

A. No. There are no customers on these rates at this time[67] so there is no high level of urgency at this time. The Company's proposal needs to be further examined, as significant basic items such as the definition of Backup/Standby Service and Supplemental Service are not in the tariff.[68]

Considering the number of rate changes that will need to be implemented if the Commission approves them, adding changes to PRS Service will only increase the impact on the Company. As there is no revenue impact this change could be handled after the completion of this case.

[67] TEP Response to STF 1.065
[68] Email from TEP dated October 8, 2012

Q. Do you support the Company's proposed change to the PPFAC that recovers all fuel and purchased power costs through the PPFAC and develops multiple PPFAC rates to differentiate between time periods, voltage levels and interruptible service?

A. The Company has described the conceptual basis for this change in its testimony. At this time I am concerned that this overarching change that would affect every one of the Company's rates would increase the confusion level during a significant rate change. Therefore I recommend that the concept be revisited in the future.

Q. Please describe the Company's Lifeline proposal.

A. The Company is proposing to simplify and consolidate the existing Lifeline options while also reflecting movement towards the costs to serve these customers.[69]

Q. Please summarize the existing Lifeline program.

A. There are four Lifeline options that can apply to the different residential rates and some of these options are frozen.[70] The Customer Charge is discounted and a further discount is applied on a sliding scale that decreases as consumption increases.[71] Lifeline customers are exempt from paying the PPFAC and DSM charges.[72]

Q. What is the overall value of the Lifeline program?

A. The Company's testimony indicates that the combination of all these "concessions" totaled over $2.2 million during the test year for approximately 23,000 customers.[73]

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[69] Jones Direct 69:16
[70] Jones Direct 69:23
[71] Jones Direct 70:4
[72] Jones Direct 70:11
[73] Jones Direct 70:16

The Company has detailed the direct program costs as $2.512 million in discounts, $1.759 million in fuel cost related subsidies and $0.285 of avoided DSM related charges for a total of $4.556 million.[74]

The Company has indicated that it increased the subsidy to $2,605,960 in its Test Year calculations, which is a 14% increase to reflect the 14% increase in residential rates.[75]

Q. What is the Company's Lifeline proposal?

A. Lifeline customers now receiving a sliding scale discount of from 0 to 35% (Rates R-04, R-05 and R-08) will be moved to a new rate with a 25% discount on all volumetric charges. Existing Rate R-06 customers now receiving a flat $8.00 discount (approximately 70% of Lifeline customers) will receive a flat $10.00 per month discount.[76]

Lifeline customers in the "senior" and "medical" categories would receive the same discount as other Lifeline customers who will now be subject to a limit of income below 150% of the federal defined poverty level.[77]

Q. Is the Company proposing other changes to Lifeline rates?

A. Yes. All Lifeline customers will no longer be exempt from the PPFAC and the DSM charges.[78] The Company has indicated that the proposed discount applied to Lifeline

[74] TEP Response to STF 1.093
[75] TEP Response to STF 1.094
[76] Jones Direct 71:15
[77] Jones Direct 72:14
[78] Jones Direct 71:20

1 customers would apply to PPFAC and DSM charges and the net lower rates would flow
2 through to the annual under recovery within the true –up calculation.[79]
3
4 The Company is also proposing to eliminate making the Lifeline rate mobile and requiring
5 customers to re-qualify if they move and also subject to re-qualification annually at the
6 Company's request.[80]
7
8 **Q. Have you reviewed the Company's proposal to revise the Lifeline programs?**
9 A. Yes and I support the concept of the Company's recommendation to simplify the structure
10 of the program and reduce potential confusion upon entry into and exit from the program.
11
12 To highlight the total value of the programs provided by other customers, the Company
13 has proposed a simpler/clearer method that would allow a customer to take service on an
14 existing residential rate schedule and then have all of the benefits be provided through an
15 embedded rate rider. This concept is appropriate.
16
17 **Q. The Company has proposed applying the PPFAC and DSMS charges to the Lifeline**
18 **rate schedules[81], do you agree with this proposal?**
19 A. Yes. The Company's argument to include the PPFAC and DSMS adjustors for these
20 customers is supported by concepts of rate clarity and simplicity.
21

[79] Email from TEP dated October 23, 2012
[80] Jones Direct 71:4
[81] Jones Direct 71:20

Q. The Company has proposed to cancel a customer's Lifeline rate if the customer moves and require reapplication. Is this appropriate?

A. The Company has stated that a change in location can indicate a change in status and this would be an optimal time to verify if a customer still qualifies for a discounted rate.[82] The Company already requires annual requalification for the program.[83] I recommend that the Company's proposal to re-qualify customers upon a move be rejected as there is an annual process in place and a secondary requalification will probably increase costs with little, if any, benefit.

Q. Is the Company's Lifeline proposal appropriate when viewed on a customer impact basis?

A. No. The Company provided estimates of its proposed rates to current rates.[84] Non-Lifeline customers served under the various residential rates generally will experience consistent increases. Almost all of the Lifeline customers will experience percentage increases significantly higher than other customers. The following table summarizes this situation.

	% Change to Total Bill				
Rate	Std.	04	05	08	06
R-01	14.1	24.8	9.7	39.7	14.4
R-21F TOU	27.8	49.3	31.3	67.4	38.6
R-70F TOU	15.1	39.0	22.2	56.0	27.8
R-201AF	11.3		29.1	63.6	36.6
R-201BF	11.8		24.7		30.8

[82] TEP Response to STF 1.096
[83] TEP Response to STF 1.097
[84] TEP Exhibit CAJ-1 Corrected 8-17-12

This situation is at variance with the Company's response that it has increased the Lifeline amounts by 14%. When that same exhibit is examined for total dollar impact the Rate R-08-XX series have large dollar increases compared to the other Lifeline and non-Lifeline rates.

Q. How do you recommend that the proposed Lifeline rates be revised?

A. In its discovery response the Company indicated that the subsidy had been increased by 14% similar to reflect the 14% increase in residential rates. At present it is appropriate to maintain the existing "benefit" of the Lifeline rates at the $ 4.6 million dollar level plus an offset for any increase granted.

When the final rates are determined the Company should prepare its documentation to ensure all parties that the Lifeline "benefit" has not been significantly changed.

Rate R-08-XX should be adjusted to reduce the predicted impact. Also the impact at various usage levels should be examined to minimize the impact at lower usage. The Company's Schedule H-4 (pages 1 and 2) demonstrates that the Company has the tools available to make that analysis. One method to reduce the impact would be to retain the declining discount concept now used for the Lifeline rates.

Q. The Company is proposing a number of miscellaneous tariff changes. Have you reviewed those proposals?

A. Yes. The Company proposes to move the fees[85] to one location called "Statement of Charges" to make them easier for customers to locate.[86] I support that proposal.

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[85] Exhibit CAJ-9
[86] Jones Direct 74:20

Q. Have you examined the proposed miscellaneous charges?

A. Yes. In response to a Staff data request, the Company provided the background information to support the revised fees.[87] I am concerned that the Meter Test and Service Establishment fees are excessive. My review of these rates indicates that a 60.6% Labor Overhead was added in the calculation of this rate. Other fees do not use any Labor Overhead. The calculations should be adjusted to remove the Labor Overhead.

Q. Do you suggest any other changes to the Company's tariffs?

A. Yes. The Company's present tariffs allow the Company to require and retain a deposit to guarantee the payment of all bills until service is discontinued and all bills have been paid. While there is a procedure to return the deposit for residential customers it appears that the Company can retain the deposit from a non-residential customer until service is discontinued.

In contrast the tariff for Arizona Public Service ("APS") provides that the non-residential customers deposits will be reviewed after 24 months of service and the deposit will be returned based upon the past 12 months payment performance.

In Decision No. 73142, for UNS Gas, Inc. the Commission considered this issue and adopted provisions similar to APS' tariff as suggested by Staff.[88]

In light of the Commission's recent consideration of this issue, I recommend that the Company be ordered to change its tariff provisions for non-residential deposits consistent with Decision No. 73142.

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[87] TEP Response to STF 1.100
[88] Docket No. G-04204A-11-0158

Q. Do you also have a concern about a proposed door hanging fee?

A. Yes. The Company has added "Door Hanging Fee" to its proposed Statement of Charges among the list of items under the $20.00 Trip Charge. The Company does not currently have a door hanging fee listed on its Statement of Additional Charges.

Q. Please describe your concern regarding the door hanger issue.

A. The Company is introducing a door hanger fee when the Company places a door hanger as part of the Company's disconnection of service process. Staff does not believe that a door hanger fee should be charged by the Company to its customers who are facing possible disconnection of service. Such customers are struggling to pay their utility bill, and an additional $20 door hanger fee would just aggravate an already financially difficult situation for such customers. A door hanger is not required by Commission rules. The Commission considered this issue for UNS Gas and rejected the door hanger fee in Decision No. 73142.

Therefore, Staff recommends against adoption of the door hanger fee proposed by the Company. The Company may provide door hangers free of charge if the Company so chooses, but customers should not be charged an additional fee for a door hanger.

Q. Do you have any overall recommendations as a result of your rate design review in this case?

A. Yes. There are a number of areas where the Company has not conducted specific research other than as part of its rate design process. The Company should plan and perform research to support its ongoing rate design efforts. The Company should be required to define for the Staff a rate research plan within three months of the end of this case,

complete the plan within an additional nine months and then provide the results to Staff. The plan might include:

- Reviewing or justifying the existing blocks and tiers within rate schedules in light of recent load research, appliance saturation, new uses such as heat pump water heaters, energy efficient computers, televisions and the penetration of energy efficient appliances
- Determining if, when and how distribution (delivery) rates might shift from volumetric to demand based to eliminate the need for a decoupling mechanism
- Performing a loss study to support cost of service efforts
- Enhancing load research to produce load strata data

Q. You have made a number of rate design recommendations that potentially interact with each other and are dependent on the final revenue increase, if any. How can the recommendations be implemented?

A. Unlike the revenue requirements process, rate design is much less linear and therefore it is less suited to having the final rates set by an adversarial process. While the parties can each argue for their rate design methodologies, once those positions are accepted or rejected (either by settlement or the Commission's decision) the Company is in the best position to use its models and customer data to develop compliance rates. Under either process all parties should have the opportunity to review the "final" rates, determine if the rate design positions were properly and accurately implemented and request alternate rates to better meet the decided positions before providing their approval. Through its technical conferences (formal and informal) and the data request process the Company has demonstrated its ability to participate in an interactive process. Hopefully, this positive behavior by all parties will take place during the settlement process or subsequent to and directed by the Commission's rate design decision.

Q. Is there some risk when significant rate design changes are made?

A. Yes. There is always a risk that outlier customers can experience unintended consequences such as some of the conditions I have found and highlighted in my testimony. This risk is increased when customer research is limited or has not been performed.

I recommend that the Commission include a process to allow Staff to reopen the rate design portion of this case if concerns develop over rate design subsequent to the implementation of new rates. Legal counsel should develop the details of this process, including notice and hearings.

Q. Does this conclude your testimony?

A. Yes.

Present On-Peak
Present Shoulder
Weekday Only | TEP Proposed On-Peak

Time of Use Periods

Hour Ending

Rate Schedule	# Customers	Proposed Rate Schedule	AM 1	2	3	4	5	6	7	8	9	10	11	12	PM 1	2	3	4	5	6	7	8	9	10	11	12
Summer																										
General Service																										
GS-76N	105	GS-76N																								
GS-76F	614	GS-76N																								
Large General Service																										
LGS-85N	72	LGS-85N																								
LGS-85AF	16	LGS-85N																								
LGS-85F	8	LGS-85N																								
LLP-90F	4	LLP-90N																								
LLP-90N	4	LLP-90N																								
LLP-90AF	2	LLP-90N																								
Residential																										
R-21 F	2366	R-80																								
R-04-21F	4	R-80																								
R-05-21F	4	R-80																								
R-06-21F	25	R-80																								
R-08-21F	9	R-80																								
R-70N-B	226	R-80																								
R-70N-B Weekend		R-80																								
R-70N-C	684	R-80																								
R-70N-C Weekend		R-80																								
R-70N-D	485	R-80																								
R-70 F	4010	R-80																								
R-04-70F	6	R-80																								
R-05-70F	16	R-80																								
R-06-70	109	R-80																								
R-08-70	24	R-80																								
R-06-201B	12	R-201BN																								
R-06-201C		R-201BN																								
R-08-201B		R-201BN																								
R-08-201C		R-201BN																								
R-201BN	58	R-201BN																								
R-201BF	473	R-201BN																								
R-201CF	151	R-201BN																								
R-201CN	18	R-201BN																								

* Source for number of customers - Exhibit CAJ-1 Corrected 8-17-12 page 1 of 2

Present On-Peak

Time of Use Periods

Hour Ending

Rate Schedule	# Customers	Proposed Rate Schedule	AM 1	2	3	4	5	6	7	8	9	10	11	12	PM 1	2	3	4	5	6	7	8	9	10	11	12
Winter																										
General Service																										
GS-76N	105	GS-76N																								
GS-76F	614	GS-76N																								
Large General Service																										
LGS-85N	72	LGS-85N																								
LGS-85AF	16	LGS-85N																								
LGS-85F	8	LGS-85N																								
LLP-90F	4	LLP-90N																								
LLP-90N	4	LLP-90N																								
LLP-90AF	2	LLP-90N																								
Residential																										
R-21 F	2366	R-80																								
R-04-21F	4	R-80																								
R-05-21F	4	R-80																								
R-06-21F	25	R-80																								
R-08-21F	9	R-80																								
R-70N-B	226	R-80																								
R-70N-B Weekend		R-80																								
R-70N-C	684	R-80																								
R-70N-C Weekend		R-80																								
R-70N-D	485	R-80																								
R-70 F	4010	R-80																								
R-04-70F	6	R-80																								
R-05-70F	16	R-80																								
R-06-70	109	R-80																								
R-08-70	24	R-80																								
R-06-201B	12	R-201BN																								
R-06-201C		R-201BN																								
R-08-201B		R-201BN																								
R-08-201C		R-201BN																								
R-201BN	58	R-201BN																								
R-201BF	473	R-201BN																								
R-201CF	151	R-201BN																								
R-201CN	18	R-201BN																								

* Source for number of customers - Exhibit CAJ-1 Corrected 8-17-12 page 1 of 2

Testimony - Howard Solganick

Arizona Corporation Commission
Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.

Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)

Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days.

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Exhibit HS-6
Copies of Responses to data requests and documents reference in the Direct Rate design
Testimony of Howard Solganick

Data Request/Workpaper No.	Confidential	No of Pages	Page No.
DOD 1.03 (4)	NO	6	6
STF 1.020	NO	1	9
STF 21.1	NO	2	9, 17, 19
AECC 3.5 (a)	NO	1	9
STF 1.032	NO	2	9, 14
AECC 3.1 (c)	NO	2	9, 14
AECC 6.1 (b) (i)	NO	4	9
VSI 3.02	NO	1	12
STF 1.008	NO	1	13
STF 1.006	NO	1	13
STF 1.079	NO	1	13, 24
STF 1.005	NO	1	13, 26
STF 1.007	NO	1	13
STF 1.041	NO	1	14
STF 1.031	NO	4	14
STF 1.077	NO	1	14
STF 1.037	NO	1	14
Worksheet R-01	NO	4	16
TEP email to Staff	NO	2	16
AECC 11.4	NO	1	17
EMAIL TO STAFF	NO	2	20, 31`
STF 1.083	NO	1	24
STF 1.003	NO	1	24
STF 1.065	NO	4	28
TEP Email to Staff	NO	2	28
STF 1.093	NO	14	30
STF. 1.094	NO	2	30
STF 1.096	NO	1	32
STF 1.097	NO	1	32
STF 1.100	NO	7	34

Tucson Electric Power Company
Docket No. E-01933A-12-0291
Exhibit HS-7
Confidential Responses to Data requests and documents reference in the Direct Rate design Testimony of Howard Solganick

Data Request/Workpaper No.	Confidential	No of Pages	Page No.
STF 1.076	YES	14	14

DOD 1.03

Please provide the following for each class for calendar years 2009, 2010, 2011 actual and 2011 adjusted:

1. Monthly customer count, revenues, revenues per customer, kWh sales and kWh sales per customer.
2. Total monthly billing demands, where applicable.
3. Monthly non-coincident class peak demands ("NCP")
4. Monthly retail system peaks in megawatts ("MW"). Indicate day and time of peak.
5. Monthly class peaks in MW coincident with monthly system peaks.
6. Annual load duration curve with supporting data.

RESPONSE: October 12, 2012

1. Please see the files listed below for actual customer count, revenues and sales for 2009, 2010 and 2011.

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

File Name	Bates Numbers
DOD 1.03 01-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 02-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 03-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 04-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 05-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 06-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 07-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 08-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 09-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 10-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 11-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 12-09 Rev Sum-Confidential.xls	N/A
DOD 1.03 2010-2011 OperRevReport-Confidential.xlsx	N/A
DOD 1.03-1-Confidential.xls	N/A

2011 adjusted revenues are in the TEP Revenue Proof 12-31-11-Confidential.xlsx provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\1. Confidential).

Adjusted Customer counts and kWh sales are in Billind Determinants adjusted monthly.xls provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\3. Schedule H Support).

Per customer data can be calculated from the above referenced worksheets.

2. 2011 actual monthly billing demands are in TEP TY Billing Determinants 12-31-11 – Confidential provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\1. Confidential).

   2011 adjusted monthly billing demands are in Billind Determinants adjusted monthly.xls provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\3. Schedule H Support).

   2009 and 2010 billing demand was not calculated for purposes of this rate case and therefore is unavailable.

3. Monthly non-coincident class peaks are in Average and Peaks Allocation 12-31-11 (Revised 10-05-12) provided in response to UDR 1.1 (located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Schedule G and H Support\5. Load Research).

   2009 and 2010 billing demand was not calculated for purposes of this rate case and therefore is unavailable.

4. Please see DOD 1.03-4 retail system peaks.xls for 2009, 2010, and 2011 day and time retail system peaks.

5. See response to question 1.03 (3).

6. Please see DOD 1.03-6 2011 Load Duration Curve.xls for the requested information.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

SUPPLEMENTAL RESPONSE TO PARTS 2, 3 AND 5: October 26, 2012

THE FILE LISTED BELOW CONTAINS CONFIDENTIAL INFORMATION AND IS BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT DATED JULY 6, 2012.

In response to DOD 2.1, Please see the following:

2. Please see DOD 1.03-2-Confidential.xls for billing demand data for 2009 and 2010 for all applicable classes.

3.&5. The Company objects to DOD 1.3(3) and DOD 1.3(5), since it does not have system data readily available to generate the non-coincident peak or the coincident peak data outside the test year in a manner responsive to DOD 1.3(3) or DOD 1.3(5). To generate the requested information would be overly burdensome and time consuming.

RESPONDENT:

Pricing (A. Leschak)

WITNESS:

Craig A. Jones

REVISED RESPONSE TO PART 4: November 5, 2012

Please see DOD 1.03-4 retail system peaks-revised.xls for corrected numbers to tab 2009 from the FERC Form 1. The Excel file is <u>not</u> identified by Bates numbers.

RESPONDENT:

Pricing (A. Leschak)

WITNESS:

Craig A. Jones

Monthly System Peaks 2011

Line No.	Date &Time	Total system Peak (MW)
1	1/4/2011 8:00	1,286
2	2/3/2011 8:00	1,519
3	3/31/2011 17:00	1,170
4	4/28/2011 17:00	1,379
5	5/27/2011 17:00	1,721
6	6/27/2011 16:00	2,334
7	7/2/2011 16:00	2,214
8	8/24/2011 17:00	2,303
9	9/1/2011 16:00	2,199
10	10/2/2011 16:00	1,630
11	11/1/2011 17:00	1,233
12	12/6/2011 8:00	1,327
13		2,334

DOD
1.03 (4)

Monthly System Peaks 2010

Line No.	Date &Time	Total system Peak (MW)
1	1/25/2010 14:00	1,614
2	2/10/2010 20:00	1,491
3	3/10/2010 8:00	1,466
4	4/27/2010 16:00	1,548
5	5/28/2010 16:00	1,996
6	6/30/2010 16:00	2,610
7	7/15/2010 16:00	2,848
8	8/12/2010 16:00	2,696
9	9/20/2010 16:00	2,520
10	10/1/2010 16:00	2,328
11	11/30/2011 8:00	1,568
12	12/31/2010 19:00	1,607
13		2,848

Monthly System Peaks 2009

Line No.	Date &Time	Total system Peak (MW)
1	1/28/2009 8:00	3,139
2	2/11/2009 8:00	3,180
3	3/2/2009 20:00	2,970
4	4/21/2009 17:00	3,538
5	5/18/2009 17:00	3,836
6	6/29/2009 16:00	4,139
7	7/28/2009 16:00	4,348
8	8/20/2009 16:00	4,161
9	9/1/2009 16:00	3,923
10	10/19/2009 16:00	3,482
11	11/5/2009 16:00	3,144
12	12/7/2009 18:00	3,295
13		4,348

STF 1.020

Jurisdictional Allocation: Please provide the FERC Order or communication that indicates acceptance of the use of the 4CP methodology by the Company. [Jones Direct 12:25]

RESPONSE:

The 4CP approach was approved by FERC in settlement Order No. OA96-140-000, and has been accepted by the Commission in TEP's last three general rate cases for purposes of the jurisdictional allocation method.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

STF 21.1

The Company's response to DOD 2.2 confirms that the Unit Cost data in Schedule G-6-1 is not cost data but unit revenue data.

a. Please confirm that the data presented is revenue such as unit revenue (example) line 18 shows residential as $363,572,522 which is the same as the Residential Total Electric Revenue from Sales on line 20 on Schedule G-1.

b. Please compute the Unit Cost for each component shown on lines 1 through 18 of Schedule G-6-1 for customer, demand (kW) and energy (kWh) ASSUMING the Company's requested overall rate of return for this case.Provide the following information:

RESPONSE:

a. Yes, the Company has identified all costs necessary to serve each individual class. Schedule G-6-1 referenced in this data request includes all of these costs, including the test year actual return on rate base. The return is simply the amount of revenue left over after all expenses have been met for the test year. Since the class cost of service study ("CCOSS") is designed to determine the cost to serve each individual class, the costs and the revenues should match. Therefore, the test year "Revenue" amount of $363,572,522 for the residential class mentioned above is assumed to be the same value as the "cost" to serve that class for the test year. In this case it shows the residential test-year revenues resulted in a negative return on plant (i.e., revenues were not sufficient in the test year to produce a return on the plant used to serve this class).

b. Please see STF 21.1.xls for the unit cost by class for the test year plus the additional proposed revenues being requested by class at the Company's proposed rate of return. Adding the additional "revenue" needed to offset the "cost" associated with the return and related taxes will increase the "cost" and "revenues" for each class proportionally. All demand components are calculated on a per KW basis whereas the energy component uses sales and customer components use customers.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY REVENUES AND UNIT COST

TEST YEAR PERIOD ENDING DECEMBER 31, 2011

LINE NO.	REVENUES	TOTAL	TOTAL COMPANY	RESIDENTIAL	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING
1	DEMAND COMPONENTS	$632,382,196	$632,382,196	$274,512,306	$181,093,756	$92,989,020	$40,613,160	$40,064,661	$3,109,293
2	DEMAND PRODUCTION		365,436,713	158,296,072	101,032,137	54,916,536	24,115,403	24,343,209	2,733,357
3	DEMAND PRODUCTION MUST RUN		27,361,991	11,908,943	7,491,405	4,086,145	1,821,229	1,846,496	207,773
4	DEMAND TRANSMISSION EHV		51,016,770	24,783,234	10,585,789	6,492,350	4,133,510	4,577,520	444,368
5	DEMAND TRANSMISSION NON-EHV		51,016,770	24,783,234	10,585,789	6,492,350	4,133,510	4,577,520	444,368
6	DEMAND ANCILLARY SERVICES		17,144,607	7,461,962	4,694,000	2,560,316	1,141,154	1,156,986	130,187
7	DEMAND DISTRIBUTION		120,405,345	47,278,861	46,704,636	18,441,323	5,268,355	3,562,930	(850,760)
8	ENERGY COMPONENTS	292,189,698	292,189,698	121,102,785	69,067,097	40,234,780	27,174,234	33,425,978	1,184,824
9	ENERGY FUEL DIRECT		292,189,698	121,102,785	69,067,097	40,234,780	27,174,234	33,425,978	1,184,824
10	ENERGY PRODUCTION		0	0	0	0	0	0	0
11	ENERGY CUSTOMER		0	0	0	0	0	0	0
12	ENERGY UNCOLLECTIBELS		0	0	0	0	0	0	0
13	CUSTOMER COMPONENTS	$40,126,025	$40,126,025	$27,998,899	$8,158,634	$1,456,340	$819,725	$715,662	$976,765
14	CUSTOMER DELIVERY		11,425,770	6,442,161	3,029,427	721,593	431,419	347,164	454,005
15	CUSTOMER METERS		9,011,558	4,980,043	3,043,401	420,601	207,586	172,659	187,318
16	CUSTOMER BILLING & COLLECTIONS		16,013,025	13,430,713	1,691,213	255,402	147,019	159,278	329,399
17	CUSTOMER METER READING		3,675,673	3,145,981	394,592	58,744	33,751	36,561	6,043
18	TOTAL COMPANY	$964,697,920	$964,697,920	$423,613,990	$258,319,487	$134,680,140	$68,607,120	$74,206,301	$5,270,882
	PER UNIT COST								
19	DEMAND COMPONENTS	$28.9894	$28.9894	$31.7304	$43.0316	$30.6630	$24.6241	$23.6782	$1.2049
20	DEMAND PRODUCTION		$16.7522	$18.2971	$24.0073	$18.1087	$14.6214	$14.3868	$1.0593
21	DEMAND PRODUCTION MUST RUN		$1.2543	$1.3765	$1.7801	$1.3474	$1.1042	$1.0913	$0.0805
22	DEMAND TRANSMISSION EHV		$2.3387	$2.8646	$2.5154	$2.1408	$2.5062	$2.7053	$0.1722
23	DEMAND TRANSMISSION NON-EHV		$2.3387	$2.8646	$2.5154	$2.1408	$2.5062	$2.7053	$0.1722
24	DEMAND ANCILLARY SERVICES		$0.7859	$0.8625	$1.1154	$0.8443	$0.6919	$0.6838	$0.0505
25	DEMAND DISTRIBUTION		$5.5196	$5.4649	$11.0980	$6.0810	$3.1942	$2.1057	-$0.3297
26	ENERGY COMPONENTS	$13.3945	$13.3945	$0.0312	$0.0317	$0.0329	$0.0295	$0.0309	$0.0317
27	ENERGY FUEL DIRECT		$13.3945	$0.0312	$0.0317	$0.0329	$0.0295	$0.0309	$0.0317
28	ENERGY PRODUCTION		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
29	ENERGY DEMAND SIDE MANAGEMENT		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
30	ENERGY UNCOLLECTIBELS		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
31	CUSTOMER COMPONENTS	$1.8394	$1.8394	$6.3299	$18.2523	$195.5869	$4,554.0277	$29,819.2698	$4.1600
32	CUSTOMER DELIVERY		$0.5238	$1.4564	$6.7773	$96.9101	$2,396.7718	$14,465.1467	$1.9836
33	CUSTOMER METER READING		$0.4131	$1.1259	$6.8086	$56.4868	$1,152.9771	$7,194.1368	$0.7978
34	CUSTOMER BILLING & COLLECTIONS		$0.7341	$3.0364	$3.7835	$34.3006	$816.7739	$6,636.5914	$1.4029
35	CUSTOMER METERS		$0.1685	$0.7112	$0.8828	$7.8834	$187.5049	$1,523.3950	$0.0257
36	TOTAL COMPANY	$44.2233	$44.2233	$38.0914	$61.3155	$226.2828	$4,578.6812	$29,842.9788	$5.3966
37	TOTAL THRUPUT (kWh)	9,332,107,046	9,332,107,046	3,887,303,965	2,179,138,260	1,222,621,614	922,341,014	1,083,071,404	37,430,790
38	TOTAL ANNUAL CUSTOMERS	5,112,747	5,112,747	4,423,307	446,993	7,446	180	24	234,797
39	TOTAL AVERAGE CUSTOMERS		426,062	368,609	37,249	621	15	2	19,566
40	TOTAL CUSTOMER ($/ CUSTOMER)		$7.85	$6.33	$18.25	$195.59	$4,554.03	$29,819.27	$4.16
41	TOTAL DEMAND & CUSTOMER ($/ CUSTOMER)		$131.54	$68.39	$423.39	$12,684.04	$230,182.70	$1,699,180.13	$17.40

AECC 3.5

Class Cost of Service - Please refer to the CCOS study provided in TEP's response to AECC DR No. 1-7. Please answer the following questions related to each class's share of income tax under present rates.

a. Please explain why TEP allocates total jurisdictional income tax expense using plant in service instead of directly calculating each class's income tax expense using each class's taxable net income derived using its revenues and expenses other than income taxes?

b. Would TEP agree that allocating income taxes using plant in service assigns excess taxes to classes with earnings below the system average and assigns insufficient taxes to classes with earnings above the system average? If not, please explain how TEP's allocation of income taxes results in an appropriate level of income tax expense for each rate class.

c. Please prepare a CCOS study that derives each class's earnings under present rates with the income taxes calculated for each rate class based on its class-specific taxable net income under present rates instead of the income taxes being allocated using plant in service.

RESPONSE:

a. The allocation of income taxes should be based on what each class should be paying if there were an equalized return on plant. To apply taxes in the manner suggested in this question would make existing inequities between classes even more inequitable. An example of this inequity would be to assume only one class is generating a positive return on plant (thus income). It would be unjust and unreasonable to allocate to it <u>all</u> of the income tax to that single class. This would result in the customers who are not covering their cost of service to pay even less, and those covering more than their cost of service to pay even more. The Company's believes its method is considerably more equitable.

b. No, the Company does not agree. See the response to part a.

c. The Company objects to preparing a new CCOSS. AECC has been provided the Company's CCOSS in electronic format. AECC, therefore,has the capability to run different versions of the study based on its own assumptions. It would be overly burdensome for the Company to create a series of calculations and perform the necessary test for validity related to creating changes that assign all of the income tax costs to classes that the Company believes are already paying more than their share of the costs.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

STF 1.032

Cost of Service: Please provide the system loss study used in the Cost of Service Study.

RESPONSE:

The Company did not prepare a system loss study in this rate case. Distribution and transmission losses used in the CCOSS are prepared in Excel and included in the file 2011 Jurisdictional Allocation 12-31-11.xlsx, tab Loss Summary, which was provided in the revised response to UDR 1.1 dated August 17, 2012. This file 2011 Jurisdictional Allocation 12-31-11.xlsx can be found in the data response under the headings CCOSS: Jurisdictional Allocation.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY
ACC/FERC JURISDICTION - ENERGY /DEMAND ALLOCATION
TEST PERIOD YEAR END DECEMBER 31, 2011

#N/A

ENERGY ALLOCATON - BASE CASE

Line No.			ACC	FERC	Total	Line No.
			(a)	(b)	(c)	
1	Sales to ultimate customers including unbilled		1,083,071,404	1,032,598,000	2,115,669,404	1
	Adjustments:					
2	Year-end Customers and Weather Normalization		(46,514,056)		(46,514,056)	2
3	TOTAL		1,036,557,348	1,032,598,000	2,069,155,348	3
	Local Losses					
4	As % of Sales		6.39%			4
5	kWh	(Line 3 * Line 4)	66,245,035		66,245,035	5
6	Local Generation and Deliveries from EHV	(Line 3 + Line 5)	1,102,802,383	1,032,598,000	2,135,400,383	6
	EHV Losses					
7	As % of Deliveries/Sales		3.85%	3.85%		7
8	kWh	(Line 6 * Line 7)	42,434,243	39,732,880	82,167,122	8
9	Energy Required	(Line 6 + Line 8)	1,145,236,626	1,072,330,880	2,217,567,506	9
10	**Energy Allocation Factor** (Line 9 - (a)/(c) and (b)/(c)		51.64%	48.36%		10

AECC 3.1

Class Cost of Service - Please refer to the Average and Peaks Excel workpaper file "Average and Peak Allocation 12-31-2011". In cells N53:N64, TEP provides monthly coincident peak (CP) demand losses.

a. Please confirm that these loss values are correct for each month. If these values are incorrect, please provide corrected monthly losses.

b. If these values are correct, please explain how the monthly demand losses can vary from a low of 1.8% in December 2011 to a high of 30.4% in July 2011 (calculated by dividing the values in cells N53:N64 by the values in cells N38:N49). Even taking account of summer losses, shouldn't the CP loss percentages be more consistent than this across all months?

c. Please provide a copy of TEP's most recent line loss study.

d. Please confirm that TEP has customers that take service variously at Secondary voltage, Primary voltage, non-EHV, and EHV. If this statement is incorrect, please identify the error(s) and explain why the statement is in error.

e. Please identify the voltage (secondary, primary, etc.) at which service is provided for each of the eleven TEP rate classes shown in the workpaper. If service for any rate class is provided at more than one voltage level, please identify the proportion of that rate class's monthly non-coincident peak (comparable to cells C6:M17) and monthly coincident peak (comparable to cells C21:M32) that is served at each applicable voltage.

f. Please explain why the loss values TEP applied to each rate class in its CCOS are not differentiated by voltage level.

g. Please provide the monthly CP demand loss factors applicable to each of the voltage levels at which TEP retail customers take service, i.e., secondary, primary, non-EHV, and EHV (or other applicable categories).

h. Please provide the comparable workpaper from TEP's 2007 rate case, including losses. Please explain the reason for any major changes in demand losses between the 2007 rate case and the current case.

RESPONSE:

a. Load Research demand was not adjusted for losses back to generation. Cells N53:N64 represent the excess or shortfall to the difference between the system monthly coincident-peak loads less the summation of coincident peak for all class loads based on load research data. The hourly load data was then grossed up by allocating the excess or shortfall proportionately to classes.

b. See response to part a.

c. The Company has not completed an engineering study on line losses over the last two rate cases. The losses calculated and used in the jurisdictional allocation have been provided in response to UDR 1.1 (jurisdictional allocation can be located in TEP's electronic data room, see Uniform Data Requests\Attachments\UDR 1.01\WP – Schedules\Schedule G and H Support\ Jurisdictional Allocation \2011 Jurisdictional Allocation 12-31-11.xlsx).

d. Correct.

e. The chart below shows the percentage of services at voltage levels, and primary or secondary service by rate class. For those classes that have services, or more than one service, under different voltages, the Company does not have that hourly load data readily available.

Class Description	Non-EHV (≤49 kV)	EHV (≥138 kV)	Secondary	Primary
Residential	100%	0%	100%	0%
Residential TOU	100%	0%	100%	0%
Small Commercial	100%	0%	94%	6%
Small Commercial TOU	100%	0%	100%	0%
Large Commercial	100%	0%	94%	6%
Large Commercial TOU	100%	0%	98%	2%
Water Pumping	100%	0%	100%	0%
Lighting	100%	0%	100%	0%
LL&P	100%	0%	7%	93%
LL&P TOU	100%	0%	71%	29%
Mining	91.3%	8.7%	0%	100%

f. See response to a and c.

g. TEP does not track or bill information that would be responsive to this request.

h. Please see AECC 3.1-h.xls for the Average & Peaks workpaper from the 2007 rate case. There are no changes in the methodology between work papers.

RESPONDENT:

Pricing (B. Pries)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY
ACC/FERC JURISDICTION - ENERGY /DEMAND ALLOCATION
TEST PERIOD YEAR END DECEMBER 31, 2011

#N/A

ENERGY ALLOCATON - BASE CASE

Line No.			ACC	FERC	Total	Line No.
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3	TOTAL		1,036,557,348	1,032,598,000	2,069,155,348	3
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4	As % of Sales		6.39%			4
5	kWh	(Line 3 * Line 4)	66,245,035		66,245,035	5
6	Local Generation and Deliveries from EHV	(Line 3 + Line 5)	1,102,802,383	1,032,598,000	2,135,400,383	6
	EHV Losses					
7	As % of Deliveries/Sales		3.85%	3.85%		7
8	kWh	(Line 6 * Line 7)	42,434,243	39,732,880	82,167,122	8
9	Energy Required	(Line 6 + Line 8)	1,145,236,626	1,072,330,880	2,217,567,506	9
10	**Energy Allocation Factor** (Line 9 - (a)/(c) and (b)/(c)		51.64%	48.36%		10

AECC 6.1

Follow up to TEP's Response to AECC 3.1.a.

a. Please define "Load Research demand" as used in TEP's response. In answering this question please indicate whether "Load Research demand" is referring to the demand of all retail load or just the load for which sampling techniques are used to derive class hourly loads.

b. Please clarify the statement "Load Research demand was not adjusted for losses back to generation" in light of the fact that heading of the cells being discussed (cell N52 of the workpaper entitled "Average and Peaks Allocation 12-31-2011") is entitled "Losses." Specifically:

   i. Is TEP indicating that the heading "Losses" is incorrect? If the heading "Losses" is not incorrect, please clarify in light of the statement quoted above.

   ii. Is TEP indicating that cells N53:N64 include losses but that a loss factor was not applied to derive the values in these cells?

   iii. If cells N53:N64 are accounting for items other than losses, identify each of those items.

   iv. Please confirm that the values shown under the heading "Losses" exceed 18% for each month from April to October (calculated by dividing the values in cells N53:N64 by the values in cells N38:N49). If TEP disagrees, please reconcile using the values in the workpaper. If these cells (N53:N64) are simply the difference between the monthly coincident peak load that TEP has measured using its Load Research data and TEP's system monthly peak, what proportion of the April through October "Losses" is attributable to a measurement error in which TEP's load research data fails to reconcile to TEP's measured system output after adjusting for reasonable losses (e.g., 9.6%)? If TEP disputes that a material portion of these reported "Losses" values is attributable to a measurement error as described above, please fully account for the "Losses" value for each month for which the reported "Losses" deviates from the 9.6% Annual Average Loss Factor used by TEP elsewhere in its workpapers.

   v. Please reconcile the monthly "Losses" in cells N53:N64 to the monthly Losses shown in Schedule G Support Workpaper entitled "2011 TEP Average Peaks Summary." Is the difference in the "Losses" presented in these two workpapers attributable wholly (or largely) to the inclusion in cells N53:N64 of a measurement error in which TEP's load research data fails to reconcile to TEP's measured system output? If not, please explain in the reconciliation these two sets of reported "Losses".

vi. Please explain TEP's rationale in assigning a pro rata share of the difference between the monthly coincident peak load that TEP has measured using its Load Research data and TEP's system monthly peak to classes for which monthly coincident peak was measured using the aggregated load of the class population (as opposed to a statistical sample). Does TEP agree that this pro rata allocation assigns a portion of the measurement error attributable to statistical sampling to the classes for which class load was derived based on the measured load of the class population? If TEP disagrees, please fully explain the basis of TEP's disagreement.

c. Please refer to the load data in cells C21:M32 in workpaper entitled "Average and Peaks Allocation 12-31-2011.

i. For each class shown in this range of cells, please indicate which class load data was derived using a statistical sample and which class load was derived by aggregating the measured load of the class population.

ii. What is the class population (i.e., number of annual customers) of each class shown in this range of cells?

iii. What is the sample size of each class for which a statistical sample was used to derive monthly coincident peak loads?

iv. What is the age of the sample for each class for which a statistical sample was used to derive monthly coincident peak loads?

v. Please describe the specific sampling philosophy that the Company employs for its load studies. Does TEP employ Stratified Random Sampling or Simple Random Sampling? What are the confidence bounds used in determining the sample size for each class for which a statistical sample was used to derive monthly coincident peak loads. Please show this calculation.

vi. Please provide the workpaper (in Excel format with all formulas intact) that shows how the sample load data for each class (for which a statistical sample was utilized) is used to estimate class monthly coincident peak loads.

vii. For each class for which a statistical sample was used to derive monthly coincident peak loads, please provide a table that identifies the monthly kWh that is predicted by the sample load data and compares it to actual class kWh, for each month in 2011.

RESPONSE:

a. "Load Research Demand" refers to the demand amounts arrived at for classes not having demand meters and is based on the sample data which is then converted to generate a value for the class.

b. i. The heading referenced in this question does not thoroughly describe everything that is included in the data in the column below it. The data in the column does include the value of average system losses allocated to each class, but it also includes the allocation of variance amounts resulting from load research data. No specific amount was added to the class, the total variance (which would include the loss amount) itself was allocated to each class as shown on the spreadsheet. This column could be referred to as the "balancing adjustment".

ii. Yes.

iii. Please refer to the response to AECC 6.1b.i.

iv. TEP confirms that the values shown under the "Losses" exceed 18% for each month from April to October.

The adjustment mentioned in the column originally labeled "losses" is, as stated in the question, simply the difference between the monthly coincident peak load that TEP calculates based on its load research data and TEP's system peak. Since not all customers have demand meters, the monthly class demand is modeled using the load research for those classes without demand meters. Losses are not identifiable by rate class, so they are assumed to be part of the overall difference between the calculated peak based on load research and the system peak. If the total system demand for the year is 20,313 MW and the losses are the stated 9.6%, then 1,950 MW of the 2,749 MW difference between the load-research based peak and the system peak relate to the estimated losses. Since losses are likely to vary in any given month for a variety of reasons, this calculation is just an approximation. Some portion of the remaining 799 MW of difference can be assumed to be the adjustment necessary to make the numbers match. It is not a measurement error as characterized in this question, it is simply the balancing adjustment necessary to align the two forms of data.

v. Please see the response to AECC 6.1b.iv.

vi. As mentioned in the response to AECC 6.1b.iv., the differences were primarily attributable to losses. Since the data is not available to determine the specific losses by customer class, it was determined that a proportional allocation of those differences to all classes was appropriate. There are a number of variables (temperature, voltage, load factor, etc.) that could contribute to more or less of the losses being allocated to individual classes or individual months, but the data necessary to arrive at a specific calculation is not available. Since the variables could increase or decrease the amount of losses going to any individual class or month, it was determined that allocating the entire total of the balancing adjustment on a weighted basis would be the most equitable method of assigning the balancing adjustment to all classes.

VSI 3.02

Please describe the time frame over which TEP plans to achieve 100% deployment of "smart meters" for its residential, commercial, and industrial customers, and for the remainder of its distribution feeders. (follow-up to VSI 2.02)

RESPONSE:

The residential class has 177,211 automated meter reading ("AMR") meters installed out of 390,128 total meters. TEP plans to have the remaining meters exchanged within 6 years.

The commercial class has 16,276 AMR meters installed out of 39,155 total meters. TEP plans to have the remaining meters exchanged within 5 years.

The industrial class has 108 meters and all of them currently have a Smart Meter installed.

TEP has 277 Smart Meters installed on 408 distribution feeders. The remaining 131 feeders have meters that provide the data needed at this time. There are no plans to replace any of the remaining 131 meters with Smart Meters.

RESPONDENT:

Jim Taylor

WITNESS:

Craig A. Jones

STF 1.008

Background: Does the Company use competitive fuel (or energy) forecasting for any customer classes? If so, please provide a narrative description of the process, price inputs and results beginning January 1, 2008 through 2012.

RESPONSE:

No, the Company does not use competitive fuel (or energy) forecasting for any customer classes..

RESPONDENT:

David Couture

WITNESS:

David Hutchens

STF 1.006

Background: Does the Company employ end use forecasting for any customer classes? If so, please provide a narrative description of the process and results beginning January 1, 2008 through 2012.

RESPONSE:

No, the Company does not currently have the capability to construct end-use forecasts, and does not foresee being able to construct such forecasts for several years.

RESPONDENT:

Pricing (Craig A. Jones and Luc Thiltges)

WITNESS:

Craig A. Jones

STF 1.079

Rate Design: Please provide any studies by Black & Veatch and/or the Company to compare the TOU price differentials to customer's costs to shift load between on and off peak periods and the potential increase in the number of customers that will change to the proposed TOU rates as a result. [DesLauriers Direct 28:11]

RESPONSE:

No such study has been conducted by the Company or Black & Veatch to its knowledge. The customers' costs to shift load is not an element of the analysis of optimal TOU periods since the purpose of TOU is to signal cost consequences for the Company to customers for them to use in evaluating their own individual economics of load shifting.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

STF 1.005

Background: Does the Company have a program or process to survey its commercial and/or industrial sector customers to determine their plans for operations, expansion or other changes? If so, please provide a narrative describing the program and summaries of the results for 2008, 2009, 2010, 2011 and 2012.

RESPONSE:

The Company employs a small Key Account Management group to address the electric utility service needs of its large commercial and industrial customers. Key Account Management provides the primary point of contact with large commercial and industrial customers and is tasked with fostering and maintaining positive relationships while ensuring proper regulatory compliance. While the Company does not have a formal process to survey its commercial and industrial customers, TEP uses this information in its load forecasting and planning processes, but does not keep the results of such discussions (or the information is provided confidentially to TEP by its customers and may not be released without their prior permission).

RESPONDENT:

David Couture

WITNESS:

David Hutchens

STF 1.007

Background: Does the Company perform appliance saturation studies for any customer classes? If so, please provide a narrative description of the process and results beginning January 1, 2008 through 2012.

RESPONSE:

The Company has not completed any specific appliance saturation studies by customer class for the periods January 2008 through 2012. However, a 2010 Targeted Baseline Study for EE was completed by Navigant Consulting, which included appliance saturation data for surveyed homes and businesses. The Company utilized the baseline study in the design, evaluation, and planning for its EE Programs. The study will be made available upon request.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

STF 1.041

Rate Design: Please provide any studies, investigations, analyses or reviews performed by or for the Company that considered, evaluated or reviewed the income distribution versus consumption by rate schedule.

RESPONSE:

The Company has not evaluated or reviewed the income distribution versus consumption by rate schedule.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

STF 1.031

Cost of Service: Please provide in an Excel worksheet the coincident peak (CP), non-coincident peak (NCP), energy sales (both as metered and corrected to a common generation voltage) and number of customers for each month beginning January 2008 through the present for the Company as a whole and for each of the retail customer classes (as shown on Schedules G-1 and G-2).

RESPONSE:

The file Average & Peaks Allocation 12-31-11.xls supports the coincident peak demand and non-coincident peak demand for the Company and all rate classes for the test year. That file was provided in the revised response to UDR 1.1 dated August 17, 2012, in subfolder "Schedule G & H Support\5. Load Research". The Company peak demand is in the attached file STF 1.031.pdf, Bates Nos. TEP\014883-014885 for 2008 through 2010, source FERC Form 1.

