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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

BOB STUMP, Chairman
GARY PIERCE
BRENDA BURNS
SUSAN BITTER SMITH
BOB BURNS

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 **NOTICE OF FILING DIRECT TESTIMONY (COST OF SERVICE AND RATE DESIGN) AND EXHIBITS OF KEVIN C. HIGGINS ON BEHALF OF FREEPORT-MCMORAN COPPER & GOLD INC. AND ARIZONANS FOR ELECTRIC CHOICE AND COMPETITION**

Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition (collectively "AECC"), hereby submit the Direct Testimony (Cost of Service and Rate Design) and Exhibits of Kevin C. Higgins on behalf of AECC in the above captioned Docket.

RESPECTFULLY SUBMITTED this 11th day of January 2012.

FENNEMORE CRAIG, P.C.

By [signature]
C. Webb Crockett
Patrick J. Black
3003 N. Central Avenue, Ste. 2600
Phoenix, AZ 85012-2913

Attorneys for Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition

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Docket Control
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, Arizona 85007

COPY of the foregoing was **HAND-DELIVERED/ MAILED/EMAILED** this 11th day of January 2013 to:

Lyn Farmer, Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Jane Rodda, Administrative Law Judge
Hearing Division
Arizona Corporation Commission
400 West Congress
Tucson, Arizona 85701
JRodda@azcc.gov
jane.rodda@azbar.org

Janice Alward, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
jalward@azcc.gov

Robin Mitchell, Counsel
Charles Haines
Brian Smith
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Steve M. Olea, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
solea@azcc.gov

Michael W. Patten
ROSHKA DEWULF & PATTEN
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Bradley S. Carroll
TUCSON ELECTRIC POWER COMPANY
88 E. Broadway Blvd., MS HQE910
Tucson, Arizona 85702

Daniel W. Pozefsky
RESIDENTIAL UTILITY CONSUMER OFFICE
1110 W. Washington Street, Suite 220
Phoenix, Arizona 85007

Nicholas J. Enoch
Jarrett J. Haskovec
LUBIN & ENOCH, P.C.
349 North Fourth Avenue
Phoenix, Arizona 85003
Nick@lubinandenoch.com
Jarrett@lubinandenoch.com
Attorneys for IBEW Local 1116

Kurt J. Boehm
Jody M. Kyler
BOEHM, KURTZ & LOWRY
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202
Attorneys for Kroger

Michael M. Grant
Gallagher & Kennedy, P.A.
2575 East Camelback Road
Phoenix, Arizona 85016-9225
mmg@gknet.com

Gary Yaquinto, President & CEO
Arizona Investment Council
2100 North Central Avenue, Suite 210
Phoenix, Arizona 85004
gyauinto@arizonaic.org

Travis M. Ritchie
Sierra Club
85 Second St., 2nd Floor
San Francisco, CA 94105
Travis.ritchie@sierraclub.org

Lawrence V. Robertson, Jr.
P.O. Box 1448
Tubac, Arizona 85646
Attorney for SAHBA,
EnerNOC, Inc. and SAWUA

John William Moore, Jr.
7321 North 16th Street
Phoenix, Arizona 85020
Attorney for Kroger

Stephen J. Baron
J. Kennedy & Associates
570 Colonial Park Drive, Suite 305
Roswell, GA 30075
Consultant to Kroger

Thomas L. Mumaw
Melissa Krueger
Pinnacle West Capital Corporation
P.O. Box 53999, MS 8695
Phoenix, Arizona 85072-3999

Leland Snook
Zachary J. Fryer
Arizona Public Service Company
P.O. Box 53999, MS 9708
Phoenix, Arizona 85702-3999

Timothy M. Hogan
Arizona Center for Law in the Public Interest
202 E. McDowell Road, Suite 153
Phoenix, Arizona 85004
thogan@aclpi.org
Attorneys for SWEEP and Vote Solar

Jeff Schlegel
SWEEP Arizona Representative
1167 W. Samalayuca Dr.
Tucson, Arizona 85704-3224
schlegelj@aol.com

Terrance A. Spann, Esq.
Kyle J. Smith
General Attorney
Regulatory Law Office (JALS-RL/IP)
U.S. Army Legal Services Agency
9275 Gunston Road, Suite 1300
Fort Belvoir, VA 22060-5546
Terrance.a.spann.civ@mail.mil