The NCP data has been compiled for the test year for allocation purposes and is not readily available for the years 2008 through 2010, nor is available with forecast assumptions for calendar years 2012 through 2014.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tucson Electric Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2010	End of 2009/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	1,096,394	381,751	1,469	29	0800
30	February	969,897	336,566	1,476	27	0800
31	March	1,028,086	332,268	1,399	31	2000
32	April	1,057,331	358,395	1,845	30	1700
33	May	1,326,288	408,222	2,193	29	1700
34	June	1,398,744	450,260	2,492	7	1600
35	July	1,576,756	413,664	2,670	30	1600
36	August	1,547,599	406,860	2,725	31	1600
37	September	1,302,396	340,573	2,330	30	1600
38	October	1,123,406	342,189	1,921	30	1600
39	November	1,132,957	436,021	1,598	28	1600
40	December	1,119,845	432,954	1,598	1	1800
41	TOTAL	14,679,699	4,639,723			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tucson Electric Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2011	End of 2010/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are *not* physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	1,011,116	320,464	1,614	25	1400
30	February	956,765	385,485	1,491	10	2000
31	March	995,341	260,947	1,466	10	800
32	April	966,844	270,994	1,548	27	1600
33	May	1,066,816	275,102	1,996	28	1600
34	June	1,348,014	361,383	2,610	30	1600
35	July	1,539,073	403,240	2,848	15	1600
36	August	1,534,300	409,249	2,695	12	1600
37	September	1,388,957	388,320	2,520	20	1600
38	October	1,201,832	418,873	2,328	1	1600
39	November	1,092,684	408,369	1,568	30	800
40	December	1,086,249	383,035	1,607	31	1900
41	TOTAL	14,187,991	4,285,461			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Tucson Electric Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/18/2009	End of 2008/Q4

MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	1,228,526	483,681	1,399	18	800
30	February	1,034,742	349,236	1,389	5	800
31	March	1,126,815	433,156	1,247	25	2000
32	April	1,136,521	406,453	1,544	29	1700
33	May	1,335,306	509,330	2,030	20	1700
34	June	1,697,128	637,024	2,666	16	1600
35	July	1,625,934	532,219	2,600	1	1600
36	August	1,577,224	473,460	2,650	1	1600
37	September	1,452,260	470,836	2,285	5	1600
38	October	1,309,196	538,340	2,039	1	1600
39	November	1,182,933	485,902	1,633	1	1600
40	December	1,239,090	517,587	1,452	15	1900
41	TOTAL	15,945,675	5,837,224			

STF 1.077

Rate Design: Please provide the loss study used for the "losses associated with the voltage level of service" considered by Black & Veatch and/or the Company. [DesLauriers Direct 23:17]

RESPONSE:

Neither Black & Veatch nor the Company conducted a loss study. Black & Veatch computed a high voltage (138+kv) and all other (low voltage) (<138kv) loss factor using existing loss data supplied by the Company and back-solving using other known factors. Black & Veatch first converted monthly loss data (provided by the Company) for power delivered at 345kv to monthly factors expected at 138kv. Black & Veatch then solved for monthly low voltage delivery factors using forecasted generation and load by month for system, high voltage customers, and system losses. Black & Veatch computed these factors so that the weighted average of high-voltage losses and all other (low-voltage) losses produce the average forecasted retail sales level losses across the system. Please refer to the direct testimony of David F. DesLauriers at page 33, lines 19-21. Please also refer to Exhibit 8, page 2 of 6 for a derivation of these loss factors.

RESPONDENT:

David F. DesLauriers

WITNESS:

David F. DesLauriers

STF 1.037

Cost of Service: Has the Company performed any marginal cost studies in contrast to embedded cost studies? If so, please provide a summary of each study.

RESPONSE:

The Company has not performed any marginal cost studies. The Company did use its embedded CCOSS for its rate design proposals included in this application in a manner similar to that filed in its previous rate applications. The CCOSS, with all work papers in tact was provided in the revised response to UDR 1.1 dated August 17, 2012, as the file Schedule G.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

WORKPAPERS:

UDR 1.1

Workpapers. Please provide a complete set of supporting workpapers for all schedules, analysis, calculations and witness testimony in TEP's filing. Provide all in Excel format with formulas and cross references intact where applicable.

SUPPLEMENTAL RESPONSE: July 16, 2012

Please see original response provided to Commission Staff on July 13, 2012. Additionally, please see the file DeConcini – Direct Workpapers-Confidential.pdf, Bates Nos. TEP\014755 to TEP/014845 on the enclosed CD.

Bates Nos. TEP\014755 to TEP/014845 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

RESPONDENT:

Regulatory Services

SUPPLEMENTAL RESPONSE: September 7, 2012

Please see original response provided to Commission Staff on July 13, 2012. Additionally, please see the following files:

- LFCR POA Schedules.xls for the electronic version of Schedules 1 through 5 of Mr. Craig A. Jones's Lost Fixed Cost Recovery Plan of Administration, as proposed in Exhibit CAJ-5 to his direct testimony; and
- 8. Annual Bill Impacts CAJ-1 corrected (2).xls for the electronic version of Exhibit CAJ-1 to Mr. Jones' direct testimony.

Please note that the file A1. Mic Service Revenue 12-31-10.xls was mistakenly included in UDR 1.1 and has been deleted from TEP's data room.

RESPONDENT:

Regulatory Services

ANNUAL BILL IMPACTS PROPOSED COMPARED TO CURRENT RATES WITH CURRENT PPFAC

Line No.	Class Description	Customer Counts To-date 5/2012	New Summer A	Summer Change B	Total Summer Change C=(B*5)	New Winter D	Winter Change E	Total Winter Change F=(E*7)	Annual Bill G=(A*5+D*7)	Annual Bill Change H=(C+F)	Revised Percent Chang to Total Bill
1	Residential R-01	330,848	$117.78	$16.63	$83.17	$60.61	$6.01	$42.06	$1,013.16	$125.23	14.1%
2	Residential Lifeline R-04-01	819	$91.33	$19.47	$97.33	$48.46	$8.71	$60.98	$795.87	$158.31	24.8%
3	Residential Lifeline R-05-01	1,722	$91.33	$9.88	$49.42	$48.46	$3.03	$21.24	$795.87	$70.66	9.7%
4	Residential Lifeline R-08-01	1,046	$91.33	$29.05	$145.24	$48.46	$11.55	$80.86	$795.87	$226.10	39.7%
5	Residential Lifeline R-06-01	13,376	$107.78	$19.95	$99.77	$50.61	$1.83	$12.81	$893.16	$112.58	14.4%
6	Residential TOU R-21F	2,366	$110.51	$17.38	$86.91	$62.30	$18.27	$127.92	$988.66	$214.83	27.8%
7	Residential Lifeline R-04-21F	4	$86.63	$24.11	$120.54	$50.48	$19.89	$139.21	$786.49	$259.75	49.3%
8	Residential Lifeline R-05-21F	4	$86.63	$15.77	$78.86	$50.48	$15.52	$108.62	$786.49	$187.48	31.3%
9	Residential Lifeline R-08-21F	9	$86.63	$32.44	$162.22	$50.48	$22.07	$154.51	$786.49	$316.73	67.4%
10	Residential Lifeline R-06-21F	25	$100.51	$25.14	$125.72	$52.30	$16.60	$116.22	$868.66	$241.94	38.6%
11	Residential TOU R-70F	4,010	$110.51	($9.04)	($45.21)	$62.30	$25.02	$175.16	$988.66	$129.95	15.1%
12	Residential Lifeline R-04-70F	6	$86.63	$17.86	$89.30	$50.48	$18.76	$131.33	$786.49	$220.63	39.0%
13	Residential Lifeline R-05-70F	16	$86.63	$8.69	$43.45	$50.48	$14.23	$99.61	$786.49	$143.06	22.2%
14	Residential Lifeline R-08-70F	24	$86.63	$27.03	$135.14	$50.48	$21.03	$147.19	$786.49	$282.33	56.0%
15	Residential Lifeline R-06-70F	109	$100.51	$16.81	$84.06	$52.30	$14.99	$104.96	$868.66	$189.02	27.8%
16	Residential R-201AF	4,617	$110.48	$1.14	$5.69	$57.57	$13.07	$91.50	$955.38	$97.19	11.3%
17	Residential Lifeline 05- 201AF	3	$85.86	$28.94	$144.71	$46.18	$3.56	$24.89	$752.54	$169.60	29.1%
18	Residential Lifeline 08- 201AF	12	$85.86	$42.33	$211.66	$46.18	$11.55	$80.84	$752.54	$292.50	63.6%
19	Residential Lifeline 06- 201AF	336	$100.48	$41.52	$207.58	$47.57	$2.29	$16.05	$835.38	$223.63	36.6%
20	Residential R-201BF	473	$101.27	$2.39	$11.94	$48.46	$11.00	$76.97	$845.55	$88.91	11.8%
21	Residential Lifeline 05- 201BF	0	$81.95	$2.94	$14.71	$48.35	$19.06	$133.39	$748.24	$148.10	24.7%
22	Residential Lifeline 06- 201BF	12	$94.27	$9.32	$46.59	$49.47	$20.85	$145.94	$817.66	$192.53	30.8%
23	Residential Water Heating R-02	1,947	$15.16	$2.10	$10.52	$7.58	($1.50)	($10.48)	$128.89	$0.04	0.0%
24	Residential Time-of-Use R-21 Frozen	2,366	$110.51	$17.38	$86.91	$62.30	$18.27	$127.92	$988.66	$214.83	27.8%
25	Residential Time-of-Use R-70 Frozen	4,010	$110.51	($9.04)	($45.21)	$62.30	$25.02	$175.16	$988.66	$129.95	15.1%
26	Residential TOU 70N-B	226	$110.51	$22.97	$114.84	$62.30	$4.77	$33.39	$988.66	$148.23	17.6%
27	Residential TOU 70N-C	684	$110.51	$17.53	$87.64	$62.30	$5.50	$38.52	$988.66	$126.16	14.6%
28	Residential TOU 70N-D	485	$110.51	$17.68	$88.42	$62.30	$4.49	$31.45	$988.66	$119.87	13.8%
29	Residential TOU 201AF	4,617	$110.48	$1.14	$5.69	$57.57	$13.07	$91.50	$955.38	$97.19	11.3%
30	Special Residential Service 201AN	6,059	$110.48	($18.29)	($91.45)	$57.57	$18.11	$126.77	$955.38	$35.32	3.8%
31	Residential TOU 201BF	473	$101.27	$2.39	$11.94	$48.46	$11.00	$76.97	$845.55	$88.91	11.8%
32	Residential TOU 201CF	151	$71.16	($2.76)	($13.81)	$40.73	$20.84	$145.89	$640.92	$132.08	26.0%
33	Special Residential Service 201BN	58	$104.27	$3.43	$17.14	$59.47	$17.77	$124.37	$937.66	$141.51	17.8%
34	Special Residential Service 201CN	18	$104.27	$36.48	$182.40	$59.47	$17.29	$121.01	$937.66	$303.41	47.8%
35	General Service GS-10	34,921	$595.79	$63.61	$318.07	$388.34	$19.00	$133.01	$5,697.31	$451.08	8.6%
36	General Service PS-40	793	$1,537.83	$238.98	$1,194.88	$1,100.53	$129.69	$907.80	$15,392.86	$2,102.68	15.8%

ANNUAL BILL IMPACTS PROPOSED COMPARED TO CURRENT RATES WITH CURRENT PPFAC

Line No.	Class Description	Customer Counts To-date 5/2012	New Summer A	Summer Change B	Total Summer Change C=(B*5)	New Winter D	Winter Change E	Total Winter Change F=(E*7)	Annual Bill G=(A*5+D*7)	Annual Bill Change H=(C+F)	Revised Percent Change to Total Bill
1	Mobile Home Park Service C-11	340	$956.20	$156.04	$780.20	$1,061.39	$124.10	$868.72	$12,210.76	$1,648.92	15.6%
2	Municipal Interruptible WP Service PS-45	123	$1,503.36	$300.38	$1,502	$955.59	$32.57	$228	$14,206	$1,729.91	13.9%
3	Interruptible Agricultural Pumping C-31	38	$1,485.36	$336.76	$1,683.80	$937.59	($69.24)	($484.65)	$13,989.96	$1,199.15	9.4%
4	Municipal Water Pumping Service PS-43	414	$2,198	$333	$1,666	$1,576	$116	$813	$22,019	$2,479.33	12.7%
5	SGS Time of Use SGS-76F	814	$1,521.58	$265.85	$1,329.27	$1,030.81	$272.84	$1,909.90	$14,823.61	$3,239.17	28.0%
6	SGS Time of Use SGS-76N	105	$1,521.58	$180.93	$904.67	$1,030.81	$36.76	$257.29	$14,823.61	$1,161.96	8.5%
7	LGS Time of Use LGS-85AF	16	$8,429.21	($7,776.60)	($38,882.99)	$11,698.81	$304.11	$2,128.78	$124,037.75	($36,754.21)	-22.9%
8	LGS Time of Use LGS-85F	8	$14,757.36	($667.88)	($3,339.42)	$11,698.81	$1,791.31	$12,539.14	$155,678.48	$9,199.72	6.3%
9	LGS Time of Use LGS-85N	72	$12,934.17	$1,460.42	$7,302.09	$10,416.40	$1,409.12	$9,863.83	$137,585.63	$17,165.92	14.3%
10	Large General Service I-13	523	$16,721.47	$870.61	$4,353.04	$13,895.57	$1,744.37	$12,210.62	$180,876.32	$16,563.66	10.1%
11	Large Light & Power I-14	4	$568,236.23	$55,063.49	$275,317.47	$431,240.00	$69,440.00	$486,080.00	$5,859,861.16	$761,397.47	14.9%
12	LLP Time of Use I-90F Frozen	4	$290,039.47	($12,400.27)	($62,001.33)	$259,041.39	$15,217.31	$106,521.16	$3,263,487.09	$44,519.83	1.4%
13	LLP Time of Use I-90AF Frozen	2	$290,039.47	($20,808.98)	($104,044.90)	$259,041.39	($7,081.41)	($49,569.84)	$3,263,487.09	($153,614.74)	-4.5%
14	LLP Time of Use I-90N	4	$281,465.24	$13,264.22	$66,321.08	$252,410.12	$57,250.87	$400,756.10	$3,174,197.05	$467,077.18	17.3%
15	Mining		$2,794,852	($65,980)	($329,900)	$2,500,836	$559,972	$3,919,803	$31,480,111	$3,589,903.02	12.9%
16	Traffic Signal and Street Light Service PS-41	1,285	$209.15	$60.36	$302	$164.31	$15.51	$109	$2,196	$410.38	23.0%

Attachment _

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation
($000)

	(A)			(B)	(C)	(D)	(E)		(F) B x D x E
Line No.	Rate Schedule			Adjusted Test Year Billing Determinants	Units	Delivery Charge	Demand Stability Factor		Total Revenue
1.	Residential Service (R-01)			-	kWh	$	100%	$	-
2	Residential Service (R-80)			-	kWh	$	100%	$	-
3	Residential Service (R-201AN)			-	kWh	$	100%	$	-
4	Residential Service (R-201BN)			-	kWh	$	100%	$	-
5		subtotal		-	kWh	$		$	-
6									
7	Small General Service (GS-10)		1	-	kWh	$	100%	$	-
8	Small General Service (SGS-76)			-	kWh	$	100%	$	-
9		subtotal		-	kWh			$	-
10									
11	Large General Service (LGS-13)			-	kW	$	50%	$	-
12	Large General Service (LGS-13)			-	kWh	$	100%	$	-
13	Large General Service (LGS-85)			-	kW	$	50%	$	-
14	Large General Service (LGS-85)			-	kWh	$	100%	$	-
15		subtotal		-	kW	$		$	-
16		subtotal		-	kWh	$		$	-
17									
18	Large Light and Power (LLP-14)			-	kW	$	50%	$	-
19	Large Light and Power (LLP-14)			-	kWh	$	100%	$	-
20	Large Light and Power (LLP-90)			-	kW	$	50%	$	-
21	Large Light and Power (LLP-90)			-	kWh	$	100%	$	-
22		subtotal		-	kW	$		$	-
23		subtotal		-	kWh	$		$	-
24									
25	Total kW			-	kW	$		$	-
26	Total kWh			-	kWh	$		$	-
				-		$		$	-

note 1: Includes former Municipal PS-40 customers.

Robin Mitchell

From:	howard@energytactics.com
Sent:	Wednesday, January 09, 2013 2:21 PM
To:	Robin Mitchell
Subject:	Fwd: Follow-up to Conference Call on 9/25

Footnote 42 10/19

Begin forwarded message:

From: <jbryne@TEP.Com>
Subject: RE: Follow-up to Conference Call on 9/25
Date: October 19, 2012 11:35:31 AM EDT
To: <howard@energytactics.com>

Howard,

I know that Craig responded back to you on your first 2 questions, please see below for the response to your third question.

3 - Confirm that no load research by strata was available
Response:
No load research by strata is available.

Jessica Bryne
Regulatory Services
(520) 884-3680

-----Original Message-----
From: howard@energytactics.com [mailto:howard@energytactics.com]
Sent: Monday, October 15, 2012 6:34 AM
To: Bryne, Jessica
Cc: Robin Mitchell; Barbara Keene; Terri Ford
Subject: Follow-up to Conference Call on 9/25

Jessica

My notes indicate that during the call on the 25th that the Company said it would:

1- Determine if data for Lifeline customers (similar to H-5) was available and if so that would be sent out.

2 - Supplement STF 1.092 and provide calculations (including the supporting worksheet) for the LFCR proposal for 2012 through 2016 (as the DR asked for). This is important as it followed the discussion that the expected $36 million initial year value may be understated.

3 - Confirm that no load research by strata was available

I did receive your e mail confirming that the definitions supplemental and backup were not in the tariff, however I haven't seen responses to the other items.

Regards

Howard

AECC 11.4

In TEP's cost-of-service study, how are the costs of TEP's 46 kV facilities functionalized? Are these costs functionalized as non-EHV or primary? If these costs are functionalized as primary, please separately identify and allocate them in the Distribution Plant, Accumulated Depreciation, ADIT, and Distribution Expense accounts in Schedule G.

RESPONSE:

Distribution facilities include facilities that are below 138,000V which include 46,000V facilities and are not functionalized as non-EVH or primary cost.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

STF 1.083

Rate Design: Please provide any studies, investigations, analyses or reviews performed by or for the Company or known to the Company that measure how TOU rates are sending customers the appropriate price signals.

RESPONSE:

The Company has not conducted any such studies. The Company believes that TOU rates send customers appropriate price signals because they more closely track underlying cost causation aspects. A TOU differentiated PPFAC rate will more clearly communicate the true cost differences that exist to purchasing electricity between on and off peak periods. A non-TOU rate will not communicate this important cost difference; and in turn, customers will not have the information they need to make the most informed purchasing decisions. Please also refer to the direct testimony of David F. DesLauriers at page 29, lines 15-24 for additional support as to why TOU rates send appropriate price signals. The key element of any price signal is for proposed rates to reflect, to the extent practicable, the actual costs of the Company.

RESPONDENT:

David F. DesLauriers

WITNESS:

David F. DesLauriers

STF 1.003

Background: Please address how rate design (such as TOU) and/or demand management options are evaluated compared to generation and transmission options.

RESPONSE:

TEP evaluates demand management options or programs using a battery of costs test that compare the demand management options with the generation and transmission options/costs. Consistent with Decision No. 71819 (Electric Energy Efficiency Standard), the screening test is the societal cost test.

The societal cost test evaluates the benefits of the avoided supply costs of energy and demand, through the reduction in transmission and generation, valued at marginal costs for the periods when there is a load reduction due to the demand management program. The benefits are then compared to the costs of the program. For a more complete explanation of the analysis, please see Mr. Jones' direct testimony exhibit CAJ-7, the Energy Efficiency Resource Plan's Plan of Administration, Attachment A – Cost Effectiveness and Savings Assessment.

While mandated TOU rates (or other rates like super-peak rates, critical-peak rates, real-time pricing, et cetera) contribute to a reduction in systems peak needs, voluntary participation limits that benefit. The primary benefit of TOU rates is the potential reduction in fuel purchased or generated during peak periods. TOU rates are not as effective for peak cost reduction as other load control or demand management options.

RESPONDENT:

Denise Smith

WITNESS:

Craig A. Jones

STF 1.065

Rate Design: Please provide in an Excel worksheet (with all supporting inputs, data sources and information defined) the calculations supporting the changes to customers served under Partial Requirements Service rates. Specifically address the impact on these customers of varying usage levels and varying load factors and/or individual customers on each of the three rates. [Jones Direct 47:15]

RESPONSE:

Mr. Craig A. Jones direct testimony, page 47, lines 14 through 22, describes in detail the changes to the Company's proposed Partial Requirement Service ("PRS") tariffs. The workpaper supporting the new design changes for the PRS schedules are attached as file STF 1.065 TEP PRS Proposed rates.xls. There are currently no customers on any current PRS tariffs; therefore, the Company did not conduct any bill impact schedules for this class.

RESPONDENT:

Pricing (Brenda Pries)

WITNESS:

Craig A. Jones

	A	B	C	D	E	F	G	H	I	J
1	PARTIAL REQUIREMENTS TARIFFS									
2										
3	PRS-10									
4										
5			Adjusted Billing				Proposed PRS			
6			Determinants for Design Change	Proposed Rates	Proposed Revenues		Rates	SGS Inputed Demand from LR		
7	Small General Service SGS-10-NEW							Jan-11	297,496	
8	Customer Charge (Single Phase)		215,020	$18.00	$3,870,360.0			Feb-11	324,262	
9	Customer Charge (Three Phase)		212,653	$24.00	5,103,672		$20.98	Mar-11	457,989	
10	Summer							Apr-11	328,815	
11	First 500, kWh		74,822,676	$0.0760	5,686,523			May-11	474,000	
12	≥ 501 kWh		844,467,249	$0.0980	82,757,790		$35.02	Jun-11	597,542	
13	Winter							Jul-11	512,830	
14	First 500, kWh		105,220,676	$0.0560	5,892,358			Aug-11	440,175	
15	≥ 501 kWh		864,013,835	$0.0780	67,393,079			Sep-11	501,218	
16	Primary Metering Discount				($4,847.65)		$29.36	Oct-11	461,096	
17	Subtotal Delivery (Margin) Revenue				$170,698,935			Nov-11	338,956	
18	PPFAC Summer		919,289,925	$0.033075	30,405,514			Dec-11	288,155	
19	PPFAC Winter		969,234,510	$0.030654	29,710,915				5,022,035	
20	TOTAL SGS-10 NEW REVENUE		$1,888,524,435	$0	$230,815,364					
21	TOTAL SALES									
22										
23	PRS-13									
24										
25			Adjusted Billing							
26			Determinants for Design Change	Proposed Rates	Proposed Revenues					
27	LARGE GENERAL SERVICE LGS-13-NEW									
28	Customer Charge		6,420	$900.00	$5,778,000		$900.00			
29	ALL kW		3,277,079	$21.00	68,831,262	(0)				
30	Summer kWh		494,868,791	$0.0036	1,781,528	$28,679,693	$22.30			
31	Winter kWh		550,195,023	$0.0032	1,760,624	$40,151,570	$21.92	$22.08		
32	Primary Metering Discount				(35,628)					
33	Transformer Owned Discount				(27,317)					
34	Subtotal Delivery (Margin) Revenue				$78,088,470					
35	Base Power				-					
36	Summer kWh		494,868,791	0.033075	16,367,785					
37	Winter kWh		550,195,025	0.030654	16,865,678					
38	TOTAL LGS-13 REVENUE				111,321,933					
39										
40	PRS-14									
41	LL&P I-14									
42	LARGE LIGHT & POWER SERVICE									
43	Customer Charge		48	$2,000.00	$96,000.00		$2,000.00			
44	Demand per kW		775,035	$21.00	16,275,730	(0)				
45	Summer kWh		164,577,383	$0.0079	1,300,161	$6,781,554	$25.03			
46	Winter kWh		186,876,897	$0.0069	1,289,451	$9,494,176	$23.85	$24.34		
47	Power Factor Adjustment				-					
48	Subtotal Delivery (Margin) Revenue				$18,961,342					
49	Base Power									
50	Summer kWh		164,577,383	$0.030795	$5,068,161					
51	Winter kWh		186,876,897	$0.028540	5,333,467					
52	TOTAL GS-43 REVENUE				$29,362,969					

	K	L	M	N	O	P	Q	R
1								
2								
3								
4								
5								
6								
7	GENERAL SERVICE PRS-10 UNBUNDLE				LARGE GENERAL SERVICE PRS-13 UNBUNDLE			
8								
9	CUSTOMER DELIVERY	$5.62			CUSTOMER DELIVERY	$417.18		
10	CUSTOMER METERS	6.55			CUSTOMER METERS	$230.72		
11	CUSTOMER BILLING & COLLECTIONS	7.71			CUSTOMER BILLING & COLLECTIONS	$204.96		
12	CUSTOMER METER READING	1.10			CUSTOMER METER READING	$47.14		
13	Customer Charge ($/month)	$20.98			Customer Charge ($/month)	$900.00		
14								
15	Backup Service				Backup Service			
16	Summer Delivery ($/kW)	$11.63			Summer Delivery ($/kW)	$11.24		
17	Winter Delivery ($/kW)	$5.97			Winter Delivery ($/kW)	$10.86		
18	GenerationCapacity ($/kW)	$18.50			GenerationCapacity ($/kW)	$7.02		
19	Fixed Must Run ($/kW	$1.39			Fixed Must Run ($/kW	$0.92		
20	Transmission ($/kW)	$2.78			Transmission ($/kW)	$2.43		
21	Transmission Ancillary ($/kW)				Transmission Ancillary ($/kW)			
22	System Control & Dispatch	$0.04			System Control & Dispatch	$0.03		
23	Reactive Supply & Voltage Control	$0.15			Reactive Supply & Voltage Control	$0.13		
24	Regulation & Frequency Response	$0.14			Regulation & Frequency Response	$0.13		
25	Spinning Raserve Service	$0.39			Spinning Reserve Service	$0.34		
26	Supplemental Reserve Service	$0.06			Supplemental Reserve Service	$0.06		
27	Supplemental Service				Supplemental Service			
28	Summer Delivery ($/kW)	$5.82			Summer Delivery ($/kW)	$5.62		
29	Winter Delivery ($/kW)	$2.99			Winter Delivery ($/kW)	$5.43		
30	GenerationCapacity ($/kW)	$9.25			GenerationCapacity ($/kW)	$3.51		
31	Fixed Must Run ($/kW	$0.70			Fixed Must Run ($/kW	$0.46		
32	Transmission ($/kW)	$1.37			Transmission ($/kW)	$1.22		
33	Transmission Ancillary ($/kW)				Transmission Ancillary ($/kW)			
34	System Control & Dispatch	$0.02			System Control & Dispatch	$0.02		
35	Reactive Supply & Voltage Control	$0.08			Reactive Supply & Voltage Control	$0.07		
36	Regulation & Frequency Response	$0.07			Regulation & Frequency Response	$0.07		
37	Spinning Reserve Service	$0.19			Spinning Reserve Service	$0.17		
38	Supplemental Reserve Service	$0.03			Supplemental Reserve Service	$0.03		
39								
40	Backup Service				Backup Service			
41	Summer ($/kW)	$35.02	$0.00		Summer ($/kW)	$22.30	($0.00)	
42	Winter ($/kW)	$29.36	$0.00		Winter ($/kW)	$21.92	($0.00)	
43	Supplemental Servic3				Supplemental Servic3			
44	Summer ($/kW)	$17.51	$0.00		Summer ($/kW)	$11.15	($0.00)	
45	Winter ($/kW)	$14.68	$0.00		Winter ($/kW)	$10.96	($0.00)	
46								
47								
48								
49								
50								
51								
52								

	S	T	U
1			
2			
3			
4			
5			
6			
7	LARGE LIGHT & POWER PRS-14 UNBUNDLE		
8			
9	CUSTOMER DELIVERY	$929.66	
10	CUSTOMER METERS	$477.35	
11	CUSTOMER BILLING & COLLECTIONS	$487.16	
12	CUSTOMER METER READING	$111.88	
13	Customer Charge ($/month)	$2,000.00	
14			
15	Backup Service		
16	Summer Delivery ($/kW)	$12.30	
17	Winter Delivery ($/kW)	$11.12	
18	GenerationCapacity ($/kW)	$8.25	
19	Fixed Must Run ($/kW	$1.91	
20	Transmission ($/kW)	$2.00	
21	Transmission Ancillary ($/kW)		
22	System Control & Dispatch	$0.03	
23	Reactive Supply & Voltage Control	$0.11	
24	Regulation & Frequency Response	$0.10	
25	Spinning Reserve Service	$0.28	
26	Supplemental Reserve Service	$0.05	
27	Supplemental Service		
28	Summer Delivery ($/kW)	$6.15	
29	Winter Delivery ($/kW)	$5.56	
30	GenerationCapacity ($/kW)	$4.13	
31	Fixed Must Run ($/kW	$0.96	
32	Transmission ($/kW)	$1.00	
33	Transmission Ancillary ($/kW)		
34	System Control & Dispatch	$0.02	
35	Reactive Supply & Voltage Control	$0.06	
36	Regulation & Frequency Response	$0.05	
37	Spinning Reserve Service	$0.14	
38	Supplemental Reserve Service	$0.05	
39			
40	Backup Service		
41	Summer ($/kW)	$25.03	$0.00
42	Winter ($/kW)	$23.85	($0.00)
43	Supplemental Servic3		
44	Summer ($/kW)	$12.52	$0.00
45	Winter ($/kW)	$11.93	($0.00)
46			
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STF 1.093

Lifeline: Please provide a worksheet with all supporting information that calculates the cost of the Company's existing Lifeline discounts (subsidies) by each rate, rate block and foregone adjustors or other items. [Jones Direct 69:13 and 70:11]

RESPONSE:

Test year totals include $2.512 million (the Commission amount of $2.3 million excludes certain specified components of the discounts) of margin (non-fuel) related subsidies plus approximately $1.759 million of fuel cost related subsidies (on an annualized basis) plus $285,000 of avoided DSM related charges, for a total of $4.556 million of subsidies being paid by the remaining rate payers or the Company. Please see STF 1.093 Lifeline Discount Reports 2011.pdf, Bates Nos. TEP\015059-015070, for available information responsive to the requested discount amounts by rate class.

In addition to the above subsidies, approximately 4 hours each month are spent by pricing personnel to generate compliance reports. A minimum of 20 additional hours are spent each time any rate changes for bill testing and verification.

While the above charges can be quantified, the Company does not track all of the costs associated with each Lifeline Rate separately, nor are any of the costs tracked by rate block. Please see the table below for a partial list of administrative costs associated with the Lifeline Program. The Company does not consider the following list fully representative of the costs associated with monitoring and implementing the Lifeline program since many other man-hours associated with accommodating the Lifeline rates are not tracked separately but simply fall on the shoulders of other rate payers.

Lifeline	
Marketing/Brochures	2011 - $2,155 – reprint of English brochure 2010 - $1,600 – reprint of English brochure 2009 - $6,542 reprints of English and Spanish brochures 3-year average - $3,500
Administration (Applications, master metering reporting, gathering reporting data)	2011 - $47,000
Compliance administration	Average - $2,000
IT administration	Average - $7,200
Lifeline Medical administration (home visits, verification of applications)	Average - $65,000
TOTAL	**$124,700**

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

Tucson Electric Power - Lifeline Discounts

Jan-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$16,577.82	1,389,152
5010	TE5-01	$18,404.38	3,633,530
5016	TE6-01	$133,868.44	13,143,874
5026	TE8-01	$14,846.95	913,048
5008	TE4-21	$39.94	5,896
5012	TE5-21	$40.69	13,144
5017	TE6-21	$264.00	40,413
5027	TE8-21	$104.41	9,571
5009	TE4-70	$46.68	10,689
5013	TE5-70	$90.54	29,160
5022	TE6-70	$1,160.00	144,480
5028	TE8-70	$228.40	23,704
5014	TE5-201A	$2.97	5,100
5015	TE5-201B	$0.00	1,213
5023	TR6-201A	$3,022.01	458,957
5029	TE8-201A	$182.31	21,511
5024	TE6-201B	$112.00	15,429
5032	TE6-01BC	$0.00	-
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$188,991.54**	**19,858,871**
	Federal Reported Numbers	**$210,339.51**	**19,858,871**

228,513,105 KWh x .007696 = $1,758,637
228,513,105 Kwh x .001249 = 285,413
2,044,050

ACC 12 mo $2,331,842.19 delivery only
Fed 12 mo 2,511,852.19 delivery plus Cust Chg

Tucson Electric Power - Lifeline Discounts

Feb-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$16,045.63	1,163,463
5010	TE5-01	$19,947.34	2,949,061
5016	TE6-01	$134,318.14	11,087,112
5026	TE8-01	$13,633.45	761,351
5008	TE4-21	$44.33	3,975
5012	TE5-21	$42.86	10,731
5017	TE6-21	$256.00	31,662
5027	TE8-21	$84.09	7,329
5009	TE4-70	$59.03	9,591
5013	TE5-70	$100.18	21,137
5022	TE6-70	$1,151.43	114,439
5028	TE8-70	$221.97	19,432
5014	TE5-201A	$9.98	4,340
5015	TE5-201B	$4.97	851
5023	TR6-201A	$3,044.90	409,365
5029	TE8-201A	$175.87	18,085
5024	TE6-201B	$112.00	12,923
5032	TE6-01BC	$16.00	740
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	$189,268.17	16,625,587
	Federal Reported Numbers	$210,061.10	16,625,587

Tucson Electric Power - Lifeline Discounts

Mar-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$16,417.73	1,003,894
5010	TE5-01	$22,242.16	2,555,745
5016	TE6-01	$144,001.71	10,035,061
5026	TE8-01	$14,057.10	728,192
5008	TE4-21	$52.01	3,694
5012	TE5-21	$67.41	7,965
5017	TE6-21	$288.00	32,179
5027	TE8-21	$139.00	9,336
5009	TE4-70	$77.44	9,452
5013	TE5-70	$120.50	19,659
5022	TE6-70	$1,240.00	104,198
5028	TE8-70	$262.40	22,066
5014	TE5-201A	$8.35	3,780
5015	TE5-201B	$3.62	674
5023	TR6-201A	$3,094.18	345,213
5029	TE8-201A	$245.56	21,759
5024	TE6-201B	$112.00	10,712
5032	TE6-01BC	$32.00	2,160
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	$202,461.17	14,915,739
	Federal Reported Numbers	$224,368.05	14,915,739

Tucson Electric Power - Lifeline Discounts

Apr-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$15,070.60	816,363
5010	TE5-01	$21,978.40	2,268,920
5016	TE6-01	$134,579.35	9,031,204
5026	TE8-01	$12,985.71	666,045
5008	TE4-21	$43.97	2,721
5012	TE5-21	$67.96	7,298
5017	TE6-21	$264.00	25,177
5027	TE8-21	$93.07	6,078
5009	TE4-70	$75.85	5,733
5013	TE5-70	$121.61	17,712
5022	TE6-70	$1,159.27	88,851
5028	TE8-70	$224.55	14,784
5014	TE5-201A	$9.34	3,720
5015	TE5-201B	$4.38	791
5023	TR6-201A	$3,016.00	309,249
5029	TE8-201A	$187.96	16,631
5024	TE6-201B	$112.00	8,376
5032	TE6-01BC	$31.03	1,650
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$190,025.05**	**13,291,303**
	Federal Reported Numbers	**$210,567.82**	**13,291,303**

Tucson Electric Power - Lifeline Discounts

May-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$15,647.42	851,194
5010	TE5-01	$22,137.89	2,497,239
5016	TE6-01	$133,089.50	10,056,933
5026	TE8-01	$14,714.95	769,984
5008	TE4-21	$45.50	3,318
5012	TE5-21	$52.76	9,078
5017	TE6-21	$256.00	25,955
5027	TE8-21	$95.19	6,159
5009	TE4-70	$83.55	6,424
5013	TE5-70	$148.18	20,623
5022	TE6-70	$1,127.97	100,289
5028	TE8-70	$310.49	18,004
5014	TE5-201A	$8.60	4,330
5015	TE5-201B	$3.78	685
5023	TR6-201A	$2,990.83	338,186
5029	TE8-201A	$206.03	17,982
5024	TE6-201B	$112.00	9,414
5032	TE6-01BC	$39.07	2,410
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	$191,069.71	14,738,207
	Federal Reported Numbers	$214,814.97	14,738,207

Tucson Electric Power - Lifeline Discounts

Jun-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$18,159.44	1,167,918
5010	TE5-01	$21,214.01	3,342,542
5016	TE6-01	$138,107.74	14,058,291
5026	TE8-01	$18,549.21	1,075,231
5008	TE4-21	$73.85	5,893
5012	TE5-21	$58.28	13,044
5017	TE6-21	$272.00	33,455
5027	TE8-21	$118.56	7,887
5009	TE4-70	$120.63	10,579
5013	TE5-70	$147.28	30,828
5022	TE6-70	$1,206.15	152,418
5028	TE8-70	$490.75	31,971
5014	TE5-201A	$12.96	5,380
5015	TE5-201B	$5.20	733
5023	TR6-201A	$3,079.26	441,863
5029	TE8-201A	$273.47	22,639
5024	TE6-201B	$120.00	13,258
5032	TE6-01BC	$96.00	9,699
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	$202,104.79	20,423,629
	Federal Reported Numbers	$231,987.27	20,423,629

Tucson Electric Power - Lifeline Discounts

Jul-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$15,831.23	1,567,962
5010	TE5-01	$13,845.69	4,573,379
5016	TE6-01	$121,914.54	18,697,016
5026	TE8-01	$17,382.55	1,368,712
5008	TE4-21	$33.67	8,662
5012	TE5-21	$33.47	18,278
5017	TE6-21	$216.00	37,770
5027	TE8-21	$102.14	7,450
5009	TE4-70	$39.57	11,013
5013	TE5-70	$73.29	37,589
5022	TE6-70	$983.15	182,104
5028	TE8-70	$432.81	33,840
5014	TE5-201A	$7.79	7,770
5015	TE5-201B	$0.00	1,851
5023	TR6-201A	$2,863.63	598,745
5029	TE8-201A	$202.75	23,184
5024	TE6-201B	$104.00	18,508
5032	TE6-01BC	$80.00	11,427
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$174,146.28**	**27,205,260**
	Federal Reported Numbers	**$198,747.92**	**27,205,260**

Tucson Electric Power - Lifeline Discounts

Aug-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$16,723.80	1,493,665
5010	TE5-01	$14,439.93	4,467,801
5016	TE6-01	$144,360.56	20,390,465
5026	TE8-01	$21,347.59	1,549,565
5008	TE4-21	$54.43	9,722
5012	TE5-21	$24.10	15,484
5017	TE6-21	$280.00	52,040
5027	TE8-21	$171.84	12,623
5009	TE4-70	$123.57	14,807
5013	TE5-70	$105.13	38,600
5022	TE6-70	$1,246.37	226,922
5028	TE8-70	$613.93	51,381
5014	TE5-201A	$4.56	6,230
5015	TE5-201B	$0.00	2,180
5023	TR6-201A	$3,096.00	575,322
5029	TE8-201A	$381.81	34,086
5024	TE6-201B	$120.00	18,001
5032	TE6-01BC	$112.00	17,466
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$203,205.62**	**28,976,360**
	Federal Reported Numbers	**$230,946.34**	**28,976,360**

Tucson Electric Power - Lifeline Discounts

Sep-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$13,310.00	1,213,137
5010	TE5-01	$12,312.84	4,017,883
5016	TE6-01	$133,349.22	19,111,209
5026	TE8-01	$19,669.24	1,429,644
5008	TE4-21	$59.18	7,577
5012	TE5-21	$24.37	15,696
5017	TE6-21	$248.00	42,568
5027	TE8-21	$126.12	10,569
5009	TE4-70	$88.18	11,683
5013	TE5-70	$114.62	34,284
5022	TE6-70	$1,080.00	191,682
5028	TE8-70	$561.54	34,287
5014	TE5-201A	$4.64	6,800
5015	TE5-201B	$0.00	2,406
5023	TR6-201A	$3,020.90	601,809
5029	TE8-201A	$229.16	25,750
5024	TE6-201B	$112.00	18,405
5032	TE6-01BC	$96.00	15,428
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$184,406.01**	**26,790,817**
	Federal Reported Numbers	**$208,405.45**	**26,790,817**

Tucson Electric Power - Lifeline Discounts

Oct-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$11,353.72	700,970
5010	TE5-01	$15,112.62	2,501,695
5016	TE6-01	$128,241.99	12,716,551
5026	TE8-01	$17,817.53	994,868
5008	TE4-21	$32.39	3,629
5012	TE5-21	$27.49	6,744
5017	TE6-21	$264.00	32,934
5027	TE8-21	$109.48	7,009
5009	TE4-70	$78.16	6,801
5013	TE5-70	$105.53	22,404
5022	TE6-70	$1,024.00	118,403
5028	TE8-70	$462.09	24,826
5014	TE5-201A	$10.57	4,600
5015	TE5-201B	$0.00	1,793
5023	TR6-201A	$3,016.00	416,731
5029	TE8-201A	$225.31	20,531
5024	TE6-201B	$104.00	12,221
5032	TE6-01BC	$80.00	10,280
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$178,064.88**	**17,602,990**
	Federal Reported Numbers	**$201,016.71**	**17,602,990**

Tucson Electric Power - Lifeline Discounts

Nov-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$8,753.74	475,447
5010	TE5-01	$14,456.32	1,635,500
5016	TE6-01	$125,815.22	9,817,957
5026	TE8-01	$14,953.32	768,849
5008	TE4-21	$40.14	3,111
5012	TE5-21	$31.43	4,446
5017	TE6-21	$240.00	26,325
5027	TE8-21	$82.00	5,829
5009	TE4-70	$79.18	5,365
5013	TE5-70	$129.66	17,721
5022	TE6-70	$1,056.00	101,683
5028	TE8-70	$319.16	17,362
5014	TE5-201A	$8.70	4,050
5015	TE5-201B	$0.00	1,020
5023	TR6-201A	$3,006.96	340,974
5029	TE8-201A	$163.65	14,730
5024	TE6-201B	$112.00	10,723
5032	TE6-01BC	$88.00	9,271
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	**$169,335.48**	**13,260,363**
	Federal Reported Numbers	**$187,657.70**	**13,260,363**

Tucson Electric Power - Lifeline Discounts

Dec-11

Sub Account	Rate-ID	Amount	Usage_Cons
5002	TE4-01	$7,892.06	560,287
5010	TE5-01	$10,872.69	1,566,188
5016	TE6-01	$128,969.17	11,200,690
5026	TE8-01	$15,231.67	866,015
5008	TE4-21	$46.03	4,130
5012	TE5-21	$14.61	3,156
5017	TE6-21	$248.00	33,862
5027	TE8-21	$129.01	9,609
5009	TE4-70	$41.09	5,655
5013	TE5-70	$77.69	18,522
5022	TE6-70	$1,080.00	115,281
5028	TE8-70	$301.30	24,391
5014	TE5-201A	$9.21	4,030
5015	TE5-201B	$4.42	933
5023	TR6-201A	$2,943.49	370,482
5029	TE8-201A	$188.59	18,420
5024	TE6-201B	$112.00	11,334
5032	TE6-01BC	$112.00	10,994
5030	TE8-201B	$0.00	-
5025	NO CUSTOMERS		
5031	NO CUSTOMERS		
	ACC Reported Numbers	$168,273.03	14,823,979
	Federal Reported Numbers	$182,939.35	14,823,979

STF 1.094

Lifeline: Please provide a worksheet with all supporting information that calculates the cost of the Company's proposed Lifeline discounts (subsidies) by each rate, rate block and forgone adjustors or other items. [Jones Direct 69:13 and 70:11]

RESPONSE:

There will still be personnel costs associated with providing the Lifeline subsidies, but the Company has not attempted to quantify the total hours saved. As the rates become easier to explain and less confusing, less time will be needed modifying the billing system, testing new rates, developing complex data gathering programs for reporting purposes, speaking with customers, and training personnel. As the rates become less complicated and less time is required of the Company's personnel, the time and efforts will be redirected to additional or enhanced service to the customers.

The actual amount of subsidy built into the current rates is approximately the same as in the existing test year, except it is about 14% higher to reflect the 14% increase in residential rates. The new total can be found on lines 40 and 41 of the summary page of the file provided in the revised response to UDR 1.1 dated August 17, 2012, labeled 6. 2012 TEP Proposed Rates-Corrected, and total $2,605,960.

RESPONDENT:

Craig A. Jones

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY
SUMMARY PROPOSED REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

-5,924,009

Line No.	Rate Class	Adjusted Customers	Adjusted Sales (kWh)	Margin Revenue	Purchase Power & Fuel	Test Year Adjusted Revenue	Proposed Revenues: Margin Revenue ($)	Proposed Revenues: Purchase Power & Fuel	Proposed Revenues: Total Revenues
1	Proposed Increased								
2									
3									
4	Residential Service	360,521	3,699,107,059	$241,095,410	$111,635,462	$352,730,872	$292,058,299	$118,425,580	$410,483,879
5	Residential Time Of Use	8,873	129,923,963	7,043,984	3,797,665	10,841,649	8,741,564	4,388,547	13,130,111
6	Small General Service	35,978	1,947,489,380	156,798,459	55,398,880	212,197,338	173,512,315	62,017,156	235,529,471
7	Small General Service Time of Use	924	123,590,519	8,103,358	3,384,976	11,488,333	10,007,939	4,109,476	14,117,415
8	Irrigation & Water Pumping	484	107,584,687	4,446,839	2,908,651	7,355,490	5,424,053	3,248,547	8,672,601
9	Large General Service	536	1,046,539,305	55,085,198	30,598,384	85,683,582	83,968,872	33,283,559	117,252,430
10	Large General Service Time of Use	87	216,614,667	8,424,561	6,579,663	15,004,224	10,264,013	7,163,697	17,427,710
11	Large Light & Power Service	4	351,454,280	12,469,651	10,271,504	22,741,155	19,347,941	10,401,627	29,749,569
12	Large Light & Power Service Time of Use	9	542,786,937	17,883,872	13,900,001	31,783,872	22,816,280	16,041,271	38,857,551
13	Mining Service	2	1,083,071,404	30,374,675	29,264,219	59,638,894	42,277,383	31,928,918	74,206,301
14	Traffic Signals & Lighting Service	19,566	37,430,789	3,022,183	913,817	3,936,000	4,089,559	1,181,323	5,270,882
15	TOTAL	426,985	9,285,592,991	$544,748,189	$268,653,221	$813,401,411	$672,508,219	$292,189,701	$964,697,920
16									
17	Rate Schedule								
18	R-01 - Lifeline	19,858	190,498,193	$11,801,193	$5,712,319	$17,513,513	$15,284,739	$6,066,433	$21,351,173
20	R-01	327,921	3,364,805,199	223,461,936	102,007,849	325,469,785	269,512,527	107,542,327	377,054,854
21	R-02	1,985	3,727,106	185,953	109,756	295,709	231,353	117,461	348,815
22	R-201AF	4,943	69,035,331	3,588,889	2,061,241	5,650,130	4,784,167	2,196,272	6,980,440
19	R-201AF - Lifeline	352	4,797,453	235,965	143,480	379,445	333,717	152,620	486,337
23	R-201AN	5,462	62,392,149	3,306,229	1,927,235	5,233,464	4,483,748	1,987,709	6,471,457
24	**TOTAL RESIDENTIAL SERVICE**	**360,521**	**3,695,255,432**	**$242,580,166**	**$111,961,880**	**$354,542,046**	**$294,630,252**	**$118,062,823**	**$412,693,075**
25									
26	R-21F - Lifeline	51	601,680	$27,889	$17,837	$45,726	$42,235	$20,218	$62,453
27	R-70F - Lifeline	198	2,036,942	114,504	59,014	173,519	148,184	68,605	216,789
28	R-201BF - Lifeline	13	151,418	6,684	4,342	11,025	9,869	5,086	14,955
29	R-21F	2,411	40,511,249	1,929,952	1,222,077	3,152,029	2,687,368	1,367,656	4,055,023
30	R-70F	4,110	59,486,521	3,441,136	1,722,450	5,163,586	4,065,192	2,011,789	6,076,981
31	R-70N-B	202	2,721,591	179,745	80,748	260,493	188,692	92,078	280,770
32	R-70N-C	651	7,853,166	519,667	232,140	751,807	556,479	265,638	822,117
33	R-70N-D	452	5,786,727	382,164	171,439	553,603	405,243	195,779	601,022
34	R-201BF	494	7,561,541	333,854	214,871	548,725	462,088	253,954	716,041
35	R-201CF	205	2,211,821	103,121	66,786	169,907	145,393	74,107	219,500
36	R-201BN	58	847,816	39,443	25,350	64,793	52,370	28,495	80,864
37	R-201CN	27	153,489	7,999	4,773	12,772	12,459	5,143	17,601
38	**TOTAL RESIDENTIAL TOU SERVICE**	**8,873**	**129,923,963**	**$7,086,159**	**$3,821,825**	**$10,907,984**	**$8,775,571**	**$4,388,547**	**$13,164,118**
39									
40	Total Lifeline Discount Non-TOU			-1,484,756	-689,175	-2,173,931	-2,571,953		-2,571,953
41	Total Lifeline Discount TOU			-42,175	-24,160	-66,335	-34,007		-34,007
42	R-01 Community Solar		3,851,627	0	362,757	362,757		362,757	362,757
43	**TOTAL RESIDENTIAL SERVICE**	**369,394**	**3,829,031,022**	**$248,139,394**	**$115,433,127**	**$363,572,522**	**$300,799,863**	**$122,814,127**	**$423,613,990**

Robin Mitchell

From:	howard@energytactics.com
Sent:	Wednesday, January 09, 2013 2:16 PM
To:	Robin Mitchell
Subject:	Fwd: Exhibit 15 Part 4 of 4

Footnote 67 10/8

Begin forwarded message:

From: "howard@energytactics.com" <howard@energytactics.com>
Subject: Fwd: Exhibit 15 Part 4 of 4
Date: November 13, 2012 2:38:34 PM EST
To: Tracy Klaes <tklaes@blueridgecs.com>

The PRS footnote

Begin forwarded message:

From: <jbryne@TEP.Com>
Subject: RE: Exhibit 15 Part 4 of 4
Date: October 8, 2012 12:20:05 PM EDT
To: <howard@energytactics.com>

No they are not. Hopefully you just decided to take today off for Columbus' sake.

Jessica Bryne
Regulatory Services
(520) 884-3680

-----Original Message-----
From: howard@energytactics.com [mailto:howard@energytactics.com]
Sent: Friday, October 05, 2012 6:50 PM
To: Bryne, Jessica
Subject: Re: Exhibit 15 Part 4 of 4

Jessica

when I worked at Atlantic Electric we never got Columbus day off either. On the other hand the folks at the DC Commission this week were looking forward to their day off. As for me since I work for my self and have a home office just about anythings goes for Monday

Enjoy

BTW are the definitions specified anywhere in the tariff?

Regards

Howard

On Oct 5, 2012, at 8:23 PM, <jbryne@TEP.Com> wrote:

Howard,

Thanks for the well wishes, but I don't get that holiday off! Unbelievable I know. I hope you have a good one though.

Below are the definitions you requested in your meeting with Craig and Brenda.

Determination of Supplemental Service

Supplemental service shall be defined as demand and energy contracted by Customer to augment the power and energy generated by the Customer's generation facility.

Back-up/Standby Energy

Back-up energy shall be defined to be electric energy supplied by Company to replace power ordinarily generated by Customer's generation facility during unscheduled full and partial outages of said facility.

-Jessica

-----Original Message-----

From: howard@energytactics.com [mailto:howard@energytactics.com]

Sent: Friday, October 05, 2012 12:01 PM

To: Bryne, Jessica

Subject: Re: Exhibit 15 Part 4 of 4

Enjoy the holiday weekend!

On Oct 5, 2012, at 2:59 PM, <jbryne@TEP.Com> wrote:

Great thanks. I think I owe you a few more items, I will try to get them to you as soon as I can.

Jessica Bryne
Regulatory Services
(520) 884-3680

-----Original Message-----
From: howard@energytactics.com [mailto:howard@energytactics.com]
Sent: Friday, October 05, 2012 11:59 AM
To: Bryne, Jessica
Subject: Exhibit 15 Part 4 of 4

Part 4

Robin Mitchell

From: howard@energytactics.com
Sent: Wednesday, January 09, 2013 2:25 PM
To: Robin Mitchell
Subject: Fwd: TEP Water Pumping

Footnote 54 10/23

Last of Three

Begin forwarded message:

From: "howard@energytactics.com" <howard@energytactics.com>
Subject: Re: TEP Water Pumping
Date: October 23, 2012 6:05:08 PM EDT
To: <CJones@tep.com>
Cc: <BPries@tep.com>

Craig

Thank you for the quick response

regards

Howard

On Oct 23, 2012, at 5:27 PM, <CJones@tep.com> wrote:

Hi Howard,

Here are our responses to the water pumping questions you had this morning. As always feel free to follow up if you have additional questions.

Thanks.

Craig

> **From:** "howard@energytactics.com" <howard@energytactics.com>
> **Date:** October 23, 2012, 8:46:17 AM MST
> **To:** <CJones@tep.com>
> **Subject: TEP Water Pumping**

Craig

Schedule H-2-1 shows Interruptible Agricultural Pumping as being moved to Proposed Rate Schedule GS-43 and Municipal Water Pumping to GS-43. **Correct.**

Schedule H-2-2 shows Interruptible Agricultural Pumping as being moved to Proposed Rate Schedule GS-31 and Municipal Water Pumping to PS-43, 45. **The labeling should read Interruptible Agricultural Pumping proposed rate GS-43 and Municipal Pumping to GS-43.**

Can I presume that that Schedule H2-2 is incorrect? **Labels are incorrect in H2-2 and should be changed to reflect GS-43 as mentioned above.**

Your testimony includes Original Sheet No. 801 - Rate: GS-43 Water Pumping Service, but no PS-43, 45 or GS - 31. **This is correct, PS-43 and GS-31 are combined into the GS-43 rate proposed and will be applicable to all water pumping customers including the City of Tucson Water Utility and private water companies.**

However this Rate is available "...to the City of Tucson Water Utility and private water Companies..."

Questions
1- Are Interruptible Agricultural Pumping customers to be served on Rate GS-43? **Yes.**

2- Are there any minimum demand or minimum bills for these customers. **These minimum requirements are not in the current rates and were not proposed in this application.**

3 - Why is there no demand charges for this Rate? **None of these rates currently have a demand component and one was not proposed in this filing in lieu of all other changes.**

4 - For new customers on this rate will there be any analysis of construction costs versus expected or minimum revenue? **Yes, the existing line extension rules will be used to determine any customer contribution needed to make the addition of the new customer economically feasible.**

5 - Does any CIAC or other profitability test apply? **Yes, if required by the line extension policy.**

Regards

Howard

STF 1.096

Lifeline: Please explain why a customer must be requalified for the proposed Lifeline rate if they move from one service location to another? [Jones Direct 72:4]

RESPONSE:

In order to maintain accurate, up to date information on its customers, the Company requires Lifeline rate customers to re-qualify upon change of location. The financial status of a consumer periodically changes. A change of location can indicate a change in status; therefore, it provides an optimal time to verify if the consumer still qualifies for a discounted rate. In addition, the Company is obligated to its customers and to the Commission to ensure oversight of discount-rate programs.

RESPONDENT:

Lindy Sheehey

WITNESS:

Lindy Sheehey

STF 1.097

Lifeline: Please provide a narrative describing the requirements for the annual requalification for the proposed Lifeline rate for low-income, senior and/or medical. [Jones Direct 72:10]

RESPONSE:

On an annual basis, the Company mails a letter requesting Lifeline, low-income, senior and/or medical customers to re-qualify for special programs.

The Company's billing system provides a list of customers with special programs and/or discounts. Letters are manually generated and mailed to customers. Customers have up to 4 weeks to respond and provide the Company with an updated application.

This exercise allows the Company to maintain accurate records and provide discount programs to those who qualify, reduce fraud, remove discounts from accounts where the customer is deceased, and, if a customer is deceased, the process allows the Company to identify a potential change in consumer and update records.

The Company is obligated to its customers and to the Commission to ensure oversight of discount-rate programs.

RESPONDENT:

Lindy Sheehey

WITNESS:

Lindy Sheehey

STF 1.100

Miscellaneous Service Fees: Please provide an Excel worksheet and supporting information including determinants for each fee to support the existing value of $2,617,926. [Jones Direct 74:9]

RESPONSE:

Please see Income – Service Fees Late Fees.xlsm provided in the revised response to UDR 1.1 dated August 17, 2012, for the Company proposed changes to miscellaneous service fees.

RESPONDENT:

Pricing (Ashley Leschak)

WITNESS:

Craig A. Jones

TUCSON ELECTRIC POWER COMPANY
INCOME STATEMENT PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2010

ADJUSTMENT NAME	Misc Service Revenues - Service & Late Fees
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	March 7, 2012
PREPARED BY:	Ashley Leschak
CHECKED BY:	Brenda Pries
REVIEWED BY:	Craig Jones

		Total Company		ACC Jurisdictional	
FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT	DEBIT	CREDIT
451	Miscellaneous Service Revenues		$1,109,816		$1,109,816
	ENTRY TOTAL	$0	$1,109,816	$0	$1,109,816

Reason for Adjustment

To increase Miscellaneous Service Revenues (FERC 451) due to an increase to fees.

TUCSON ELECTRIC POWER COMPANY
SERVICE FEE ADJUSTMENTS
TEST YEAR ENDED DECEMBER 31, 2010

Line	SERVICE REVENUES	TY Fees	TY Revenue	Units	Proposed Fees	TY Revenue Impact
1	Establishment/Re-establishment of Service, service read only	$13.50	$1,557,576	115,376	$20.00	$749,944
2	-Regular Working Hours					
3	Establishment of Service Connect or Reconnect under usual operating procedures	$22.00	$699,235	31,783	$32.00	$317,834
4	-Regular Working Hours					
5	Establishment of Service Connect or Reconnect under usual operating procedures	$51.00	$297,483	5,833	$57.00	$34,998
6	-all hours other then Regular Working Hours					
7	Establishment of Service Connect or Reconnect under usual operating procedures	$71.00	$45,156	636	$78.00	$4,452
8	-Regular Working Hours - Three Phase Metering					
9	Establishment of Service Connect or Reconnect under usual operating procedures	$198.00	$16,830	85	$216.00	$1,530
10	-all hours other then Regular Working Hours - Three Phase Metering					
11	Customer Requested Meter Rereads (Includes Out of Cycle Reads)	$13.00	$494	38	$32.00	$722
12	Late Fee	1.5%			1.5%	$0
13	Metering Field Test	$144.00	$1,152	8	$186.00	$336
14	TOTAL TY ACTIVITY AND ADJUSTMENT TO SERVICE REVENUES		$2,617,926			$1,109,816

TUCSON ELECTRIC POWER COMPANY
TEST YEAR ACTIVITY - SERVICE FEES

CIS+	CC&B	Description	UNITS	Fee
	CONNECT	Connect Fee	27,617	$22.00
RES1	SC	Service Establishment Fee	112,317	$13.50
RECRS1	RCON	Reconnect Fee	4,166	$22.00
		Residential	**144,100**	
RECRSP	PREMRC	Premium (after hours) Reconnect F	5,809	$51.00
RECRSM	SPLMT	Special Reconnect Fee	-	$35.00
RECRST	SPECRC	Special Reconnect Fee	109	$150.00
RES1SP	SPECSC	Special Service Establishment Fee	7	$150.00
		Residential	**5,925**	
	CONNECT	Connect Fee	611	$71.00
RECGS1	RCON3	Reconnect Fee	25	$71.00
RECRSP	PREMRC	Premium (after hours) Reconnect F	84	$198.00
GS1	SC	Service Establishment Fee	3,059	$13.50
		Commercial	**3,779**	
GSP	PREMSC	Premium Connect Fee	24	$51.00
RECGSP	SPLMT	Premium Reconnect Fee	-	$35.00
RESP	PREMSC3	Premium (after hours) Connect Fee	1	$198.00
		Commercial	**25**	
REREAD	REREAD	Meter Reread Service Charge	38	$13.00
MTRTST	MTRTST	Meter Test Charge	8	$144.00

Data provided by CC&B

TUCSON ELECTRIC POWER COMPANY
METER REREADS & TESTING ACTIVITY

Customer Requested Rereads							XREREAD	Current Rate		
Single Phase Tech	$31.59	per read		0.50	read	$15.80				
TEP Supplied Vehicle	$4.87	per read		1.00	read	$4.87				
Call Center Representative	$4.28	per call	x	1.00	No. of calls =	$4.28				
Total Material				$0.00						
Total labor				$24.95						
Total Direct (Material & Labor)				$24.95						
Labor Overhead	0.00% x Labor						$0.00			
Materials Overhead	4.54% x Material						$0.00			
E&S	15.68% x (T.D. +O.H.)						$3.91			
A&G	12.07% x (T.D. + ENG. + O.H.)						$3.48			
Total Cost							$32.35	$13.00	($19.35)	$32.00

Meter Field Testing							XMTRTST			
Journeyman Metering Technician	$38.50	per hr.	x	2.00	hrs.	= $77.00				
Metering Services Scheduling Coordinato	$30.92	per hr.	x	0.33	hrs.	= $10.20				
Call Center Representative	$4.28	per call	x	1.00	No. of calls =	$4.28				
Total Material				$0.00						
Total labor				$87.20						
Total Direct (Material & Labor)				$87.20						
Labor Overhead	60.6% x Labor						$52.86			
Materials Overhead	0.00% x Material						$0.00			
E&S	15.68% x (T.D. +O.H.)						$21.97			
A&G	12.07% x (T.D. + ENG. + O.H.)						$19.56			
Total Cost							$185.87	$144.00	($41.87)	$186.00

TUCSON ELECTRIC POWER COMPANY
SERIVCE ESTABLISHMENT ACTIVITY

							2011 calc	Current Rate	net change	Proposed Charge
Service Establishment/Reestablishment - Service Reads Only (SES)						XSC				
SES Contract Fee	$6.00	per read		1.00	read	$6.00				
TEP Supplied Vehicle	$4.87	per read		1.00	read	$4.87				
Call Center Representative	$4.28	per call	x	1.00	No. of calls =	$4.28				
Total Material				$0.00						
Total labor				$15.15						
Total Direct (Material & Labor)				$15.15						
Labor Overhead	0.00%	x Labor					$0.00			
Materials Overhead	4.54%	x Material					$0.00			
E&S	15.68%	x (T.D. +O.H.)					$2.38			
A&G	12.07%	x (T.D. + ENG. + O.H.)					$2.12			
Total Cost							$19.64	$13.50	($6.14)	$20.00
Service Connect and Reconnect during regular working hours - Single Phase							XRCON			
Single Phase Metering Tech	$31.59	per hr.	x	0.50	hrs. =	$15.80	XCONNECT			
SES Administration	$27.14	per hr.	x	0.10	hrs. =	$2.71				
TEP Call Center Representative	$4.28	per call	x	1.00	No. of calls =	$4.28				
TEP Supplied Vehicle	$4.87	per read	x	0.50	per connect	$2.44				
Other direct Charges				$6.72						
Total labor				$18.51						
Total Direct (Material & Labor)				$25.23						
Benefits	0.00%	x Labor					$0.00			
PR FICA,FUTA,SUTA	4.54%	x Labor					$0.84			
Workers Comp	15.68%	x Labor					$2.90			
A&G	12.07%	x (T.D. + ENG. + O.H.)					$2.58			
Total Cost							$31.55	$22.00	($9.55)	$32.00
Service Connect and Reconnect all hours excluding regular working hours - Single Phase							XPREMSC			
Single Phase Metering Tech	$31.59	per hr.	x	1.00	hrs. =	$31.59	XPREMRC			
SES Administration	$27.14	per hr.	x	0.15	hrs. =	$4.07				
Call Center Representative	$4.28	per call	x	1.00	No. of calls =	$4.28				
TEP Supplied Vehicle	$4.87	per read	x	1.00	per connect	$4.87				
Other direct Charges				$9.15						

TUCSON ELECTRIC POWER COMPANY
SERIVCE ESTABLISHMENT ACTIVITY

			2011 calc	Current Rate	net change	Proposed Charge
Total labor		$35.66				
Total Direct (Material & Labor)		$44.81				
Benefits	0.00% x Labor		$0.00			
PR FICA,FUTA,SUTA	4.54% x Material		$1.62			
Workers Comp	15.68% x (T.D. +O.H.)		$5.59			
A&G	12.07% x (T.D. + ENG. + O.H.)		$4.98			
Total Cost			$57.00	$51.00	($6.00)	$57.00

TUCSON ELECTRIC POWER COMPANY
SERIVCE ESTABLISHMENT ACTIVITY

						2011 calc	Current Rate	net change	Proposed Charge
Service Establishment and Reestablishment regular working hours - Three Phase									
Metering Journeyman	$33.15 per hr.	x	1.00 hrs.	=	$33.15				
Metering Services Scheduling Coordinato	$22.26 per hr.	x	0.10 hrs.	=	$2.23				
Call Center Representative	$4.28 per call	x	1.00 No. of calls	=	$4.28				
Total Material			$0.00						
Total labor			$35.38						
Total Direct (Material & Labor)			$35.38						
Labor Overhead	60.6% x Labor					$21.45			
Materials Overhead	4.54% x Material					$0.00			
E&S	15.68% x (T.D. +O.H.)					$8.91			
A&G	12.07% x (T.D. + ENG. + O.H.)					$7.94			
Total Cost						$77.96	$71.00	($6.96)	$78.00

Service Establishment and Reestablishment all hours excluding regular working hours - Three Phase (Metering/Trou						XSPECRC	
Metering Journeyman	$49.73 per hr.	x	2.00 hrs.	=	$99.45	XSPECSC	
Metering Services Scheduling Coordinato	$22.26 per hr.	x	0.10 hrs.	=	$2.23		
Call Center Representative	$4.28 per call	x	1.00 No. of calls	=	$4.28		
Total Material			$0.00				
Total labor			$101.68				
Total Direct (Material & Labor)			$101.68				
Labor Overhead	60.6% x Labor					$61.64	
Materials Overhead	0.00% x Material					$0.00	
E&S	15.68% x (T.D. +O.H.)					$25.61	
A&G	12.07% x (T.D. + ENG. + O.H.)					$22.81	
Total Cost						$216.02	$198.00	($18.02)	$216.00

EXHIBIT HS-7 HAS BEEN REDACTED DUE TO CONFIDENTIAL INFORMATION

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

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 ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. E-01933A-12-0291

TESTIMONY

IN SUPPORT OF

THE SETTLEMENT AGREEMENT

HOWARD SOLGANICK

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

FEBRUARY 15, 2013

EXHIBIT
S-14

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ATTACHMENT

SUMMARY OF TESTIMONIES HS-1

EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291

My testimony details the background concepts and various rate design elements within the Settlement Agreement.

My testimony reviews the details and implementation of the Lost Fixed Cost Recovery ("LFCR") mechanism proposed in the Settlement Agreement and defined by the Plan of Administration.

I provide details of the LFCR mechanism; the sources of required data; how the initial year is recognized; that the sales reductions are documented by an existing process; how the annual calculations are made; the customer protections included; and the opportunity for review and compliance reporting.

I also compare the LFCR mechanism to revenue decoupling, highlighting that weather, business and other risks are not transferred to customers.

Staff recommends that the rate design and Lost Fixed Cost Recovery mechanism, as proposed in the Settlement Agreement, be adopted.

SECTION I - INTRODUCTION

Q. Please state your name, position and business address.

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc.

Q. Please summarize your qualifications and experience.

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning submetering and billing. I also previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 35 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have prepared and delivered expert testimony in utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand side management, capacity and system planning, regulatory issues and restoration after major outages.

I have also led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects

focused on the marketing, sale and delivery of retail energy, energy related products and services, and support services provided to utilities and retailers.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and have advised the Board of Directors of a public power utility consortium. For a period of four years I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and the Public Utilities Commission of Ohio. I also provided (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric and gas rate cases.

I have also been engaged to review utility performance before, during and after outages resulting from major storms including Hurricane Ike and the two major storms that affected New Jersey in 2011.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998, I was a Managing Consultant for AT&T Solutions. From 1990 to 1994, I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held progressively increasing positions of responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice and implementation in both New Jersey and Pennsylvania.

Q. Have you previously submitted testimony in regulatory proceedings?

A. Yes. In this proceeding I submitted testimony in regard to Lost Fixed Cost Recovery on December 21, 2012 and rate design on January 11, 2013.

I have also testified and/or presented testimony (summarized in Attachment HS-1) before the following regulatory bodies.

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission

- Michigan Public Service Commission
- Missouri Public Service Commission
- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

SECTION II – DIRECT TESTIMONY

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission").

Q. What is the purpose of your testimony?

A. My testimony supports the Settlement Agreement for Tucson Electric Power Company ("TEP" or "Company") filed by Staff on February 4, 2013, specifically the rate design and the Lost Fixed Cost Recovery ("LFCR") mechanism.

I describe the background and elements of the revenue allocation and rate design proposed to be implemented as a result of the Settlement Agreement.

My testimony also describes the operation of the LFCR mechanism adopted by the parties to the Settlement Agreement. I compare the LFCR mechanism to the generic concept of revenue decoupling; compare the risks transferred to customers and other aspects of decoupling a utility's revenues.

Rate Design

Q. How was the revenue allocation between the major rate classes determined?

A. In its testimony, the Company proposed the use of an Average and Peak ("A&P") methodology to allocate production plant (generation). Arizonans for Electric Choice & Competition ("AECC") proposed the use of an Average and Excess ("A&E") methodology. Kroger Company proposed a 100% demand 4 coincident peak methodology. In my rate design testimony, I highlighted that the Company was planning investments to meet future peak loads and to retain cost effective lower cost energy generation. This situation supports a cost allocation methodology that reflects methodologies such as A&E or A&P. During the settlement process the parties advocated for their methodologies and the revenue allocation in Attachment B of the Settlement Agreement was agreed upon. This revenue allocation also reflects the cost of service situation of the Small General Service class that had the highest return of any class.

Q. What are the major rate design concerns addressed in the Settlement Agreement?

A. At present, customers have a myriad of rates to choose from with the resulting costs to administer. The Company proposed the consolidation of a number of rates to reduce customer confusion and costs. The large number of currently available rates and the Company's proposal to consolidate those rates is well detailed in Exhibit CAJ-2 to Company witness Craig Jones' Direct Testimony. The Company also proposed to increase the customer charges, which would stabilize its revenue and reflect its cost structure.[1] For classes that have demand charges, the Company also proposed to increase demand charges for the same reason. Frozen rates were proposed to be eliminated and consolidated with other rate schedules.[2]

[1] Jones Direct 29:1
[2] Jones Direct 24:21

The Settlement Agreement includes the consolidation of rates to reduce customer confusion and decrease administration costs. It also unfreezes rates, raises customer charges, raises demand charges and increases the demand ratchet.

Q. Why are frozen rates created and what are the initial effects?

A. Rates are often frozen to shield a class or subclass from the effects of a rate increase. If "freezing" affects only a subclass of a rate schedule then that results in creation of an additional rate schedule with its attendant costs of administration. New customers starting service after a rate is frozen may not be eligible for the frozen rate creating a situation where two similar customers pay different rates for the same service.

Q. What are the longer term effects of frozen rates?

A. At the utility's next rate case, the subclass has an incentive to maintain its favored position even though costs may have increased for that subclass. Additionally, the process of merging the frozen rate back into an existing rate schedule often entails an above average increase for the subclass, which may be objectionable thus perpetuating the subclass. Members of the original subclass may move and no longer directly need the frozen rate but often the subclass requests that the frozen rate follow the customer not the location of the usage. Each of these situations causes the frozen rate to diverge from the original good intentions. In some cases, an exemption from an adjustor such as fuel and purchase power works against the subclass when costs decrease and the adjustor goes negative, but the subclass receives no benefit from the credit due to its previous exemption.

Q. What rate design changes for non-time of use ("TOU") residential customers are proposed in the Settlement Agreement?

A. The number of residential rates has decreased. The non-TOU Rate R-01 now includes a block at 501-1000 kWh, which better reflects the average customer's usage. The customer charge has been increased to $10.00 per month, which better matches rates to costs and serves to lower the LFCR adjustment. There are now five summer months rather than six. The existing Rate R-02 for water heating is now rolled into the Rate R-01. New Lifeline customers are eligible for a flat $9.00 per month discount up from $8.00.

The Rate R-201AN, for space and water heating customers, now includes a block at 501-1000 kWh. The customer charge has been increased to $10.00 per month, which better matches rates to costs and serves to lower the LFCR adjustment. There are now five summer months rather than six. New Lifeline customers are eligible for a flat $9.00 per month discount up from $8.00.

Q. What rate design changes for TOU residential customers are proposed in the Settlement Agreement?

A. To encourage adoption of TOU rates, a six-hour summer On-Peak period has been adopted and the shoulder period has been eliminated. The shorter summer On-Peak period offers customers more opportunities to shift load to off-peak periods.

The residential TOU Rate R-80 now includes a reduced Off-Peak energy charge for electric vehicle owners to encourage charging electric vehicles during off-peak hours instead of on-peak. To reduce costs, this rate does not require a separate meter for the electric vehicle.

Q. What rate design changes for Lifeline customers are proposed in the Settlement Agreement?

A. The Company had proposed to consolidate Lifeline customers within the standard residential rates. Staff supported this consolidation and sought to maintain the level of support for Lifeline customers. The complete consolidation could not be accomplished without excessive impacts on some Lifeline customers that did not reflect the average increase of a standard Rate R-01 customer. Therefore, separate Lifeline rates (and characteristics) continue to be available in order to preserve the benefits to existing Lifeline customers. For existing TOU Lifeline customers their TOU characteristics (periods and seasons) have not been changed. In a move toward consolidation, the Purchase Power and Fuel Adjustment Clause ("PPFAC") rate and the Demand Side Management ("DSM") surcharge will now apply to Lifeline customers.

New Lifeline customers can take service under Rates R-01 and R-201AN or TOU Rates R-80 and R-201BN and receive a flat $9.00 discount. Existing Lifeline customers that move are now considered new customers and transition to these "standard" rates and the flat $9.00 discount.

Q. How have residential customers that want to retain an analog meter been accommodated?

A. For residential customers that do not wish to have the benefit of automated meter reading ("AMR"), the residential rates offer the ability to retain an analog, non-AMR meter as long as the obsolete technology is economically available, but this rate also recognizes the additional costs that the customer's decision imposes on the Company. The additional charges for non-AMR metering encourage the Company and the customer to jointly reduce costs through self-meter reading.

Q. What rate design changes for small general service customers are proposed in the Settlement Agreement?

A. The customer charge has been increased and a number of rates have been consolidated.

Q. What rate design changes for municipal customers are proposed in the Settlement Agreement?

A. To reduce the impact on Rate PS-40 serving municipal customers, which will be served on Rate GS-10, a 'rate blocker" mechanism has been implemented to reduce the rates by 16.5% (except for the Customer Charge). This rate blocker is designed to ease the transition to Rate GS-10.

Q. What rate design changes for water pumping customers are proposed in the Settlement Agreement?

A. The customers of the present Rate GS-31 and Rate PS-43 will be consolidated within Rate GS-43 that also includes an interruptible option. Rate GS-43 customers are excluded from the LFCR mechanism.

Q. What rate design changes for large general service customers are proposed in the Settlement Agreement?

A. Customers on demand rates will also be consolidated, demand rates will be increased and the demand ratchet has been increased to 75%. These changes serve to reflect fixed costs, standardize the demand ratchet and for Rate LLP-14 and Rate LLP-90 the increase in demand charges allows for these customers to be excluded from the LFCR mechanism.

Q. What rate design changes for TOU non-residential customers are proposed in the Settlement Agreement?

A. To encourage adoption of TOU rates a six-hour summer On-Peak period has been adopted and the shoulder period has been eliminated. The shorter summer On-Peak period offers customers more opportunities to shift load.

Q. What tariff changes are proposed in the Settlement Agreement?

A. The treatment of non-residential customer deposits has been changed to provide a refund after two years similar to both UNS Gas, Inc. and Arizona Public Service Company ("APS").

Q. What protections are offered to customers that may be adversely affected by the new rate design?

A. Although the parties have explored the rate impacts of the new rate design and consolidation, the Company does not have an extensive customer research program in place. There is a possibility of unforeseen impacts to customers. The rate design portion of the Settlement Agreement is held open until July 1, 2014 to allow for the possible adjustment of specific tariffs to correct for unanticipated customer rate impacts that are determined to be inconsistent with the public interest, while not reducing the Company's non-fuel revenue requirement.

Q. Do you recommend the adoption of the rate design portion of the Settlement Agreement?

A. Yes. I recommend the adoption of the revenue allocation and rate design proposed within the Settlement Agreement as it not only has been accepted by the Signatories but also implements many of the rate design concepts proposed by Staff, other interveners and the

Company. These rate design concepts will reduce customer confusion, ease tariff administration, encourage the adoption of TOU rates and offer other benefits to customers.

Lost Fixed Cost Recovery

Q. Have you reviewed specific decoupled rate design proposals?

A. I have reviewed proposals for decoupled electric and gas rate designs in Delaware for the Staff of the Delaware Public Service Commission where I also assisted in the pre-implementation education process. I have also reviewed decoupling proposals by gas utilities and offered testimony in Maryland for the People's Counsel and in Michigan for the Attorney General. In addition, I assisted the Staff of the District of Columbia Public Service Commission in the evaluation and implementation of a decoupled rate design for delivery of electricity. I provided testimony and assisted in the development of the settlement that included rate design changes and the LFCR mechanism for APS on behalf of Staff.

Q. What is the purpose of the LFCR mechanism?

A. The LFCR mechanism is designed to provide recovery of the Test Year fixed costs that have been documented to be lost as a result of the Commission approved energy efficiency ("EE") and distributed generation ("DG") programs. These fixed costs are related to transmission and distribution revenue requirements that are collected in volumetric rates rather than in demand charges or a fixed charge such as the Customer Charge. The LFCR is designed to remove the disincentive against EE and DG that arises when the Company's sales are reduced by those programs.

Q. Please describe how the LFCR mechanism works.

A. The LFCR mechanism would begin on January 1, 2013 on a calendar year basis with the first LFCR surcharge expected on July 1, 2014.

After the Commission's decision in this case, the Company's compliance filing will define the values for the LFCR mechanism. The Lost Fixed Cost Rate is the allowed Distribution and Transmission Revenue divided by the test year billing determinants. Generation fixed costs are not included in the LFCR.

The annual LFCR process is initiated by the Company's Measurement, Evaluation and Research ("MER") of its EE program results. The Company's outside MER consultant studies each EE program and determines the level of energy sales reductions for each program during the preceding year. The Company uses the MER report to determine the sales reduction for the applicable rate schedules. The Company is metering the DG sales reductions. The sales reduction for the applicable DG is added to EE sales reduction and is called the Recoverable kWh Savings.

The Company will file its annual LFCR Adjustment for the previous calendar year by May 15th. This adjustment is the product of the Recoverable kWh Savings times the applicable Lost Fixed Cost Rate. That product is divided by the Applicable Company Revenues to determine the LFCR Adjustment. The Staff will perform its review of the compliance reports and other data including the MER. The LFCR adjustment would be applied to customer bills beginning July 1st, after Commission approval.

Q. Is there an option for those residential customers do not wish to be subject to the LFCR mechanism?

A. Residential customers that do not wish to be subject to the LFCR mechanism can select an alternate Customer Charge ("Lost Fixed Cost Recovery Fixed Charge option") within their existing rate schedule. After a trial period, the customer will have to remain on the alternate Customer Charge for at least 12 months. During the calculation of the LFCR Adjustment, the associated sales and revenues of these customers are excluded.

Q. Are there customer (rate) classes that will not be subject to the LFCR mechanism?

A. Yes. Lighting, water pumping and large light and power customers served under rate schedules PS-41 and PS-50, GS-43, and LLP-14 and LLP-90, respectively are excluded from the LFCR mechanism because these rate schedules have fixed charges and/or are not expected to be impacted by EE and DG programs. The demand charge in some of these rate schedules was increased to allow them to be excluded from the LFCR mechanism.

Q. Why are the other rate schedules subject to the LFCR mechanism?

A. The included rate schedules are expected to be impacted by EE and DG programs and have some or all of the fixed transmission and distribution costs collected by a volumetric rate.

Q. Why does the LFCR mechanism not include generation costs?

A. The Company's Integrated Resource Plan demonstrated that total sales are still expected to rise in the near future. The Company also has off-system and/or non-Commission jurisdictional opportunities to sell any excess energy, therefore, there is no need to include generation costs in the LFCR mechanism.

Q. Why does the LFCR mechanism not include the Customer Charge?

A. If a customer reduces its energy consumption in response to an EE or DG program, the customer is still responsible for paying the applicable Customer Charge. Therefore, there is no need to include the Customer Charge in the LFCR mechanism.

Q. Why does the LFCR mechanism recover only 50% of the distribution demand charge revenue?

A. If a customer reduces its energy consumption in response to an EE or DG program, it is unlikely that there will be a proportional reduction in the demand level. To recognize that there may be some demand reduction a 50% Demand Stability Factor is applied, which reduces the magnitude of the LFCR adjustment.

Q. Is there a cap on the LFCR mechanism?

A. Annual adjustments are limited to 1% and are estimated to be below that level for the next four years based on the expected level of EE and DG programs.[3] The EE and DG programs are subject to the Commission's annual review and approval process.

Q. How are the claimed EE sales reductions measured and verified?

A. A MER review is integral to a well-designed EE program. The Company's annual MER report will be used to estimate or measure the results of its energy efficiency programs. Good practice requires that the Company examine the effectiveness of each EE program. Over time new energy savings technologies become available, existing technologies become commonplace and some programs are found to have been poorly constructed or ineffective.

[3] Solganick Direct Exhibit HS-3

The MER process employs an outside party to study the performance of each EE program using various techniques and statistical methods. MER is a common and established practice.

Q. Does the LFCR mechanism increase the Company's revenue?

A. No. LFCR is limited to only the documented reduction of sales that occur after December 31, 2012. The mechanism provides the Company with revenues lost due to EE and DG programs. If no sales are lost there is no LFCR Adjustment.

Q. Does the LFCR mechanism provide additional revenue if the Company's sales decline due to weather?

A. No. Should weather conditions be normal, any sales reductions as a result are not included in the LFCR mechanism. Weather risk remains with the Company and its shareholders as it is now. The LFCR mechanism is focused on the measured sales reduction due to the EE and DG programs. These programs are those determined by the Commission to be cost effective and appropriate.

Q. Does the LFCR mechanism provide additional revenue if the Company's sales decline due to economic conditions?

A. No. Should economic conditions worsen, any resulting sales reductions are not recovered by the LFCR mechanism. Business risk remains with the Company and its shareholders as it is now.

Q. Does the LFCR remove the disincentive to the Company to engage in EE and DG programs and activities?

A. Yes. The LFCR mechanism provides a means to recover lost fixed costs that result from documented sales reductions due to EE and DG programs. From a revenue perspective, the Company is neutral.

Q. If the Company failed to achieve documented results from its EE and DG programs what is the effect of the LFCR mechanism?

A. If the Company's MER is unable to document sales reductions from its EE and DG programs, then the LFCR mechanism would produce a zero result and customers would see no impact for that period.

Q. How is revenue decoupling different from the LFCR mechanism?

A. As applied in some jurisdictions, generic revenue decoupling looks at a gross measure of sales reduction per customer and adjusts revenue levels to compensate for any changes. The sales reduction could be the result of weather, economic conditions, outages, price elasticity or the result of EE and DG programs.

Q. What risks are transferred from the utility to the customer if revenue decoupling is implemented?

A. The implementation of generic revenue decoupling usually transfers outage, weather and business risks to customers.

Q. Is transferring these risks to customers necessary to encourage a utility to pursue EE and/or DG programs?

A. No. While generic revenue decoupling will remove the perceived disincentives of EE and DG programs, the shift of other risks to customers is not necessary.

Q. Is the administration of revenue decoupling less costly than an LFCR mechanism?

A. No. There is no additional cost for the MER. The LFCR calculations use compliance filing values and annual sales data and are made once per year by the Company and reviewed by Staff.

Revenue decoupling requires similar sales data for its calculation. In some jurisdictions, the concern over the impact of weather has led to revenue decoupling implemented on a monthly basis, requiring additional calculations and reviews. If weather is excluded, then a weather normalization process must be applied to the sales data on a monthly basis, requiring additional algorithms, calculations and reviews. If outages are a concern, then a process has to be developed to reflect lost sales due to each applicable outage, which must be tracked and analyzed.

Q. What is your recommendation?

A. I recommend that the LFCR as proposed by the Settlement Agreement be adopted. The LFCR mechanism is the result of the input of a number of parties to this Settlement Agreement. It is designed to remove the Company's disincentive to pursue EE and DG programs due to sales reductions.

The lost fixed cost rate is determined as a result of the rate case and will be part of the compliance filing.

The existing MER evaluation process documents the sales reduction.

There is an option for residential customers that wish to exclude themselves from the LFCR mechanism. To further stabilize revenues, the demand rates of some of the excluded rate schedules have been increased.

The LFCR mechanism does not shift weather or business risks to customers; they remain with the Company and its shareholders.

There is a 1% annual cap on any increases resulting from the LFCR mechanism.

Reporting requirements have been defined. The calculations are defined and performed annually. There is a process to provide Staff with adequate time for the annual review.

The LFCR mechanism specified in the Settlement Agreement is very similar to the LFCR mechanism adopted for APS.

Q. **Does this conclude your testimony?**

A. Yes.

Testimony of Howard Solganick
Docket No. Docket No. E-01933A-12-0291

Arizona Corporation Commission
Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November 2011)
Client – Staff of the Arizona Corporation Commission
Scope – Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Testimony of Howard Solganick
Docket No. Docket No. E-01933A-12-0291

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Testimony of Howard Solganick
Docket No. Docket No. E-01933A-12-0291

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)
Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Testimony of Howard Solganick
Docket No. Docket No. E-01933A-12-0291

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2010-2166212 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

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 ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. E-01933A-12-0291

TESTIMONY

IN SUPPORT OF

THE SETTLEMENT AGREEMENT

STEVEN M. OLEA

DIRECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

FEBRUARY 15, 2013

EXHIBIT
S-15

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EXECUTIVE SUMMARY
TUCSON ELECTRIC POWER COMPANY
DOCKET NO. E-01933A-12-0291

Mr. Olea's testimony supports the adoption of the Settlement Agreement ("Agreement") as proposed by the Signatories in this case. This testimony describes the settlement process as open, candid, transparent and inclusive of all Signatories to this case. Mr. Olea explains why Staff believes this Agreement is in the public interest.

Mr. Olea's testimony recommends that the Commission adopt the Agreement as proposed.

SECTION I - INTRODUCTION

Q. Please state your name and business address.

A. Steven M. Olea, 1200 West Washington, Phoenix, Arizona, 85007.

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

A. I am employed by the Arizona Corporation Commission ("Commission") as the Director of the Utilities Division ("Staff").

Q. Please state your educational background.

A. I graduated from Arizona State University ("ASU") in 1976 with a Bachelors Degree in Civil Engineering. From 1976 to 1978 I obtained 47 graduate hours of credit in Environmental Engineering at ASU.

Q. Please state your pertinent work experience.

A. From April 1978 to October 1978, I worked for the Engineering Services Section of the Bureau of Air Quality Control in the Arizona Department of Health Services ("ADHS"). My responsibilities were to inspect air pollution sources to determine compliance with ADHS rules and regulations.

From November 1978 to July 1982, I was with the Technical Review Unit of the Bureau of Water Quality Control ("BWQC") in ADHS (this is now part of the Arizona Department of Environmental Quality ["ADEQ"]). My responsibilities were to review water and wastewater construction plans for compliance with ADHS rules, regulations, and Engineering Bulletins.

From July 1982 to August 1983, I was with the Central Regional Office, BWQC, ADHS. My responsibilities were to conduct construction inspections of water and wastewater facilities to determine compliance with plans approved by the Technical Review Unit. I also performed routine operation and maintenance inspections to determine compliance with ADHS rules and regulations, and compliance with United States Environmental Protection Agency requirements.

From August 1983 to August 1986, I was a Utilities Consultant/Water-Wastewater Engineer with the Division. My responsibilities were to provide engineering analyses of Commission regulated water and wastewater utilities for rate cases, financing cases, and consumer complaint cases. I also provided testimony at hearings for those cases.

From August 1986 to August 1990, I was the Engineering Supervisor for the Division. My primary responsibility was to oversee the activities of the Engineering Section, which included one technician and eight Utilities Consultants. The Utilities Consultants included one Telecommunications Engineer, three Electrical Engineers, and four Water-Wastewater Engineers. I also assisted the Chief Engineer and performed some of the same tasks as I did as a Utilities Consultant.

In August 1990, I was promoted to the position of Chief Engineer. My duties were somewhat the same as when I was the Engineering Supervisor, except that now I was less involved with the day-to-day supervision of the Engineering Staff and more involved with the administrative and policy aspects of the Engineering Section.

In April 2000, I was promoted to the position of one of two Assistant Directors of the Division. In this position, I assisted the Division Director in the policy aspects of the Division. I was primarily responsible for matters dealing with water and energy.

In August 2009, I was promoted to my present position as Director of the Utilities Division. In this position, I manage the day-to-day operations of the Utilities Division with the assistance of the Utilities Division Assistant Directors and oversee the management of the Division's Telecom & Energy Section, the Financial & Regulatory Analysis Section, the Consumer Services Section, the Engineering Section and the Administrative Section. In addition, I am responsible for making policy decisions for the Division.

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

A. The purpose of my testimony is to support the Proposed Settlement Agreement ("Agreement"). I will also provide testimony which addresses the settlement process, public interest benefits and general policy considerations.

Q. Did you participate in the negotiations that led to the execution of the Agreement?

A. Yes, I did.

Q. How is your testimony being presented?

A. My testimony is organized into six sections. Section I is this introduction, Section II provides discussion of the settlement process, Section III discusses the various parts of the Agreement, Section IV is a response to a letter from Commissioner Pierce, Section V identifies and discusses the reasons why the Agreement is in the public interest and Section VI addresses general policy considerations.

Q. Will there be other Staff witnesses providing testimony in this case?

A. Yes. Howard Solganick will be providing testimony to discuss rate design and the Lost Cost Fixed Recovery Mechanism.

SECTION II – SETTLEMENT PROCESS

Q. Please discuss the settlement process.

A. The settlement process was open, transparent and inclusive. All parties received notice of the settlement meetings and were accorded an opportunity to raise, discuss, and propose resolutions to any issue that they desired.

Q. Who participated in those meetings?

A. The following parties were participants in some or all of the meetings: Tucson Electric Power Company ("TEP" or "Company"); the Residential Utility Consumer Office ("RUCO"); the Arizona Investment Council ("AIC"); the Southwest Energy Efficiency Project ("SWEEP"), Cynthia Zwick, Arizona Public Service Company ("APS"), the Department of Defense on behalf of Federal Executive Agencies ("DoD"), Kroger Co. ("Kroger"), Freeport-McMoRan Copper & Gold Inc. ("Freeport-McMoRan"), Arizonans for Electric Choice and Competition ("AECC"), IBEW Local 1116 ("IBEW"), Southern Arizona Homebuilders Association ("SAHBA"), Southern Arizona Water Users Association ("SAWUA"), the Sierra Club ("Sierra"), Opower, Inc. ("Opower") Solar Energy Industries Association ("SEIA"), Arizona Solar Energy Industries Association ("AriSEIA"), EnerNOC, Inc. ("EnerNoc"), Vote Solar Initiative ("VSI") and Staff.

Q. Could you identify some of the diverse interests that were involved in this process?

A. Yes. The diverse interests included Staff, RUCO, TEP, investment council, consumer representatives, demand-side management ("DSM")/energy efficiency advocates, low-

income consumer advocates, renewable energy advocates, realtors, labor unions, large/industrial users, competitive power producers and the mines.

Q. Were there parties who chose not to execute the Agreement?

A. Yes. The Agreement was signed by all participants with the exception of SWEEP, APS and the Sierra Club.

Q. Was there an opportunity for all issues to be discussed and considered?

A. Yes, each party had the opportunity to raise and have its issues considered.

Q. Were the Signatories able to resolve all issues?

A. Yes, the Signatories were able to resolve and reach agreement on all issues.

Q. How would you describe the negotiations?

A. I believe that all participants zealously advocated and represented their interests. I would characterize the discussions as candid but professional. While acknowledging that not all participants executed the Agreement, I must re-emphasize that all participants had the opportunity to be heard and to have their issues fairly considered.

Q. Would you describe the process as requiring give and take?

A. Yes, I would. As a result of the varied interests represented in the settlement process, a willingness to compromise was necessary. As evidenced in the Agreement, the Signatories compromised on what could be described as vastly different litigation positions.

Q. Because of such compromising, do you believe the public interest was compromised?

A. No. As I will discuss later in this testimony, I believe that the compromises made by the Signatories further the public interest.

Q. Mr. Olea, you have indicated that the Agreement incorporates diverse interests including those of low-income customers, residential customers, large commercial/industrial customers, energy efficiency advocates, renewable energy advocates, the Company and the investment community. Please discuss how the Agreement addresses the diverse interests of these entities.

A. In the Agreement, there are specific provisions which address many of the concerns expressed by the various interests. For example, Sections VII and VIII, which address the interests of those concerned about promoting energy efficiency at any level or pace set by this Commission. Section IX addresses the Environmental Compliance Adjustor surcharge. Section X of the Settlement Agreement addresses Springville Unit 1. Section XI addresses the TEP energy procurement program. Section XII addresses the low-income customer issues. Section XIII addresses the Nogales Transmission Line, Section XIV addresses the San Juan thermal event (fire), Section XVIII addresses quality of service and Section XX addresses four issues raised by RUCO.

Q. What is the revenue increase and cost of equity requested by the Company?

A. TEP requested a net increase in non-fuel base rates of $128 million, which included a requested cost of equity of 10.75 percent.

Q. What is the revenue increase and cost of equity recommended by the settling Signatories?

A. The settling Signatories recommend a non-fuel base rate increase of approximately $76 million, which includes a 10.0 percent cost of equity.