Court S. Rich
Carroll Rose Law Group, PC
6613 N. Scottsdale Road, Suite 200
Scottsdale, Arizona 85250
Attorney for SEIA

Michael L. Neary
Executive Director
AriSEIA
111 W. Renee Dr.
Phoenix, Arizona 85027

Cynthia Zwick
1940 E. Luke Avenue
Phoenix, Arizona 85016

Annie Lappe
Rick Gilliam
The Vote Solar Initiative
1120 Pearl Street, Suite 200
Boulder, Colorado 80302
annie@votesolar.org
rick@votesolar.org

Dan Neidlinger
Neidlinger & Associates
3020 N. 17th Drive
Phoenix, Arizona 85004

Robert Metli
Munger Chadwick,PLC
2398 Camelback Road, Suite 240
Phoenix, Arizona 85012

Rachel Gold
Senior Regulatory Analyst
Opower
642 Harrison Street, Floor 2
San Francisco, California 94110

By: W. M. McCracken

7841392.1

BEFORE THE ARIZONA CORPORATION COMMISSION

In the Matter of the Application of Tucson Electric Power Company for the Establishment of Just and Reasonable Rates And Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Operations Throughout the State of Arizona	)))))))	Docket No. E-01933A-12-0291

Direct Testimony of Kevin C. Higgins

on behalf of

Freeport-McMoRan Copper & Gold Inc. and

Arizonans for Electric Choice & Competition

Cost of Service / Rate Design

January 11, 2013

DIRECT TESTIMONY OF KEVIN C. HIGGINS

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DIRECT TESTIMONY OF KEVIN C. HIGGINS

INTRODUCTION

Q. Please state your name and business address.

A. Kevin C. Higgins, 215 South State Street, Suite 200, Salt Lake City, Utah, 84111.

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

A. I am a Principal in the firm of Energy Strategies, LLC. Energy Strategies is a private consulting firm specializing in economic and policy analysis applicable to energy production, transportation, and consumption.

Q. Are you the same Kevin C. Higgins who pre-filed direct testimony in this case on behalf of Freeport-McMoRan Copper & Gold Inc. and Arizonans for Electric Choice and Competition ("AECC")[1] on the subject of revenue requirements?

A. Yes, I am.

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

A. My testimony addresses the topics of cost-of-service, rate spread, and rate design.

Q. What are the primary conclusions and recommendations presented in this phase of your testimony?

A. (1) TEP's proposal to use a variant of the Peak and Average Demand method to allocate production and transmission plant should be rejected by the

[1] Henceforth in this testimony, Freeport-McMoRan Copper & Gold Inc. and AECC collectively will be referred to as "AECC."

Commission. This method is rarely adopted by utility regulatory commissions because of its structural bias that unreasonably disadvantages higher-load factor customer classes. Instead, I encourage the Commission to adopt the Average and Excess Demand method, which is used by Arizona Public Service Company ("APS") and Salt River Project ("SRP"), or alternatively, the 4-CP Method, which TEP uses to allocate jurisdictional costs.

To the extent that the Peak and Average Demand method is considered at all, it should be a version that is cured of the various analytical flaws committed by TEP, as discussed in my testimony.

(2) I am recommending that rates be spread using an across-the-board equal percentage increase for each of the major customer classes, subject to a number of qualifications. The equal percentage increase should be calculated using present revenues equal to current base rates plus the Forward Component of the 2012 PPFAC, as this is most representative of current going-forward rates. Within the LGS and LLP classes (including Mining), I am recommending retaining the same relationship between time-of-use ("TOU") and non-TOU rate schedules as proposed by TEP.

To the extent that the final overall rate increase in this case is less than 10 percent, the Commission should give consideration to allowing the Residential/Lighting percentage rate increase to be somewhat above the system average and the SGS/LGS rate increase to be somewhat below the system average, based on cost-of-service considerations. For every one percentage point that the SGS/LGS percentage rate increase is set below the system average, the Residential/Lighting increase would need to be 0.91 percentage points above the system average. The remaining classes should continue to receive the system average increase.

(3) TEP's proposal to establish a 100 percent demand ratchet should be rejected. Rather, the demand ratchet be set at 75%. This is midway between TEP's proposed 100% ratchet and the 50% ratchet currently in place for the LGS and LLP-TOU rate schedules. A 75% ratchet balances the need to compensate the Company for year-round expenses with reasonable variability in a customer's usage.