SECTION III – AGREEMENT

Q. Mr. Olea can you please describe Part II of the Agreement?

A. Part II describes the recommended rate increase agreed to by the Signatories. In its application, TEP requested a non-fuel base rate increase of approximately $128 million; however, the Signatories agreed to an increase of approximately $76 million, which is $52 million less than the Company requested. In addition, the Signatories agreed to and recommended a base fuel rate be set for TEP in order to accord them the opportunity to recover $300,252,951, which result in an annual fuel increase of $31,599,730.

Q. Please describe Section III of the Agreement?

A. When the rates of this Agreement become effective, the monthly bill for a residential customer, using the annual average of 767 kilowatt-hour ("kWh") per month, will experience a first year increase of less than $3.00, which will include a rate reduction in the Purchased Power and Fuel Adjustment Clause ("PPFAC") and DSM Surcharge.[1]

Q. Please describe Section IV of the Agreement.

A. A capital structure comprised of 55.97 percent long-term debt, 0.53 percent short-term debt and 43.50 percent common equity is proposed. In addition, the Signatories recommended a return on common equity of 10 percent, an embedded cost of long-term debt of 5.18 percent and a cost of short-term debt of 1.42 percent. Also, the Signatories

[1] This includes the PPFAC and the DSM surcharge but does not include the REST surcharge, taxes or assessments.

proposed a fair value rate of return of 5.05 percent which includes a 0.68 percent rate of return on the fair value increment of rate base.

Q. Please describe Section V of the Agreement.

A. Signatories to the Agreement recommend the adoption of the depreciation and amortization rates proposed by TEP.

Q. Can you please describe Section VI of the Agreement?

A. Yes. This section deals with the Company's PPFAC. The Signatories agreed that the average retail base fuel rate shall be set at $0.032335 per kWh. This section also addresses the following:

- A one-time $3 million credit related to previous sulfur credits;
- A deferral of costs related to the San Juan thermal event, which is discussed in detail in Part XIV;
- Pursuant to the plan of administration, the Signatories agreed that the PPFAC will be modified to allow the recovery of the following costs and/or credits: brokers fees; lime cost; sulfur credits and 100 percent of proceeds from the sale of SO2 allowances;
- TEP will continue to file with the Commission annually a request to reset its PPFAC rate.

TEP has filed a request, in Docket No. E-01933A-07-0402, to defer implementation of this year's PPFAC rate reset until the effective date of the decision in this case.

Q. Can you please explain the deferral request?

A. Pursuant to the current PPFAC approved by the Commission in Decision No. 70628, TEP is required to reset its PPFAC rate annually on April 1st of each year. The Signatories to the Agreement believe that in order to avoid a rate yo-yo effect, and in order to offset the current increase with a reduction in the PPFAC, it is in the public interest to defer the annual adjustment until the effective date of new rates in this docket.

Q. Please describe Section VII of the Agreement.

A. This section describes how TEP will implement its energy efficiency ("EE") program ("Plan"). The Signatories agreed that on an ongoing basis, consistent with Staff's Direct Testimony, TEP will treat energy efficiency similar to a typical generation resource. The Company will invest its own capital in cost-effective energy efficiency measures that have been approved the Commission.

Q. Is this a departure from how Energy Efficiency programs are being treated today?

A. Yes.

Q. Can you please explain?

A. Pursuant to the rules at Arizona Administrative Code R14-2-2401 *et seq.*, electric utilities such as TEP are required to achieve energy savings by implementing cost-effective energy efficiency programs. The utilities are required to file an implementation plan with the Commission for Staff's review and Commission approval. Based on the utility's plan and Staff's recommendation, the Commission sets a budget and a surcharge (DSMS). This surcharge collects money to pay for the EE program before the EE program costs are incurred.

However, consistent with this Settlement Agreement, the Company will invest its own capital, just as TEP does with other typical generation resource. After providing documentation that the energy efficiency programs have been effective, TEP will be given the opportunity to recover the cost of its energy efficiency investment, to include the rate of return established in this case, through TEP's existing DSM adjustor mechanism. To that effect, the Signatories agree to the following:

- TEP will amortize annual energy efficiency investments under the plan over five years.
- TEP will resume funding of programs previously approved by the Commission beginning March 1, 2013, and shall request recovery of such costs through the plan.
- Upon the effective date of the rates in this case, TEP will begin investing in cost-effective DSM/EE programs pursuant to the Plan for the remainder of year 2013 based upon the Commission's approval of the Plan, which includes the programs and the annual budget (approximately $12 million on a pro rata basis assuming a July 1, 2013 start date) recommended by Staff in Staff's proposed order for TEP's 2011-2012 Energy Efficiency Implementation Plan filed in Docket No. E-01933A-11-0055 on November 16, 2011.
- Upon the effective date of the rates in this case and approval of the Plan, TEP will file a request to close Docket No. E-01933A-11-0055.
- Any customer who can demonstrate an active DSM program and whose single site usage is 25 MW or greater may file a petition with the Commission for an exemption from the DSM adjustor and, if approved, will be removed from the Energy Efficiency Standard denominator. The Signatories are not required to support any such petition and some Signatories may plan to oppose any such petition.

- Upon adoption of the Plan, the DSM surcharge will be assessed on a per kWh basis for residential customers and on a percentage of bill basis for non-residential customers. The current DSM surcharge for residential customers will be reset from $0.001249 per kWh to $0.000443 per kWh upon the effective date of the new rates in this case.

Q. Please explain the rationale behind the departure from the existing methodology.

A. Consistent with the Company's presentation at the Integrated Resource Planning Workshop, where the Company maintained that energy efficiency is one of the cheapest resources, Staff believes it is in the public interest to treat energy efficiency similar to other typical generation resources.

Q. Please describe Section VIII of the Agreement.

A. This section of the Agreement addresses energy efficiency, lost fixed cost recovery ("LFCR"), fixed residential rate option and large customer exclusion. As stated above, the Signatories believe and support energy efficiency as a low cost energy resource. In addition, Commission rules related to energy efficiency and distributed generation require and cause TEP to sell fewer kWh, which in turn, does not provide the Company with the opportunity to recover a portion of the fixed cost of service embedded in its volumetric rates. To that point, the Signatories believe that by adopting the LFCR mechanism (which includes a residential fixed monthly rate option), TEP will have the opportunity to recover a portion of its fixed cost of service and receive possible relief from the financial impact of verified lost kWh sales attributed to Commission requirements regarding energy efficiency and distributed generation.

Q. Please explain how the LFCR will be administered.

A. As a part of the Agreement, a Plan of Administration that details how the LFCR will be administered is included as an exhibit. In addition, consistent with the Agreement, TEP and the Signatories agree to the following:

- The LFCR shall recover a portion of the distribution and transmission cost associated with residential, commercial and industrial customers.
- It shall not recover the lost fixed cost attributed to generation and to other potential factors such as weather or general economic conditions.
- The LFCR will have 1 percent year-over-year cap.
- Any amount in excess of the 1 percent cap will be deferred.
- Residential customers shall have a fixed LFCR rate option.
- TEP shall implement a customer outreach program by February 1, 2014, and shall seek stakeholder input in developing this program.
- The LFCR will recover lost fixed cost on a calendar year basis beginning January 1, 2013; however, the first LFCR surcharge will not go into effect until July 1, 2014.

Q. Please explain Section IX of the Agreement.

A. TEP will implement an Environmental Compliance Adjustor ("ECA") for government mandated environmental controls. The ECA provides for the recovery of and return on capital investments and associated costs related to environmental investments made by TEP and not already recovered in base rates approved in this case or recovered through another Commission-approved mechanism. These investments or projects are designed to comply with established environmental standards required by federal, state, tribal, or local laws and regulations. TEP must demonstrate that any environmental control is

government mandated and is a reasonable and prudent option that was available to TEP at that time to meet such government mandate.

Q. Please explain Section X of the Agreement.

A. Currently, TEP is leasing Springerville Generating Station ("SGS") Unit 1; the lease is set to expire in January 2015. In order to ensure that the Commission obtain timely information on the status of SGS Unit 1 and to ensure that TEP has explored all options available to it when considering either to extend the lease, build a new generation resource, enter into a Purchase Power Agreement ("PPA") or other option, the Signatories agree that TEP will provide the following information to the Commission no later than July 31, 2014.

- Commitments made by TEP to purchase SGS Unit 1 or any agreement entered into by TEP to otherwise retain capacity rights to SGS Unit 1.
- Commitments made by TEP to purchase replacement generating resource, or any PPA entered into by TEP for replacement power.
- Commitments made by TEP to purchase the SGS Coal Handling Facilities or any agreement entered into by TEP to extend the Coal Handling Facilities lease.
- Estimated non-fuel revenue requirement associated with each commitment listed above, including the proposed rate treatment of any remaining balance of SGS leasehold improvements.

Q. Please describe Section XI.

A. This section deals with the Power Procurement Program. TEP agrees to adopt Staff's proposed modifications (except for the Risk Manager recommendation) to the Company's energy procurement program.

Q. Please explain Section XII of the Agreement.

A. Pursuant to Commission's Decision No. 59594, TEP set up a LIFE Fund of $4.5 million. The annual interest from the fund was used for the benefit of low-income customers. The Signatories agree that the LIFE fund should be eliminated and that TEP will make an annual contribution to the Arizona Community Action Association in the amount of $150,000 to fund the low income utility bill assistance program, commencing on September 1, 2013.

The Agreement will also limit Lifeline customers' increase to an amount that is generally reflective of the average monthly dollar increase of less than $3.00.

Q. Please explain Section XIII of the Agreement.

A. In its application, TEP was requesting rate recovery from the Commission for the cost related to the development of the transmission line from Tucson to Nogales; however, based on this Agreement, TEP agrees that it will seek recovery of those costs through the Federal Energy Regulatory Commission ("FERC").

Q. Please explain Section XIV of the Agreement.

A. In September 2011, there was a fire (thermal event) at the San Juan mine. Pursuant to this Agreement, TEP agrees to defer all the direct cost (except for the insurance deductible) related to the event until the insurance settlement has been completed. To that point, TEP agrees to the following:

- To maintain a separate accounting of all direct cost related to the event.
- That the estimated deferral cost is $9.7 million.
- That after a prudency review, TEP shall be eligible to put through all the prudent costs in excess of the insurance through the PPFAC.

Q. Please explain Section XVII of the Agreement.

A. The Signatories agree to eliminate the GreenWatts tariff. The Signatories believe that the recently approved Tucson Bright Solar project in the Renewable Energy Standard Implementation Plan is a substitute for the GreenWatts tariff.

Q. Please explain Section XVIII of the Agreement.

A. In order to maintain quality of service, TEP agrees to the following:

- Continue to evaluate reliability on the basis of distribution indices maintained at present levels.
- To initiate a study within 180 days of the effective date of the Decision to examine potential loss reductions and costs required to convert 4.16 kV circuits to 13.8 kV.

TEP also agrees to meet with Staff within 180 days of the effective date of the Decision to address the following:

- The possibility of increasing the pace of upgrading critical circuits in need of preventative maintenance.
- Establishment of a routine of periodic load flow analysis of its system and confirming the accuracy of utilized model.
- Equip feeder circuits with meters or other equipment so that power information can be relayed to Energy Management Service ("EMS") through Supervisory Control and Date Acquisition ("SCADA") to determine losses on a circuit by circuit basis.

Q. Please explain Section XIX of Agreement.

A. Pursuant to this section of the Agreement, TEP is requesting the elimination of certain reporting requirements as set forth in previous Commission Decisions or Commission rules. The Signatories agree with eliminating certain reporting requirements, with the exception of the following:

- The reporting requirement under Commission's Retail Electric Competition Rules (A.A.C. R14-2-1601).
- The cost containment report pursuant to Decision No. 59594.

Q. Can you please describe Section XX of the Agreement?

A. In an effort to address issues raised by some of the Signatories, the Company agrees to the following:

- In its next rate case, the Company will propose to treat the retail space to reflect revenue from rent equivalent to $20.83 per square foot.
- Within 60 days following the final decision in this docket, the Company will request that the Commission initiate a generic docket to address which accounting treatment of Net Operating Losses ("NOL") is appropriate.
- If TEP makes any filing with the Commission related to the early retirement of any production asset, TEP will propose that any then-existing excess depreciation reserve for Production Plant will be applied to the unrecovered book value of the retiring asset.
- TEP will propose in its next rate case that the remaining excess Production Plant depreciation, if any, after the application to the aforementioned early asset retirement will be amortized over 15years.
- TEP agrees to meet with RUCO and Staff once a year for the next 3 years to discuss TEP's capital expenditures, planning horizons, and related planning

(reconciled with TEP's IRP) for the upcoming year. TEP will provide the capital expenditure details and supporting information at least one week prior to the scheduled meeting.

- As a compliance item, TEP agrees that it will file in this docket by August 30, 2013, a proposed tariff for interruptible rates. Staff agrees that it will review the filing and docket a Staff Report and Proposed Order for the consideration of the Commission by December 31, 2013.
- In its next general rate case, TEP agrees to propose a rate for customers that take service at 138 kV or higher.

SECTION IV – RESPONSE TO COMMISSIONER GARY PIERCE'S LETTER

Q. On February 1, 2013, Commissioner Gary Pierce wrote a letter to the Docket setting forth several thoughts and questions regarding energy efficiency and the Energy Efficiency Resource Plan ("Plan") proposed in the Settlement Agreement. Have you read Commissioner Pierce's letter?

A. Yes.

Q. Do you have any comments regarding that letter?

A. Yes. Commissioner Pierce mentions perhaps permanently exempting TEP from the Commission's Energy Efficiency Rules ("EE Rules") if the Plan is implemented. From a Staff perspective, whether TEP is exempted from the EE Rules is a policy call for the Commission. However, even if TEP were no longer required to comply with the EE Rules, Staff still believes that the rate treatment for EE as outlined in the Plan and the Agreement is the correct treatment. In that instance, if TEP required additional generation resources as noted in its Integrated Resource Planning process, TEP could make the investment in EE resources and recover its investment as proposed by the Agreement.

Q. If the Commission is going to treat EE as any other typical generation resource, why would should the ratemaking treatment for such a resource be different than any other generation resource, i.e., through a DSM adjustor surcharge?

A. Unlike any other generation resource in which TEP invests, EE is the only generation resource that causes TEP to lose sales of kWh. Even when TEP invests in solar, since it owns that generation, it does not lose sales of kWh. However, with the installation of EE measures, TEP will lose sales revenue. It is for this reason that Staff believes that TEP should not be required to wait for the next rate case for the recovery of its EE investment, but instead recovery should occur through a DSM adjustor surcharge.

SECTION V - PUBLIC INTEREST

Q. Mr. Olea, is the Agreement in the public interest?

A. Yes, in Staff's opinion, the Agreement is fair, balanced, and in the public interest.

Q. Would you summarize the reasons that led Staff to conclude that the Agreement is fair, balanced, and in the public interest?

A. This Agreement results in a settlement package that addresses TEP's needs while balancing those needs with terms and conditions that provide customer benefits, such as:

- A limited first-year bill impact for customers (less than $3.00 per month[2] for a residential customer using the annual average of 767 kWh per month) despite the fact that TEP's current rates will have been in effect for almost 5 years at the time the new rates go into effect;
- A lower percentage rate impact on small commercial customers than the other customer classes;
- Continuing bill assistance for low income customers;

[2] This includes the PPFAC and the DSM surcharge but does not include the REST surcharge, taxes or assessments.

- A proposal that provides rate treatment for investments in energy efficiency in a manner similar to rate treatment for investments in other resources and that reduces the rate impact to the customer;
- An Environmental Compliance Adjustment mechanism that allows recovery, with a cap, of government-mandated environmental compliance costs in a manner that smooths the rate impact of such compliance;
- A narrowly-tailored LFCR mechanism that supports EE and DG at any level or pace set by this Commission; and
- A fixed cost LFCR rate option for residential customers preferring to a pay a specified charge for lost fixed costs rather than the variable LFCR.

Q. Please discuss how the Agreement is fair to the utility.

A. The revenue recommended will provide TEP with adequate funds to provide reliable and safe service, while at the same time ensuring the financial health of the Company. The LFCR mechanism will also improve TEP's revenue stability, which will have a positive impact on its financial profile and credit ratings.

Q. Mr. Olea, what was Staff's goal when it agreed to be a Signatory to the Agreement?

A. The primary goal of Staff in this matter, as in all rate proceedings before the Commission, is to protect the public interest by recommending rates that are just, fair and reasonable for both the ratepayers and the Company. Staff believes it has accomplished this by reviewing the facts presented and making the appropriate recommendations to the Commission for its consideration, which will balance the interests of the Company and the ratepayers, by promoting the Commission's desire to ensure that the Company has the tools and financial health to provide safe, adequate and reliable service, while complying with Commission requirements at just and reasonable rates.

SECTION VI – POLICY CONSIDERATIONS

Q. Mr. Olea, what was the major policy considerations the Signatories had to deal with in this Docket?

A. I believe there were two major policy considerations that Staff and other Signatories had to address in order to balance the interests of all Signatories. The Commission, in Docket Nos. E-00000J-08-0314 and G-00000C-08-0314, issued its Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures ("Policy Statement"). The Policy Statement did not adopt a requirement or mandate a specific revenue decoupling mechanism, but noted that utilities may file a proposal for decoupling or an alternative mechanism for addressing disincentives, in their next general rate case. The other policy consideration has to do with the implementation of EE programs. In this Agreement the Signatories agree that EE should be treated as any other typical energy source. In addition, the Signatories also agree that rather than collecting the surcharge in advance from its ratepayers, the Company first will invest its own capital, just like with other typical generation resources, thereafter the Company can then seek recovery on and of its investment, after a prudency determination.

Q. Is there anything else you would like to add regarding the Agreement?

A. I would like to reiterate that the settlement discussions were transparent, candid, professional and open to all parties in this docket. All Parties were allowed to openly express their views and opinions on all issues. I believe the Settlement Agreement is in the public interest.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT
TEP-1
ADMITTED

EXHIBIT A

TUCSON ELECTRIC POWER COMPANY

PROPOSED SETTLEMENT AGREEMENT

DOCKET NO. E-01933A-12-0291

FEBRUARY 4, 2013

(UPDATED MARCH 1, 2013)

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PROPOSED SETTLEMENT AGREEMENT OF DOCKET NO. E-01933-A-12-0291 TUCSON ELECTRIC POWER COMPANY REQUEST FOR RATE ADJUSTMENT

The purpose of this Settlement Agreement ("Agreement") is to settle disputed issues related to Docket No. E-01933A-12-0291, Tucson Electric Power Company's ("TEP" or "Company") application to increase rates. This Agreement is entered into by the following entities:

Tucson Electric Power Company
Arizona Corporation Commission Utilities Division ("Staff")
Residential Utility Consumer Office ("RUCO")
Southern Arizona Homebuilder's Association ("SAHBA")
Kroger Co. ("Kroger")
Freeport-McMoRan Copper & Gold Inc. ("Freeport-McMoRan")
Arizonans for Electric Choice and Competition ("AECC")
EnerNOC, Inc. ("EnerNOC")
IBEW Local 1116 ("IBEW")
Cynthia Zwick ("Zwick")
Arizona Investment Council ("AIC")
Opower, Inc. ("Opower")
The Vote Solar Initiative ("Vote Solar")
U.S. Department of Defense and all other Federal Executive Agencies ("DOD")
Southern Arizona Water Users Association
Arizona Solar Energy Industries Association
Solar Energy Industries Association

These entities shall be referred to collectively as "Signatories;" a single entity shall be referred to individually as a "Signatory."

I. RECITALS

1.1 TEP filed the rate application underlying Docket No. E-01933A-12-0291 on July 2, 2012. Staff found the application sufficient on August 2, 2012.

1.2 Subsequently, the Arizona Corporation Commission ("Commission") approved applications to intervene filed by SAHBA, Kroger, Freeport-McMoRan and AECC (collectively "AECC"), RUCO, EnerNOC, Arizona Public Service, Southwest Energy Efficiency Project, IBEW, Sierra Club, DOD, Solar Energy Industries Association, AIC, Cynthia Zwick, Opower, Vote Solar, Arizona Solar Energy Industries Association and Southern Arizona Water Users Association (collectively "Parties").

1.3 TEP filed a notice of settlement discussions on January 8, 2013. Settlement discussions began on January 15, 2013. The settlement discussions were open, transparent, and inclusive of all Parties to this Docket who desired to participate. All Parties to this Docket were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided with an equal opportunity to participate. Staff filed a Preliminary Term Sheet regarding this matter on January 22, 2013, which was discussed in a Special Open Meeting held on January 23, 2013.

1.4 The terms of this Agreement are just, reasonable, fair, and in the public interest in that they, among other things, establish just and reasonable rates for TEP customers; promote the convenience, comfort and safety, and the preservation of health, of the employees and patrons of TEP; resolve the issues arising from this Docket; and avoid unnecessary litigation expense and delay.

1.5 The Signatories believe that this Agreement balances the interests of both TEP and its customers. These benefits include:

- a limited first year bill impact for customers (less than $3.00 per month[1] for a residential customer using the annual average of 767 kilowatt-hour ("kWh") per month) despite the fact that TEP's current rates will have been in effect for almost 5 years at the time the new rates go into effect;

- a lower percentage rate impact on small commercial customers than the other customer classes;

[1] This includes the PPFAC and the DSM surcharge but does not include the REST surcharge, taxes or assessments.

- continuing bill assistance for low income customers;

- a proposal that provides rate treatment for investments in energy efficiency in a manner similar to rate treatment for investments in other resources and that reduces the rate impact to the customer;

- an Environmental Compliance Adjustment ("ECA") mechanism that allows recovery, with a cap, of government-mandated environmental compliance costs in a manner that smooths the rate impact of such compliance;

- a narrowly-tailored Lost Fixed Cost Recovery ("LFCR") mechanism that supports energy efficiency ("EE") and distributed generation ("DG") at any level or pace set by this Commission; and

- a fixed cost LFCR rate option for residential customers preferring to a pay a specified charge for lost fixed costs rather than the variable LFCR.

1.6 The Signatories agree to ask the Commission (1) to find that the terms and conditions of this Agreement are just and reasonable and in the public interest, along with any and all other necessary findings, and (2) to approve the Agreement such that it and the rates contained herein may become effective on July 1, 2013.

TERMS AND CONDITIONS

II. RATE INCREASE

2.1 TEP shall receive a non-fuel base rate increase of $76,194,000 over adjusted test-year retail revenues, reflecting a total non-fuel revenue requirement of $659,724,574. Attachment A sets forth the adjustments to TEP's initial request for a non-fuel base rate increase of $127,760,000 that results in the settlement amount.

2.2 TEP's base fuel rates shall be set to recover a total of $300,252,951 which is an annual increase of $31,599,730 over the amount recovered through current base fuel rates. However, as agreed to in this Agreement, the Purchased Power and Fuel Adjustment Clause ("PPFAC") rate will be reset on the effective date of the new rates, which will reduce the present annual recovery of fuel costs by $52,750,597.

2.3 The Company's jurisdictional fair value rate base used to establish the rates agreed to herein is $2,268,199,253, representing an average of the original cost rate base of $1,507,062,648 and the replacement cost new less depreciation rate based of $3,029,335,858. The Company's total adjusted Test Year revenue requirement is $959,977,525.

III. BILL IMPACT

3.1 Upon the effective date of the new rates, the monthly bill for a residential customer, using the annual average of 767 kWh per month, will increase by less than $3.00. This overall impact reflects a base rate increase, as well as a reduction in the PPFAC rate and a reduction in the Demand Side Management ("DSM") surcharge resulting from the adoption of the proposed Energy Efficiency Resource Plan.

3.2 The percentage revenue allocation resulting from this Agreement among the customer classes is set forth in Attachment B.

IV. COST OF CAPITAL

4.1 The actual test year capital structure comprised of 55.97% long term debt, 0.53% short term debt and 43.50% common equity shall be adopted.

4.2 A return on common equity of 10.0%, an embedded cost of long-term debt of 5.18% and a cost of short-term debt of 1.42% shall be adopted.

4.3 A fair value rate of return of 5.05%, which includes a rate of return on the fair value increment of rate base of 0.68%, shall be adopted.

4.4 The provisions set forth herein regarding the quantification of cost of capital, fair value rate base, fair value rate of return, and the revenue requirement are made for purposes of settlement only and should not be construed as admissions against interest or waivers of litigation positions related to other or future cases.

V. DEPRECIATION/AMORTIZATION

5.1 The depreciation and amortization rates proposed by TEP and contained in Exhibit REW-1 to Dr. Ron White's Pre-filed Direct Testimony shall be adopted until further order of the Commission.

VI. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE ("PPFAC")

6.1 The average retail base fuel rate shall be set at $0.032335 per kWh. This rate reflects a total of $300,252,951 in annual fuel and purchased power costs. This base rate does not include the PPFAC rate established in this Agreement, which includes a one-time $3 million credit related to previous sulfur credits and a $9.7 million deferral of costs related to the San Juan Thermal Event (as described in Section XIV below). Therefore, on the effective date of new rates in this docket, the PPFAC rate will be set at negative $0.001388 per kWh (i.e., it will be a credit to the customer's bill).

6.2 TEP's existing PPFAC mechanism will continue with administrative changes, as set forth in the PPFAC Plan of Administration in Attachment C. The PPFAC is modified to include the recovery of the following costs and/or credits: broker fees; lime costs; sulfur credits; and 100% of proceeds from the sale of SO2 allowances. TEP will continue to recover its base purchased power and fuel costs through base fuel rates as determined by the Commission in this case. TEP will continue to file annually for the reset of the PPFAC and Staff will review the filings for the appropriateness of the forecasts and the numerical accuracy of the filing. Such Staff review does not imply prudency.

6.3 The Signatories believe it is in the public interest to defer the next reset of TEP's PPFAC rate until the effective date of the rates in this docket in order to partially offset the base rate increase. Therefore, TEP will seek expedited Commission authorization to defer TEP's April 1, 2013 PPFAC rate adjustment until the effective date of new rates in this docket and the Signatories agree to either support or not oppose that motion.

VII. ENERGY EFFICIENCY RESOURCE PLAN

7.1 TEP will implement an Energy Efficiency Resource Plan ("Plan"), as proposed by Staff in its Direct Testimony, which is intended to treat energy efficiency similar to a typical generation resource. Under this Plan, TEP will invest (just as TEP does with other conventional energy resources) in cost-effective energy efficiency programs that have been approved by the Commission. After providing documentation that the energy efficiency programs have been effective, TEP will be allowed to recover the cost of its energy efficiency investments, including the rate of return established in this case on those investments, through TEP's existing DSM adjustor mechanism.

7.2 TEP will amortize annual energy efficiency investments under the Plan over five years.

7.3 TEP will resume funding programs previously approved by the Commission beginning March 1, 2013, and shall request recovery of such costs through the Plan.

7.4 Upon the effective date of the rates in this case, TEP will begin investing in cost-effective DSM/EE programs pursuant to the Plan for the remainder of year 2013 based upon the Commission's approval of the Plan, which includes the programs and the annual budget (approximately $12 million on a pro rata basis assuming a July 1, 2013 start date) recommended by Staff in Staff's proposed order for TEP's 2011-2012 Energy Efficiency Implementation Plan filed in Docket No. E-01933A-11-0055 on November 16, 2011.

7.5 Upon the effective date of the rates in this case, and approval of the Plan, TEP will file a request to close Docket No. E-01933A-11-0055.

7.6 Any customer who can demonstrate an active DSM program and whose single site usage is 25 MW or greater may file a petition with the Commission for an exemption from the DSM adjustor and, if approved, will be removed from the Energy Efficiency Standard denominator. The Parties are not required to support any such petition and some Parties may plan to oppose any such petition.

7.7 TEP will conduct the Plan pursuant to a Plan of Administration, which is set forth in Attachment D.

7.8 Upon adoption of the Plan, the DSM surcharge will be assessed on a per kWh basis for residential customers and on a percentage of bill basis for non-residential customers. The current DSM surcharge for residential customers will be reset from $0.001249 per kWh to $0.000443 per kWh upon the effective date of the new rates in this case.

7.9 Nothing in the Plan is intended to bind the Commission to any specific EE policy or standard, but merely sets up the method of recovery for investments in EE for any EE policy or standard established by the Commission.

VIII. LOST FIXED COST RECOVERY/FIXED RESIDENTIAL RATE OPTION /LARGE CUSTOMER EXCLUSION

8.1 The Signatories support energy efficiency as a low cost energy resource. The Signatories also recognize that, under TEP's current volumetric rate design, the Company recovers a significant portion of its fixed costs of service through kWh sales. Commission rules related to EE and DG require TEP to sell fewer

kWh, which, in turn, prevents the Company from being able to recover a portion of the fixed costs of service embedded in its volumetric rates.

8.2 The Signatories also recognize the Commission's interest in directing EE and DG policy. In signing this Agreement, the Signatories intend that an LFCR mechanism with a residential fixed rate option shall be adopted that allows TEP relief from the financial impact of verified lost kWh sales attributable to Commission requirements regarding EE and DG while preserving maximum flexibility for the Commission to adjust EE and DG requirements, either upward or downward, as the Commission may deem appropriate as a matter of policy. Nothing in this Agreement is intended to bind the Commission to any specific EE or DG policy or standard.

8.3 The Signatories propose that the Commission approve an LFCR mechanism that is similar to the LFCR approved for other Arizona utilities. The LFCR shall recover a portion of distribution and transmission costs associated with residential, commercial and industrial customers when sales levels are reduced by EE and DG. It shall not recover lost fixed costs attributable to generation and to other potential factors, such as weather or general economic conditions.

8.4 The LFCR will have a 1% year-over-year cap. The annual 1% year over year cap is based on total applicable TEP retail revenues (i.e., average bills for customers shall not increase by more than 1%). Any amount in excess of the 1% cap will be deferred for collection consistent with the LFCR Plan of Administration. The amount of the cap level set herein shall be evaluated in TEP's next rate case.

8.5 The LFCR mechanism shall not apply to large light & power, water pumping or lighting customers, as delineated in the LFCR Plan of Administration. However, rate design for these customer classes shall be such that they pay their fair share of fixed costs through their monthly minimum and/or demand charge.

8.6 Residential customers shall have a fixed LFCR rate option providing the opportunity to elect an optional higher monthly service charge, graduated by kWh monthly usage. That option is attached hereto as Attachment E. The optional monthly service charge will be incorporated into each residential rate schedule to provide customers with the maximum flexibility to choose the fixed LFCR rate option without requiring a shift to a different rate schedule. The purpose of this fixed LFCR rate option is to replicate, on average, the effects of the LFCR.

8.7 TEP shall seek stakeholder input regarding the development of a customer outreach program to inform and educate customers about the LFCR and shall implement this outreach program by February 1, 2014.

8.8 The LFCR will recover lost fixed cost on a calendar year basis from January 1, 2013 forward and the first LFCR surcharge will not go into effect until July 1, 2014.

8.9 The LFCR Plan of Administration is attached hereto as Attachment F.

IX. ENVIRONMENTAL COMPLIANCE ADJUSTOR SURCHARGE

9.1 TEP will implement an Environmental Compliance Adjustor ("ECA") that will recover environmental compliance costs, subject to a cap equal to 0.25 percent of total TEP retail revenue. TEP will be held responsible for demonstrating that the environmental controls were government-mandated and represented a reasonable and prudent option available to TEP at the time sufficient to meet the environmental requirement. The ECA Plan of Administration is set forth as Attachment G.

X. SPRINGERVILLE UNIT 1

10.1 TEP shall file a report with the Commission no later than July 31, 2014, addressing the status of the Springerville Generating Station ("SGS") lease agreements and the estimated change in TEP's non-fuel revenue requirement at the conclusion of each primary lease term. Specifically, TEP commits to reporting on the following matters:

- The details concerning any commitments made by TEP to purchase SGS Unit 1, or any agreements entered into by TEP to otherwise retain capacity rights to SGS Unit 1, after the end of the primary lease term in January 2015;

- The details concerning any commitments made by TEP to purchase replacement generating resources, or any purchased power agreements entered into by TEP for replacement power, if TEP elects not to purchase or otherwise retain capacity rights to SGS Unit 1 after the end of the primary lease term in January 2015;

- The details concerning any commitments made by TEP to purchase the SGS Coal Handling Facilities, or any agreements

entered into by TEP to extend the Coal Handling Facilities lease term, after the end of the primary lease term in April 2015; and

- The estimated non-fuel revenue requirement associated with each of the commitments described above, including the proposed rate treatment of any remaining balance of SGS leasehold improvements.

10.2 Based on the information in the above reporting, the Commission, on its own motion or a recommendation of a Signatory in this case, may require TEP to explain why the Commission should not conduct a proceeding to have TEP's rates reduced accordingly.

XI. PROCUREMENT

11.1 TEP agrees to adopt Staff's proposed modifications to the Company's energy procurement program discussed in the Direct Testimony of Emily Medine, except for the Risk Manager recommendation. The adopted modifications are set forth in Attachment H.

XII. LOW INCOME PROGRAMS

12.1 TEP will limit a typical Lifeline customer's increase to an amount that is generally reflective of the average monthly dollar increase of a standard R-01 customer. The anticipated bill impacts for Lifeline customers are set forth in Attachment I.

12.2 The PPFAC rate and DSM surcharge shall apply to Lifeline customers, and the currently frozen rates shall no longer be portable.

12.3 In compliance with Decision No. 59594 (March 29, 1996), TEP set up a LIFE Fund of $4.5 million. The annual interest from the LIFE Fund was used for the benefit of low-income customers. The Signatories agree that the LIFE Fund should be extinguished and that TEP will make an annual contribution to the Arizona Community Action Association in the amount of $150,000 to fund low-income utility bill assistance programs, commencing on September 1, 2013.

XIII. NOGALES TRANSMISSION LINE

13.1 TEP agrees that, before requesting any rate recovery from the Commission for the cost related to the development of the transmission line between Tucson and Nogales, it will seek recovery of those costs from the Federal Energy

Regulatory Commission ("FERC"). Nothing herein shall preclude Parties from challenging before FERC or the Commission the inclusion of this cost in rates.

XIV. SAN JUAN THERMAL EVENT

14.1 TEP agrees to maintain a separate accounting of all direct costs related to the thermal event at the San Juan mine and that such cost recovery, with the exception of TEP's share of the insurance deductible, be deferred until the insurance settlement has been completed. The estimate of deferred costs is $9.7 million. TEP shall then be eligible to put through all costs in excess of the insurance recovery subject to the standard prudence determination of all fuel costs recovered through the PPFAC. This accounting and regulatory treatment is not intended to set a precedent for future events.

XV. RATE DESIGN

15.1 In addition to the provisions affecting rate design set forth in this Agreement above, rate design shall be addressed as set forth in Attachment J.

15.2 The rate design portion of this Agreement shall remain open until July 1, 2014, to allow for the possible adjustment of specific tariffs to correct for unanticipated customer rate impacts that are determined to be inconsistent with the public interest. Any tariff changes will not have the effect, in the aggregate, of reducing TEP's non-fuel revenue requirement.

XVI. RULES AND REGULATIONS

16.1 TEP's revised Rules and Regulations shall be as agreed to between the Company and Staff. The final version of the Rules and Regulations will be attached to the Company's testimony in support of the Agreement.

XVII GREENWATTS TARIFF AND STATEMENT OF CHARGES

17.1 TEP's GreenWatts tariff is eliminated.

17.2 TEP's revised Statement of Charges is set forth in Attachment K.

XVIII. QUALITY OF SERVICE

18.1 TEP agrees to: (i) continue to evaluate TEP's reliability on the basis of the distribution indices being maintained at present levels and (ii) initiate a study within 180 days of the effective date of the approval of this Agreement to examine potential loss reductions and the costs required to convert 4.16 kV circuits to 13.8 kV.

18.2 TEP agrees to meet with Staff within 180 days of the effective date of the approval of this Agreement to address: (i) potentially increasing the pace of upgrading critical circuits in need of preventative maintenance; (ii) establishing a routine of periodic load-flow analysis of its system and confirming the accuracy of utilized model; and (iii) equip feeder circuits with meters or other equipment so that power information can be relayed to Energy Management Service ("EMS") through Supervisory Control and Data Acquisition ("SCADA") to determine losses on a circuit-by-circuit basis.

XIX. COMPLIANCE MATTERS

19.1 TEP's request for elimination of reporting requirements, as set forth in the Direct Testimony of Craig A. Jones at pages 76-81, shall be approved with the exception of: (i) the reporting requirements under the Commission's Retail Electric Competition Rules (A.A.C. R14-2-1601 et seq.) and (ii) the Cost Containment Report pursuant to Decision No. 59594 (March 29, 1996). The reporting requirements that are eliminated or modified are set forth in Attachment L.

XX. ADDITIONAL SETTLEMENT PROVISIONS

20.1 With respect to the retail space (approximately 12,000 square feet) at the Company's headquarters building, TEP will in its next rate case propose to treat the retail space in a similar manner as set forth in Attachment A.

20.2 Net Operating Losses: Within 60 days following the final decision in Docket No. E-01933A-12-0291, TEP will make a filing proposing the Commission open a generic docket to address the appropriate accounting treatment of Net Operating Losses (NOLs) in future rate cases.

20.3 Depreciation Reserves: In recognition of RUCO's excess depreciation concerns, TEP agrees to the following: (a) If TEP makes any filing with the Commission related to the early retirement of any production asset, TEP will propose that any then-existing excess depreciation reserve for Production Plant will be applied to the unrecovered book value of the retiring asset and (b) TEP will propose in its next rate case that the remaining excess Production Plant depreciation, if any, after the application to the aforementioned early asset retirement will be amortized over 15 years.

20.4 Capital Expenditures for Distribution Plant: TEP agrees to meet with RUCO and Staff once a year for the next 3 years to discuss TEP's capital expenditures, planning horizons, and related planning (reconciled with TEP's IRP) for the

upcoming year. TEP will provide the capital expenditure details and supporting information at least one week prior to the scheduled meeting.

20.5 As a compliance item, TEP agrees that it will file in this docket by August 30, 2013 a proposed tariff for interruptible rates. Staff agrees that it will review the filing and docket a Staff Report and Proposed Order for the consideration of the Commission by December 31, 2013.

20.6 In its next general rate case, TEP agrees to propose a rate for customers that take service at 138 kV or higher.

XXI. COMMISSION EVALUATION OF PROPOSED SETTLEMENT

21.1 All currently filed testimony and exhibits shall be offered into the Commission's record as evidence.

21.2 The Signatories recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

21.3 This Agreement shall serve as a procedural device by which the Signatories will submit their proposed settlement of TEP's pending rate case, Docket No. E-01933A-12-0291, to the Commission.

21.4 The Signatories recognize that the Commission will independently consider and evaluate the terms of this Agreement. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute Commission approval of the Agreement. Thereafter, the Signatories shall abide by the terms as approved by the Commission.

21.5 If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Signatories may withdraw from this Agreement, and such Signatory or Signatories may pursue without prejudice their respective remedies at law. For purposes of this Agreement, whether a term is material shall be left to the discretion of the Signatory choosing to withdraw from the Agreement. If a Signatory withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Signatories, except for Staff, shall support the application for rehearing by filing a document with the Commission that supports approval of the Agreement in its entirety. Staff shall not be obligated to file any document or take any position regarding the withdrawing Signatory's application for rehearing.

XXII. MISCELLANEOUS PROVISIONS

22.1 This case has attracted a large number of participants with widely diverse interests. To achieve consensus for settlement, many participants are accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because this Agreement, as a whole, is consistent with their long-term interests and with the broad public interest. The acceptance by any Signatory of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.

22.2 No Signatory is bound by any position asserted in negotiations, except as expressly stated in this Agreement. No Signatory shall offer evidence of conduct or statements made in the course of negotiating this Agreement before this Commission, any other regulatory agency, or any court.

22.3 Neither this Agreement nor any of the positions taken in this Agreement by any of the Signatories may be referred to, cited, and/or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except to secure approval of this Agreement and enforce its terms.

22.4 To the extent any provision of this Agreement is inconsistent with any existing Commission order, rule, or regulation, this Agreement shall control.

22.5 Each of the terms of this Agreement is in consideration of all other terms of this Agreement. Accordingly, the terms are not severable.

22.6 The Signatories shall make reasonable and good faith efforts necessary to obtain a Commission order approving this Agreement. The Signatories shall support and defend this Agreement before the Commission. Subject to Paragraph 21.5 above, if the Commission adopts an order approving all material terms of the Agreement, the Signatories will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.

22.7 This Agreement may be executed in any number of counterparts and by each Signatory on separate counterparts, each of which when so executed and delivered shall be deemed an original and all of which taken together shall constitute one and the same instrument. This Agreement may also be executed electronically or by facsimile.

ARIZONA CORPORATION COMMISSION

UTILITIES DIVISION STAFF

By_____

Title_____

Date_____

TUCSON ELECTRIC POWER COMPANY

By_____

Title_____

Date_____

22.7 This Agreement may be executed in any number of counterparts and by each Signatory on separate counterparts, each of which when so executed and delivered shall be deemed an original and all of which taken together shall constitute one and the same instrument. This Agreement may also be executed electronically or by facsimile.

ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION STAFF

By_____

Title Utilities Division Director

Date 2-4-13

TUCSON ELECTRIC POWER COMPANY

By_____

Title President

Date February 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Residential Utility Consumer Office

By _____

Title Director RUCO

Date 2/4/2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

David Godlewski

Southern Arizona Home Builders Association

By _____

Title President

Date 1/4/13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

KROGER CO.

By _____

Title Attorney

Date 2-4-13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Freeport-McMoRan Copper & Gold Inc.

By _____

C. Webb Crockett
Patrick J. Black
Fennemore Craig, P.C.

Title Attorneys for Freeport-McMoRan Copper & Gold Inc.

Date February 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Arizonans for Electric Choice and Competition

By _____

C. Webb Crockett
Patrick J. Black
Fennemore Craig, P.C.

Title Attorneys for Arizonans for Electric Choice and Competition

Date February 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

[PARTY NAME]

By Mona Tierney Lloyd

Title Director, Reg Affairs, Energy

Date 2-4-13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

IBEW LOCAL 1116

By _____

Title Attorney for IBEW (on behalf of Frank Grijalva, Business Manager)

Date 2/4/13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Cynthia Zwick

By _____

Title _____

Date FEBRUARY 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

ARIZONA INVESTMENT COUNCIL

By _____

Title President

Date 2/4/2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

[Opower Inc.]

By _____

Title ATTORNEY

Date 2-4-13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

The Vote Solar Initiative

By _____

Title Attorney for VSI

Date Feb. 4, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

United States Department of Defense and all other Federal Executive Agencies

By _____

Kyle J. Smith

Title General Attorney

Date February 5, 2013

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

[Southern Arizona Water Users Association]

By _____

Title Board President

Date 2-4-13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Arizona Solar Energy Industries Association

By _____

Title Executive Director

Date 2-12-13

Signatory to February 4, 2013 Tucson Electric Power Company Settlement Agreement

Docket No. E-01933A-12-0291

Solar Energy Industries Association

By _____

Title Senior Vice President

Date February 13, 2013

ATTACHMENT

"A"

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2011

	As Filed TEP 6/30/12	Settlement 2/4/13	Summary
Original Cost Rate Base - Unadjusted	$1,627,962,142	$1,627,962,142	
Rate Base Adjustments			
Sahuarita - Nogales Transmission Line	11,088,732	-	For purposes of settlement and to be reflected in rates in this proceeding, the Settling Parties agree that recovery will be pursued at the Federal Energy Regulatory Commission.
Leasehold Improvements	(765,060)	(765,060)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Post Test Year Plant	20,441,231	20,441,231	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Post Test Year Plant - Renewable	15,710,443	15,710,443	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Delayed Plant	7,650,854	7,650,854	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Accumulated Deferred ITC	(1,605,208)	(1,605,208)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Accumulated Deferred Income Tax	(126,648,626)	(126,648,626)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Allowance for Working Capital	(34,761,146)	(35,683,128)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Total Adjustments to Rate Base	(108,888,780)	(120,899,494)	
Rate Base	$ 1,519,073,362	$ 1,507,062,648	
Requested Rate of Return	7.74%	7.26%	For purposes of settlement and to be reflected in rates, the Settleing Parties agree that a capital structure of 43.50 % Equity @10.00% and 55.97% Long-Term Debt @ 5.18% and .53% Short-Term Debt @ 1.42% be used.
Required Operating Income OCRB	$117,609,698	$109,412,748	
Fair Value Increment of Rate Base	$761,142,979	$761,136,605	
Fair Value Rate Base (FVRB)	$2,280,216,341	$2,268,199,253	
Proposed FVROR	5.68%	5.05%	
Required Operating Income on FVRB	129,483,528	$114,588,477	
ROR on Fair Value Increment of Rate Base	1.56%	0.68%	The Settling Parties agree to the reduced level of return on the fair value rate base increment for purposes of settlement.

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2011

	As Filed TEP 6/30/12	Settlement 2/4/13	Summary
Original Operating Income - Unadjusted	$257,751,277	$257,751,277	
Operating Revenue Adjustments			
State Energy Program	(1,254,299)	(1,254,299)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
REST & DSM	(46,633,198)	(46,633,198)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Green Watts	(81,180)	(81,180)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Springerville Unit 3 & 4	(87,568,386)	(80,607,382)	For purposes of settlement and to be reflected in rates the parties agree to adjust the reimbursement of operating expenses to 100%.
Power Supply Management	(641,665)	(641,665)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Customer and Weather Adjustment	(7,922,107)	(7,922,107)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
PPFAC Adjustment	(12,436,902)	(12,176,849)	For purposes of settlement and to be reflected in rates, the Settling Parties agree to adjustments to reflect the current PPFAC rate.
Service Fees & Late Fees	1,109,816	1,109,816	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Customer Care & Billing (CC&B) Allocation	717,619	717,619	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
People Soft Allocation	(64,566)	(64,566)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Building Allocation to Affiliates	506,224	506,224	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Sulfur Credit	-	(5,076,000)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Lime Expense	-	12,879,613	For purposes of settlement and to be reflected in rates, the Settling Parties agree to adjustments that reflect lime expense and sulfur credits as PPFAC includable costs.
Headquarter Return Offset		2,389,000	For purposes of settlement and to be reflected in rates in this proceeding, the Settling Parties agree to include a reduction to TEP's cost of service producing a return "on" its new office building at TEP's cost of debt.
Headquarter Retail Space Rent	-	250,000	For purposes of settlement and to be reflected in rates in this proceeding, the Settling Parties have agreed to assume a rent equivalent to $20.83/square foot on 12,000 square feet of retail space. [Market equivalent $12-$15 per square foot]
Total Adjustments to Operating Revenues	($154,268,644)	($136,604,974)	

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2011

	As Filed TEP 6/30/12	Settlement 2/4/13	Summary
Operating Expense Adjustments			
Implementation Cost Regulatory Asset	(3,553,210)	(3,553,210)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
State Energy Program	(1,253,688)	(1,253,688)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
REST & DSM	(34,129,577)	(34,129,577)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Green Watts	(28,094)	(28,094)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Springerville Units 3 & 4	(66,126,339)	(66,126,339)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Revenue form Sale of S02 Allowances	1,212	1,212	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Sales for Resale	(128,262,147)	(128,262,147)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Power Supply Management	(217,252)	(217,252)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
PPFAC Adjustment	168,304,294	168,564,347	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Sahuarita - Nogales Tran Line Amortization	2,982,638	-	For purposes of settlement and to be reflected in rates in this proceeding, the Settling Parties agree that recovery will be pursued at the Federal Energy Regulatory Commission.
Generating Facilities - Operating Lease	(3,148,432)	(3,148,432)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Springerville Unit 1	41,014,390	41,000,514	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Overhaul & Outage Normalization	1,191,868	(1,322,100)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Payroll Expense	2,898,605	2,898,605	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Payroll Tax Expense	193,390	193,390	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Pension & Benefits	200,143	200,143	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Retiree Medical	1,235,251	1,235,251	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Incentive Compensation	2,014,330	(80,108)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Rate Case Expense	192,187	(25,998)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Injuries and Damages	599,268	599,268	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.

TUCSON ELECTRIC POWER COMPANY
COMPARISON OF ADJUSTMENTS TO ACC JURISDICTIONAL REVENUE REQUIREMENT
TEST YEAR ENDED DECEMBER 31, 2011

	As Filed TEP 6/30/12	Settlement 2/4/13	Summary
Membership Dues	(79,913)	(191,016)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Bad Debt Expense	639,648	639,648	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
CC&B Allocation	1,217,949	1,217,949	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
People Soft Allocation	(187,570)	(187,570)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Depr. & Amort. Expense Annualization	(3,197,238)	(3,197,238)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Non-Recurring	(1,492,550)	(1,492,550)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Property Tax	2,305,832	848,741	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Asset Retirement Obligation	(299,189)	(299,189)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Building Expense Annualization	286,055	286,055	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Lime Expense	1,246,043	1,246,043	reflected in rates in this proceeding. The net Lime expense and sulfur credit amount in O&M were offset and reflected as PPFAC includable costs.
Credit Support		21,000	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Post Test Year Depreciation		1,520,175	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Income Tax	(23,564,462)	(14,198,335)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
OATT	90,028,056	90,028,056	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Directors and Officers Liability Insurance		(289,320)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Day Nite / General Corporate Advertising		(13,061)	The Settling Parties agree to this adjustment for purposes of settlement and that the adjustment be reflected in rates in this proceeding.
Total Adjustments to Operating Expense	$51,011,498	$52,485,173	
Total Net Adjustments	($205,280,142)	($189,090,147)	
Adjusted Operating Income	$52,471,135	$68,661,130	
Operating Income Deficiency	$77,012,393	$45,927,347	
Gross Revenue Conversion Factor	1.6590	1.6590	
Increase in Gross Revenue Requirement	$127,760,018	$76,194,257	

ATTACHMENT

"B"

Tucson Electric Power Company
Test Period Ending December 31, 2011
Revenue Allocation - Test Year Adjusted
Attachment B

Line No.	Description	Total Adjusted TY Revenues	Total Fuel Revenue Increase	Total Non-Fuel Revenue Increase	Total Proposed Revenues	Percent Allocated
1	Residential	$363,572,522	$11,968,386	$36,283,601	$411,824,508	13.3%
2	Small General Service	223,685,672	9,960,816	17,646,762	251,293,250	12.3%
3	Water Pumping	7,355,490	481,929	554,386	8,391,806	14.1%
4	Large General Service	100,687,806	4,369,445	9,861,330	114,918,581	14.1%
5	Large Light and Power	114,163,922	4,502,721	11,608,894	130,275,537	14.1%
6	Lighting	3,936,000	316,595	239,336	4,491,931	14.1%
7	Subtotal	$813,401,411	$31,599,892	$76,194,310	$921,195,613	13.3%

ATTACHMENT

"C"

Tucson Electric Power Company
Purchased Power and Fuel Adjustment Clause
Plan of Administration

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1. GENERAL DESCRIPTION

This document describes the plan for administering the Purchased Power and Fuel Adjustment Clause ("PPFAC") the Arizona Corporation Commission ("Commission") approved for Tucson Electric Power Company ("TEP") in Decision No. 70628 (December 1, 2008) and amended by the Commission in Decision No. XXXXX (date).~~- The PPFAC provides for the recovery of fuel and purchased power costs from the date of Decision No. XXXXXthat decision forward.~~

The PPFAC described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs to set a rate that is then reconciled to actual costs experienced. This POA describes the application of the PPFAC.

2. DEFINITIONS

Applicable Interest - Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15. The interest rate is adjusted annually on the first business day of the calendar year.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power cost embedded in the base rates as approved by the Commission in TEP's most recent rate case. The Base Cost of Fuel and Purchased Power revenue is the approved rate per kWh times the applicable sales volumes. Decision No. ~~70628~~ XXXXX set the base cost at $0.032335 per kWh ~~at $0.02896 per kWh~~ effective on ~~December 1, 2008~~[date].

~~Fixed CTC True-Up Revenues – The incremental revenue that was collected as a result of retaining the Fixed CTC in place and maintaining Standard Offer rates, pursuant to Decision No. 69568.~~
Brokerage Fees – The costs attributable to the use of brokers recorded in Federal Energy Regulatory Commission ("FERC") Account 557.

Forward Component - An amount expressed as a rate per kWh charge that is updated annually on April 1 of each year and effective with the first billing cycle in April. The Forward Component for the PPFAC Year will adjust for the difference between the forecasted fuel and purchased power costs expressed as a rate per kWh less the Base Cost of Fuel and Purchase Power generally expressed as a rate per kWh embedded in TEP's base rates. The result of this calculation will equal the Forward Component, expressed as a rate per kWh.

Forward Component Tracking Account - An account that records on a monthly basis TEP's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component revenue; plus Applicable Interest. The balance of this account as of the end of each PPFAC Year is, subject to periodic audit, reflected in the next True-Up Component calculation. TEP files the balances and supporting details underlying this Account with the Commission on a monthly basis via a monthly reporting requirement.

Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by TEP to serve both Total Native Load Energy Sales and Short Term Sales~~, less the costs associated with Mark-to-Market Accounting adjustments~~. Wheeling costs are included. ~~Broker's fees and other expenses TEP records in Account 557 are not included.~~

Lime Costs (FERC Account 502) – The costs recorded for lime used to remove sulfur compounds formed during coal combustion.

Long Term Energy Sales - The portion of load from Total Native Load Energy Sales wholesale customers (currently Salt River Project, Tohono O'odham Utility Authority and Navajo Tribal Utility Authority) that is served by TEP, excluding the load served with Preference Power. Wholesale sales with a duration of one year or greater are also included.

~~Mark-to-Market Accounting – Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.~~

PPFAC - The Purchased Power and Fuel Adjustment Clause approved by the Commission in Decision No. 70628 and amended by the Commission in Decision No. XXXXX, ~~which~~ is a combination of two rate components that track changes in the cost of obtaining power supplies based upon forward-looking estimates of fuel and purchased power costs that are eventually reconciled to actual costs experienced. This PPFAC also provides for a reconciliation between actual and estimated costs of the last three months of estimated costs used in True-Up Component calculations.

PPFAC Year - A consecutive 12-month period beginning each April 1 and lasting through March 31 the following year. ~~The initial term of the PPFAC will begin on the effective date of the Commission decision in this proceeding (Decision No. 70628) and end on March 31, 2009. The first full year of the PPFAC will begin on April 1, 2009 and end on March 31, 2010. The first True-Up Component will include costs and revenues from January 1, 2009 through March 31, 2009.~~

Preference Power - Power allocated to TEP wholesale customers by federal power agencies such as the Western Area Power Administration.

Retail Native Load Energy Sales – The portion of load from Total Native Load Energy Sales that serves TEP's retail customers ~~that is served by TEP and~~ located within the TEP control area.

Short Term Sales – Wholesale sales with~~for~~ durations of less than one year made to non-Native Load customers for the purpose of optimizing the TEP system, using TEP owned or contracted generation and purchased power~~, less Mark-to-Market Accounting adjustments~~.

Short Term Sales Revenue - The revenue recorded from wholesale sales with durations of less than one year made to non-Native Load customers, for the purpose of optimizing the TEP

system, using TEP-owned or contracted generation and purchased power~~, less Mark-to-Market Accounting adjustments~~.

SO_2 Allowance Sales – The revenues related to the sale of SO_2 emission allowances, including gain on SO_2 allowance sales and auction proceeds net of Brokerage Fees~~Commissions~~ paid.

Sulfur Credits – Credits received by TEP related to coal sulfur content that offset the cost of chemicals used to remove sulfur compounds formed during coal combustion.

Total Native Load Energy Sales – Retail Native Load Energy Sales and Long Term Energy Sales for which TEP has a generation service obligation.

True-Up Component - An amount expressed as a rate per kWh charge that is updated annually on April 1 of each year and effective with the first billing cycle in April. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PPFAC Year tracking account balances to be refunded/collected from customers in the coming year's PPFAC rate. ~~The first True-Up Component will include costs and revenues from January 1, 2009 through March 31, 2009.~~

True-Up Component Tracking Account - An account that records on a monthly basis the account balance to be collected or refunded via the True-Up Component rate as compared to the actual True-Up Component revenues, plus Applicable Interest; the balance of which at the close of the preceding PPFAC Year is, subject to periodic audit, then reflected in the next True-Up Component calculation. TEP files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of TEP's electricity over transmission facilities owned by others.

Wholesale Trading Activity – Revenue recorded from realized wholesale trading profits.

3. PPFAC COMPONENTS

The PPFAC Rate will consist of two components designed to provide for the recovery of actual, prudently incurred fuel and purchased power costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PPFAC Year (each April 1 through March 31 period shall constitute a PPFAC Year) fuel and purchased power costs and those embedded in base rates.

2. The True-Up Component, which tracks the differences between the PPFAC Year's actual fuel and purchased power costs and those costs recovered through the combination of base rates and the Forward Component, and which provides for their recovery during the next PPFAC Year.

The PPFAC Year begins on April 1 and ends the following March 31. ~~The first full PPFAC Year in which the PPFAC rate shall apply will begin on April 1, 2009 and end on March 31, 2010. Succeeding PPFAC Years will begin on each April 1 thereafter.~~

~~For the period from when the Commission issued Decision No. 70628 in this case – until March 31, 2009 – the Base Cost of Fuel and Purchased Power rate established in that decision will be in effect. The first True-Up will include costs and revenues from January 1, 2009 through March 31, 2009.~~

On or before October 31 of each year, TEP will submit a PPFAC Rate filing, which shall include an estimate~~a proposed calculation~~ of the components for the following April's PPFAC rate. This filing shall be accompanied by supporting information as Staff determines to be required. TEP will update~~supplement~~ this filing ~~with a True-Up Component filing~~ on or before February 1 in order to replace estimated balances with actual balances, as explained below.

A. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) the fuel and purchased power costs embedded in base rates and (2) the forecasted fuel and purchased power costs over a PPFAC Year that begins on April 1 and ends the following March 31. TEP will submit, on or before October 31 of each year, a forecast for the upcoming PPFAC year (April 1 through March 31) of its fuel and purchase power costs. It will also submit a forecast of kWh sales for the same PPFAC year, and divide the forecasted costs by the forecasted sales to produce the cents per kWh unit rate required to collect those costs over those sales. The result of subtracting the Base Cost of Fuel and Purchased Power from this unit rate shall be the Forward Component.

Credits to the PPFAC

The following will be credited to the PPFAC:

1. All revenues from Short Term Sales; ~~will be credited against fuel and purchased power costs.~~
2. Ten percent of the net positive margins realized by TEP during the PPFAC year on its Wholesale Trading Activities;
3. ~~will be credited against fuel and purchased power costs.~~ One hundred (100%)~~Fifty~~ percent of the margins realized by TEP on SO_2 Allowance Sales (net of brokerage fees);
4. ~~will be credited against fuel and purchased power costs.~~All Sulfur Credits received by TEP; and
5. ~~1.~~The sale of renewable energy credits that do not flow through the Renewable Energy Standard Tariff.

TEP shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record TEP's over/under-recovery of its actual costs of fuel and purchased power as compared to the actual Base Cost of Fuel and Purchased Power revenue and Forward Component

revenue. This Account will operate on a PPFAC Year basis (i.e. April 1 to the following March 31), and its balances will be used to administer this PPFAC's True-Up Component, which is described immediately below.

B. True-Up Component Description

The True-Up Component in any current PPFAC Year is intended to refund or recover the balance accumulated in the Forward Component Tracking Account (described above) during the previous PPFAC year. Also, any remaining balance from the True-Up Component Tracking Account as of March 31 would roll over into the True-Up Component for the coming PPFAC year starting April 1. The sum of projected Forward Component Tracking Account and True-Up Component Tracking Account balances on March 31 is divided by the forecasted PPFAC year kWh sales to determine the True-Up Component for the coming PPFAC year.

TEP shall maintain and report monthly the balances in a True-Up Component Tracking Account, which will reflect monthly collections or refunds under the True-Up Component and the amounts approved for use in calculating the True-Up Component.

Each annual TEP filing on October 31 will include an accumulation of Forward Component Tracking Account balances and True-Up Component Tracking Account balances for the preceding April through September and an estimate of the balances for October through March (the remaining six months of the current PPFAC Year). The TEP filing shall use these balances to calculate a preliminary True-Up Component for the coming PPFAC Year. On or before February 1, TEP will ~~submit a supplemental filing that recalculates the True-Up Component~~ update the October filing. This update~~recalculation~~ shall replace estimated monthly balances with those actual monthly balances that have become available since the October 31 filing.

The October 31 filing's use of estimated balances for October through March (with supporting workpapers) is required to allow the PPFAC review process to begin in a way that will support its completion and a Commission decision before April 1. The February 1 updating will allow for the use of the most current balance information available before the PPFAC rate would go into effect. In addition to the February 1 update filing, TEP monthly filings (for the months of September through December) of Forward Component Tracking Account balance information and True-Up Component Tracking Account balance information will include a recalculation (replacing estimated balances with actual balances as they become known) of the projected True-Up Component unit rate required for the next PPFAC Year.

The True-Up Component Tracking Account will measure the changes each month in the True-Up Component balance used to establish the current True-Up Component as a result of collections under the True-Up Component in effect. It will subtract each month's True-Up Component collections from the True-Up Component balance. The True-Up Component Account will also include Applicable Interest on any balances. TEP shall file the amounts and supporting calculations and workpapers for this account each month.

4. CALCULATION OF THE PPFAC RATE

The PPFAC rate is the sum of the two components:~~;~~ ~~i.e.,~~the Forward Component and the True-Up Component. The PPFAC rate shall be applied to customer bills._ Upon Commission approval, T~~t~~he proposed PPFAC rate (as amended by the updated February 1 filing) shall go into effect on April 1. The PPFAC rate shall be applicable to TEP's retail electric rate schedules (except those specifically exempted) and is adjusted annually. The PPFAC Rate shall be applied to the customer's bill as a monthly kilowatt-hour ("kWh") charge that is the same for all customer classes.

The PPFAC rate shall be reset on April 1 of each year, and shall be effective with the first April billing cycle only after approved by the Commission. It is not prorated~~. The first True-Up Component will include costs and revenues from January 1, 2009 through March 31, 2009.~~

~~5. CALCULATION OF THE FIXED CTC TRUE-UP REVENUE CREDIT~~

~~In addition to the True-Up Component as described in the preceding paragraph, Commission No. 70628 requires that all Fixed CTC True-Up Revenues be credited in their entirety to the ratepayers by means of a credit to the PPFAC.~~

~~The Fixed CTC Revenues shall be credited against PPFAC eligible costs in a manner that keeps the PPFAC rate at zero until the Fixed CTC True-UP Revenues are fully credited. Once the annual PPFAC Rate has been calculated in accordance with Section 4 of this Plan of Administration, the Fixed CTC Revenue Credit shall be equal and opposite of the PPFAC Rate until the Fixed CTC Revenues have been fully credited back to the ratepayers.~~

~~A Tracking Account shall be used to track the Fixed CTC Revenue Credit until the account balance reaches zero.~~

~~5~~6. FILING AND PROCEDURAL DEADLINES

A. October 31 Filing

TEP shall file the PPFAC rate with all Component calculations for the PPFAC year beginning on the next April 1, including all supporting data, with the Commission on or before October 31 of each year. That calculation shall use a forecast of kWh sales and of fuel and purchased power costs for the coming PPFAC year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the True-Up Component calculation for the year beginning on the next April 1, with all supporting data. That calculation will use the same forecast of sales used for the Forward Component calculation.

B. February 1 Filing

TEP will update the October 31 filing by February 1. This update will replace estimated Forward Component Tracking Account balances, and the True-Up Component Tracking

Account balances, with actual balances and with more current estimates for those months (January, February and March) for which actual data are not available. The new PPFAC rate will go into effect on April 1 upon Commission approval.

C. Additional Filings

TEP will also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PPFAC.

D. Review Process

The Commission Staff and interested parties will have an opportunity to review the October 31 and February 1 forecast, balances, and supporting data on which the calculations of the two PPFAC components have been based. Any objections to the October 31 calculations must be filed within 45 days of the TEP filing. Any objections to the February 1 calculations must be filed within 15 days of the TEP filing.

~~6.~~ 7. VERIFICATION AND AUDIT

The amounts charged through the PPFAC will be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded in the True-Up Component for the following year (i.e. starting the next April 1).

TEP agrees to pay the cost of biennial audits of its PPFAC by an outside auditor retained by the Commission.

~~7.~~ 8. SCHEDULES

Samples of the following schedules are attached to this Plan of Administration:

Schedule 1	PPFAC Rate Calculation
Schedule 2	PPFAC Forward Component Rate Calculation
Schedule 3	PPFAC Forward Component Tracking Account
Schedule 4	PPFAC True-Up Component Rate Calculation
Schedule 5	PPFAC True-Up Component Tracking Account

~~8.~~ 9. COMPLIANCE REPORTS

TEP shall provide monthly reports to Staff's Compliance Section and to the Residential Utility Consumer Office detailing all calculations related to the PPFAC. A TEP Officer shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief and that there have been no changes to the Allowable Costs recovered through the PPFAC without Commission approval. These monthly reports shall be due within 45~~30~~ days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PPFAC Rate Calculation (Schedule 1); Forward Component and True-Up Component Calculations (Schedules 2 and 4); Annual Forward Component and, True-Up Component Tracking Account Balances (Schedules 3 and 5). Additional information will provide other relative inputs and outputs such as:

    a. Total power and fuel costs.
    b. Customer sales in both MWh and thousands of dollars by customer class.
    c. Number of customers by customer class.
    d. A detailed listing of all items excluded from the PPFAC calculations.
    e. A detailed listing of any adjustments to the adjustor reports.
    f. Total short term sales revenues.
    g. System losses in MWh.
    h. Monthly maximum retail demand in MW.
    i. SO_2 allowance sales.
2. Identification of a contact person and phone number from TEP for questions.

TEP shall also provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 45~~30~~ days of the end of the reporting period. All of these additional reports must be provided confidentially.

A. Information for each generating unit will include the following items:
    1. Net generation, in MWh per month, and 12 months cumulatively.
    2. Average heat rate, both monthly and 12-month average.
    3. Equivalent forced-outage rate, both monthly and 12-month average.
    4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
    5. Total fuel costs per month.
    6. The fuel cost per kWh per month.

B. Information on power purchases will include the following items per seller (information on economy interchange purchases may be aggregated):
    1. The quantity purchased in MWh.
    2. The demand purchased in MW to the extent specified in the contract.
    3. The total cost for demand to the extent specified in the contract.
    4. The total cost of energy.

C. Fuel purchase information shall include the following items:
   1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
   2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm, total cost, supply basin, and volume by contract.

D. TEP will also provide:
   1. Monthly projections for the next 12-month period showing estimated (Over)/undercollected amounts.
   2. A summary of unplanned outage costs by resource type.
   3. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.
   4. The data necessary to arrive at the Total Fuel and Purchase Power cost reflected in the non-confidential filing (Section 8.1.a).

In addition, TEP will prepare certain schedules and documents that will provide the necessary transparency of TEP's fuel and purchased power procurement activities such that the prudence of these activities can be determined and compliance with company procurement protocols can be confirmed.

Workpapers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate protective agreement. TEP will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PPFAC at any time. Any costs flowed through the PPFAC are subject to refund, if those costs are found to be imprudently incurred.

~~9~~10. *ALLOWABLE COSTS*

A. Accounts

The allowable PPFAC costs include fuel and purchased power costs incurred to provide service to retail customers. Additionally, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PPFAC. The allowable cost components include the following Federal Energy Regulatory Commission ("FERC") accounts:

- 501 Fuel (Steam)
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

B. Other Allowable Costs/Credits

- Brokerage Fees recorded in FERC Account 557
- Lime costs recorded in FERC Account 502
- Sulfur credits recorded in FERC Account 501 or 502 (whichever FERC requires)

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

No other costs or credits are allowed without~~ne without pre~~ approval from the Commission in an Order.

Tucson Electric Power Company
Purchased Power and Fuel Adjustment Clause
Monthly Information Filing
Proposed 20xx & 20xx PPFAC Rate Filing

Schedule 1	Projected Rate Calculation effective April 1, 20xx
Schedule 2	Projected PPFAC Forward Component Rate Calculation Effective April 1, 20xx
Schedule 3	Projected Forward Component Tracking Account Balance
Schedule 4	Projected PPFAC True-Up Component Rate Calculation Effective April 1, 20xx
Schedule 5	Projected True-Up Component Tracking Account Balance
	Lime Cost Support
	Sulfur Credit Support
	Brokerage Cost Support
	Forecast

Tucson Electric Power Contact Information

Toby Voge (520) 745-3332
Senior Director, Tucson Electric Power

TUCSON ELECTRIC POWER COMPANY

Schedule 1

Purchased Power and Fuel Adjustment Clause (PPFAC) Rate Calculation

($/kWh)

Line No.	PPFAC Rate Calculation	Current 4/1/20xx	Proposed 4/1/20xx	Increase / (Decrease) $.000000/kWh	%
1	Forward Component Rate (Sch. 2, L12) [1]				
2	True-Up Component Rate (Sch. 4, L5) [2]				
3	PPFAC Rate April 1, 20xx (L1+L2)				
4	Average Base Rate April 1, 20xx [3]				
5	Average Total Rate April 1, 20xx (L3+L4)				

Notes:

[1] TEP PPFAC effective April 1, 20xx, and proposed 20xx rate

[2] A Historical Component is a true-up related to respective prior period PPFAC activity.

[3] Average Base Rate as defined in Decision No.XXXXX

A

TUCSON ELECTRIC POWER COMPANY

Schedule 2

PPFAC Forward Component Rate Calculation Effective April 1, 20xx

(Forward Component Rate in $/kWh)

Line No.	PPFAC Forward Component Rate - Calculation	Current 4/1/20xx	Proposed 4/1/20xx	Increase / (Decrease) $ Values	%
1	Projected PPFAC Fuel and Purchased Power Costs 1				
2	Projected Short Term Sales Revenue Credit [2]				
3	Projected Wholesale Trading Activities Credit 3				
4	Projected SO2 Allowance Sales Credit [4]				
5	Net Fuel and Purchased Power Cost (L1+ L2+L3 +L4)				
6	Projected Native Load Energy Sales (kWhs)				
7	Projected Average Net Fuel Costs $/kWh (L5/L6)				
8	Base Cost of Fuel and Purchased Power $/kWh				
9	Difference between Projected Cost & Base Cost (L7-L8)				
10	Forward Component Costs (L6*L9)				
11	Projected Energy Sales (kWh)				
12	Forward Component Rate $/kWh (L10/L11)				

Notes:

[1] Includes Sulfur Credits, Lime Costs, and Brokerage Costs per Commission Decision No. xxxxx

[2] Short Term Sales revenues are credited at 100% as approved by the Commission in Decision No. 70628.

[3] 10% of Wholesale Trading Activities credited against Fuel and Purchased Power Costs as approved by the Commission in Decision No. 70628.

[4] 100% of SO2 Allowance Sales credited against Fuel and Purchased Power Costs per Commission Decision No. xxxxx

B

TUCSON ELECTRIC POWER COMPANY
Schedule 5
True-Up Component Tracking Account - Prior PPFAC True-Up Component Rate in Effect April 1, 20xx through Mar 31, 20xx
($ in thousands; rate in $/kWh)

Line No.		Actual data						Forecasted data			
		Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	Jan-13
1a	TU Beginning Balance as of Apr. 1, 2009 [1] and thereafter										
1b	FC Tracking Account Balance as of March 31, 20xx										
2	Revenue True-Up from January-March Estimate [2]										
3	TU Adjusted Beginning Balance (L1 + L2)										
4	Applicable True Up Component Rate ($/kWh)										
5	Retail Billed Sales Less Low-Income Sales (MWhs) [3]										
6	Less Revenue from Application TU (L4 x L5) [4]										
7	Monthly Interest (Line 3 * Int Rate/12) [5]										
8	TU Ending Balance; (L3 - L6 + L7)										

Notes:

[1] Beginning Balance as of April 1, 20xx - carried forward April 1, 20xx PPFAC Filing.

[2] True-up is the result of using estimated revenue for January through March since the actual amount was not available at the time of prior period PPFAC filing

[3] Sales amounts are for energy billed beginning with the first billing cycle of April 20xx. Retail Billed Sales excludes low income customers not subject to the PPFAC Rate.

[4] Generally, Line 4 x Line 5 = Line 6; however, differences may occur due to billing adjustments.

[5] Based on one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release, H-15 on the first business day of the calendar year. As of 1/3/2012 0.00%

Schedule presentation will appear to roundup $'s and MWhs; however calculations are performed on an actual $ and MWh basis with resultant Rate/kWh roundup to $0.000000/kWh

E

TUCSON ELECTRIC POWER COMPANY

Lime Costs

el Imbalance Tracking Account - PPFAC Rate in effect Month/Day/Year

($ in thousands; Rates in $/kWh)

	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13
Forecasted Tons								
Forecasted $/Ton								
Forecasted Cost								
Forecasted Generation								
Expected $/MWh								
Actual Tons								
Actual Costs								
Actual Generation								
Actual $/MWh								

TUCSON ELECTRIC POWER COMPANY

Sulfur Credit

ıel Imbalance Tracking Account - PPFAC Rate in effect Month/Day/Year

($ in thousands; Rates in $/kWh)

	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13
Forecasted Tons/mmbtu									
Forecasted $/Ton									
Forecasted Cost									
Forecasted Generation									
Expected $/MWh									

TUCSON ELECTRIC POWER COMPANY

Brokerage Costs

Fuel Imbalance Tracking Account - PPFAC Rate in effect Month/Day/Year

($ in thousands; Rates in $/kWh)

	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13
Costs							

TEP MONTHLY PPFAC REPORT

Ascend Analytics
PowerSimm Planner
TEP
Monthly

TEP PPFAC COSTS ($000)	2012.08	2012.09	2012.10	2012.11	2012.12	2013.01	2013.02	2013.03	2013.04	2013.05	2013.06	2013.07	2013.08	2013.09	2013.10	2013.11	2013.12	2014.01	2014.02	2014.03
Fuel Expense																				
Purchases Power Expense																				
Total Fuel & Purchase Power																				
Renewable Delta																				
Firm Purchase Power Demand Charges																				
Transmission Wheeling Charges																				
Net Position on Financial Gas Hedges																				
Total PPFAC Eligible Costs Excl Wholesale																				

FIRM LOAD (MWh)	2012.08	2012.09	2012.10	2012.11	2012.12	2013.01	2013.02	2013.03	2013.04	2013.05	2013.06	2013.07	2013.08	2013.09	2013.10	2013.11	2013.12	2014.01	2014.02	2014.03
Retail Load with System Losses																				
Firm Wholesale Load																				
Total Firm Load Obligations																				

SALES (MWh)	2012.08	2012.09	2012.10	2012.11	2012.12	2013.01	2013.02	2013.03	2013.04	2013.05	2013.06	2013.07	2013.08	2013.09	2013.10	2013.11	2013.12	2014.01	2014.02	2014.03
Retail Sales																				
System Sales																				
Total Sales																				

LOSSES (MWh)	2012.08	2012.09	2012.10	2012.11	2012.12	2013.01	2013.02	2013.03	2013.04	2013.05	2013.06	2013.07	2013.08	2013.09	2013.10	2013.11	2013.12	2014.01	2014.02	2014.03
Retail Losses																				
Firm Losses																				
Total Losses																				

SALES WITH LOSSES (MWh)	2012.08	2012.09	2012.10	2012.11	2012.12	2013.01	2013.02	2013.03	2013.04	2013.05	2013.06	2013.07	2013.08	2013.09	2013.10	2013.11	2013.12	2014.01	2014.02	2014.03
Retail Sales																				
Long Term Wholesale Sales																				
Total System Losses																				
Total Sales with Losses																				

JURISDICTIONAL ALLOCATION	2012.08	2012.09	2012.10	2012.11	2012.12	2013.01	2013.02	2013.03	2013.04	2013.05	2013.06	2013.07	2013.08	2013.09	2013.10	2013.11	2013.12	2014.01	2014.02	2014.03
Energy Ratio																				

TOTAL PPFAC ELIGIBLE COSTS JURISDICTIONAL ALLOCATION	2012.08	2012.09	2012.10	2012.11	2012.12	2013.01	2013.02	2013.03	2013.04	2013.05	2013.06	2013.07	2013.08	2013.09	2013.10	2013.11	2013.12	2014.01	2014.02	2014.03
Thermal Production - FERC 501 and FERC 547																				
Purchased Power - Energy - FERC 555																				
Purchased Power - Demand - FERC 555																				
Transmission of Electricity by Others - FERC 565																				
Total PPFAC Eligible Costs Allocated to Retail																				
Less: Wholesale Sales Revenue																				

ATTACHMENT
"D"

Tucson Electric Power Company
Energy Efficiency Resource Plan
Plan of Administration

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1. General Description

This document describes the Plan of Administration ("POA") for the Energy Efficiency Resource Plan ("EERP") approved for Tucson Electric Power Co. ("TEP" or "Company") by the Arizona Corporation Commission ("Commission") on XXXX, 2013 in Decision No. XXXX ("Decision"). The EERP mechanism provides for the recovery of allowable costs related to Demand Side Management/Energy Efficiency Programs ("DSM/EE") as a capital investment, setting recovery of the asset over a five-year term where TEP recovers the revenue requirements from carrying costs and regulatory asset amortization in cost-effective DSM/EE programs through the Demand Side Management Surcharge ("DSMS"), as described within this POA.

2. Definitions

Amortize – The process of ratably distributing a previously capitalized cost to expense over a designated period.

Avoided Cost – The avoided cost is the marginal cost to produce one more unit of energy. The avoided cost consist of two components: avoided cost of energy and avoided cost of capacity.

> TEP's avoided cost of energy or marginal energy cost is determined using the Resource Planning Hourly Economic Dispatch Model.
>
> TEP's avoided cost of capacity is determined through TEP's long-term planning modeling of capacity. The plan for meeting capacity needs is determined on both economics and reliability. Future capacity costs include market purchase power capacity, transmission upgrades and capacity build options.

Carrying Costs – Costs recovered through the DSMS charge include a return on EERP Program Investment Base[1] based on TEP's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. XXXXX.

Combined Heat and Power ("CHP") – Combined heat and power, which is using a primary energy source to simultaneously produce electrical energy and useful process heat.

Cost-Effective – The result of an action or series of actions where the total incremental benefits from a DSM/EE measure or DSM/EE program exceed total incremental costs over the life of the DSM/EE measure.

Demand Savings – The load reduction, measured in kW, occurring during a relevant peak period or periods as a direct result of energy efficiency and demand response programs.

Demand Response ("DR") – Modification of customer's electricity consumption patterns, affecting the timing or quantity of customer demand and usage, achieved through intentional actions taken by an affected utility or customer because of changes in prices, market conditions, or threats to system reliability.

[1] Program Investment Base as delineated in Section 6.A.

Demand Side Management ("DSM") – Reduction of electricity use through the implementation and maintenance of Company-sponsored measures, programs or plans.

DSM Measure – Any material, device, technology, educational program, pricing option, practice, or facility alteration designed to result in reduced peak demand, increased energy efficiency, or shifting of electricity consumption to off-peak periods and includes CHP used to displace space heating, water heating, or another load.

DSM Program – One or more DSM measures provided as part of a single offering to customers.

Demand Side Management Surcharge ("DSMS") – A Commission-approved provision in TEP's rate schedule allowing TEP to change certain rates through a surcharge, in an established manner, when changes in specific costs and charges are incurred by TEP.

Energy Efficiency ("EE") – The production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers.

Energy Efficiency Programs – Any program that is specifically designed to reduce energy use and/or provide some non-coincident and coincident peak demand savings.

Energy Savings – The reduction in a customer's energy consumption directly resulting from a DSM/EE program, expressed in kWh, at the generator.

Energy Efficiency Standard – The Arizona Electric Energy Efficiency Standards, Title 14, Chapter 2, Article 24 of the Arizona Administrative Code.

Incentives – Financial payments, goods, or services offered by a utility to promote energy and related cost savings including, but not limited to, cash rebates or financial payments, advanced financing of project costs, design and implementation of utility related projects, energy management services, facilities alterations, installation of technologies and energy savings devices, or water conservation devices.

Incremental Cost – Additional expenses of DSM/EE measures, relative to baseline.

Measurement, Evaluation, and Research ("MER") – The performance of studies and activities aimed at determining the effects of an energy efficiency program, which may include data collection, monitoring, and analysis associated with the calculation of energy and demand savings from measures or projects, and including research necessary to inform the evaluation of existing EE programs and the design of new EE programs.

Non-Energy Benefits – Non-energy benefits (or non-market benefits) are the improvements in societal welfare that are not bought or sold. These benefits are any program implementation or participation effect that is other than the direct energy savings effects associated with an energy efficiency, resource acquisition, or resource procurement program. Some examples may include: reduced water consumption, reduced emission and environmental benefits in a building, secondary economic impacts from low income programs, health and safety, job creation, improved comfort, indoor air quality, longevity of equipment, improved worker productivity, and worker retention.

Program Costs – The expenses incurred as a result of developing, marketing, implementing, administering, and evaluating Commission-approved DSM/EE programs.

Regulatory Asset – A capitalized cost that would otherwise be accounted for as an expense, but for its inclusion in a Commission approved cost recovery mechanism providing for such costs to be deferred and then transferred to expense and recovered through basic service rates or a specific surcharge in effect for a designated period.

Societal Test – A cost-effectiveness test of the net benefits of DSM/EE programs that starts with the Total Resource Cost Test, but includes non-energy benefits and costs to society.

Total Resource Cost Test – A cost-effectiveness test that measures the net benefits of a DSM/EE program as a resource, including incremental measure costs, incremental affected utility costs, and carrying costs as a component of avoided capacity cost, but excluding incentives paid by affected utilities and non-market benefits to society.

3. Annual Energy Efficiency (EE) Investment

Program investments will be the sum of actual costs for all DSM/EE programs, plus allowable costs outlined in section 7. Actual costs incurred, after program savings have been verified through the MER process, will be deemed to be allowable investments for recovery.

4. Cost-effectiveness

TEP will invest in existing DSM/EE programs and measures that have been previously approved by the Commission and implemented by TEP. In addition, TEP will invest in and implement new EE measures and programs only once it is shown that they produce a benefit/cost ratio greater than one, resulting from using the Societal Test.

A new EE measure or program that passes the Societal Test as defined herein will be filed for Commission approval in an annual EE Implementation Plan.

5. Annual Implementation Plans

TEP will file annual Implementation Plans by June 1 of each year. The Implementation Plan approved by the Commission shall remain in effect until further order of the Commission. The Company will propose (at a minimum) in their annual Implementation Plans:

- New programs and measures, if any
- Societal test results and models
- Proposed Budgets
- Annual savings
- Cost per kWh (based on lifetime savings)
- Targets for annual savings and costs per kWh

Based on the Implementation Plan filed by June 1st, Staff will file a Staff Report and proposed order by November 15th of same year.

6. Revenue Requirement

The following discussion provides inputs and methodologies for each of the terms in the capitalization model. The revenue requirement will be determined by applying a 5-year amortization schedule to actual DSM/EE Costs for the previous calendar year. Exhibit 1 provides an example of what the revenue requirement worksheets would look like over the next four years. Investment dollars are for illustration purposes only.

A. Program Investment Base

Program Investment Base will be equivalent to the actual DSM/EE spending after providing documentation through the MER reports. For purposes of computing the amortization expense and the return components of the program revenue requirement that will underlie the DSMS, a program investment base will be comprised of a regulatory asset for which the actual program spending will be accumulated. Upon implementation of a specific program, all actual program costs will be charged to the regulatory asset. Deducted from the regulatory asset will be the accumulated amortizations based on recovery of all actual expenses at a rate of 20% for each of the five years. In addition, the net program investment base will be reduced by Accumulated Deferred Income Taxes reflecting the book-tax timing difference created by all program expenditures being currently deducted for tax, but deferred and amortized over five years for accounting purposes. Based on the previous year's actual DSM/EE spending, the revenue requirement will be calculated as the sum of the average of the beginning and end of year net investment balances, multiplied by the allowed rate of return, plus the regulatory asset amortization.

Should the EE Resource Plan be discontinued at a future date, TEP will be permitted to recover the balance remaining in the regulatory asset through continued use of the DSMS in existence at the time and until such time that the entire balance is collected. In connection with the discontinued EE Resource Plan, TEP would provide final documentation reconciling all differences between program budgets and actual costs incurred producing any unrecovered balance remaining in the regulatory assets at the end of the last funding cycle.

B. Carrying Costs

TEP's return on the EE Resource Plan investments will be based on TEP's WACC as approved by the Commission in Decision No. XXXXX (DATE). TEP's investment in EE/DSM will accrue Carrying Costs from the date expenditures are incurred.

C. Annual Recovery of Program Investment Base

TEP will recover the allowable costs associated with the EERP if actual results of the EE/DSM investments achieve a minimum annual portfolio level savings (kWh) and do not exceed the maximum portfolio level cost ($ per kWh) (based on lifetime savings) set annually in implementation plans as approved by the Commission.

Beginning in 2013 the minimum annual portfolio level savings shall be set at 84,024,000 kWh and will not exceed a maximum portfolio level cost of $0.02208 per kWh. These levels will remain in effect until further order of the Commission.

For the purposes of this calculation Demand Response or Direct Load Control Programs will be set at the level of saving credit specified in A.C.C. R-14-2-2404. C. (Peak reduction capability will be converted to an annual energy saving equivalent based on an assumed 50% annual load factor and not to exceed 10% of the energy efficiency standard).

7. Demand Side Management Surcharge

A. Rate Schedule Applicability

The DSMS shall be applied monthly to every rate schedule unless exempted by order of the Commission. A DSMS schedule is included in Exhibit 2 and shall be updated with Commission Order.

A self-direction option exists for qualifying customers of sufficient size in which the amount of money paid by each qualifying customer toward DSM costs is tracked for the customer and made available for use by the customer for approved DSM investments. Details on the self-direction option are included in Exhibit 3.

B. Allowable Costs

Allowable Costs include: program implementation; rebates and incentives; training and technical assistance; consumer education; marketing; planning and administration; measurement, evaluation and research; new program development and analysis; any software development required for tracking and reporting of EE and DR programs; and any other expenses required to design and implement cost-effective EE and DR programs. All program costs will be charged to the appropriate regulatory asset after spending occurs and savings are verified through MER activities as previously described. As such amounts are amortized, they will be charged to FERC Account 908, Customer Assistance Expense or other appropriate accounts as required by the FERC Uniform System of Accounts. Amortization expense and revenues will be recorded monthly based on each month's retail sales volumes.

C. Determination of True-up

As delineated in Exhibit 2, the DSMS that will take effect upon the effective date of Decision No. XXXXX (DATE) will be set to include all historical unrecovered DSM expenses incurred by TEP up to the time of the effective date of this Order, which is estimated to be $4 million and will be recovered over a 12 month period. Any amount over or under collected by TEP's voluntary March 1, 2013 resumption of projects, shall be included as determined under this Plan in the March 1, 2014 DSMS reset.

On March 1 of each year following the effective date of this order, TEP will file a DSMS reset request that will include the revenue requirements based upon all allowable investments from the

previous program year(s). The new DSMS will be effective June 1 of each year, upon Commission approval.

D. Determination of the Surcharge

The revenue requirements (under this Plan) determined by the sum of Carrying Costs and regulatory asset amortization for each program year will be divided by the forecasted energy sales for the recovery time period to determine the $/kWh DSMS for residential customers and a percentage of bill for non-residential customers. Exhibit 5 shows an example schedule for determining the total annual revenue requirements used for calculating the DSMS for the first four years of funding.

On March 1, 2014, TEP will file a DSMS reset request for purposes of recovering investments under the EERP from March 1, 2013 through December 31, 2013. The DSMS will be calculated based upon the following formula:

$$\text{DSMS} = \frac{\text{RR1}}{\text{Sales}}$$

Where:

RR1	=	First year of 2013 revenue requirement is equal to expenses from March 1, 2013 above historical spending levels through the effective date of this order in excess of the estimated $4 million under recovery from prior periods, plus expenses after the effective date of Decision No. XXXXX through December 2013.
Sales	=	Forecasted energy (kWh) sales under applicable rate schedules during the period in which the DSMS will be effective.

On March 1, 2015, TEP will file a DSMS reset request for purposes of recovering investments under the EERP for the 2014 program year (January 1, 2014- December 31, 2014). The DSMS will be calculated based upon the following formula:

$$\text{DSMS} = \frac{\text{RR2}}{\text{Sales}}$$

Where:

RR2	=	First year of 2014 revenue requirement plus the second year of 2013 revenue requirement.
Sales	=	Forecasted energy (kWh) sales under applicable rate schedules (as defined above) during the period in which the DSMS will be effective.

All subsequent March 1st filings for a DSMS reset will follow the procedure outlined above.

The proposed DSMS Tariff is provided in Exhibit 4.

8. DSM/EE Reports

In accordance with A.A.C. R14-2-2409, the Company will provide a previous year progress report to the Commission by March 1st and a current mid-year status report by September 1st of each year. The compliance filings and dates contained in this POA and Decision No. XXXXX (DATE) supersede the requirements contained in previous Commission Orders.