(4) TEP's proposal to abandon the price signal to shift capacity usage to off-peak periods should be rejected. Instead, TEP should be required to retain the current rate design in which the demand charge is limited to the on-peak period and incremental off-peak demand charges are not incurred until the off-peak demand reaches 150% of the on-peak billing demand. Moreover, the same pricing relationship between on-peak and incremental off-peak rates should be retained and the definition of the weekday on-peak period (as applicable to on-peak demand) should remain unchanged.

(5) TEP's proposal to flatten the base power rates for TOU customers in the LGS and LLP classes (LGS-85N and LLP-90N, respectively) should be rejected. Rather, the rate design should retain the current price signal for customers to shift energy usage to the off-peak periods, as discussed in my testimony.

(6) The structure of the unbundled portion of TEP's proposed tariff suffers from ambiguity, inconsistency, and numerous typographical errors – even in the corrected version of the tariff that was filed August 17, 2012. It does not

meet the minimum standard of a well-structured unbundled tariff. I recommend that the Commission order TEP to re-file the unbundled sections of its tariff in a manner that responds to the issues I discuss in my testimony, which includes clearly delineating all unbundled rate components by function.

(7) TEP should be required to restate its proposed energy charges for distribution service as demand charges for demand-billed classes.

(8) TEP's proposed relationship between delivery charges and generation capacity charges in its unbundled tariff would unreasonably thwart direct access and should be rejected. Instead, TEP should be ordered to re-file its unbundled rate components such that the relationships among the functions correspond to the underlying cost relationships using the cost-of-service methodology approved by the Commission in this case.

(9) TEP should be ordered to state clearly in its tariff that customers taking service at 138 kV or above are not subject to the Delivery charges stated in the unbundled portion of the tariff.

(10) I recommend that the Commission approve TEP's proposed interruptible tariff, Rider 5-ISCC filed in Docket No. E-01933A-07-0402, but with the removal of the "shared savings factor" and subject to the modifications recommended in Exhibit KCH-29 of this direct testimony.

COST OF SERVICE

Q. What is the purpose of cost-of-service analysis?

A. Cost-of-service analysis is conducted to assist in determining appropriate rates for each customer class. It involves the assignment of revenues, expenses, and rate base to each customer class, and includes the following steps:

- Separating the utility's costs in accordance with the various *functions* of its system (e.g., generation [or production], transmission, distribution);
- *Classifying* the utility's costs with respect to the manner in which they are incurred by customers (e.g., customer-related costs, demand-related costs, and energy-related costs); and
- *Allocating* responsibility for the utility's costs to the various customer classes based on principles of cost causation.

Q. What is the role of cost-of-service analysis in setting rates?

A. Each of the three steps above has an important role in the ratemaking process. If rates are unbundled by function, as they are in Arizona, then separating the utility's costs by function is important in determining which costs are generation-related, transmission-related, and distribution-related.

The classification of costs is critical to the rate design process, i.e., in determining the proper customer charge, demand charge, and energy charge for each rate schedule.

Finally, the allocation of costs to customer classes is important for determining revenue apportionment across customer classes, also called "rate spread." In determining rate spread, it is important to align rates with cost causation to the greatest extent practicable. Properly aligning rates with the costs caused by each customer class is essential for ensuring fairness, as it minimizes cross subsidies among customers. It also sends proper price signals, which improves efficiency in resource utilization.

Q. What approach has TEP used for allocating generation plant costs between TEP retail customers and FERC-jurisdictional customers?

A. As explained in the direct testimony of TEP witness Craig A. Jones, TEP uses the 4-Coincident Peaks ("4-CP") method for allocating generation plant costs between its state and federal jurisdictional loads. The 4-CP method allocates fixed production costs based on the average of system peak demands in the four summer months, which is when TEP's production capacity requirements are determined.

Q. In your opinion, is the 4-CP method appropriate for allocating TEP's jurisdictional generation plant costs?

A. Yes, it is. TEP's maximum system demands are driven by summer usage. Given the characteristics of TEP's system, the 4-CP method properly aligns the allocation of the Company's fixed costs with cost causation. As noted by Mr. Jones, the 4-CP method is also accepted in TEP's cases before FERC.

Q. Does TEP also use the 4-CP method for allocating generation plant costs across its retail customer classes in this case?

A. No. For allocating costs across retail customer classes, TEP uses a variant of the "Peak and Average Demand" method, which Mr. Jones refers to as the

"Average and Peaks" method.[2] TEP also uses this method for allocating transmission costs.