EERP POA –Exhibit 1 – Example Revenue Requirements

2013 Revenue Requirement

	Capitalization of EE Investments	
Year		
2013	$ 14,544,577	Original Cost
(Mar '13 - Dec '13)	5	Asset Life
	39.6%	Income Tax Rate
	7.74%	Nominal Return
	10.98%	Pre-tax Return
	6.64%	After-tax Return
		Capital Structure:
	54.00%	Debt
	46.00%	Equity
		Short-Term Debt
		Cost of Capital:
	5.18%	Debt
	10.75%	Equity
		Short-Term Debt

		2014	2015	2016	2017	2018	2019
	0	1	2	3	4	5	6
Regulatory Asset Amortization		$ 2,908,915	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ -
Tax depreciation	$ -	$ 14,544,577	$ -	$ -	$ -	$ -	$ -
Net book basis (end of year)	$ -	$ 11,635,662	$ 8,726,746	$ 5,817,831	$ 2,908,915	$ -	$ -
Tax basis (end of year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADIT (end of year) ((book basis minus tax basis) times t	$ -	$ 4,604,231	$ 3,453,174	$ 2,302,116	$ 1,151,058	$ -	$ -
Long-term debt balance (end of year)	$ -	$ 3,796,972	$ 2,847,729	$ 1,898,486	$ 949,243	$ -	$ -
LT Debt Interest		$ 237,367	$ 172,098	$ 122,927	$ 73,756	$ 24,585	$ -
Rate Base, end of year							
Regulatory Asset	$ -	$ 14,544,577	$ 14,544,577	$ 14,544,577	$ 14,544,577	$ 14,544,577	$ 14,544,577
Accumulated Amortization		$ (2,908,915)	$ (5,817,831)	$ (8,726,746)	$ (11,635,662)	$ (14,544,577)	$ (14,544,577)
ADIT	$ -	$ (4,604,231)	$ (3,453,174)	$ (2,302,116)	$ (1,151,058)	$ -	$ -
Unamortized ITC	$ -	$ -	$ -	$ -	$ -	$ -	
Rate Base, end of year	$ -	$ 7,031,430	$ 5,273,573	$ 3,515,715	$ 1,757,858	$ -	$ -
Revenue Requirement							
Carrying Costs	$ -	$ 931,769	$ 675,558	$ 482,542	$ 289,525	$ 96,508	$ -
Regulatory Asset Amortization	$ -	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ 2,908,915	$ -
Gross Revenue Requirement		**$ 3,840,685**	**$ 3,584,474**	**$ 3,391,457**	**$ 3,198,440**	**$ 3,005,424**	**$ -**

EERP POA –Exhibit 1 – Example Revenue Requirements

2014 Revenue Requirement

	Capitalization of EE Investments	
Year		
2014	$ 24,739,192	Original Cost
	5	Asset Life
	39.6%	Income Tax Rate
	7.74%	Nominal Return
	10.98%	Pre-tax Return
	6.64%	After-tax Return
		Capital Structure:
	54.00%	Debt
	46.00%	Equity
		Short-Term Debt
		Cost of Capital:
	5.18%	Debt
	10.75%	Equity
		Short-Term Debt

		2014	2015	2016	2017	2018	2019
	0	1	2	3	4	5	6
Regulatory Asset Amortization		$ 4,947,838	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ -
Tax depreciation	$ -	$ 24,739,192	$ -	$ -	$ -	$ -	$ -
Net book basis (end of year)	$ -	$ 19,791,354	$ 14,843,515	$ 9,895,677	$ 4,947,838	$ -	$ -
Tax basis (end of year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADIT (end of year) ((book basis minus tax basis) times t	$ -	$ 7,831,439	$ 5,873,579	$ 3,915,719	$ 1,957,860	$ -	$ -
Long-term debt balance (end of year)	$ -	$ 6,458,354	$ 4,843,766	$ 3,229,177	$ 1,614,589	$ -	$ -
LT Debt Interest		$ 403,743	$ 292,725	$ 209,089	$ 125,454	$ 41,818	$ -
Rate Base, end of year							
Regulatory Asset	$ -	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192	$ 24,739,192
Accumulated Amortization		$ (4,947,838)	$ (9,895,677)	$ (14,843,515)	$ (19,791,354)	$ (24,739,192)	$ (24,739,192)
ADIT	$ -	$ (7,831,439)	$ (5,873,579)	$ (3,915,719)	$ (1,957,860)	$ -	$ -
Unamortized ITC	$ -	$ -	$ -	$ -	$ -	$ -	
Rate Base, end of year	$ -	$ 11,959,915	$ 8,969,936	$ 5,979,957	$ 2,989,979	$ -	$ -
Revenue Requirement							
Carrying Costs	$ -	$ 1,584,867	$ 1,149,072	$ 820,766	$ 492,459	$ 164,153	$ -
Regulatory Asset Amortization	$ -	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ 4,947,838	$ -
Gross Revenue Requirement		**$ 6,532,705**	**$ 6,096,910**	**$ 5,768,604**	**$ 5,440,298**	**$ 5,111,992**	**$ -**

EERP POA –Exhibit 1 – Example Revenue Requirements

2016 Revenue Requirement

Year 2016	Capitalization of EE Investments	
	$ 27,856,255	Original Cost
	5	Asset Life
	39.6%	Income Tax Rate
	7.74%	Nominal Return
	10.98%	Pre-tax Return
	6.64%	After-tax Return
		Capital Structure:
	54.00%	Debt
	46.00%	Equity
		Short-Term Debt
		Cost of Capital:
	5.18%	Debt
	10.75%	Equity
		Short-Term Debt

	0	2016 1	2017 2	2018 3	2019 4	2020 5	2021 6
Regulatory Asset Amortization		$ 5,571,251	$ 5,571,251	$ 5,571,251	$ 5,571,251	$ 5,571,251	$ -
Tax depreciation	$ -	$ 27,856,255	$ -	$ -	$ -	$ -	$ -
Net book basis (end of year)	$ -	$ 22,285,004	$ 16,713,753	$ 11,142,502	$ 5,571,251	$ -	$ -
Tax basis (end of year)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
ADIT (end of year) ((book basis minus tax basis) times t	$ -	$ 8,818,176	$ 6,613,632	$ 4,409,088	$ 2,204,544	$ -	$ -
Long-term debt balance (end of year)	$ -	$ 7,272,087	$ 5,454,065	$ 3,636,044	$ 1,818,022	$ -	$ -
LT Debt Interest		$ 454,614	$ 329,607	$ 235,434	$ 141,260	$ 47,087	$ -
Rate Base, end of year							
Regulatory Asset	$ -	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255	$ 27,856,255
Accumulated Amortization		$ (5,571,251)	$ (11,142,502)	$ (16,713,753)	$ (22,285,004)	$ (27,856,255)	$ (27,856,255)
ADIT	$ -	$ (8,818,176)	$ (6,613,632)	$ (4,409,088)	$ (2,204,544)	$ -	$ -
Unamortized ITC	$ -	$ -	$ -	$ -	$ -	$ -	
Rate Base, end of year	$ -	$ 13,466,828	$ 10,100,121	$ 6,733,414	$ 3,366,707	$ -	$ -
Revenue Requirement							
Carrying Costs		$ 1,784,555	$ 1,293,852	$ 924,180	$ 554,508	$ 184,836	$ -
Regulatory Asset Amortization		$ 5,571,251	$ 5,571,251	$ 5,571,251	$ 5,571,251	$ 5,571,251	$ -
O & M		$ -	$ -	$ -	$ -	$ -	$ -
Gross Revenue Requirement		**$ 7,355,806**	**$ 6,865,103**	**$ 6,495,431**	**$ 6,125,759**	**$ 5,756,087**	**$ -**

Self-Direction Option

Self-Direction is an option that will be made available to large qualifying industrial customers. Self-Direction allows participating customers to reserve their DSM/EE contributions, less administrative and other program costs, for their exclusive use to help fund qualifying DSM/EE projects at their facilities. Self-Direction will be offered to the largest customers since they have the ability and resources (technical knowledge, expertise, and funding) to implement effective DSM/EE and they may desire to have the flexibility to use their DSM/EE contributions to fund their own energy efficiency projects. The following parameters define the Self Direction option:

1. To be eligible for Self-Direction, a customer must use a minimum of 35 million kWh per calendar year, based on an aggregation of all of the customer's TEP accounts.
2. Qualifying Self-Direction customers who choose to self-direct their DSM/EE funds must elect Self-Direction by notifying the Company in each year that they wish to Self-Direct. Customers who elect to Self-Direct must continue to contribute their share of DSM/EE funds through the DSMS.
3. After a customer notifies the Company of their intent to Self-Direct, 90% of the customer's DSMS contribution will be reserved for tracking purposes for the customer's future energy efficiency project. The remaining 10% will be retained to cover the Self-Direction program administration, management, and MER costs.
4. Self-Direction funds will be reserved for tracking purposes for the calendar year the Self-Direction election is received by the Company. Such election must be received on or before December 1st. There will be no retroactive Self-Direction funds set aside from prior budget years, since the Company's books were closed prior to the customer's election.
5. Self-Direction funds will be paid to the qualifying customer once a year in December beginning in the year that the EE project is completed and verified. If project costs exceed the credited amount in one year, then funding will continue to be paid in December of each year until the project is 100% funded or in the fourth year of funding, or until the Commission terminates this program, whichever comes sooner.
6. If the EE project is not completed within two (2) years of the Self-Direction election date, then the Self-Direction funds from the first calendar year from the Self-Direction election will not be available to the customer and will revert to the DSMS general account.
7. Qualifying customers will be required to commit all of their facilities to the Self-Direction option for the duration of the specific Self-Direction project's funding period. Customers would not be able to designate some of their accounts for Self-Direction, while allowing some of their other accounts to remain eligible for other TEP commercial EE programs. Customers choosing to Self-Direct will not be permitted to participate in any other TEP commercial EE program offerings for any of their accounts.
8. Aggregation would be allowed only within a given customer set of accounts, not across groups of customers. This means that groups of customers would not be able to form buying associations for the purpose of meeting the Self-Direction size criteria.

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) applies to all Customers in the entire territory served by the Company as mandated by the Arizona Corporation Commission (ACC), unless otherwise specified.

RATE
The DSMS shall be applied to all monthly bills. The Rate is shown in the TEP Statement of Charges.

REQUIREMENTS
The 2013 TEP DSMS is effective XXXX, XX, 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 the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider

ATTACHMENT
"E"

Attachment E

INCREMENTAL FIXED OPTION LFCR CHARGES FOR RESIDENTIAL CUSTOMERS

Standard Service or Time of Use Service

Addition to Customer Charge with usage less than 2,000 kWh	$2.50 per month
Addition to Customer Charge with usage of 2,000 kWh or more	$6.50 per month

ATTACHMENT
"F"

TUCSON ELECTRIC POWER COMPANY
LOST FIXED COST RECOVERY MECHANISM ("LFCR")
PLAN OF ADMINISTRATION

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1. General Description

This document describes the plan of administration for the LFCR mechanism approved for Tucson Electric Power ("TEP" or "Company") by the Arizona Corporation Commission ("ACC") in Decision No. xxxxx (date). 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 costs included in base rates exclusive of the Customer Charge and 50% of the demand rates in effect.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules, less the amount attributable to sales to those residential customers who chose the Fixed Cost Option.

Current Period – The most recent adjustment year.

Demand Stability Factor – Fifty percent of Demand-based revenue (excluding any purchased power and fuel costs) produced by base rates.

Distribution and Transmission 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) by their approved 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 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 savings will consist of the following by class:

1. Cumulative Verified: The total kWh or kW reduction as metered each year 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 the LFCR will begin on January 1, 2013.

2. 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 excluded rate classes.
4. 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.

EE Savings – The amount of sales, expressed in kWh or kW, reduced by Energy Efficiency activities as demonstrated by the Measurement, Evaluation, and Research ("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 filings accuracy. EE Savings shall be quantified based on the cumulative lost kWh or kW occurring starting January 1, 2013 and shall be 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. Cumulative Verified: The cumulative total kWh or kW reduction 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 be January 1, 2012, (the end of the Test Year in Decision xxxxx, dated xx,). 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 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 (PS-41), ~~the~~ ~~l~~Lighting Service (GS-50), ~~w~~Water ~~p~~Pumping Service (GS-43), or the ~~l~~Large ~~l~~Light and ~~p~~Power Service (LLP-14 and LLP-90) rate schedules.

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 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 adjustment rate 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 Distribution and Transmission Revenue (which excludes the customer 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 and DG Savings during the measurement period. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable kWh Savings, by rate class.

Recoverable kWh Savings - The sum of EE and DG Savings by applicable rate class.

3. *LFCR Annual Incremental Cap*

The LFCR Adjustment will be subject to an annual 1% year over year cap based on Applicable Company Revenues. If the annual incremental LFCR Adjustment results in a surcharge in excess of 1% of Applicable Company Revenues, any amount in excess of the 1% cap will be deferred for collection until the next year. Any deferred amounts will be collected in a subsequent year or rolled into the next rate case, whichever occurs first. Where the 1% cap limits the recovery of deferrals in any program year, and thus moves their recovery to the following year, a first-in, first-out ("FIFO") approach will be applied. In connection therewith, the new surcharge billed in the following year will first recover any such carried-over deferrals, and then recover new deferrals arising in that following year. The one-year Nominal Treasury Constant Maturities rate contained in the Federal Reserve Statistical Release H-15 or its successor publication will be applied annually to any deferred balance. The interest rate shall be adjusted annually and shall be that annual rate applicable to the first business day of the calendar year.

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, 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: Distribution and Transmission Revenue Calculation

SCHEDULES

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 1: LFCR Annual Adjustment Rate (Percentage)
($000)

Line No.	(A) Annual Per kWh Adjustment	(B) Reference		(C) Total
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 13	$	-
2.	Forecast of Applicable Company's Revenues	Schedule 2, Line 1		-
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
($000)

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference		(C) Totals
1	Applicable Company Revenues		$	
2	Allowed Cap %			1.00%
3	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	$	-
4	Total Lost Fixed Cost Revenue	Schedule 3, Line 55, Column C	$	-
5	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 11, 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)	$	-
9	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 13, Column C	$	-
10	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9)	$	-
11	Amount in Excess of Cap to Defer	(Line 10 - Line 3)	$	-
12	Incremental Period Adjustment	[(Line 10 - Line 11)/ Line 1]		-
13	Total Lost Fixed Cost Revenue for Current Period	(Line 8 - Line 11)	$	-

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation
($000)

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Residential				
	Energy Efficiency Savings				
1	Current Period				kWh
2	% of Residential Customers choosing fixed-option			0.0%	
3	Excluded kWh reduction	(Line 1 * Line 2)		-	kWh
4	Net - Current Period	(Line 1 - Line 3)		-	kWh
5	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 6, Column C		-	kWh
6	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 6, Column C + Line 4)		-	kWh
7	Total Recoverable EE Savings	Line 6		-	kWh
8	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	0.0308	$/kWh
9	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 7 * Line 8)	$	-	
	Distributed Generation				
10	Current Period				kWh
11	% of Residential Customers choosing fixed-option			0.0%	
12	Excluded kWh reduction	(Line 10 * Line 11)		-	kWh
13	Net - Current Period	(Line 10 - Line 12)		-	kWh
14	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 15, Column C		-	kWh
15	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 15, Column C + Line 13)		-	kWh
16	Total Recoverable DG Savings	Line 15		-	kWh
17	Residential - Lost Fixed Cost Rate	Schedule 4, Line 3, Column C	$	0.0308	$/kWh
18	Residential - Lost Fixed Cost Revenue Relating to EE	(Line 16 * Line 17)	$	-	
	Small General Service				
	Energy Efficiency Savings				
19	Current Period			-	kWh
20	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 21, Column C		-	kWh
21	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 21, Column C + Line 19)		-	kWh
22	Total Recoverable EE Savings	Line 21		-	kWh
23	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	0.0314	$/kWh
24	Small General Service - Lost Fixed Cost Revenue Relating to EE	(Line 22 * Line 23)	$	-	
	Distributed Generation				
25	Current Period			-	kWh
26	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 27, Column C		-	kWh
27	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 27, Column C + Line 25)		-	kWh
28	Total Recoverable DG Savings	Line 27		-	kWh
29	Small General Service - Lost Fixed Cost Rate	Schedule 4, Line 6, Column C	$	0.0314	$/kWh
30	Small General Service - Lost Fixed Cost Revenue Relating to DG	(Line 28 * Line 29)	$	-	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 3: LFCR Calculation
($000)

Line No.	(A) LFCR Fixed Cost Revenue Calculation	(B) Reference		(C) Totals	(D) Units
	Large General Service - Delivery Revenue - Demand				
	Energy Efficiency Savings				
31	Current Period			-	kW
32	Prior Period kW EE losses	Previous Filing, Schedule 3, Line 33, Column C		-	kW
33	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 33, Column C + Line 31)		-	kW
34	Total Recoverable EE Savings	Line 33		-	kW
35	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	2.3901	$/kW
36	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 34 * Line 35)	$	-	
	Distributed Generation				
37	Current Period			-	kW
38	Prior Period kW DG losses	Previous Filing, Schedule 3, Line 39, Column C		-	kW
39	Cumulative Recoverable kW savings	(Previous Filing, Schedule 3, Line 39, Column C + Line 37)		-	kW
40	Total Recoverable DG Savings	Line 39		-	kW
41	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 9, Column C	$	2.3901	$/kW
42	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 40 * Line 41)	$	-	
	Large General Service - Delivery Revenue				
	Energy Efficiency Savings				
43	Current Period			-	kWh
44	Prior Period kWh EE losses	Previous Filing, Schedule 3, Line 45, Column C		-	kWh
45	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 45, Column C + Line 43)		-	kWh
46	Total Recoverable EE Savings	Line 45		-	kWh
47	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	0.0042	$/kWh
48	Large General Service - Lost Fixed Cost Revenue Relating to EE	(Line 46 * Line 47)	$	-	
	Distributed Generation				
49	Current Period			-	kWh
50	Prior Period kWh DG losses	Previous Filing, Schedule 3, Line 51, Column C		-	kWh
51	Cumulative Recoverable kWh savings	(Previous Filing, Schedule 3, Line 51, Column C + Line 49)		-	kWh
52	Total Recoverable DG Savings	Line 51		-	kWh
53	Large General Service - Lost Fixed Cost Rate	Schedule 4, Line 12, Column C	$	0.0042	$/kWh
54	Large General Service - Lost Fixed Cost Revenue Relating to DG	(Line 52 * Line 53)	$	-	
55	Total Lost Fixed Cost Revenue	Sum Line 9 + 18 + 24 + 30 + 36 + 42 + 48 + 54	$	-	

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 4: LFCR Test Year Rate Calculation
($000)

Line No.	(A) LFCR Fixed Cost Calculation	(B) Reference		(C) Total
	Residential Customers			
1	Delivery Revenue	Schedule 5, Line 5, Column F	$	111,739,643
2	kWh Billed	Forecasted		3,627,093,708
3	Lost Fixed Cost Rate	Line 1/Line 2	$	0.0308
	Small General Service			
4	Delivery Revenue	Schedule 5, Line 8, Column F	$	63,186,286
5	kWh Billed	Forecasted		2,012,114,954
6	Lost Fixed Cost Rate	Line 4/Line 5	$	0.0314
	Large General Service			
7	Delivery Revenue - Demand	Schedule 5, Line 13, Column F	$	8,172,790
8	kW Billed	Forecasted		3,419,489
9	Lost Fixed Cost Rate	Line 7/Line 8	$	2.3901
	Large General Service			
10	Delivery Revenue	Schedule 5, Line 16, Column F	$	5,319,772
11	kWh Billed	Forecasted		1,261,678,481
12	Lost Fixed Cost Rate	Line 10/Line 11	$	0.0042

Tucson Electric Power
Lost Fixed Cost Recovery Mechanism
Schedule 5: Delivery Revenue Calculation
($000)

	(A)	(B)	(C)		(D)	(E)		(F) B x D x E
Line No.	Rate Schedule	Adjusted Test Year Billing Determinants	Units		Delivery Charge	Demand Stability Factor		Total Delivery Revenue
1	Residential Service (R-01)	3,368,532,306	kWh	$	0.0314	100%	$	105,811,858
2	Residential Service (R-80)	116,359,255	kWh	$	0.0229	100%	$	2,664,627
3	Residential Service (R-201AN)	131,427,481	kWh	$	0.0230	100%	$	3,016,454
4	Residential Service (R-201BN)	10,774,668	kWh	$	0.0229	100%	$	246,705
5	Subtotal - kWh	3,627,093,708	kWh	$			$	111,739,643
6	Small General Service (GS-10)	1,888,524,435	kWh	$	0.0314	100%	$	59,326,481
7	Small General Service (SGS-76)	123,590,518	kWh	$	0.0312	100%	$	3,859,805
8	Subtotal - kWh	2,012,114,954	kWh				$	63,186,286
9	Large General Service (LGS-13) - kW	2,719,841	kW	$	5.13	50%	$	6,976,392
10	Large General Service (LGS-85) - kW	699,648	kW	$	3.42	50%	$	1,196,398
11	Subtotal - kW - Demand	3,419,489	kW				$	8,172,790
12	Large General Service (LGS-13)	1,045,063,814	kWh	$	0.0049	100%	$	5,071,019
13	Large General Service (LGS-85)	216,614,667	kWh	$	0.0011	100%	$	248,753
14	Subtotal - kWh - Delivery	1,261,678,481	kWh				$	5,319,772

ATTACHMENT
"G"

TUCSON ELECTRIC POWER COMPANY
ENVIRONMENTAL COMPLIANCE ADJUSTOR ("ECA")
PLAN OF ADMINISTRATION

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Attachments
Schedule 1 - Qualified Investments for ECA
Schedule 2 – Capital Carrying Costs and Adjustor Calculation

1. GENERAL DESCRIPTION

This document describes the plan for administering the ECA as approved by the Arizona Corporation Commission ("Commission" or "ACC") for Tucson Electric Power Company ("TEP") in Decision No. XXXXX [DATE]. The ECA provides for the recovery of and return on capital investments and associated 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 mechanism. The ECA will be calculated annually based on the ECA Qualified Investments closed to plant-in-service during the preceding calendar year.

2. DEFINITIONS

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 In-Service 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 - Those projects designed to comply with established environmental standards required by federal, state, tribal, or local laws and regulations. In general, these environmental standards include, but are not limited 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.

Capital Carrying Costs – Costs recovered through the ECA charge include return on ECA Qualified Investments based on TEP's Weighted Average Cost of Capital ("WACC") approved by the Commission in Decision No. XXXXX; depreciation expense; income taxes; property taxes; deferred income taxes and tax credits where appropriate; and associated operations and management ("O&M") costs.

Total Retail kWh Sales – Total retail kWh sales served under applicable ACC jurisdictional rate schedules as reported in TEP's FERC Form No. 1 for the prior calendar year.

3. ECA QUALIFIED INVESTMENTS - FERC ACCOUNTS

Each ECA Qualified investment may be classified in one or more of the FERC Plant In Service accounts listed below, any successor FERC account, or any other FERC Account approved by the Commission upon going into service. The Plant In-Service FERC Accounts shall include the following:

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

Please note that this list may expand to include other accounts approved by the ACC in the future.

4. CALCULATION OF ECA CAPITAL CARRYING COSTS

The recoverable ECA Capital Carrying Costs used in calculating the ECA $ per kWh rate will include: 1) Return on ECA Qualified Investments based on TEP's WACC approved by the Commission in Decision No. XXXXX; 2) depreciation expense; 3) income taxes; 4) property taxes; 5) deferred income taxes and tax credits where appropriate; and 6) associated O&M costs. The annual amount of Capital Carrying Costs to be recovered is subject to a cap equal to 0.25 percent of the total retail revenue requirement approved by the Commission in Decision No. xxxxx. 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 $ PER KWH RATE

The ECA rate to be applied to customers' bills will be calculated by dividing the total ECA Capital Carrying Costs by Total Retail kWh Sales. The ECA will not exceed $0.00025 per kWh. The initial ECA rate will be set to zero.

6. ACCOUNTING

From the effective date of the ECA, all ECA Capital Carrying Costs, including operating and maintenance expenses, depreciation, taxes, and the debt component of the WACC will be recorded in Other Regulatory Assets in Account 182.3, as they are incurred. Each month as the ECA surcharge revenues are billed, corresponding amortizations will be made from Account 182.3 and recorded in the proper income statement expense accounts. ECA Qualified Investments will continue to be accounted for as Plant In-Service.

7. RECOVERY PERIOD

The initial ECA measurement period will become effective August 1, 2013. The ECA per kWh rate is designed to recover the annual ECA Capital Carrying Costs over a 12-month period. Should the ECA be modified or discontinued, any unrecovered balance in the ECA regulatory asset shall continue to be recovered through the ECA surcharge until all such costs have been collected.

8. FILING AND PROCEDURAL DEADLINES

TEP will file the calculated ECA rate including all supporting data with the Commission for the previous calendar year on or before March 1st. See Schedules 1 and 2, attached.

The Commission Staff and interested parties shall have the opportunity to review the ECA filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted to suspend the filing or Staff has filed an objection by May 1st, the new ECA rate proposed by TEP will go into effect with the first billing cycle in May (without proration) and will remain effective for the following 12-month period.

Schedule 1: Qualified Investments for ECA
Electric Plant In Service for Calendar Year 20XX

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
	Qualified Environmental Compliance 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			$ -	$ -

Schedule 2: Capital Carrying Costs and Adjustor Calculation
Plant in Service for Calendar Year 20XX
Billing Period 1/1/20XX-12/31/XX

Line No.	ECA Rate Calculation		
	Qualified Net Plant		
1.	Qualified Environmental Compliance Projects (Schedule 1 - Total Line Colur	$	-
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%
	ECA Revenue Requirement		
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)		
12.	Calculated ECA Rate ($/kWh) (Line 10 / Line 11)		
13.	ECA Rate Cap ($/kWh)	$	0.00025
14.	ECA Rate ($/kWh) Lesser of Line 13 or Line 14	$	-

ATTACHMENT
"H"

ATTACHMENT H

PROCUREMENT RECOMMENDATIONS

1. TEP should prepare a complete natural gas hedging plan consistent with the requirements outlined in the TEP Hedging Manual.

2. TEP should revise its hedging strategy for natural gas and power to reflect the fundamental changes in the energy markets.

3. TEP should reduce the unit cost of coal in determining cost of coal in inventory by non-recurring costs and ash handling costs.

4. TEP should add resources to the solid fuel group to develop additional support for current solid fuel activities.

5. TEP should develop a plan to minimize solid fuel cost consequences of any decisions to retire plants in response to regional haze requirements.

ATTACHMENT
"I"

ATTACHMENT I - COMPARISON OF LOW INCOME BILL IMPACT WITH AUGUST 2013 PPFAC

Line No.	Class Description	Customer Counts	Average Annual Bill	Average Annual Bill Change (from Current)	Revised Percent Change to Total Bill	$ change in monthly bill	Lifeline bill below R-01 monthly bill
1	Residential R-01	330,848	$966.06	$34.92	3.8%	$2.91 (1)	
2	Residential Lifeline R-04-01	819	$647.15	$31.64	5.1%	$2.64	$26.58
3	Residential Lifeline R-05-01	1,722	$736.03	$36.01	5.1%	$3.00	$19.17
4	Residential Lifeline R-08-01	1,046	$577.75	$28.45	5.2%	$2.37	$32.36
5	Residential Lifeline R-06-01	13,376	$780.85	$31.77	4.2%	$2.65	$15.43
6	Residential Lifeline R-04-21F	4	$562.14	$36.91	7.0%	$3.08	$33.66
7	Residential Lifeline R-05-21F	4	$639.29	$42.01	7.0%	$3.50	$27.23
8	Residential Lifeline R-08-21F	9	$501.49	$33.13	7.1%	$2.76	$38.71
9	Residential Lifeline R-06-21F	25	$663.52	$38.96	6.2%	$3.25	$25.21
10	Residential Lifeline R-04-70F	6	$600.59	$34.73	6.1%	$2.89	$30.46
11	Residential Lifeline R-05-70F	16	$682.93	$39.50	6.1%	$3.29	$23.59
12	Residential Lifeline R-08-70F	24	$535.20	$31.04	6.2%	$2.59	$35.91
13	Residential Lifeline R-06-70F	109	$715.39	$35.76	5.3%	$2.98	$20.89
14	Residential Lifeline 05- 201AF	3	$688.32	$37.13	5.7%	$3.09	$23.15
15	Residential Lifeline 08- 201AF	12	$538.99	$29.36	5.8%	$2.45	$35.59
16	Residential Lifeline 06- 201AF	336	$721.21	$33.16	4.8%	$2.76	$20.40
17	Residential Lifeline 06- 201BF	12	$656.83	$31.70	5.1%	$2.64	$25.77

Note (1) This reflects the inclusion of the PPFAC rate as proposed in the Settlement, which includes $3 million of sulfur credits, deferral of $9.7 million of San Juan "thermal event" costs. Impacts do not include the anticipated changes in DSM or REST rates.

ATTACHMENT
"J"

TUCSON ELECTRIC POWER COMPANY
SUMMARY OF CURRENT, PROPOSED AND SETTLEMENT RATE DESIGN

Rate Schedule	Current Design	Settlement
Lifeline	• Includes 19 rate schedules with different designs • 12 different discounts – one flat and 11 percentage discounts • Excluded from PPFAC charges • Excluded from DSM charges • TOU schedules includes shoulder peak period in delivery • Fuel in base rates with shoulder peak period in TOU schedules	• Include PPFAC charges • Include DSM charges • Increased fixed rate discount from $8 to $9 • Remainder of rates adjusted upward to reflect the same overall dollar change as the R-01 class • No other changes in rate design
Residential R-01	• Three block structure • 6 summer months/6 winter months • Fuel in base rates	• Four block structure • Consolidated R-02 into R-01 • Increase customer and energy charges • 5 summer months/7 winter months • Added AMI opt-out charge • LFCR fixed charge option added • Base Power as in current structure
Residential R-201	• Two different rate structures with and without blocks • Rate structure includes three seasons • 6 summer months/6 winter months • Discounted from R-01 • Fuel in base rates	• Consolidated two rate schedules into one with four blocks • Changed to only a winter and summer season • 5 summer months/7 winter months • Includes 10% discount on non-fuel components to R-01 • Increase customer and energy charges • Base Power as in current structure

TUCSON ELECTRIC POWER COMPANY
SUMMARY OF CURRENT, PROPOSED AND SETTLEMENT RATE DESIGN

Rate Schedule	Current Design	Settlement
Residential R-80 TOU	• Includes 5 rate structure with and without blocks • Includes three different on peak periods • Includes shoulder peak period in delivery • 6 summer months/6 winter months • Fuel in base rates with shoulder peak period	• Consolidated 5 TOU rate schedules into one without blocks • Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Changed to only a winter and summer season • Removed shoulder peak period in delivery • Increase customer and energy charges • 5 summer months/7 winter months • Base Power as in current structure without shoulder peak period
Residential R-201 TOU	• Four different rate structures with and without blocks • Rate structure includes three seasons • Includes shoulder peak period in delivery • 6 summer months/6 winter months • Discounted from R-01 • Fuel in base rates with shoulder peak period	• Consolidated four rate schedules into one without blocks • Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Changed to only a winter and summer season • Removed shoulder peak period in delivery • Increase customer and energy charges • 5 summer months/7 winter months • Includes 15% discount on non-fuel components toR-80 • Base Power as in current structure without shoulder peak period

TUCSON ELECTRIC POWER COMPANY
SUMMARY OF CURRENT, PROPOSED AND SETTLEMENT RATE DESIGN

Rate Schedule	Current Design	Settlement
Small General Service GS-10	• One schedule with two blocks • 6 summer months/6 winter months • Fuel in base rates	• One schedule with two blocks • Increase customer and energy charges • 5 summer months/7 winter months • Municipal Rate 40 included in small general service with a 16.5% discount • Base Power as in current structure
Small General Service GS-76 TOU	• Two schedules with and without blocks • 6 summer months/6 winter months • Includes shoulder peak period in delivery • Fuel in base rates with shoulder peak period	• Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Remove shoulder peak period • Increase customer and energy charges • 5 summer months/7 winter months • Base Power as in current structure without shoulder peak
Large General Service I-13	• Demand ratchet at 50% • 6 summer months/6 winter months • Fuel in base rates	• Increase customer charge • Standard demand and energy increases • Increased demand ratchet from 50% to 75% • 5 summer months/7 winter months • Base Power as in current structure
Large General Service I-85 TOU	• Three rate schedules with two different demand structures • Two different sets of on-peak periods • Includes shoulder peak period in delivery • 6 summer months/6 winter months • Demand ratchet at 50% • Fuel in base rates include shoulder peak period	• Consolidated three rate schedules into one • Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Removed shoulder peak period • 5 summer months/7 winter months • Increase customer charge • Standard demand and energy increases • Increased demand ratchet from 50% to 75%

TUCSON ELECTRIC POWER COMPANY
SUMMARY OF CURRENT, PROPOSED AND SETTLEMENT RATE DESIGN

Rate Schedule	Current Design	Settlement
		(ratchet will be new for 85N) • Base Power as in current structure without shoulder peak period
Large Light & Power I-14	• Demand ratchet at 66.7% • 6 summer months/6 winter months • Fuel in base rates • Power factor a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW	• Increase customer charge • Standard demand and energy increases • Increased demand ratchet from 66.7% to 75% • 5 summer months/7 winter months • Base Power as in current structure • Power factor charges applied to all power factors under 100%
LL&P I-90 TOU	• Three rate schedules • Demand is On-peak & Excess • Two sets of on-peak periods • Includes shoulder peak periods in delivery • Demand ratchet at 50% • 6 summer months/6 winter months • Fuel in base rates with shoulder peak period • Power factor a discount or a charge of 1.3¢ per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0¢ per kW	• Consolidated three rate schedules into one • Consolidated on peak periods into a single period for the summer from 2:00 pm to 8:00 pm and two winter periods from 6:00 am to 10:00 am and 5:00 pm to 9:00 pm • Removed shoulder peak period • Increase customer charge • Standard demand and energy increases • Increased demand ratchet from 50% to 75% • 5 summer months/7 winter months • Base Power as in current structure without shoulder peak period • Power factor charges applied to all power factors under 100%

PROOF
OF
REVENUE

TUCSON ELECTRIC POWER COMPANY
SUMMARY PROPOSED REVENUES

TEST PERIOD ENDING DECEMBER 31, 2011

Line No.	Proposed Increased Rate Class	Adjusted Customers	Adjusted Sales (kWh)	Margin Revenue	Base Power&PPFAC	Test Year Adjusted Revenue	Proposed Revenues Margin Revenue	Proposed Revenues Base Power	Proposed Revenues Total Revenue
4	Residential Service	360,521	3,699,107,059	$241,095,410	$111,635,462	$352,730,872	$276,525,140	$123,201,293	$399,726,432
5	Residential Time Of Use	8,873	129,923,963	7,043,984	3,797,665	10,841,649	7,897,878	4,200,221	12,098,099
6	Small General Service	35,978	1,947,489,380	156,798,459	55,398,880	212,197,338	172,523,430	64,822,405	237,345,835
7	Small General Service Time of Use	924	123,590,519	8,103,358	3,384,976	11,488,333	10,026,004	3,922,266	13,948,270
8	Irrigation & Water Pumping	484	107,584,687	4,446,839	2,908,651	7,355,490	5,001,226	3,390,580	8,391,806
9	Large General Service	536	1,046,539,305	55,085,198	30,598,384	85,683,582	63,396,775	34,774,183	98,170,957
10	Large General Service Time of Use	87	216,614,667	8,424,561	6,579,663	15,004,224	9,974,701	6,773,309	16,748,010
11	Large Light & Power Service	4	351,454,280	12,469,651	10,271,504	22,741,155	15,465,873	10,507,517	25,973,390
12	Large Light & Power Service Time of Use	9	542,786,937	17,883,872	13,900,001	31,783,872	19,487,175	15,800,087	35,287,262
13	Mining Service	2	1,083,071,404	30,374,675	29,264,219	59,638,894	37,382,924	31,630,841	69,013,765
14	Traffic Signals & Lighting Service	19,566	37,430,789	3,022,183	913,817	3,936,000	3,261,519	1,230,412	4,491,931
15	TOTAL	426,985	9,285,592,991	$544,748,189	$268,653,221	$813,401,411	$620,942,644	$300,253,113	$921,195,757
16									
17	Rate Schedule								
18	R-01 - Lifeline	19,858	190,498,193	$11,801,193	$5,712,319	$17,513,513	$12,887,266	$5,598,340	$18,485,606
20	R-01	327,921	3,364,805,199	223,461,936	102,007,849	325,469,785	256,693,383	112,600,057	369,293,439
21	R-02	1,985	3,727,106	185,953	109,756	295,709	215,028	122,270	337,297
22	R-201AF	4,943	69,035,331	3,588,889	2,061,241	5,650,130	4,608,883	2,295,181	6,904,064
19	R-201AF - Lifeline	352	4,797,453	235,965	143,480	379,445	256,971	144,258	401,229
23	R-201AN	5,462	62,392,149	3,306,229	1,927,235	5,233,464	4,287,838	2,078,430	6,366,268
24	TOTAL RESIDENTIAL SERVICE	360,521	3,695,255,432	$242,580,166	$111,961,880	$354,542,046	$278,949,369	$122,838,536	$401,787,904
25									
26	R-21F - Lifeline	51	601,680	$27,889	$17,837	$45,726	$31,576	$17,578	$49,154
27	R-70F - Lifeline	198	2,036,942	114,504	59,014	173,519	124,671	58,266	182,937
28	R-201BF - Lifeline	13	151,418	6,684	4,342	11,025	7,338	4,284	11,621
29	R-21F	2,411	40,511,249	1,929,952	1,222,077	3,152,029	2,464,973	1,311,430	3,776,403
30	R-70F	4,110	59,486,521	3,441,136	1,722,450	5,163,586	3,708,397	1,931,874	5,640,271
31	R-70N-B	202	2,721,591	179,745	80,748	260,493	171,705	88,446	260,151
32	R-70N-C	651	7,853,166	519,667	232,140	751,807	504,697	255,111	759,808
33	R-70N-D	452	5,786,727	382,164	171,439	553,603	368,190	188,058	556,248
34	R-201BF	494	7,561,541	333,854	214,871	548,725	403,137	242,450	645,587
35	R-201CF	205	2,211,821	103,121	66,786	169,907	125,889	70,604	196,493
36	R-201BN	58	847,816	39,443	25,350	64,793	45,614	27,222	72,835
37	R-201CN	27	153,489	7,999	4,773	12,772	10,553	4,899	15,452
38	RESIDENTIAL TOU SERVICE	8,873	129,923,963	$7,086,159	$3,821,825	$10,907,984	$7,966,739	$4,200,221	$12,166,960
39									
40	Total Lifeline Discount Non-TOU			-1,484,756	-689,175	-2,173,931	-2,424,229		-2,424,229
41	Total Lifeline Discount TOU			-42,175	-24,160	-66,335	-68,861		-68,861
42	R-01 Community Solar		3,851,627	0	362,757	362,757		362,757	362,757
43	TOTAL RESIDENTIAL SERVICE	369,394	3,829,031,022	$248,139,394	$115,433,127	$363,572,522	$284,423,018	$127,401,513	$411,824,531

TUCSON ELECTRIC POWER COMPANY
SUMMARY PROPOSED REVENUES

TEST PERIOD ENDING DECEMBER 31, 2011

Line No.	Proposed Increased Rate Class	Adjusted Customers	Adjusted Sales (kWh)	Margin Revenue	Base Power&PPFAC	Test Year Adjusted Revenue	Proposed Revenues Margin Revenue	Proposed Revenues Base Power	Proposed Revenues Total Revenue
1									
2									
3									
44									
45	C-10	34,902	1,770,219,715	$146,658,776	$50,263,037	$196,921,813	$159,673,752	$58,913,527	$218,587,279
46	C-11	339	58,614,700	3,567,768	1,684,000	5,251,768	4,229,714	1,944,430	6,174,144
48	P-40	737	118,304,720	6,571,915	3,412,958	9,984,873	10,240,806	3,925,564	14,166,371
49	SMALL GENERAL SERVICE	35,978	1,947,139,135	$156,798,459	$55,359,996	212,158,454	$174,144,272	$64,783,521	$238,927,793
50									
51	C76F	828	109,764,966	$6,970,469	$2,995,352	$9,965,821	$8,900,021	$3,481,756	$12,381,777
52	C-76-N	96	13,825,553	1,132,888	389,624	1,522,512	1,125,983	440,510	1,566,493
53	TOTAL SGS TIME OF USE	924	123,590,519	$8,103,358	$3,384,976	$11,488,333	$10,026,004	$3,922,266	$13,948,270
54									
55	C-31	30	14,173,519	$360,113	$407,205	$767,318	$532,645	$430,614	$963,259
56	P-43	339	50,179,432	2,931,269	1,341,303	$4,272,572	2,958,010	1,669,303	4,627,312
57	P-45	115	43,231,736	1,155,457	1,160,143	2,315,600	1,510,571	1,290,664	2,801,235
58	WATER PUMPING SERVICE	484	107,584,687	$4,446,839	$2,908,651	$7,355,490	$5,001,226	$3,390,580	$8,391,806
59									
60	I-13	535	1,045,063,814	$54,952,648	$30,548,289	$85,500,936	$63,264,224	$34,724,088	$97,988,311
61	Contract PRS	1	1,475,491	132,551	50,095	182,646	132,551	50,095	182,646
62	LARGE GENERAL SERVICE	536	1,046,539,305	$55,085,198	$30,598,384	$85,683,582	$63,396,775	$34,774,183	$98,170,957
63									
64	I-85AF	17	31,671,453	$1,644,562	$864,899	$2,509,460	$1,153,849	$1,043,983	$2,197,832
65	I-85F	7	14,642,750	802,338	403,378	1,205,716	609,482	449,816	1,059,298
66	I-85N	63	170,300,463	5,977,661	5,311,387	11,289,048	8,211,370	5,279,510	13,490,880
67	LARGE GENERAL SERVICE TOU	87	216,614,667	$8,424,561	$6,579,663	$15,004,224	$9,974,701	$6,773,309	$16,748,010
68									
47	P-40 Discount						-1,620,842		-1,620,842
69	C-10 - Community Solar		350,244		38,884	38,884		38,884	38,884
70	TOTAL GENERAL SERVICE	38,010	3,441,818,558	$232,858,415	$98,870,553	$331,728,968	$260,922,135	$113,682,744	$374,604,879
71									
72	LL&POWER SERVICE I-14	4	351,454,280	$12,469,651	$10,271,504	$22,741,155	$15,465,873	$10,507,517	$25,973,390
73									
74	I-90F - Contract	1	29,899,899	$973,212	$706,823	$1,680,035	$873,457	$806,578	$1,680,035
75	I-90F	3	170,484,054	5,971,902	3,996,602	$9,968,504	5,714,483	4,980,736	10,695,219
76	I-90AF	1	29,796,851	1,236,204	698,332	$1,934,536	1,012,873	873,371	1,886,244
77	I-90N	4	312,606,133	9,702,553	8,498,244	$18,200,797	11,886,363	9,139,401	21,025,764
78	TOTAL LL&POWER TOU SERVICE	9	542,786,937	$17,883,872	$13,900,001	$31,783,872	$19,487,175	$15,800,087	$35,287,262
79									
80	MINING SERVICE	2	1,083,071,404	30,374,675	$29,264,219	$59,638,894	37,382,924	$31,630,841	69,013,765
81	TOTAL LL&P & MINING SERVICE	15	1,977,312,622	$60,728,198	$53,435,723	$114,163,922	$72,335,972	$57,938,445	$130,274,417
82									
83	P-41	1,251	29,734,586	$1,355,302	$767,658	$2,122,960	$1,415,366	$977,598	$2,392,965
84	Lighting	18,316	7,696,203	1,666,880	146,159	$1,813,039	1,846,152	252,814	2,098,966
85	LIGHTING SERVICE	19,566	37,430,789	$3,022,183	$913,817	$3,936,000	$3,261,519	$1,230,412	$4,491,931
86									
87	TOTAL RETAIL SERVCIE	426,985	9,285,592,991	$544,748,189	$268,653,221	$813,401,411	$620,942,644	$300,253,113	$921,195,757

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service R-01						
1	Customer Charge (Single Phase)	3,931,401	$7.00	$27,519,807.00	3,931,401	$10.00	$39,314,010.00
2	Customer Charge (Three Phase)	3,651	$13.00	47,463.00	3,651	$15.00	54,765.00
3	Sum First 500 kWh	865,521,763	$0.046925	40,614,608.75	736,730,680	$0.056200	41,404,264.20
4	Sum 501-1,000 kWh				496,017,382	$0.067200	33,332,368.09
5	Sum 1,001-3,500 kWh	1,180,855,048	$0.068960	81,431,764.12	559,338,750	$0.079800	44,635,232.26
6	Sum>3,500 kWh	25,501,217	$0.088960	2,268,588.23	24,347,732	$0.088200	2,147,469.92
7	Win First 500 kWh				905,934,678	$0.056200	50,913,528.89
8	Win 501-1,000 kWh	777,143,594	$0.047309	36,765,886.29	413,683,007	$0.065200	26,972,132.06
9	Win 1,001-3,500 kWh	510,936,480	$0.067309	34,390,623.50	222,752,388	$0.078100	17,396,961.53
10	Win>3,500 kWh	4,847,097	$0.087309	423,195.23	6,000,583	$0.087100	522,650.74
11	**Subtotal Delivery (Margin) Revenue**			**$223,461,936.13**			**$256,693,382.69**
12	Base Power Summer	2,071,878,028	$0.033198	68,782,206.78	1,816,434,544	$0.035111	63,776,833.26
13	Base Power Winter	1,292,927,171	$0.025698	33,225,642.44	1,548,370,656	$0.031532	48,823,223.51
14	**TOTAL RESIDENTIAL R-01**			**$325,469,785.35**			**$369,293,439.46**
15	*TOTAL SALES*	3,364,805,199			3,364,805,199		
	Residential Service R-02 Consolidated with Residential Service R-01						
16	Customer Charge (Single Phase)	23,820	$5.10	$121,482.00	23,820	$0.00	$0.00
17	Sum First 500 kWh				1,196,221	$0.056200	67,227.62
18	Sum 501-1,000 kWh	3,727,106	$0.017298	64,471.48	66,774	$0.067200	4,487.18
19	Sum 1,001-3,500 kWh			-	59,214	$0.079800	4,725.30
20	Sum>3,500 kWh			-	3,979	$0.088200	350.91
21	Win First 500 kWh				2,165,629	$0.056200	121,708.34
22	Win 501-1,000 kWh			-	148,257	$0.065200	9,666.34
23	Win 1,001-3,500 kWh			-	79,831	$0.078100	6,234.77
24	Win>3,500 kWh			-	7,203	$0.087100	627.36
25	**Subtotal Delivery (Margin) Revenue**			**$185,953.48**			**$215,027.81**
26	Base Power Summer	3,727,106	$0.029448	109,755.82	1,326,187	$0.035111	46,563.76
27	Base Power Winter			-	2,400,919	$0.031532	75,705.78
28	**TOTAL RESIDENTIAL R-02**			**$295,709.31**			**$337,297.35**
29	TOTAL SALES	3,727,106			3,727,106		
	Residential Lifeline Service R-01 - Is Now Frozen						
30	Customer Charge (Single Phase)	238,230	$4.90	$1,167,326.66	238,230	$6.90	$1,643,786.52
31	Customer Charge (Three Phase)	69	$12.26	845.94	69	$11.90	821.10
32	Summer (all kWh)	108,919,567	$0.057723	6,287,164.14	93,722,286	$0.061100	5,726,431.67
33	Winter (all kWh)	81,578,627	$0.053272	4,345,856.60	96,775,907	$0.057000	5,516,226.72
34	**Subtotal Delivery (Margin) Revenue**			**$11,801,193.35**			**$12,887,266.01**
35	Base Power Summer	108,919,567	$0.033198	3,615,911.77	93,722,286	$0.033198	3,111,392.45
36	Base Power Winter	81,578,627	$0.025698	2,096,407.55	96,775,907	$0.025698	2,486,947.27
37	**TOTAL RESIDENTIAL LIFELINE R-XX-01**			**$17,513,512.67**			**$18,485,605.73**
38	TOTAL SALES	190,498,193			190,498,193		

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Lifeline Service R-201A - Is Now Frozen						
1	Customer Charge (Single Phase)	4,218	$4.90	$20,668.46	4,218	$6.90	$29,104.57
2	Mid-Summer (all kWh)	1,397,135	$0.057722	80,645.44	1,397,135	$0.061100	85,364.96
3	Remaining-Summer (all kWh)	1,295,488	$0.040993	53,105.95	899,080	$0.043600	39,199.91
4	Winter (all kWh)	2,104,829	$0.038742	81,545.28	2,501,237	$0.041300	103,301.08
5	**Subtotal Delivery (Margin) Revenue**			**$235,965.14**			**$256,970.52**
6	Base Power Mid Summer	1,397,135	$0.033198	46,382.09	1,397,135	$0.033198	46,382.09
7	Base Power Remain-Summer	1,295,488	$0.033198	43,007.62	899,080	$0.033198	29,847.67
8	Base Power Winter	2,104,829	$0.025698	54,089.89	2,501,237	$0.027198	68,028.64
9	**TOTAL LIFELINE R-201**			**$379,444.75**			**$401,228.92**
10	TOTAL SALES	4,797,453			4,797,453		
	Residential Service R-201AF Consolidated with Residential Service R-201A						
11	Customer Charge (Single Phase)	59,313	$7.00	$415,193.57	59,313	$10.00	$593,133.67
12	Sum First 500 kWh	20,197,805	$0.066139	1,335,862.65	13,531,796	$0.050600	684,708.87
13	Sum 501-1,000 kWh			-	9,105,476	$0.060500	550,881.29
14	Sum 1,001-3,500 kWh	18,091,714	$0.044138	798,532.07	10,267,877	$0.071800	737,233.57
15	Sum>3,500 kWh			-	165,189	$0.079400	13,115.97
16	Win First 500 kWh	30,745,812	$0.033803	1,039,300.67	18,812,952	$0.050600	951,935.36
17	Win 501-1,000 kWh			-	11,090,120	$0.058700	650,990.04
18	Win 1,001-3,500 kWh			-	5,971,603	$0.070300	419,803.70
19	Win>3,500 kWh			-	90,319	$0.078400	7,081.01
20	**Subtotal Delivery (Margin) Revenue**			**$3,588,888.97**			**$4,608,883.48**
21	Base Power Mid-Summer	20,197,805	$0.033198	670,526.74	33,070,337	$0.035111	1,161,132.61
22	Base Power Remain-Summer	18,091,714	$0.033198	600,608.72			
23	Base Power Winter	30,745,812	$0.025698	790,105.87	35,964,994	$0.031532	1,134,048.19
24	**TOTAL R-201A**			**$5,650,130.30**			**$6,904,064.28**
25	TOTAL SALES	69,035,331			69,035,331		
	Residential Service R-201AN Consolidated with Residential Service R-201A						
26	Customer Charge (Single Phase)	65,544	$7.00	$458,808.00	65,544	$10.00	$655,440.00
27	Sum First 500 kWh				12,747,252	$0.050600	645,010.96
28	Sum 501-1,000 kWh	7,410,492	$0.065598	486,113.44	8,523,994	$0.060500	515,701.66
29	Sum 1,001-3,500 kWh	11,446,450	$0.085598	979,793.20	9,612,164	$0.071800	690,153.37
30	Sum>3,500 kWh	107,509	$0.105598	11,352.70	153,507	$0.079400	12,188.42
	Remaining Summer						
31	First 500, or all kWh	7,646,758	$0.022737	173,864.33	-		-
32	501 -3,500, kWh	9,203,000	$0.042737	393,308.63	-		-
33	>3,500 kWh	53,626	$0.062737	3,364.35	-		-
34	Win First 500 kWh	14,115,148	$0.020737	292,705.82	16,425,145	$0.050600	831,112.35
35	Win 501-1,000 kWh	12,338,852	$0.040737	502,647.80	9,653,893	$0.058700	566,683.53
36	Win 1,001-3,500 kWh				5,198,250	$0.070300	365,436.99
37	Win>3,500 kWh	70,315	$0.060737	4,270.75	77,944	$0.078400	6,110.79
38	**Subtotal Delivery (Margin) Revenue**			**$3,306,229.01**			**$4,287,838.07**
39	Base Power Mid-Summer	18,964,450	$0.043166	818,619.45	31,036,917	$0.035111	1,089,737.20
40	Base Power Remain-Summer	16,903,384	$0.023166	391,583.80			
41	Base Power Winter	26,524,315	$0.027033	717,031.81	31,355,232	$0.031532	988,693.19
42	**TOTAL R-201AN**			**$5,233,464.08**			**$6,366,268.46**
43	TOTAL SALES	62,392,149			62,392,149		