Q. Are you familiar with the Peak and Average Demand method?

A. Yes. The Peak and Average Demand method is classified in the NARUC Cost Allocation Manual as a "Judgmental Energy Weighting" approach. According to this method, fixed production cost is allocated based on a combination of each class's share of coincident peak demand, as well as each class's share of energy usage. In applying this method, class energy consumption is typically expressed as "average demand," which gives rise to the term "Peak and Average." (Average demand is simply annual energy divided by the number of hours in the year.)

Q. In your opinion, is the Peak and Average Demand method appropriate for allocating TEP's generation and transmission plant costs?

A. No, it is not a reasonable methodology. The Peak and Average Demand method has a problematic construction in that average demand is already included in peak demand and is thus counted twice in the allocation of costs. This double-weighting results in an undue bias against higher-load-factor customer classes in the allocation of costs. For this reason, the Peak and Average Demand method is rarely approved by utility regulators. In fact, a proposal to use this method was recently rejected by the Public Utility Commission of Texas, which found an alternative methodology, the Average and Excess Demand method, to be more

[2] "Peak and Average Demand" is the nomenclature used in the NARUC Electric Utility Cost Allocation Manual.

suitable.[3] This decision by the Texas commission is consistent with earlier findings by the Arizona Corporation Commission.

Q. Has the Arizona Corporation Commission previously expressed concern with the Peak and Average Demand method?

A. Yes. In Decision No. 69663 issued June 28, 2007, the Commission addressed a proposal to use the Peak and Average Demand method in the Arizona APS rate case, rather than the 4-CP method used by APS. The Commission stated:

> We agree with Staff that an energy-weighting method for allocating production plant is appropriate for APS. However, we are not convinced that the [Peak and Average Demand method] should be adopted. AECC's recommended Average and Excess Demand method would eliminate the criticism that the average demand is being counted twice. [Decision No. 69663, p. 70, line 27 – p. 71, line 2.]

Subsequent to this Commission decision, APS has used the Average and Excess demand method to allocate production plant in its rate case filings. Similarly, SRP uses the Average and Excess Demand method to allocate production plant as part of its pricing processes. In neighboring states, the Average and Excess Demand method is also used by Public Service Company of Colorado and El Paso Electric Company in both New Mexico and Texas.

When asked in discovery, TEP was unable to identify any other electric utility in the United States that has proposed this method except its affiliate UNS Electric.[4] This response is not surprising. With the exception of TEP's small affiliated company, I am not aware of any electric utility in the western United

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[3] PUC Docket No. 39896, ALJ Proposal for Decision (July 6, 2012), PUCT Order (Sep. 14, 2012).
[4] TEP's Response to AECC Data Request 2.05.

States that uses the Peak and Average Demand method to allocate production plant.

Q. Please explain the structural bias in the Peak and Average Demand method.

A. We can use a simple example to illustrate the Peak and Average Demand method and its structural bias. Assume we have two customer classes: Flat and Peaky. To highlight the underlying drivers of the Peak and Average Demand method, let us assume that the Flat class has a constant load of 500 MW throughout the year. Let us further assume that the load pattern of the Peaky class is as follows: January-March: 300 MW; April-May: 500 MW; June: 700 MW; July-August: 800 MW; September: 700 MW; October: 500 MW; and December: 300 MW.[5] This example is illustrated in Figure KCH-1, on the following page.

[5] For ease of exposition, I assume that the load of the Peaky class is constant over the duration of each month at the assumed load level. This simplifying assumption does not alter the conclusions in the example.