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Lifeline Service TOU R-21 - Is Now Frozen						
1	Customer Charge	613	$6.86	$4,208.12	613	$8.86	$5,434.98
2	Summer On-peak kWh	109,148	$0.072215	7,882.12	94,070	$0.078800	7,412.68
3	Summer Off-peak kWh	223,428	$0.026967	6,025.17	195,143	$0.030100	5,873.81
4	Winter On-peak kWh	63,890	$0.058320	3,726.08	78,969	$0.065200	5,148.76
5	Winter Off-peak kWh	205,215	$0.029467	6,047.06	233,499	$0.033000	7,705.46
6	**Subtotal Delivery (Margin) Revenue**			**$27,888.55**			**$31,575.70**
	Base Power						
7	Summer On-peak kWh	109,148	$0.053198	5,806.45	94,070	$0.053198	5,004.31
8	Summer Off-peak kWh	223,428	$0.023198	5,183.07	195,143	$0.023198	4,526.93
9	Winter On-peak kWh	63,890	$0.040698	2,600.21	78,969	$0.040698	3,213.87
10	Winter Off-peak kWh	205,215	$0.020698	4,247.53	233,499	$0.020698	4,832.96
11	**TOTAL LIFELINE TOU R-21F REVENUE**			**$45,725.82**			**$49,153.77**
12	TOTAL SALES	601,680			601,680		
	Residential Lifeline Service TOU R-70 - Is Now Frozen						
13	Customer Charge	2,375	$6.78	$16,103.20	2,375	$8.78	$20,853.40
14	Summer On-peak	245,865	$0.128473	31,587.01	214,446	$0.139300	29,872.30
15	Summer Shoulder-peak	87,900	$0.068120	5,987.76	87,900	$0.074000	6,504.61
16	Summer Off-peak	847,975	$0.034962	29,646.90	737,025	$0.037900	27,933.24
17	Winter On-peak kWh	185,561	$0.085313	15,830.80	216,981	$0.092500	20,070.70
18	Winter Off-peak kWh	669,640	$0.022921	15,348.83	780,591	$0.024900	19,436.70
19	**Subtotal Delivery (Margin) Revenue**			**$114,504.49**			**$124,670.96**
	Base Power						
20	Summer On-peak kWh	245,865	$0.055698	13,694.19	214,446	$0.055698	$11,944.20
21	Summer Shoulder-peak	87,900	$0.048198	4,236.61	87,900	$0.048198	4,236.61
22	Summer Off-peak kWh	847,975	$0.023198	19,671.32	737,025	$0.023198	17,097.50
23	Winter On-peak kWh	185,561	$0.040698	7,551.98	216,981	$0.040698	8,830.67
24	Winter Off-peak kWh	669,640	$0.020698	13,860.22	780,591	$0.020698	16,156.66
25	**TOTAL LIFELINE TOU R-70F REVENUE**			**$173,518.81**			**$182,936.62**
26	TOTAL SALES	2,036,942			2,036,942		
	Residential Service TOU R-21 Frozen Consolidated with Residential TOU R-80						
27	Customer Charge	28,932	$7.00	$202,524.00	28,932	$11.50	$332,718.00
28	Summer On-peak kWh	8,237,292	$0.101271	834,198.77	7,468,625	$0.066800	498,904.12
29	Summer Off-peak kWh	15,589,611	$0.021508	335,301.34	13,949,953	$0.051800	722,607.54
30	Winter On-peak kWh	3,844,450	$0.073292	281,767.45	7,511,294	$0.056800	426,641.52
31	Winter Off-peak kWh	12,839,897	$0.021508	276,160.50	11,581,378	$0.041800	484,101.59
32	**Subtotal Delivery (Margin) Revenue**			**$1,929,952.06**			**$2,464,972.77**
	Base Power						
33	Summer On-peak kWh	8,237,292	$0.053198	438,207.45	7,468,625	$0.050669	378,427.74
34	Summer Off-peak kWh	15,589,611	$0.023198	361,647.79	13,949,953	$0.026679	372,170.78
35	Winter On-peak kWh	3,844,450	$0.040698	156,461.44	7,511,294	$0.032893	247,069.01
36	Winter Off-peak kWh	12,839,897	$0.020698	265,760.18	11,581,378	$0.027092	313,762.68
37	**TOTAL TOU R-21F REVENUE**			**$3,152,028.91**			**$3,776,402.99**
38	TOTAL SALES	40,511,249			40,511,249		

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service TOU R-70 Consolidated with Residential TOU R-80						
1	Customer Charge	49,320	$7.00	$345,240.00	49,320	$11.50	$567,180.00
2	Summer On-peak	6,662,407	$0.174747	1,164,235.63	11,348,439	$0.066800	758,075.71
3	Summer Shoulder-peak	2,577,159	$0.102823	264,991.23	-	$0.000000	-
4	Summer Off-peak	27,114,005	$0.041176	1,116,446.26	21,204,659	$0.051800	1,098,401.36
5	Winter On-peak kWh	5,967,824	$0.025762	153,743.09	10,594,826	$0.056800	601,786.13
6	Winter Off-peak kWh	17,165,126	$0.023098	396,480.07	16,338,596	$0.041800	682,953.33
7	**Subtotal Delivery (Margin) Revenue**			**$3,441,136.29**			**$3,708,396.53**
	Base Power						
8	Summer On-peak kWh	6,662,407	$0.055698	$371,082.74	11,348,439	$0.050669	575,014.05
9	Summer Shoulder-peak	2,577,159	$0.048198	124,213.92	-	$0.000000	-
10	Summer Off-peak kWh	27,114,005	$0.023198	628,990.68	21,204,659	$0.026679	565,719.11
11	Winter On-peak kWh	5,967,824	$0.040698	242,878.52	10,594,826	$0.032893	348,495.62
12	Winter Off-peak kWh	17,165,126	$0.020698	355,283.77	16,338,596	$0.027092	442,645.26
13	**TOTAL TOU R-70F REVENUE**			**$5,163,585.92**			**$5,640,270.56**
14	TOTAL SALES	59,486,521			59,486,521		
	Residential Time-of-Use R-70N-B Consolidated with Residential TOU R-80						
15	Customer Charge	2,424	$8.00	$19,392.00	2,424	$11.50	$27,876.00
	Summer On-peak						
16	First 500, kWh	93,863	$0.079947	7,504.08	523,087	$0.066800	34,942.22
17	501 -3,500, kWh	176,848	$0.096571	17,078.41			-
18	>3,500 kWh	2,267	$0.116571	264.23			-
	Summer Shoulder-peak						
19	First 500, kWh	143,827	$0.050121	7,208.74			-
20	501 -3,500, kWh	281,334	$0.070121	19,727.44			-
21	>3,500 kWh	3,679	$0.090121	331.54			-
	Summer Off-peak						
22	First 500, kWh	349,097	$0.041217	14,388.72	979,031	$0.051800	50,713.81
23	501 -3,500, kWh	675,543	$0.057841	39,074.11			-
24	>3,500 kWh	8,856	$0.077841	689.33			-
	Winter On-peak						
25	First 500, kWh	162,731	$0.067066	10,913.71	479,959	$0.056800	27,261.67
26	501 -3,500, kWh	139,508	$0.085478	11,924.83			-
27	>3,500 kWh	507	$0.105478	53.52			-
	Winter Off-peak						
28	First 500, kWh	366,538	$0.037066	13,586.10	739,514	$0.041800	30,911.70
29	501 -3,500, kWh	315,870	$0.055478	17,523.86			-
30	>3,500 kWh	1,123	$0.075478	84.78			-
31	**Subtotal Delivery (Margin) Revenue**			**$179,745.40**			**$171,705.40**
	Base Power						
32	Summer On-peak	272,978	$0.055440	15,133.91	523,087	$0.050669	26,504.30
33	Summer Shoulder-peak	428,840	$0.034876	14,956.22	-	$0.00	-
34	Summer Off-peak	1,033,496	$0.019865	20,530.40	979,031	$0.026679	26,119.57
35	Winter On-peak kWh	302,746	$0.042874	12,979.93	479,959	$0.032893	15,787.29
36	Winter Off-peak kWh	683,532	$0.025086	17,147.08	739,514	$0.027092	20,034.92
37	**TOTAL TOU R-70N-B REVENUE**			**$260,492.93**			**$260,151.48**
38	TOTAL SALES	2,721,591			2,721,591		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Time-of-Use R-70N-C Consolidated with Residential TOU R-80						
1	Customer Charge	7,812	$8.00	$62,496.00	7,812	$11.50	$89,838.00
	Summer On-peak						
2	First 500, kWh	413,264	$0.077356	31,968.49	1,503,228	$0.066800	100,415.60
3	501 -3,500, kWh	684,298	$0.096354	65,934.87			-
4	>3,500 kWh	16,766	$0.116354	1,950.81			-
	Summer Shoulder-peak						
5	First 500, kWh	255,582	$0.049507	12,653.09			-
6	501 -3,500, kWh	429,716	$0.069507	29,868.29			-
7	>3,500 kWh	10,408	$0.089507	931.58			-
	Summer Off-peak						
8	First 500, kWh	1,170,661	$0.038229	44,753.18	2,814,086	$0.051800	145,769.65
9	501 -3,500, kWh	1,931,943	$0.057227	110,559.31			-
10	>3,500 kWh	46,780	$0.077227	3,612.69			-
	Winter On-peak						
11	First 500, kWh	503,061	$0.066452	33,429.40	1,391,693	$0.056800	79,048.19
12	501 -3,500, kWh	376,700	$0.084864	31,968.29			-
13	>3,500 kWh	2,023	$0.104864	212.18			-
	Winter Off-peak						
14	First 500, kWh	1,148,576	$0.036452	41,867.90	2,144,159	$0.041800	89,625.85
15	501 -3,500, kWh	858,787	$0.054864	47,116.49			-
16	>3,500 kWh	4,599	$0.074864	344.33			-
	Subtotal Delivery (Margin) Revenue			**$519,666.90**			**$504,697.28**
17	**Base Power**						
18	Summer On-peak	1,114,329	$0.054330	60,541.49	1,503,228	$0.050669	76,167.04
19	Summer Shoulder-peak	695,706	$0.034177	23,777.15	-	$0.000000	-
20	Summer Off-peak	3,149,384	$0.019467	61,309.06	2,814,086	$0.026679	75,077.00
21	Winter On-peak kWh	881,784	$0.042015	37,048.17	1,391,693	$0.032893	45,776.97
22	Winter Off-peak kWh	2,011,963	$0.024585	49,464.10	2,144,159	$0.027092	58,089.56
23	**TOTAL TOU R-70N-C REVENUE**			**$751,806.87**			**$759,807.85**
24	TOTAL SALES	7,853,166			7,853,166		

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Time-of-Use R-70N-D Consolidated with Residential TOU R-80						
1	Customer Charge	5,424	$8.00	$43,392.00	5,424	$11.50	$62,376.00
	Summer On-peak						
2	First 500, kWh	200,869	$0.091873	18,454.43	1,112,090	$0.066800	74,287.60
3	501 -3,500, kWh	354,929	$0.107334	38,095.99			-
4	>3,500 kWh	6,150	$0.127334	783.16			-
	Summer Shoulder-peak						
5	First 500, kWh	180,379	$0.049814	8,985.40			-
6	501 -3,500, kWh	325,516	$0.069814	22,725.59			-
7	>3,500 kWh	5,713	$0.089814	513.07			-
	Summer Off-peak						
8	First 500, kWh	919,875	$0.042073	38,701.91	2,081,044	$0.051800	107,798.09
9	501 -3,500, kWh	1,637,031	$0.057534	94,184.94			-
10	>3,500 kWh	28,367	$0.077534	2,199.37			-
	Winter On-peak						
11	First 500, kWh	289,183	$0.068737	19,877.56	1,021,079	$0.056800	57,997.31
12	501 -3,500, kWh	236,708	$0.085171	20,160.66			-
13	>3,500 kWh	1,062	$0.105171	111.73			-
	Winter Off-peak						
14	First 500, kWh	877,051	$0.038737	33,974.32	1,572,514	$0.041800	65,731.07
15	501 -3,500, kWh	720,607	$0.055171	39,756.60			-
16	>3,500 kWh	3,287	$0.075171	247.08			-
	Subtotal Delivery (Margin) Revenue			**$382,163.81**			**$368,190.08**
17	**Base Power**						
18	Summer On-peak	561,949	$0.058271	32,745.31	1,112,090	$0.050669	56,348.48
19	Summer Shoulder-peak	511,608	$0.036656	18,753.50	-	$0.000000	-
20	Summer Off-peak	2,585,273	$0.020880	53,980.50	2,081,044	$0.026679	55,520.18
21	Winter On-peak kWh	526,953	$0.045063	23,746.09	1,021,079	$0.032893	33,586.37
22	Winter Off-peak kWh	1,600,945	$0.026368	42,213.71	1,572,514	$0.027092	42,602.54
23	**TOTAL TIME OF USE R-70N-D REVENUE**			**$553,602.92**			**$556,247.64**
24	TOTAL SALES	5,786,727			5,786,727		
	Residential Lifeline Service TOU R-201B - Is Now Frozen						
25	Customer Charge (Single Phase)	159	$6.78	$1,081.31	159	$8.78	$1,400.28
	Summer						
26	Mid-Summer On-peak	8,244	$0.128473	1,059.11	8,244	$0.136900	1,128.58
27	Mid-Summer Shoulder-peak	3,900	$0.068120	265.69	3,900	$0.074700	291.35
28	Mid-Summer Off-peak	32,255	$0.034962	1,127.70	32,255	$0.038300	1,235.37
29	Remaining-Summer On-peak	7,834	$0.090717	710.66	5,483	$0.099500	545.59
30	Remaining-Summer Shoulder-peak	2,703	$0.044275	119.66	2,703	$0.048600	131.35
31	Remaining-Summer Off-peak	29,775	$0.023038	685.96	20,657	$0.025300	522.61
32	Winter On-peak	15,413	$0.059481	916.76	17,763	$0.065200	1,158.16
33	Winter Off-peak	51,295	$0.013975	716.84	60,413	$0.015300	924.32
34	**Subtotal Delivery (Margin) Revenue**			**$6,683.68**			**$7,337.60**
	Base Power						
35	Mid-Summer On-peak	8,244	$0.055698	459.16	8,244	$0.055698	459.16
36	Mid-Summer Shoulder-peak	3,900	$0.048198	187.99	3,900	$0.048198	187.99
37	Mid-Summer Off-peak	32,255	$0.023198	748.25	32,255	$0.023198	748.25
38	Remaining-Summer On-peak	7,834	$0.055698	436.33	5,483	$0.055698	305.41
39	Remaining-Summer Shoulder-peak	2,703	$0.048198	130.27	2,703	$0.048198	130.27
40	Remaining-Summer Off-peak	29,775	$0.023198	690.72	20,657	$0.023198	479.19
41	Winter On-peak	15,413	$0.040698	627.26	17,763	$0.040698	722.92
42	Winter Off-peak	51,295	$0.020698	1,061.70	60,413	$0.020698	1,250.43
43	**TOTAL LIFELINE R-XX-201B**			**$11,025.36**			**$11,621.23**
44	TOTAL SALES	151,418			151,418		

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service TOU R-201BF Consolidated with Residential TOU Service R-201B						
1	Customer Charge (Single Phase)	5,927	$7.00	$41,486.05	5,927	$11.50	$68,155.66
	Summer						
2	Mid-Summer On-peak	412,357	$0.166303	68,576.29	1,250,513	$0.056800	71,029.15
3	Mid-Summer Shoulder-peak	172,389	$0.093043	16,039.62			-
4	Mid-Summer Off-peak	1,624,561	$0.031395	51,003.10	2,339,501	$0.044000	102,938.06
5	Remaining-Summer On-peak	364,035	$0.124945	45,484.39			-
6	Remaining-Summer Shoulder-peak	119,418	$0.067767	8,092.58			-
7	Remaining-Summer Off-peak	1,456,605	$0.018756	27,320.08			-
8	Winter On-peak	773,032	$0.075935	58,700.22	1,564,449	$0.048300	75,562.88
9	Winter Off-peak	2,639,143	$0.006499	17,151.79	2,407,078	$0.035500	85,451.27
10	**Subtotal Delivery (Margin) Revenue**			**$333,854.12**			**$403,137.02**
11	Mid-Summer On-peak	412,357	$0.055698	22,967.49	1,250,513	$0.050669	63,362.25
12	Mid-Summer Shoulder-peak	172,389	$0.048198	8,308.82			
13	Mid-Summer Off-peak	1,624,561	$0.023198	37,686.57	2,339,501	$0.026679	62,415.55
14	Remaining-Summer On-peak	364,035	$0.055698	20,276.04			
15	Remaining-Summer Shoulder-peak	119,418	$0.048198	5,755.69			
16	Remaining-Summer Off-peak	1,456,605	$0.023198	33,790.31			
17	Winter On-peak	773,032	$0.040698	31,460.87	1,564,449	$0.032893	51,459.42
18	Winter Off-peak	2,639,143	$0.020698	54,624.99	2,407,078	$0.027092	65,212.56
19	**TOTAL TOU R-201BF**			**$548,724.91**			**$645,586.80**
20	TOTAL SALES	7,561,541			7,561,541		
	Residential Service TOU R-201CF Consolidated with Residential TOU Service R-201B						
21	Customer Charge (Single Phase)	2,464	$7.00	$17,248.38	2,464	$11.50	$28,336.62
	Summer						
22	Mid-Summer On-peak	154,320	$0.161981	24,996.89	346,597	$0.056800	19,686.73
23	Mid-Summer Shoulder-peak	43,356	$0.090057	3,904.52			-
24	Mid-Summer Off-peak	407,895	$0.028409	11,587.89	649,452	$0.044000	28,575.88
25	Remaining-Summer On-peak	148,960	$0.112200	16,713.28			-
26	Remaining-Summer Shoulder-peak	32,007	$0.058618	1,876.18			-
27	Remaining-Summer Off-peak	398,805	$0.012688	5,060.04			-
28	Winter On-peak	315,061	$0.066272	20,879.75	478,871	$0.048300	23,129.49
29	Winter Off-peak	711,416	$0.001201	854.41	736,900	$0.035500	26,159.96
30	**Subtotal Delivery (Margin) Revenue**			**$103,121.34**			**$125,888.68**
31	Mid-Summer On-peak	154,320	$0.055698	8,595.31	346,597	$0.050669	17,561.74
32	Mid-Summer Shoulder-peak	43,356	$0.048198	2,089.68			
33	Mid-Summer Off-peak	407,895	$0.023198	9,462.35	649,452	$0.026679	17,326.72
34	Remaining-Summer On-peak	148,960	$0.055698	8,296.76			
35	Remaining-Summer Shoulder-peak	32,007	$0.048198	1,542.67			
36	Remaining-Summer Off-peak	398,805	$0.023198	9,251.49			
37	Winter On-peak	315,061	$0.040698	12,822.37	478,871	$0.032893	15,751.52
38	Winter Off-peak	711,416	$0.020698	14,724.89	736,900	$0.027092	19,964.10
39	**TOTAL TOU R-201CF**			**$169,906.85**			**$196,492.76**
40	TOTAL SALES	2,211,821			2,211,821		

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service TOU R-201BN Consolidated with Residential TOU Service R-201B						
1	Customer Charge	696	$8.00	$5,568.00	696	$11.50	$8,004.00
	MID-Summer On-peak						
2	First 500, kWh	11,829	$0.110962	1,312.59	142,511	$0.056800	8,094.60
3	501 -3,500, kWh	24,718	$0.130962	3,237.18			-
4	>3,500 kWh	277	$0.150962	41.81			-
	MID-Summer Shoulder-peak						
5	First 500, kWh	10,819	$0.043962	475.64			-
6	501 -3,500, kWh	22,549	$0.063962	1,442.27			-
7	>3,500 kWh	249	$0.083962	20.92			-
	MID-Summer Off-peak						
8	First 500, kWh	57,234	$0.020362	1,165.40	266,449	$0.044000	11,723.77
9	501 -3,500, kWh	118,631	$0.040362	4,788.20			-
10	>3,500 kWh	1,294	$0.060362	78.09			-
	REMAIN-Summer On-peak						
11	First 500, kWh	14,825	$0.047962	711.02			-
12	501 -3,500, kWh	22,011	$0.067962	1,495.90			-
13	>3,500 kWh	41	$0.087962	3.59			-
	REMAIN-Summer Shoulder-peak						
14	First 500, kWh	11,461	$0.024162	276.93			-
15	501 -3,500, kWh	18,526	$0.044162	818.14			-
16	>3,500 kWh	37	$0.064162	2.37			-
	REMAIN-Summer Off-peak						
17	First 500, kWh	62,102	$0.016462	1,022.32			-
18	501 -3,500, kWh	100,213	$0.036462	3,653.98			-
19	>3,500 kWh	198	$0.056462	11.16			-
	Winter On-peak						
20	First 500, kWh	41,562	$0.047962	1,993.40	172,825	$0.048300	8,347.44
21	501 -3,500, kWh	53,991	$0.067962	3,669.35			-
22	>3,500 kWh	93	$0.087962	8.17			-
	Winter Off-peak						
23	First 500, kWh	119,596	$0.016462	1,968.79	266,031	$0.035500	9,444.11
24	501 -3,500, kWh	155,274	$0.036462	5,661.59			-
25	>3,500 kWh	286	$0.056462	16.17			-
26	**Subtotal Delivery (Margin) Revenue**			**$39,442.95**			**$45,613.92**
	Base Power						
27	Mid-Summer On-peak	36,825	$0.077356	2,848.60	142,511	$0.050669	7,220.87
28	Mid-Summer Shoulder-peak	33,617	$0.038166	1,283.04			-
29	Mid-Summer Off-peak	177,159	$0.033166	5,875.66	266,449	$0.026679	7,108.60
30	Remaining-Summer On-peak	36,876	$0.057356	2,115.08			-
31	Remaining-Summer Shoulder-peak	30,024	$0.018166	545.42			-
32	Remaining-Summer Off-peak	162,513	$0.013166	2,139.65			-
33	Winter On-peak	95,646	$0.061223	5,855.74	172,825	$0.032893	5,684.72
34	Winter Off-peak	275,156	$0.017033	4,686.73	266,031	$0.027092	7,207.32
35	**TOTAL TOU R-201BN REVENUE**			**$64,792.86**			**$72,835.44**
36	TOTAL SALES	847,816			847,816		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Residential Service TOU R-201CN Consolidated with Residential TOU Service R-201B						
1	Customer Charge	329	$8.00	$2,632.00	329	$11.50	$3,783.50
	MID-Summer On-peak						
2	First 500, kWh	3,953	$0.099462	393.15	24,024	$0.056800	1,364.56
3	501 -3,500, kWh	3,816	$0.117162	447.04			-
4	>3,500 kWh	-	$0.134862	-			-
	MID-Summer Shoulder-peak						
5	First 500, kWh	2,040	$0.040512	82.65			-
6	501 -3,500, kWh	2,430	$0.058212	141.44			-
7	>3,500 kWh	-	$0.075912	-			-
	MID-Summer Off-peak						
8	First 500, kWh	14,980	$0.019626	293.99	45,026	$0.044000	1,981.17
9	501 -3,500, kWh	15,497	$0.037326	578.45			-
10	>3,500 kWh	-	$0.055026	-			-
	REMAIN-Summer On-peak						
11	First 500, kWh	3,445	$0.044052	151.77			-
12	501 -3,500, kWh	3,485	$0.061752	215.18			-
13	>3,500 kWh	-	$0.079452	-			-
	REMAIN-Summer Shoulder-peak						
14	First 500, kWh	2,616	$0.022989	60.14			-
15	501 -3,500, kWh	2,711	$0.040689	110.31			-
16	>3,500 kWh	-	$0.058389	-			-
	REMAIN-Summer Off-peak						
17	First 500, kWh	14,880	$0.016175	240.68			-
18	501 -3,500, kWh	14,818	$0.033875	501.97			-
19	>3,500 kWh	-	$0.051575	-			-
	Winter On-peak						
20	First 500, kWh	11,128	$0.044052	490.19	33,302	$0.048300	1,608.49
21	501 -3,500, kWh	7,870	$0.061752	486.00			-
22	>3,500 kWh	-	$0.079452	-			-
	Winter Off-peak						
23	First 500, kWh	29,014	$0.016175	469.30	51,137	$0.035500	1,815.37
24	501 -3,500, kWh	20,808	$0.033875	704.86			-
25	>3,500 kWh	-	$0.051575	-			-
26	**Subtotal Delivery (Margin) Revenue**			**$7,999.13**			**$10,553.08**
	Base Power						
27	Mid-Summer On-peak	7,768	$0.078903	612.95	24,024	$0.050669	1,217.26
28	Mid-Summer Shoulder-peak	4,470	$0.038929	174.01	-		-
29	Mid-Summer Off-peak	30,477	$0.033829	1,031.00	45,026	$0.026679	1,201.26
30	Remaining-Summer On-peak	6,930	$0.058503	405.41	-		-
31	Remaining-Summer Shoulder-peak	5,327	$0.018529	98.71	-		-
32	Remaining-Summer Off-peak	29,698	$0.013429	398.81	-		-
33	Winter On-peak	18,998	$0.062447	1,186.36	33,302	$0.032893	1,095.40
34	Winter Off-peak	49,822	$0.017374	865.60	51,137	$0.027092	1,385.40
35	**TOTAL TOU R-201CN REVENUE**			**$12,771.99**			**$15,452.41**
36	TOTAL SALES	153,489			153,489		
37	**RESIDENTIAL STANDARD SUBTOTAL**						**$401,787,904.20**
38	**RESIDENTIAL TIME OF USE SUBTOTAL**						**$12,166,959.53**
39	**RESIDENTIAL COMMUNITY SOLAR**						**$362,756.94**
40	**RESIDENTIAL LIFELINE DISCOUNT**						**($2,493,089.80)**
41	**RESIDENTIAL TOTAL REVENUE**						**$411,824,530.88**

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Small General Service SGS-10						
1	Customer Charge (Single Phas	206,171	$8.00	$1,649,368.00	206,171	$15.50	$3,195,650.50
2	Customer Charge (Three Phase	212,653	$14.00	2,977,142.00	212,653	$20.50	4,359,386.50
	Summer						
3	First 500, kWh	83,218,214	$0.056236	4,679,859.46	70,402,123	$0.076800	5,406,883.03
4	≥ 501 kWh	924,529,471	$0.085145	78,719,061.80	794,353,073	$0.097600	77,528,859.89
	Winter						
5	First 500, kWh	85,492,289	$0.051252	4,381,650.82	98,308,380	$0.056800	5,583,916.00
6	≥ 501 kWh	676,979,742	$0.080145	54,256,541.39	807,156,140	$0.078800	63,603,903.82
7	Primary Metering Discount			(4,847.65)			(4,847.65)
8	**Subtotal Delivery (Margin) Revenue**			**$146,658,775.81**			**$159,673,752.08**
9	Base Power Summer	1,007,747,684	$0.031550	31,794,439.45	864,755,195	$0.035111	30,362,419.67
10	Base Power Winter	762,472,031	$0.024222	18,468,597.53	905,464,520	$0.031532	28,551,107.25
11	**TOTAL General Service SGS-10**			**$196,921,812.79**			**$218,587,279.00**
12	TOTAL SALES	1,770,219,715			1,770,219,715		
	Municipal Service PS-40 Consolidated with Small General Service SGS-10						
13	Customer Charge (Single Phas	8,849	$0.00	$0.00	8,849	$15.50	$137,159.50
	Summer						
14	First 500, kWh	64,734,411	$0.057530	3,724,170.65	4,420,553	$0.076800	339,498.47
15	≥ 501 kWh			-	50,114,177	$0.097600	4,891,143.64
	Winter						
16	First 500, kWh	53,570,309	$0.053159	2,847,744.07	6,912,295	$0.056800	392,618.38
17	≥ 501 kWh			-	56,857,695	$0.078800	4,480,386.36
18	**Subtotal Delivery (Margin) Revenue**			$6,571,914.72			**$10,240,806.35**
19	Base Power Summer	64,734,411	0.032245	2,087,361.07	54,534,730	$0.035111	1,914,768.89
20	Base Power Winter	53,570,309	$0.024745	1,325,597.30	63,769,990	$0.031532	2,010,795.33
21	**TOTAL PS-40 REVENUE**			**$9,984,873.09**			**$14,166,370.58**
22	TOTAL SALES	118,304,720			118,304,720		
	SGS Time of Use SGS-76F Consolidated with SGS TOU 76				-		
14	Customer Charge	9,936	$8.00	$79,488.00	9,936	$17.50	$173,880.00
15	Summer On-peak	9,825,216	$0.207220	2,035,981.36	16,433,218	$0.098700	1,621,958.60
16	Summer Shoulder-peak	3,497,021	$0.119884	419,236.89		-	-
17	Summer Off-peak	46,772,467	$0.042825	2,003,030.91	35,012,373	$0.084500	2,958,545.54
18	Winter On-peak kWh	10,425,706	$0.130159	1,356,999.48	23,274,964	$0.081000	1,885,272.08
19	Winter Off-peak kWh	39,244,555	$0.027411	1,075,732.50	35,044,410	$0.064500	2,260,364.44
20	**Subtotal Delivery (Margin) Revenue**			**$6,970,469.14**			**$8,900,020.66**
21	**Base Power**						
22	Summer On-peak kWh	9,825,216	$0.056123	551,420.62	16,433,218	$0.050669	832,654.71
23	Summer Shoulder-peak	3,497,021	$0.056123	196,263.32	-	-	-
24	Summer Off-peak kWh	46,772,467	$0.023623	1,104,905.99	35,012,373	$0.026679	934,095.11
25	Winter On-peak kWh	10,425,706	$0.038809	404,611.23	23,274,964	$0.032893	765,583.39
26	Winter Off-peak kWh	39,244,555	$0.018809	738,150.84	35,044,410	$0.027092	949,423.15
27	**TOTAL TOU SGS-76F REVENUE**			**$9,965,821.15**			**$12,381,777.02**
28	TOTAL SALES	109,764,966			109,764,965		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	SGS Time of Use SGS-76N Consolidated with SGS TOU 76						
1	Customer Charge	1,152	$9.00	$10,368.00	1,152	$17.50	$20,160.00
	Summer On-peak						
2	First 500, kWh	53,632	$0.153751	8,245.99	2,195,464	$0.098700	216,692.26
3	501 -3,500, kWh	1,659,304	$0.182660	303,088.41			-
	Summer Shoulder-peak						
4	First 500, kWh	44,206	$0.041416	1,830.82			-
5	501 -3,500, kWh	1,358,337	$0.070325	95,525.07			-
	Summer Off-peak						
6	First 500, kWh	150,763	$0.027416	4,133.31	4,658,430	$0.084500	393,637.30
7	501 -3,500, kWh	4,722,873	$0.056325	266,015.85			-
	Winter On-peak						
8	First 500, kWh	86,798	$0.088434	7,675.93	2,777,047	$0.081000	224,940.85
9	501 -3,500, kWh	1,918,001	$0.117327	225,033.25			-
	Winter Off-peak						
10	First 500, kWh	165,442	$0.027415	4,535.58	4,194,613	$0.064500	270,552.51
11	501 -3,500, kWh	3,666,198	$0.056308	206,436.27			-
	Subtotal Delivery (Margin) Revenue			**$1,132,888.48**			**$1,125,982.91**
12	**Base Power**						
13	Summer On-peak	1,712,936	$0.052000	89,072.66	2,195,464	$0.050669	111,241.95
14	Summer Shoulder-peak	1,402,543	$0.032000	44,881.37	-	-	-
15	Summer Off-peak	4,873,636	$0.022000	107,220.00	4,658,430	$0.026679	124,282.24
16	Winter On-peak kWh	2,004,799	$0.032000	64,153.57	2,777,047	$0.032893	91,345.42
17	Winter Off-peak kWh	3,831,639	$0.022000	84,296.07	4,194,613	$0.027092	113,640.44
18	**TOTAL TOU SGS 76N REVENUE**			**$1,522,512.15**			**$1,566,492.97**
19	TOTAL SALES	13,825,553			13,825,553		
	GS Mobile Home Parks GS-11 Frozen						
20	Customer Charge Single Pha	3,722	$8.00	$29,772.94	3,722	$15.50	$57,685.08
21	Customer Charge Three Pha	346	$14.00	4,849.35	346	$20.50	7,100.83
22	Summer kWh	30,805,210	$0.067290	2,072,882.60	26,876,589	$0.082000	2,203,880.28
23	Winter kWh	27,809,489	$0.052751	1,466,978.38	31,738,111	$0.062000	1,967,762.88
24	Primary Metering Discount			(3,284.98)			(3,284.98)
25	Transformer Owned Discount			(3,430.22)			(3,430.22)
26	**Subtotal Delivery (Margin) Revenue**			**$3,567,768.07**			**$4,229,713.87**
27	Base Power Summer	30,805,210	$0.028730	885,033.69	26,876,589	$0.035111	943,663.91
28	Base Power Winter	27,809,489	$0.028730	798,966.63	31,738,111	$0.031532	1,000,766.12
29	**TOTAL GS-11 REVENUE**			**$5,251,768.40**			**$6,174,143.90**
30	TOTAL SALES	58,614,700			58,614,700		

TUCSON ELECTRIC POWER COMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
1	**Water Pumping GS-43**						
2	Customer Charge	4,063	$ -	$0.00	4,063	$15.50	$62,976.50
3	Summer kWh	29,185,229	$0.060347	1,761,240.99	24,321,024	**$0.0680**	1,653,829.62
4	Winter kWh	20,994,203	$0.055731	1,170,027.93	25,858,408	**$0.0480**	1,241,203.58
5	**Subtotal Delivery (Margin) Revenue**			**$2,931,268.92**			**$2,958,009.70**
6	Base Power Summer	29,185,229	$0.029868	871,704.41	24,321,024	$0.035111	853,935.47
7	Base Power Winter	20,994,203	$0.022368	469,598.33	25,858,408	$0.031532	815,367.32
8	**TOTAL GS-43 REVENUE**			**$4,272,571.66**			**$4,627,312.48**
9	TOTAL SALES	50,179,432			50,179,432		
	Water Pumping GS-31 Consolidated with Water Pumping GS-43						
10	Customer Charge	365	$ -	$0.00	365	$15.50	$5,657.50
11	Summer kWh	11,400,116	$0.025700	292,982.97	9,620,168	$0.042000	404,047.07
12	Winter kWh	2,773,403	$0.024205	67,130.22	4,553,351	$0.027000	122,940.47
13	**Subtotal Delivery (Margin) Revenue**			**$360,113.20**			**$532,645.03**
14	Base Power Summer	11,400,116	$0.028730	327,525.33	9,620,168	$0.031310	301,207.47
15	Base Power Winter	2,773,403	$0.028730	79,679.87	4,553,351	$0.028420	129,406.22
16	**TOTAL GS-31 REVENUE**			**$767,318.39**			**$963,258.72**
17	TOTAL SALES	14,173,519			14,173,519		
	Water Pumping GS-45 Consolidated with Water Pumping GS-43						
18	Customer Charge	1,382	$ -	$0.00	1,382	$15.50	$21,421.00
19	Summer kWh	25,751,439	$0.027281	702,525.00	21,459,532	$0.042000	901,300.35
20	Winter kWh	17,480,298	$0.025911	452,931.99	21,772,204	$0.027000	587,849.51
21	**Subtotal Delivery (Margin) Revenue**			**$1,155,456.99**			**$1,510,570.87**
22	Base Power Summer	25,751,439	$0.029868	769,143.97	21,459,532	$0.031310	671,897.95
23	Base Power Winter	17,480,298	$0.022368	390,999.30	21,772,204	$0.028420	618,766.04
24	**TOTAL GS-45 REVENUE**			**$2,315,600.26**			**$2,801,234.86**
25	TOTAL SALES	43,231,736			43,231,736		
	LARGE GENERAL SERVICE LGS-13						
26	Customer Charge	6,420	$371.88	$2,387,469.60	6,420	$775.00	$4,975,500.00
27	ALL kW	2,571,910	$10.35	26,624,414.03	2,719,841	$15.25	41,477,573.96
28	Summer kWh	582,034,661	$0.025656	14,932,681.28	494,868,791	**$0.0192**	9,501,480.79
29	Winter kWh	463,029,153	$0.023910	11,071,027.04	550,195,023	**$0.0134**	7,372,613.31
30	Primary Metering Discount			(35,627.70)			(35,627.70)
31	Transformer Owned Discount			(27,316.74)			(27,316.74)
32	**Subtotal Delivery (Margin) Revenue**			**$54,952,647.51**			**$63,264,223.62**
33	**Base Power**						
34	Summer kWh	582,034,661	$0.032554	18,947,556.37	494,868,791	$0.035111	17,375,338.13
35	Winter kWh	463,029,153	$0.025054	11,600,732.40	550,195,023	$0.031532	17,348,749.46
36	**TOTAL LGS-13 REVENUE**			**$85,500,936.28**			**$97,988,311.22**
37	TOTAL SALES	1,045,063,814			1,045,063,814		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	LGS Time of Use LGS-85F Consolidated with LGS TOU 85				-		
1	Customer Charge	87	$371.88	$32,262.41	87	$950.00	$82,417.16
2	Summer On-Peak kW	19,345	$17.32	335,057.12	16,153	$14.55	235,025.85
3	Summer Shoulder-Peak kW	0	$8.66				
4	Summer Off-peak kW		$11.46	-	-	$10.92	-
5	Winter On-Peak kW	17,037	$9.65	164,338.97	20,403	$11.59	236,467.90
6	Winter Off-peak kW		$4.82	-	-	$9.10	-
7	Summer On-peak	1,276,087	$0.083765	106,891.46	1,698,736	$0.008600	14,609.13
8	Summer Shoulder-peak	437,006	$0.053910	23,558.99		$0.00	-
9	Summer Off-peak	6,281,523	$0.005693	35,760.71	5,082,830	$0.006000	30,496.98
10	Winter On-peak kWh	1,381,684	$0.053910	74,486.59	2,613,835	$0.003000	7,841.50
11	Winter Off-peak kWh	5,266,449	$0.005693	29,981.90	5,247,350	$0.000500	2,623.67
12	**Subtotal Delivery (Margin) Revenue**			**$802,338.15**			**$609,482.19**
	Base Power						
13	Summer On-peak kWh	1,276,087	$0.056452	72,037.68	1,698,736	$0.050669	86,073.27
14	Summer Shoulder-peak	437,006	$0.056452	24,669.86	-	$0.00	-
15	Summer Off-peak kWh	6,281,523	$0.023952	150,455.05	5,082,830	$0.026679	135,604.81
16	Winter On-peak kWh	1,381,684	$0.039341	54,356.84	2,613,835	$0.032893	85,976.86
17	Winter Off-peak kWh	5,266,449	$0.019341	101,858.40	5,247,350	$0.027092	142,161.20
18	**TOTAL TOU LGS-85F REVENUE**			**$1,205,715.98**			**$1,059,298.33**
19	TOTAL SALES	14,642,750			14,642,750		
	LGS Time of Use LGS-85AF Consolidated with LGS TOU 85						
20	Customer Charge	201	$371.88	$74,839.03	201	$950.00	$191,182.84
21	Summer On-Peak kW	33,507	$7.95	266,377.21	28,787	$14.55	418,848.43
22	Summer Shoulder-Peak kW	-	$5.26	-	-		-
23	Summer Off-peak kW		$3.98	-	-	$10.92	-
24	Winter On-Peak kW	30,755	$5.26	161,697.91	35,746	$11.59	414,296.16
25	Winter Off-peak kW	-	$2.63	-	-	$9.10	-
26	Summer On-peak	2,599,727	$0.053290	138,539.47	6,641,029	$0.008600	57,112.85
27	Summer Shoulder-peak	922,051	$0.044980	41,473.87	-	$0.00	-
28	Summer Off-peak	13,913,940	$0.036667	510,182.42	8,319,627	$0.006000	49,917.76
29	Winter On-peak kWh	2,874,352	$0.044980	129,288.35	5,654,275	$0.003000	16,962.83
30	Winter Off-peak kWh	11,361,383	$0.028356	322,163.38	11,056,522	$0.000500	5,528.26
31	**Subtotal Delivery (Margin) Revenue**			**$1,644,561.64**			**$1,153,849.13**
	Base Power						
32	Summer On-peak kWh	2,599,727	$0.056452	146,759.81	6,641,029	$0.050669	336,494.32
33	Summer Shoulder-peak	922,051	$0.056452	52,051.64	-	$0.00	-
34	Summer Off-peak kWh	13,913,940	$0.023952	333,266.68	8,319,627	$0.026679	221,959.33
35	Winter On-peak kWh	2,874,352	$0.039341	113,079.88	5,654,275	$0.032893	185,986.08
36	Winter Off-peak kWh	11,361,383	$0.019341	219,740.51	11,056,522	$0.027092	299,543.28
37	**TOTAL TOU LGS-85AF REVENUE**			**$2,509,460.16**			**$2,197,832.14**
38	TOTAL SALES	31,671,453			31,671,453		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	LGS Time of Use LGS-85N Consolidated with LGS TOU 85						
1	Customer Charge	756	$371.88	$281,141.28	756	$950.00	$718,200.00
2	Summer On-Peak kW	159,325	$11.87	1,891,023.85	136,794	$14.55	1,990,350.48
3	Summer Off-peak kW	152,908	$8.24	1,259,813.12	131,265	$10.92	1,433,412.12
4	Winter On-Peak kW	141,095	$8.91	1,256,876.98	168,568	$11.59	1,953,701.06
5	Winter Off-peak kW	140,289	$6.42	900,376.82	161,933	$9.10	1,473,590.00
6	Summer On-peak	14,680,576	$0.007500	110,104.32	21,189,064	$0.008600	182,225.95
7	Summer Shoulder-peak	13,087,176	$0.005000	65,435.88		$0.00	-
8	Summer Off-peak	61,745,731	$0.002500	154,364.33	55,253,420	$0.006000	331,520.52
9	Winter On-peak kWh	23,409,799	$0.002500	58,524.50	32,576,235	$0.003000	97,728.70
10	Winter Off-peak kWh	57,377,182	$0.000000	-	61,281,744	$0.000500	30,640.87
11	**Subtotal Delivery (Margin) Revenue**			**$5,977,661.07**			**$8,211,369.71**
	Base Power						
12	Summer On-peak kWh	14,680,576	$0.059253	869,868.15	21,189,064	$0.050669	1,073,628.70
13	Summer Shoulder-peak	13,087,176	$0.033588	439,572.05	-	$0.00	-
14	Summer Off-peak kWh	61,745,731	$0.025299	1,562,105.26	55,253,420	$0.026679	1,474,105.99
15	Winter On-peak kWh	23,409,799	$0.036088	844,812.82	32,576,235	$0.032893	1,071,530.09
16	Winter Off-peak kWh	57,377,182	$0.027799	1,595,028.28	61,281,744	$0.027092	1,660,245.02
17	**TOTAL TOU LGS-85AN REVENUE**			**$11,289,047.63**			**$13,490,879.50**
18	TOTAL SALES	170,300,463			170,300,463		

19	SMALL GENERAL SERVICE STANDARD	$232,753,649.57
20	SMALL GENERAL SERVICE TIME OF USE	$13,948,269.99
21	GENERAL SERVICE MOBILE HOME PARKS	$6,174,143.90
22	WATER PUMPING SERVICE	$8,391,806.07
23	LARGE GENERAL SERVICE	$97,988,311.22
24	LARGE GENERAL SERVICE CONTRACT	$182,646.07
25	LARGE GENERAL SERVICE TIME OF USE	$16,748,009.97
26	GENERAL SERVICE COMMUNITY SOLAR	$38,883.97
27	GENERAL SERVICE (PS-40) TRANSITION ADJUSTMENT	($1,620,842.00)
28	GENERAL SERVICE TOTAL REVENUE	$374,604,878.75

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
1	**LARGE LIGHT & POWER STANDARD SERVICE I-14**						
2	Customer Charge	48	$500.00	$24,000.00	48	$1,800.00	$86,400.00
3	Demand per kW	648,222	$19.02	12,331,770.68	657,888	$21.98	14,460,383.86
4	Summer kWh	194,411,279	$0.000433	84,180.08	164,577,383	$0.0032	526,647.63
5	Winter kWh	157,043,001	$0.000433	67,999.62	186,876,897	$0.0021	392,441.48
6	Power Factor Adjustment			(38,298.99)			-
7	**Subtotal Delivery (Margin) Revenue**			**$12,469,651.40**			**$15,465,872.97**
8	Base Power Summer	194,411,279	$0.032577	6,333,336.24	164,577,383	$0.031611	5,202,455.67
9	Base Power Winter	157,043,001	$0.025077	3,938,167.34	186,876,897	$0.028388	5,305,061.35
10	**TOTAL LL&P I-14 REVENUE**			**$22,741,154.98**			**$25,973,389.99**
11	TOTAL SALES	351,454,280			351,454,280		
12	**LLP Time of Use LLP-90F Consolidated with Rate LLP TOU I-90**				-		
13	Customer Charge	36	$500.00	$18,000.00	36	$2,000.00	$72,000.00
14	Summer On-Peak kW	129,214	$25.70	3,321,056.05	108,502	$20.49	2,223,204.65
15	Summer Shoulder-Peak kW	-	$19.45			$0.00	
16	Summer Off-peak kW	381	$13.20	5,026.79	0	$12.49	-
17	Winter On-Peak kW	118,244	$21.70	2,566,127.73	143,938	$15.49	2,229,604.52
18	Winter Off-peak kW	306	$9.20	2,817.33	0	$9.99	-
19	Summer On-peak	12,789,577	$0.000433	5,537.89	32,267,296	$0.006900	222,644.34
20	Summer Shoulder-peak	5,101,626	$0.000433	2,209.00		$0.00	-
21	Summer Off-peak	73,829,358	$0.000433	31,968.11	44,351,515	$0.006500	288,284.85
22	Winter On-peak kWh	15,295,174	$0.000433	6,622.81	30,752,002	$0.007500	230,640.02
23	Winter Off-peak kWh	63,468,318	$0.000433	27,481.78	63,113,261	$0.007100	448,104.16
24	Power Factor Adjustment Charge			(14,945.30)			-
25	**Subtotal Delivery (Margin) Revenue**			**$5,971,902.20**			**$5,714,482.53**
	Base Power						
26	Summer On-peak kWh	12,789,577	$0.052983	677,630.17	32,267,296	$0.045568	1,470,356.15
27	Summer Shoulder-peak	5,101,626	$0.052983	270,299.45	-	$0.00	-
28	Summer Off-peak kWh	73,829,358	$0.020483	1,512,246.74	44,351,515	$0.023985	1,063,771.09
29	Winter On-peak kWh	15,295,174	$0.035623	544,860.00	30,752,002	$0.029581	909,674.98
30	Winter Off-peak kWh	63,468,318	$0.015623	991,565.54	63,113,261	$0.024352	1,536,934.14
31	**TOTAL LLP-90F REVENUE**			**$9,968,504.09**			**$10,695,218.89**
32	TOTAL SALES	170,484,054			170,484,075		

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue	Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	LLP Time of Use LLP-90AF Consolidated with Rate LLP TOU I-90						
1	Customer Charge	12	$500.00	$6,000.00	12	$2,000.00	$24,000.00
2	Summer On-Peak kW	23,108	$25.58	591,115.52	19,420	$20.49	397,915.80
3	Summer Shoulder-Peak kW	0	$18.08	-	-	$0.00	-
4	Summer Off-peak kW	0	$10.58	-	-	$12.49	-
5	Winter On-Peak kW	21,095	$21.58	455,259.83	24,783	$15.49	383,888.67
6	Winter Off-peak kW	0	$10.58	-	-	$0.00	-
7	Summer On-peak	2,487,981	$0.006203	15,432.16	5,900,062	$0.006900	40,710.42
8	Summer Shoulder-peak	691,357	$0.006203	4,288.27	-	-	-
9	Summer Off-peak	12,031,280	$0.006203	74,626.22	8,805,988	$0.006500	57,238.92
10	Winter On-peak kWh	2,778,185	$0.006203	17,232.20	4,936,738	$0.007500	37,025.54
11	Winter Off-peak kWh	11,808,048	$0.006203	73,241.58	10,154,063	$0.007100	72,093.85
12	Power Factor Adjustment Charge			(991.62)			-
13	**Subtotal Delivery (Margin) Revenue**			**$1,236,204.14**			**$1,012,873.20**
	Base Power						
14	Summer On-peak kWh	2,487,981	$0.052983	131,820.68	5,900,062	$0.045568	268,854.00
15	Summer Shoulder-peak	691,357	$0.052983	36,630.18	-	$0.00	-
16	Summer Off-peak kWh	12,031,280	$0.020483	246,436.71	8,805,988	$0.023985	211,211.63
17	Winter On-peak kWh	2,778,185	$0.035623	98,967.27	4,936,738	$0.029581	146,033.65
18	Winter Off-peak kWh	11,808,048	$0.015623	184,477.14	10,154,063	$0.024352	247,271.74
19	**TOTAL LLP-90AF REVENUE**			**$1,934,536.13**			**$1,886,244.24**
20	TOTAL SALES	29,796,851			29,796,851		
21	**LLP Time of Use LLP-90AN Consolidated with Rate LLP TOU I-90**						
22	Customer Charge	72	$500.00	$24,000.00	72	$2,000.00	$144,000.00
23	Summer On-Peak kW	1,126,518	$20.03	5,631,073.96	942,458	$20.49	19,310,956.22
24	Summer Off-peak kW	0	$10.03	-	-	$12.49	-
25	Winter On-Peak kW	1,101,530	$15.03	3,830,620.95	1,293,879	$15.49	20,042,187.50
26	Winter Off-peak kW	0	$7.53	-	-	$9.99	-
27	Summer On-peak	119,764,712	$0.001113	31,295.27	259,407,650	$0.006900	1,789,912.78
28	Summer Shoulder-peak	117,575,158	$0.001113	29,824.13		$0.00	-
29	Summer Off-peak	482,023,611	$0.000716	80,888.09	320,205,034	$0.006500	2,081,332.72
30	Winter On-peak kWh	220,927,188	$0.000723	32,384.33	267,092,274	$0.007500	2,003,192.06
31	Winter Off-peak kWh	455,386,868	$0.000521	52,062.61	548,972,579	$0.007100	3,897,705.31
32	Power Factor Adjustment Charge			(9,596.13)			-
33	**Subtotal Delivery (Margin) Revenue**			**$9,702,553.21**			**$49,269,286.60**
	Base Power						
34	Summer On-peak kWh	119,764,712	$0.041786	1,174,936.52	259,407,650	$0.045568	11,820,687.78
35	Summer Shoulder-peak	117,575,158	$0.041786	1,119,704.50	0	$0.00	-
36	Summer Off-peak kWh	482,023,611	$0.026872	3,035,788.59	320,205,034	$0.023985	7,680,117.73
37	Winter On-peak kWh	220,927,188	$0.027126	1,215,016.88	267,092,274	$0.029581	7,900,856.57
38	Winter Off-peak kWh	455,386,868	$0.019542	1,952,797.64	548,972,579	$0.024352	13,368,580.25
39	**TOTAL LLP-90AN REVENUE**			**$18,200,797.34**			**$90,039,528.93**
40	TOTAL SALES	1,395,677,537			1,395,677,537		
41	**LARGE LIGHT & POWER STANDARD**						**$25,973,390**
42	**LARGE LIGHT & POWER TIME OF USE**						**102,620,992**
43	**LARGE LIGHT & POWER CONTRACT**						**1,680,035**
44	**LARGE LIGHT & POWER SERVICE TOTAL REVENUE**						**$130,274,417**

TUCSON ELECTRIC POWER COJMPANY
TEST YEAR RATES VS. PROPOSED RATES AND REVENUES
TEST PERIOD ENDING DECEMBER 31, 2011

LINE NO.		Test Year Adjusted Billing Determinants	Current Rates	Test Year Adjusted Revenue		Proposed Adjusted Billing Determinants	Proposed Rates	Proposed Revenues
	Traffic Signal and Street Light Service PS-41							
1	Customer Charge	15,006	$0.00	$0.00		15,006	$0.00	$0.00
2	Summer kWh	11,178,373	$0.045580	509,510.24		11,178,373	$0.047600	532,090.55
3	Winter kWh	18,556,213	$0.045580	845,792.19		18,556,213	$0.047600	883,275.74
4	**Subtotal Delivery (Margin) Revenue**			$1,355,302.43				$1,415,366.29
5								
6	PPFAC SUMMER	11,178,373	$0.025817	288,592.06		11,178,373	$0.035111	392,483.85
7	PPFAC WINTER	18,556,213	$0.025817	479,065.75		18,556,213	$0.031532	585,114.51
8	**TOTAL PS-41 REVENUE**			$2,122,960.24				**$2,392,964.66**
9	P-41 Total Sales	29,734,586				29,734,586		
	Lighting Service P-50							
10	55Watt	1,428	$7.39	$10,552.92			$8.19	$11,695.32
11	70Watt	2,472	$7.39	18,268.08			$8.19	20,245.68
12	100 Watt	121,283	$7.39	896,281.37			$8.19	993,307.77
13	250 Watt	19,574	$11.09	217,114.81			$12.29	240,564.46
14	400 Watt	3,904	$17.11	66,797.44			$18.70	73,004.80
15	Underground Service	23,986	$14.01	336,139.80			$15.53	372,502.58
16	Pole	47,144	$2.58	121,725.81			$2.86	134,831.84
17	**Subtotal Delivery (Margin) Revenue**			**$1,666,880.23**				**$1,846,152.45**
18	Base Powr							
19	55Watt	1,428	$0.43	$609.76				
20	70Watt	2,472	$0.54	1,342.30				
21	100 Watt	121,283	$0.78	94,115.61	Base Power			
22	250 Watt	19,574	$1.94	37,973.56	Sum kWh	2,832,315	$0.035111	99,445.42
23	400 Watt	3,904	$3.10	12,118.02	Win kWh	4,863,888	$0.031532	153,368.11
24	**TOTAL LIGHTING SERVICE REVENUE**			**$1,813,039.47**				**$2,098,965.99**
25	**LIGHTING SERVICE TOTAL REVENUE**							**$4,491,930.64**
26	**TOTAL REVENUE REQUIREMENT ALL CLASSES**							**$921,195,757**

UNBUNDLED TARIFFS

Residential Electric Service (R-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 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 cause excessive voltage fluctuations.

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 CUSTOMER AND ENERGY CHARGES

Customer Charge of Delivery Services:

Standard

Customer Charge, Single Phase service and minimum bill	$10.00 per month
Customer Charge, Three Phase service and minimum bill	$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)

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2]		
		Base Power	PPFAC[2]	Total[3]
0 – 500 kWh	$0.056200	$0.035111	*varies*	$0.091311
501 – 1,000 kWh	$0.067200	$0.035111	*varies*	$0.102311
1,001 – 3,500 kWh	$0.079800	$0.035111	*varies*	$0.114911
Over 3,500 kWh	$0.088200	$0.035111	*varies*	$0.123311

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 3,000 kWh	$0.087100	$0.031532	*varies*	$0.118632

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 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 volumetric charges 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.

AUTOMATED METER OPT-OUT

Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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	$1.74 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
Total	**$10.00 per month**	**$15.00 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 (Unbundled):

Component	**Summer** (May – September)	**Winter** (October - April)
0 – 500 kWh	$0.001800	$0.004200
501 – 1,000 kWh	$0.012800	$0.013200
1,001 – 3,500 kWh	$0.025400	$0.026100
Over 3,500 kWh	$0.033800	$0.035100
Generation Capacity	$0.039800	$0.037400
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 Charges:

	Summer (May – September)	**Winter** (October - April)
Base Power Component	$0.03511100	$0.03153200
PPFAC	In accordance with Rider 1 - PPFAC	

Residential Time-of-Use (R-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 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 cause excessive voltage fluctuations.

Customers must 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 AND ENERGY CHARGES

Customer Charges:

Standard
Customer Charge, Single Phase service and minimum bill — $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):

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.066800	$0.050669	*varies*	$0.117469
Off-Peak	$0.051800	$0.026679	*varies*	$0.078479

Winter (October – April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC	Total[3]
On-Peak	$0.056800	$0.032893	*varies*	$0.089693
Off-Peak	$0.041800	$0.027092	*varies*	$0.068892

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 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 volumetric charges to less than zero.

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.

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 Charge Components (Unbundled):

Standard	
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
Total	**$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
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	$0.05066900	$0.02667900
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	$0.03289300	$0.02709200
PPFAC	In accordance with Rider 1 - PPFAC	

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]		
		Base Power	PPFAC[2]	Total[3]
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 total bill excluding the Customer Charge:
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.

AUTOMATED METER OPT-OUT

Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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/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	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	PPFAC	Total[3]
On-Peak	$0.0652	$0.040698	*varies*	$0.105898
Off-Peak	$0.0330	$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 total bill excluding the Customer Charge:
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	$0.05319800	$0.02319800
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	$0.04069800	$0.02069800
PPFAC	In accordance with Rider 1 - PPFAC	

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 total bill excluding the Customer Charge:
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**

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**

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 105-3
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	

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

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 total bill excluding the Customer Charge:
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.

AUTOMATED METER OPT-OUT

Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 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 total bill excluding the Customer Charge:
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	

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] 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 Charges2 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 total bill excluding the Customer Charge:
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**

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	

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]		
		Base Power	PPFAC[2]	Total[3]
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 total bill excluding the Customer Charge:
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.

AUTOMATED METER OPT-OUT

Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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		

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	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 Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the volumetric charges 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.

AUTOMATED METER OPT-OUT
Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 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 Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the volumetric charges 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	

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 Delivery Services-Energy and Power Supply Charges. No Lifeline discount will be applied that will reduce the volumetric charges 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/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- 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 total bill excluding the Customer Charge:
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.

AUTOMATED METER OPT-OUT
Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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 scierosis 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 net 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 total bill excluding the Customer Charge:
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.

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	$0.0020698
PPFAC	In accordance with Rider 1 - PPFAC	

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 net 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 total bill excluding the Customer Charge:
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**

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/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

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 total bill excluding the Customer Charge:
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.

AUTOMATED METER OPT-OUT
Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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		

Special Residential Electric Service (R-201AN)

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 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 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 — $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 more of 2,000 or more kWh — $16.50 per month

Energy Charges:

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2]		
		Base Power	PPFAC[2]	Total[3]
0 – 500 kWh	$0.050600	$0.035111	*varies*	$0.085711
501 – 1,000 kWh	$0.060500	$0.035111	*varies*	$0.095611
1,001 – 3,500 kWh	$0.071800	$0.035111	*varies*	$0.106911
Over 3,500 kWh	$0.079400	$0.035111	*varies*	$0.114511

Winter (October - April)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
0 – 500 kWh	$0.050600	$0.031532	*varies*	$0.082132
501 – 1,000 kWh	$0.058700	$0.031532	*varies*	$0.090232
1,001 – 3,500 kWh	$0.070300	$0.031532	*varies*	$0.101832
Over 3,000 kWh	$0.078400	$0.031532	*varies*	$0.109932

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).

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:

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 volumetric charges to less than zero.

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.

AUTOMATED METER OPT-OUT

Residential rate class Customers may request, and have installed, meters that do not transmit data wirelessly. A one-time automated meter opt-out change-out fee, as specified in TEP's Statement of Charges, will apply for the installation of each analog meter that replaces a meter currently in service at the customer's premises that transmits data wirelessly. For a Customer choosing the Automated Meter Opt-out, an additional monthly customer charge as specified in the TEP Statement of Charges will be added to the applicable Customer Charge for as long as the analog meter is left in service.

The Customer may choose to self-read the analog meter. The terms and conditions for self reading of the meter shall be in accordance with Section 10 of the TEP Rules and Regulations.

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	$1.74 per month
Meter Reading	$1.17 per month
Billing & Collection	$5.04 per month
Customer Delivery	$2.05 per month
Total	**$10.00 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 (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy		
Sum First 500 kWh	$0.003400	$0.004100
Sum 501-1,000 kWh	$0.013300	$0.012200
Sum 1,001-3,500 kWh	$0.024600	$0.023800
Sum>3,500 kWh	$0.032200	$0.031900
Generation Capacity	$0.032600	$0.031900
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 Charges:

Base Power Component	Summer (May – September)	Winter (October - April)
0 – 500 kWh	$0.035111	$0.031532
PPFAC	In accordance with Rider 1 - PPFAC	

Special Residential Electric Service
Time-of-Use Program (R-201BN)

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 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 cause excessive voltage fluctuations.

Customers must 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 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 — $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 more than 2,000 kWh — $18.00 per month

Energy Charges:

Summer (May – September)	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
On-peak	$0.056800	$0.050669	*varies*	$0.107469
Off-peak	$0.044000	$0.026679	*varies*	$0.070679

Winter (October - April)	Delivery Services-Energy[1]	Power Supply Charges[2]		
		Base Power	PPFAC[2]	Total[3]
On-peak	$0.048300	$0.032893	*varies*	$0.081193
Off-peak	$0.035500	$0.027092	varies	$0.062592

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 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

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 volumetric charges to less than zero.

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 Charge Components (Unbundled):

Standard	
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
Total	**$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
Total	**$18.00 per month**

Energy Charge Components (Unbundled)

Summer (May – September)	**On-Peak**	**Off-Peak**
Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.030900	$0.018100
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	$0.050669	$0.026679
PPFAC	In accordance with Rider 1 – PPFAC	

Winter (October - April)	**On-Peak**	**Off-Peak**
Delivery-Energy	$0.011300	$0.011300
Generation Capacity	$0.022400	$0.009600
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	$0.032893	$0.027092
PPFAC	In accordance with Rider 1 – PPFAC	

Small General Service (GS-10)

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises. To all general power and lighting service unless otherwise addressed by specific Rates.

APPLICABILITY
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.

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 total bill excluding the Customer Charge.

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. 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 AND ENERGY CHARGES

Customer Charges:

Customer Charge, Single Phase service and minimum bill	$15.50 per month
Customer Charge, Three Phase service and minimum bill	$20.50 per month

Energy Charges: All energy charges below are charged per kWh basis.

Delivery Charges:

Description	Summer (May – September)	Winter (October – April)
First 500 kWh	$0.076800	$0.056800
All remaining kWh	$0.097600	$0.078800

Base Power Supply Charges:

Summer	$0.035111 per kWh
Winter	$0.031532 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.

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 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)
Delivery-Energy		
First 500 kWh	$0.021700	$0.021700
All remaining kWh	$0.022600	$0.022600
Generation Capacity		
First 500 kWh	$0.042700	$0.022700
All remaining kWh	$0.062600	$0.043800
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	$0.035111	$0.031532
PPFAC	In accordance with Rider 1 - PPFAC	

Mobile Home Park Electric Service (GS-11F)

AVAILABILITY
New Customers, including current Customers who move, are not eligible for service under this Rate.

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 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 AND ENERGY CHARGES

Customer Charges:

Customer Charge, Single Phase service and minimum bill	$15.50 per month
Customer Charge, Three Phase service and minimum bill	$20.50 per month

Energy Charges:

Delivery Charge	
Summer (May – September), all kWh	$0.082000 per kWh
Winter (October – April), all kWh	$0.062000 per kWh

Base Power Charges:

Delivery Charge	$0.035111 per kWh
Summer (May – September), all kWh	$0.031532 per kWh
Winter (October – April), all 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.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING
When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of the 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:

Customer 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	$0.035111	$0.031532
PPFAC	In accordance with Rider 1 - PPFAC	

Small General Service
Time-of-Use Program (GS-76)

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. Access to the meter during normal working hours is also a prerequisite for this Rate.

APPLICABILITY
To all general power and lighting service unless otherwise addressed by specific 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.

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 CUSTOMER AND ENERGY CHARGES

Customer Charge:

Customer Charge, single or three phase service and minimum bill $17.50 per month

Energy Charges:

Description	Summer (May – September)	Winter (October - April)
On-Peak kWh	$0.098700	$0.081000
Off-Peak kWh	$0.084500	$0.064500

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

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.

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.

ADJUSTMENT FOR TRANSFORMER OWNERSHIP AND METERING

When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of 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.

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.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components (Unbundled):

Description	Customer 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**

Energy Charge Components (Unbundled)

Summer (May – September)	On-Peak	Off-Peak
Local Delivery-Energy[1]	$0.022300	$0.022300
Generation Capacity	$0.064000	$0.049800
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	$0.050669	$0.026679
PPFAC	In accordance with Rider 1 - PPFAC	

Energy Charge Components (Unbundled)

Winter (October - April)	On-Peak	Off-Peak
Delivery-Energy	$0.022300	$0.022300
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	

Large General Service (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 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 200 kW.

Not applicable to resale, breakdown, temporary, standby, or auxiliary service.

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. Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge:	$775.00 per month
Demand Charge:	$15.25 per kW
Energy Charges:	
Summer (May – September)	$0.019200 per kWh
Winter (October – April)	$0.013400 per kWh
Base Power Charges:	
Summer (May – September)	$0.035111 per kWh
Winter (October – April)	$0.031532 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 200 kW.

ADJUSTMENT FOR PRIMARY SERVICE AND METERING
When Customer owns transformers and energy is metered on primary side of transformers, the demand shall be metered and the above schedule subject to a discount of 20.6¢ per kW per month of 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 Charges:	
Meter Services	$211.38 per month
Meter Reading	$ 32.43 per month
Billing & Collection	$140.81 per month
Customer Delivery	$390.38 per month
Total	**$775.00 per month**
Demand Charge (in $/kW):	
Delivery Charge	$1.71 per kW
Generation Capacity	$9.17 per kW
Fixed Must-Run	$0.95 per kW
Transmission	$2.67 per kW
Transmission Ancillary Services	
System Control & Dispatch	$0.04 per kW
Reactive Supply and Voltage Control	$0.14 per kW
Regulation and Frequency Response	$0.14 per kW
Spinning Reserve Service	$0.37 per kW

Supplemental Reserve Service	$0.06 per kW
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Energy Charges (kWh): (in $/kWh)

Delivery Charge	
Summer	$0.005800 per kWh
Winter	$0.004000 per kWh
Generation Capacity	
Summer	$0.013400 per kWh
Winter	$0.009400 per kWh
Base Power Supply Charge	
Summer	$0.035111 per kWh
Winter	$0.031532 per kWh

Large General Service
Time-of-Use Program (LGS-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
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.

Customers must stay on this Rate for a minimum period of one (1) year.

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. Primary metering shall be required for new installations with service requirements in excess of 2,500 kW.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge and minimum bill	$950.00 per month
Demand Charges (includes Generation Capacity):	
Summer On-peak	$14.55 per kW
Summer Off-peak (applies to all off-peak demand bill determinates)	$10.92 per kW
Winter On-peak	$11.59 per kW
Winter Off-peak 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: All energy charges below are charged on a per kWh basis.

Delivery Charges ($/kWh)

	Summer (May – September)	Winter (October - April)
On-Peak	$0.008600	$0.003000
Off-Peak	$0.006000	$0.000500

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.

Base Power Supply Charges ($/kWh)

	Summer (May – September)	**Winter** (October – April)
On-Peak	$0.050669	$0.032893
Off-Peak	$0.026679	$0.027092

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.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the combination of the following;

The greatest of the following during the On-Peak period:

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 200 kW, and

The greatest of the following during the Off-peak period:

1. The maximum 15 minute measured demand during the off-peak period of the billing month;
2. 75% of the maximum off-peak period billing demand used for billing purposes in the preceding 11 months; or
3. The contract demand amount, not to be less than 200 kW.

PRIMARY SERVICE

The Rates contained in this Schedule are designed to reflect secondary service but where service is taken at a primary voltage 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.

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	$259.11 per month
Meter Reading	$ 39.75 per month
Billing & Collection	$172.61 per month
Customer Delivery	$478.53 per month
	$950.00 per month
Demand Charges ($/kW)	
Generation Capacity Charges (in $/kW)	
Summer On-peak	$10.18 per kW
Summer Off-peak	$ 6.55 per kW
Winter On-peak	$ 7.22 per kW
Winter Off-peak	$ 4.73 per kW
Fixed Must-Run Charges (in $/kW)	$ 0.95 per kW
Transmission (in $/kW)	$ 2.67 per kW
Transmission - Ancillary Services System Control & Dispatch (in $/kW)	
System Control & Dispatch	$ 0.04 per kW
Reactive Supply and Voltage Control	$ 0.14 per kW
Regulation and Frequency Response	$ 0.14 per kW
Spinning Reserve Service	$ 0.37 per kW
Supplemental Reserve Service	$ 0.06 per kW
Energy Imbalance Service: Currently charged pursuant to the Company's OATT	

Energy Charges ($/kWh):

Delivery Charges	
Summer On-peak	$0.002600 per kWh
Summer Off-peak	$0.001800 per kWh
Winter On-peak	$0.000900 per kWh
Winter Off-peak	$0.000150 per kWh
Generation Capacity	
Summer On-peak	$0.006000 per kWh
Summer Off-peak	$0.004200 per kWh
Winter On-peak	$0.002100 per kWh
Winter Off-peak	$0.000350 per kWh
Base Power Supply Charge	
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

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 grestest 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

Large Light and Power Service
Time of Use Program (LLP-90)

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 3000 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.

Customers must stay on this Rate for a minimum period of one (1) year.

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 and minimum bill $2,000.00 per month

Demand Charges (includes Generation Capacity):

Summer On-peak	$20.49 per kW
Summer Off-peak Excess Demand	$12.49 per kW
Winter On-peak	$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: All energy charges below are charged on a per kWh basis.

Delivery Charges ($/kWh):

	Summer (May – September)	**Winter** (October – April)
On-Peak	$0.006900	$0.007500
Off-Peak	$0.006500	$0.007100

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.

Base Power Supply Charges ($/kWh)

	Summer (May – September)	Winter (October – April)
On-Peak	$0.045568	$0.029581
Off-Peak	$0.023985	$0.024352

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.

DETERMINATION OF BILLING DEMAND

The greatest of the following:

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

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.

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.

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%.

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	$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 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)	
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 Excess Demand (kW)	$ 2.88 per kW
Transmission - Ancillary System Control	
Summer & Winter On-peak	$ 0.05 per kW
Summer & Winter Excess Demand (kW)	$ 0.04 per kW

Transmission – Ancillary Reactive Supply	
Summer & Winter On-peak	$ 0.20 per kW
Summer & Winter Excess Demand (kW)	$ 0.15 per kW
Transmission - Ancillary Frequency Response	
Summer & Winter On-peak	$ 0.20 per kW
Summer & Winter Excess Demand (kW)	$ 0.15 per kW
Transmission - Ancillary Spinning Reserve	
Summer & Winter On-peak	$ 0.54 per kW
Summer & Winter Excess Demand (kW)	$ 0.40 per kW
Transmission - Ancillary Supplemental Reserve	
Summer & Winter On-peak	$ 0.09 per kW
Summer & Winter 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

Traffic Signal and Street Lighting Service (PS-41)

AVAILABILITY
Available for service to the 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 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	$0.047600 per kWh
Base Power Charges:	
Summer (May – September)	$0.035111 per kWh
Winter (October – April)	$0.031532 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.

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)	
Summer	$0.003400 per kWh
Winter	$0.003400 per kWh
Generation Capacity (in $/kWh)	
Summer	$0.010200 per kWh
Winter	$0.010200 per kWh
Fixed Must-Run (in $/kWh)	$0.014300 per kWh
Transmission (in $/kWh)	$0.015300 per kWh
Transmission Ancillary Services (in $/kWh)	
System Control & Dispatch	$0.000200 per kWh
Reactive Supply and Voltage Control	$0.000800 per kWh
Regulation and Frequency Response	$0.000800 per kWh
Spinning Reserve Service	$0.002200 per kWh
Supplemental Reserve Service	$0.000400 per kWh
Energy Imbalance Service: Currently charged pursuant to the Company's OATT.	
Base Power Supply Charge	
Summer	$0.035111 per kWh
Winter	$0.031532 per kWh

Lighting Service (PS-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
Multiple or series street lighting system at option of Company and at one standard nominal voltage.

RATE
A monthly bill at the following rate plus any adjustments incorporated herein.

BUNDLED STANDARD OFFER SERVICE – SUMMARY OF CUSTOMER AND ENERGY CHARGES

Delivery Charge:

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Per unit Per month	$8.19	$8.19	$8.19	$12.29	$18.70	$15.53	$2.86

Note:

The watt high pressure sodium lamps are charged per unit per month.

Per one pole addition and an extension of up to 100 feet of overhead service are charged per pole.

Underground Service is per 100 watt or less high pressure sodium lamp unit per month mounted on standard pole.

Base Power Supply Charge:

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt	Underground Service	Pole
Per unit Per month	$0.85	$0.94	$1.34	$3.36	$5.38	$0.00	$0.00

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.

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.

SPECIAL PROVISIONS

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.

3. 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. The Customer is not authorized to make connections to this lighting circuit or to make attachments or alterations to the Company owned pole.

5. If a Customer requests a relocation of a lighting installation, the costs of such relocation must be borne by the Customer.

6. The Customer is expected to notify the Company when lamp outages occur.

7. 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. Light installation is subject to the governmental agency approval process.

10. 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.

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:

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	

Base Power Supply Charge

Service	55OH, 55P, 55UG	70UG	100 Watt	250 Watt	400 Watt
Per unit Per month	$0.85	$0.94	$1.34	$3.36	$5.38

Water Pumping Service (GS-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
Single 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 AND ENERGY CHARGES

Customer Charge: $15.50 per month

Energy Charges:

Firm Service
Delivery Charge
Summer (May – September) $0.068000 per kWh
Winter (October – April) $0.048000 per kWh

Interruptible Service
Delivery Charge
Summer (May – September) $0.042000 per kWh
Winter (October – April) $0.027000 per kWh

Base Power Supply Charges:

	Summer (May-September)	Winter (October – April)
Firm Service	$0.035111	$0.031532
Interruptible Service	$0.031310	$0.028420

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.

Primary Voltage Discount
A discount of 5% will be 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 Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$5.78 per month
Meter Reading	$0.74 per month
Billing & Collection	$3.19 per month
Customer Delivery	$5.79 per month
Total	**$15.50 per month**

Energy Charge Components (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.021700	$0.021700
Generation Capacity	$0.033900	$0.013900
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	$0.0004
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	$0.035111	$0.031532
PPFAC	In accordance with Rider 1 - PPFAC	

Interruptible Service

Customer Charge Components (Unbundled):

Description	Customer Charge
Meter Services	$5.78 per month
Meter Reading	$0.74 per month
Billing & Collection	$3.19 per month
Customer Delivery	$5.79 per month
Total	***$15.50 per month***

Energy Charge Components (Unbundled):

Component	Summer (May – September)	Winter (October - April)
Local Delivery-Energy	$0.021700	$0.007900
Generation Capacity	$0.007900	$0.006700
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	$0.031310	$0.028420
PPFAC	In accordance with Rider 1 - PPFAC	

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. XXXXX dated XXXXXX XX, 2013 and as updated and defined in the Company's PPFAC Plan of Administration approved in ACC Decision No. XXXXX.

RATE
The Customer monthly bill shall consist of the applicable Rate, charges and adjustments in addition to the PPFAC. The PPFAC adjustor Rate, as shown in the TEP Statement of Charges, is an amount expressed as a Rate per kWh charge to reflect the cost to the Company for energy either generated or purchased.

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 the above Rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider.

Rider R-2
Demand Side Management Surcharge (DSMS)

APPLICABILITY
The Demand Side Management Surcharge (DSMS) will be applied to all Customers taking Standard Offer service from the Company pursuant to the Arizona Corporation Commission (ACC) Decision No. XXXXX dated XXXXXX XX, 2013

RATE
The DSMS shall be applied to all monthly bills. The DSMS will be assessed on a per kWh basis for residential Customers and on a percentage of bill basis for non-residential Customers. The Rates are shown in the TEP Statement of Charges.

REQUIREMENTS
The 2013 TEP DSMS is effective XXXX, XX, 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 the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider

Rider R-3
Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS

AVAILABILITY

The Market Cost of Comparable Conventional Generation (MCCCG) calculation, Rider-3, is restricted solely to Rider-4, Net Metering for Certain Partial Requirements Service (NM-PRS). If for a billing month a Rider-4 NM-PRS Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation as described in Rider-4 NM-PRS. The excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the positive balance of excess kWhs (if any) after netting against billing period usage. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of Rider-4 NM-PRS shall be the simple average of the hourly MCCCG as described below for the applicable year.

The Arizona Corporation Commission (ACC) provided guidance on defining MCCCG in the context of its REST Rules and identified the MCCCG as "the Affected Utility's energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly, seasonal and long term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs." R14-2-1801.11.

CALCULATION/METHODOLOGY

For purposes of calculating credits to the Customer for Excess Generation, the unit price paid (Credit for Excess Generation) shall be the simple average of the MCCCG over the 8,760 hours (8,784 in a leap year) hours in the forecasted year. The MCCCG in each hour is based on whether native load requirements will be met by internally owned or contracted generation resources or if market purchases will be required to meet native load requirements. The following table provides a description of the MCCCG methodology. The hourly MCCCG cost determination criteria is based on the Market Condition and Dispatch Type. This method of cost determination is very data intensive and will be calculated annually by running 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.

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 R-4
Net Metering for Certain
Partial Requirements Service (NM-PRS)

AVAILABILITY

Available throughout the Company's entire electric service area to any Customer with a facility for the production of electricity on its premises using Renewable Resources [1], a Fuel Cell [2] or Combined Heat and Power (CHP) [3] to generate electricity, which is operated by or on behalf of the Customer, is intended to provide all or part of the Customer's electricity requirements, has a generating capacity less than or equal to 125% of the Customer's total connected load at the metered premise, or in the absence of load data, has capacity less than the Customer's electric service drop capacity, and is interconnected with and can operate in parallel and in phase with the Company's existing distribution system. Customer shall comply with all applicable federal, state, and local laws, regulations, ordinances and codes governing the production and/or sale of electricity.

For purposes of this Rate, the following notes and/or definitions apply:

[1]Renewable Resources means natural resources that can be replenished by natural process. Renewable Resources include biogas, biomass, geothermal, hydroelectric, solar, or wind.

[2]Fuel Cell means a device that converts the chemical energy of a fuel directly into electricity without intermediate combustion or thermal cycles. The source of the chemical reaction must be derived from Renewable Resources.

[3]Combined Heat and Power (CHP) also known as cogeneration means a system that generates electricity and useful thermal energy in a single integrated system such that the useful power output of the facility plus one-half the useful thermal energy output during any 12-month period must be no less than 42.5 percent of the total energy input of fuel to the facility.

CHARACTER OF SERVICE

The service shall be single- or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering will be used by mutual agreement between the Company and the Customer.

RATE

Customer Charges shall be billed pursuant to the Customer's standard offer Rate otherwise applicable under full requirements of service.

Power sales and special services supplied by the Company to the Customer in order to meet the Customer's supplemental or interruptible electric requirements will be priced pursuant to the Customer's standard offer Rate otherwise applicable under full requirements service.

Non-Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is not a time-of-use rate, the Customer Supplied kWh shall be credited against the Company Supplied kWh. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

Time-of-Use Rates: For Customers taking service under a Standard Retail Rate that is a time-of-use rate, the Customer Supplied kWh during on-peak hours shall be credited against the Company Supplied kWh during on-peak hours. All Customer Supplied kWh during off-peak hours shall be credited against the Company Supplied kWh during off-peak hours. The Customer's monthly bill shall be based on this net kWh amount. Any monthly Excess Generation will be treated in accordance with the provisions outlined below.

EXCESS GENERATION

If for a billing month the Customer's generation facility's energy production exceeds the energy supplied by the Company, the Customer's bill for the next billing period shall be credited for the excess generation. That is, the excess kWh during the billing period shall be used to reduce the kWh supplied (not kW or kVA demand or customer/facilities charges) and billed by the Company during the following billing period. Customers taking service under a time-of-use rate who are to receive credit in a subsequent billing period for excess kWh generated shall receive such credit in the next billing period for the on-peak or off-peak periods in which the kWh were generated by the Customer. Time-of-Use Customer's taking service in the billing month of April shall receive a credit to summer on-peak and summer off-peak usage in the billing month of May for any winter on-peak and/or winter off-peak excess generation for April.

Each calendar year, for the customer bills produced in October (September usage) or a customer's "Final" bill - the Company shall credit the Customer for the balance of excess kWhs after netting. The payment for the purchase of the excess kWhs will be at the Company's applicable avoided cost, which for purposes of this rate shall be the simple average of the hourly Market Cost of Comparable Conventional Generation (MCCCG) Rider-3 for the applicable year. The MCCCG, as it applies to this rate, is specified in Rider-3 MCCCG - Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS (Net Metering for Certain Partial Requirements Service).

METERING

The Company will install a bi-directional meter at the point of delivery to the customer and meter at the point of output from each of the Customer's generators. At the Company's request a dedicated phone line will be provided by the customer to the metering to allow remote interegation of the meters at each site. If by mutal agreement between company and customer that a phone line is impractical or can not be provided - the customer will work with company to allow for the installation of equipment, on or with customer facilities or equipment to allow remote acces to each meter. Any additional cost of communication, such as but not limited too, cell phone service fees will be the responsibility of the customer.

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 the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this 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 XXXXXX XX, 2013 is further restricted to Customers being served under one of the following Rates:

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 XXXXXX XX, 2013 is further restricted to Customers being served under one of the following Rates:

1) Residential Electric Service, Rate R-01
2) Small General Service, Rate GS-10
3) Large General Service, Rate LGS-13

Customers being served under self-generation riders or plans may not purchase power under Rider-5 (including, but not limited to Net Metering for Certain Partial Requirements Service Rider-4 and Non-Firm Power Purchase from Renewable Energy Resources and Qualifying Cogeneration Facilities of 100 kilowatts (kW) or Less Capacity Rider-101).

RATE

Customers can contract for a portion or up to their average annual usage in solar blocks of 150 kilowatt hours (kWh) each. Transmission and distribution charges will be applied to all energy delivered, including energy delivered under Rider-5. The Customer is responsible for paying (each month) all charges incurred under their applicable rate schedule, and the total solar energy contracted for multiplied by the applicable solar block energy rate. Any demand based charges under the Customer's current Rate will not be affected by elections under Rider-5.

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.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

TERMS AND CONDITIONS

1) Customers may contract for a portion or up to their average annual usage in solar blocks of 150 kWh. If Customer's annual average usage is not available, 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 rate. If electricity usage is below the amount covered by the solar block(s), then the excess kWhs will be rolled forward and credited again the Customer's usage in the following month. The Customer will still be responsible for the full cost of the block(s) each month.

   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) 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 February 1, 2013, any Customer who has received incentives under the REST Rules, shall pay the average of the REST surcharge paid by members of their Customer class. This requirement shall apply to renewable systems reserved on and after January 1, 2012. 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 the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

Rider 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 SCHEDULES

- REST-TS1 - Renewable Energy Program Expense Recovery

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 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 will be placed in effect and charged to the participating Rate classes for the 12-month period the LFCR adjustment is applicable. The total year-on-year adjustment cannot exceed 2% of the Company's most recent total combined retail calendar year revenues for all participating Rate classes.

The LFCR adjustment shall be applied to all monthly bills as a percentage of the total bill and is 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 the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this rate.

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. XXXX dated XXX, 2013 and as defined in the Company's ECA Plan of Administration.

RATE
The Customer 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, 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 the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
This standard Rules and Regulations of the Company as on file with the ACC shall apply where not inconsistent with this Rider.

Rider R-10
MGC-1 Market Generation Credit (MGC) Calculation

INTRODUCTION

There are two purposes of the Market Generation Credit (MGC). The first purpose is to establish a price to which TEP's energy customers can compare to the prices of competitors. The second purpose is to enable the calculation of the variable or "floating" component of TEP's stranded cost recovery. Shown below are the terms of 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 thirty (30) 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. The MGC shall be equal to the hours-weighted average of the on-peak and off-peak pricing components and shall reflect the cost of serving a one hundred percent (100%) load factor customer.

To reflect the cost of serving a 100% load factor customer, the actual MGC used for billing calculations will be a loss adjusted average price that is weighted by the ratio of on-peak and off-peak hours. This process is illustrated in equations 4 and 5 below and will be posted to TEP's website http://partners.tucsonelectric.com thirty (30) days prior to each calendar month. This composite price will be credited to all energy consumption, regardless of the time period in which it is consumed.

CALCULATIONS

Five 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

Thirty (30) days prior to each calendar estimation month, the Tullet Prebon 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.

$$MGC_{ON,i} = \frac{\sum (TULLETT)_i}{3} \qquad \text{(Equation 1)}$$

The calculation is illustrated in the table below.

Forward Prices per MWh	Apr-2002
3/1/2002	$25.50
2/28/2002	$25.50
2/27/2002	$24.75
Average	$25.25

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. Weighting the MGC for hours in the month

The on-peak and off-peak MGCs are combined to form an average MGC by computing a weighted average of the two time periods. This is done by multiplying the on-peak MGC by the percentage of on-peak hours in the same month of the previous year and then adding the product of the off-peak MGC and the percentage of off-peak hours in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$MGC_{WEIGHT,i} = MGC_{ON,i} * \left(\frac{ONHOURS}{ONHOURS + OFFHOURS}\right) + MGC_{OFF,i} * \left(\frac{OFFHOURS}{ONHOURS + OFFHOURS}\right)$$

(Equation 4)

4. **Loss-adjusting the MGC**

The average MGC must be adjusted for line losses. The appropriate line loss adjustment factor (LLAF) for a large industrial customer is 1.0515. For all other customers, the appropriate factor is 1.0919.

$$MGC_{LOSS,i} = MGC_{WEIGHT,i} * LLAF \qquad \text{(Equation 5)}$$

5. **Adjusting the MGC for variable must-run**

The MGC will be adjusted for variable must-run as defined in TEP's Stranded Cost Settlement Agreement and AISA protocols. Fifteen (15) days prior to each month, TEP forecasts a ratio of its variable must-run generation to retail system demand for the following month. The MGC is determined by adding the product of MGC_{LOSS} and one minus the ratio of variable must-run generation to total retail system demand to the product of $15/MWh and the variable must-run ratio.

$$MGC_i = \left[MGC_{LOSS,i} * (1 - VMR_i)\right] + (\$15 * VMR_i) \qquad \text{(Equation 6)}$$

This calculation produces the final value for the Market Generation Credit.

GLOSSARY

$DJPVI_{OFF}$	Simple average of off-peak prices on the Dow Jones Palo Verde Index.
$DJPVI_{ON}$	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.
AISA	Arizona Independent Scheduling Administrator, a temporary entity, independent of transmission-owning organizations, intended to facilitate nondiscriminatory retail direct access using the transmission system in Arizona. Required by the Arizona Corporation Commission Retail Electric Competition Rules.
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}	MGC_{WEIGHT} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
MGC_{WEIGHT}	A weighted average of MGC_{ON} and MGC_{OFF} by ONHOURS and OFFHOURS.
Must-run Generation	The cost associated with the running of local generating units needed to maintain distribution system reliability and to meet load requirements in times of congestion on certain portions of the interconnected grid.
NERC	North American Electric Reliability Council. A voluntary not-for-profit organization established to promote bulk electric system reliability and security. Membership includes: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.
OFFHOURS	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.
ONHOURS	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.
VMR	Ratio of variable must-run generation (MW) to total retail system demand (MW) in TEP's service territory.
WEIGHT	Ratio of off-peak to on-peak prices on the Dow Jones Palo Verde Index.

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.

$$MGC_{ON,i} = \frac{\sum (TULLETT)_i}{3} \qquad \text{(Equation 1)}$$

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.

$$\mathrm{MGC}_{\mathrm{OFF},i} = \mathrm{MGC}_{\mathrm{ON},i} * \mathrm{WEIGHT}_i \qquad \text{(Equation 2)}$$

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

$DJPVI_{OFF}$	Simple average of off-peak prices on the Dow Jones Palo Verde Index.
$DJPVI_{ON}$	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.

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.

ATTACHMENT
"K"

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	$ 20.00	PENDING	PENDING
2.	Customer-Requested Meter Re-read	$ 20.00	PENDING	PENDING
3.	Special Meter Reading Fee	$ 20.00	PENDING	PENDING
4.	Automated Meter Opt-Out Meter Change-Out Fee	$ 20.00	PENDING	PENDING
5.	Additional Customer Charge for Automated Meter-Opt Out Customers	$ 10.00	PENDING	PENDING
6.	Additional Customer Charge for Self-Read Automated Meter Opt-Out Customers	$ 5.00	PENDING	PENDING
7.	Service Establishment and Reestablishment under usual operating procedures During Regulator Business Hours – Single-Phase Service	$ 32.00	PENDING	PENDING
8.	Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Single Phase Service	$ 57.00	PENDING	PENDING
9.	Service Establishment and Reestablishment under usual operating procedures During Regular Business Hours – Three-Phase Service	$ 78.00	PENDING	PENDING
10.	Service Establishment and Reestablishment under usual operating procedures After Regular Business Hours (includes Saturdays, Sundays and Holidays) – Three-Phase Service	$ 216.00	PENDING	PENDING
11.	Service Reestablishment under other than usual operating procedures – Single-Phase Service	$ 150.00	PENDING	PENDING
12.	Single-Phase Line Extension Charge per Foot	$ 17.00	PENDING	PENDING
13.	Three-Phase Line Extension Charge per Foot	$ 27.00	PENDING	PENDING
14.	Underground Differential Line Extension Charge per Foot	$ 21.00	PENDING	PENDING
15.	PME Switchgear Cabinet	$20,500.00	PENDING	PENDING
16.	Meter Test	$ 186.00	PENDING	PENDING
17.	Returned Payment Fee	$ 10.00	PENDING	PENDING
18.	Late Payment Finance Charge	1.5%	PENDING	PENDING

Filed By: Kentton C. Grant
Title: Vice President of Finance and Rates
District: Entire Electric Service Area

Rate: Statement of Charges
Effective: Pending
Decision No.:

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 801-1

Superseding:

TEP STATEMENT OF CHARGES
(continued)

Description	Rate	Effective Date	Decision No.
Rider R-1 – Purchased Power and Fuel Adjustment Clause (PPFAC)	$(0.001388) per kWh	PENDING	PENDING
Rider R-2 – Demand Side Management Surcharge (DSMS) RESIDENTIAL: Effective Date of Order – June 2014 (or until the next DSMS ACC Decision) NON-RESIDENTIAL: Effective Date of Order – June 2014 (or until the next DSMS ACC Decision)	 $0.000443 per kWh 0.5033%	PENDING	PENDING
Rider R-3 – Market Cost of Comparable Conventional Generation (MCCCG) Calculation as Applicable to Rider-4 NM-PRS	$0.025854 per kWh	April 5, 2012	73085
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	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	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 Commercial Customers: For Large Commercial Customers: For Industrial Customers: For Public Authority: For Lighting:	$0.008000 per kWh Monthly Cap $ 3.80 per month $ 130.00 per month $1,050.00 per month $7,700.00 per month $ 170.00 per month $ 130.00 per month	February 1, 2013	73637

*The Rider R-5 approved by Decision No. 71835 is closed for new enrollment as of XXXXX XX, 2013

TEP STATEMENT OF CHARGES
(continued)

Description	Rate	Effective Date	Decision No.
Rider R-6 – Renewable Energy Standard and Tariff Surcharge REST-TS1 Renewable Energy Program Expense Recovery Customers receiving REST incentives since January 1, 2012 are charged the following average cap (in place of a $ per kWh surcharge) Monthly Cap For Residential Customers: For Small Commercial Customers: For Large Commercial Customers: For Industrial Customers: For Public Authority: For Lighting:	Monthly Cap $ 3.21 per month $ 24.10 per month $ 797.05 per month $7,283.00 per month $ 53.50 per month $ 12.03 per month	February 1, 2013	73637
Rider R-8 – Lost Fixed Cost Recovery (LFCR) Mechanism	XXXXX %	On or around July 2014	PENDING
Rider R-9 – Environmental Compliance Adjustor (ECA)	$0.0000 per kWh	PENDING	PENDING

ATTACHMENT
"L"

ATTACHMENT L

LIST OF MODIFIED OR ELIMINATED REPORTING REQUIREMENTS

1. Eliminating the requirement from Decision No. 56526 (June 22, 1989) that TEP file monthly reports on the unit performance for each generation unit, other sources of energy, costs for each generating unit, costs of other sources of energy and disposition of energy.

2. Eliminating the requirement from Decision Nos. 57029 (July 18, 1990) and 57924 (July 2, 1992) that TEP file annual reports covering the period from July 1 through June 30 of each year required by regarding an agreement with Liquid Air.

3. Modifying the Lifeline Discount Tariff reporting requirements from Decision No. 56659 (October 24, 1989) (as modified in Decision Nos. 56781, 56819, and 57370) to now require TEP to submit the following information on an annual basis: (i) The total number of participating customers receiving a discount; (ii) The total number of kWh consumed by customers receiving the discount; and (iii) The total dollar amount of discounts provided.