Figure KCH-1

Peak and Average Demand Method: Illustrative Example

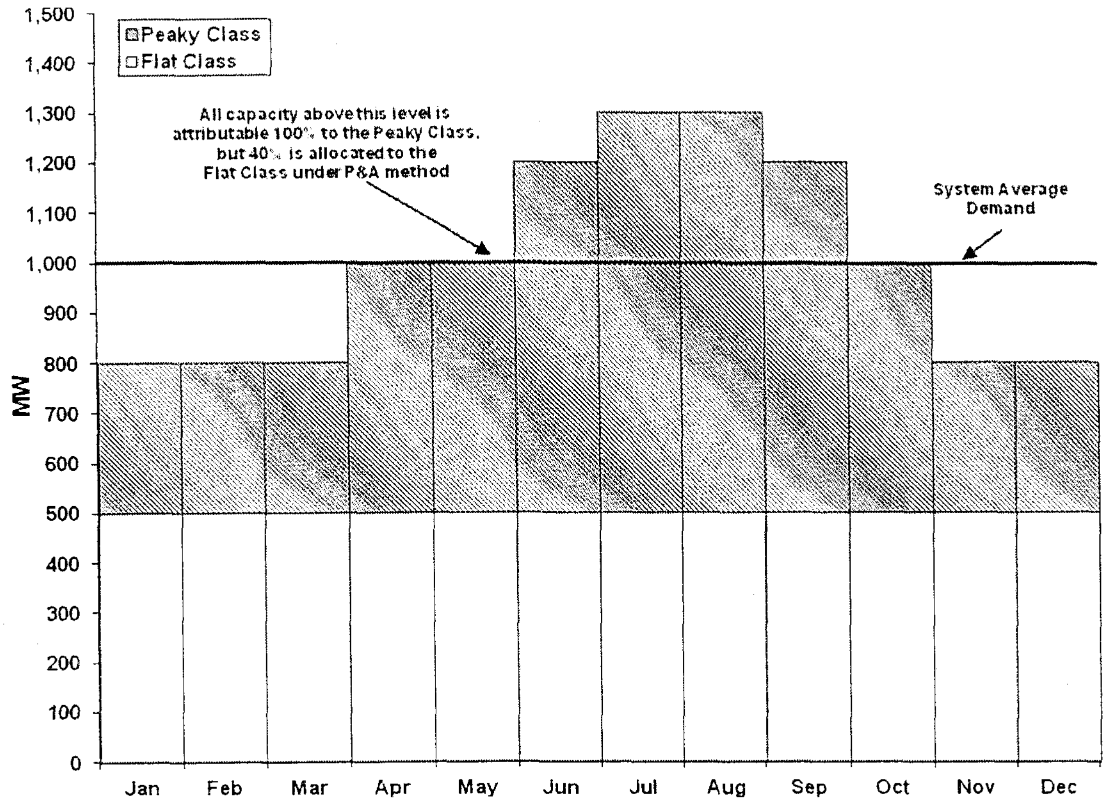

Figure KCH-1 shows the monthly demand of the Flat class at the bottom of the diagram. The monthly demand of the Peaky class is stacked on top of the Flat class's demand, such that the sum of the two constitutes the total demand for the system. The average demand of each of these classes is 500 MW,[6] resulting in an average demand for this two-class system of 1000 MW. Accordingly, the Peak and Average Demand method will allocate each of these classes 50 percent of the responsibility for the average demand portion of costs.

The system peak demand averages 1250 MW in the four summer months, June through September. It is clear in this example that all of the incremental

[6] For simplicity we assume that the duration of each month is 1/12 of a year. The varying durations of each month actually causes the average demand of the Peaky class to be slightly higher – 501 MW.

capacity required above the system average of 1000 MW demand is attributable to the needs of the Peaky class; the load of the Flat class is, of course, flat. But the Peak and Average Demand method will not allocate the full cost of this incremental capacity to the Peaky class. Instead, it will allocate these incremental costs in accordance with the share of each class's demand during the peak summer months;[7] that is, the Flat class will be allocated 40% of the incremental cost (500 MW/1250 MW) and the Peaky class will be allocated 60% of the incremental cost. Put another way, even though all of the Flat class's usage during the summer has already been accounted for in the allocation of average demand, the Flat class will be allocated an additional 40% of the costs of the incremental capacity above system average demand when the summer peak demand is apportioned. This additional allocation occurs because the Peak and Average Demand method allocates capacity costs based on total demand during the summer – not just the excess above average demand, even though average demand has already been fully allocated in the first step. This additional allocation is the double-weighting to which I referred previously in my testimony. In my opinion, this double-weighting amounts to a serious analytical bias in the Peak and Average Demand method.

Q. On page 20 of his direct testimony, Mr. Jones suggests that TEP's proposed method for allocating production costs was approved by the Commission in TEP's last general rate case. Do you agree with this statement?

[7] The use of the four summer months to allocate the peak component is consistent with the approach adopted by TEP.

A. No. This statement is incorrect. TEP's last general rate case took place during 2007 and 2008. Mr. Jones did not become a TEP employee until November 2009, and thus, did not participate in that proceeding, whereas I did.

In the Company's last general rate case, TEP *proposed* that the Peak and Average Demand method be used to allocate production costs, but the Company's proposal was strongly opposed by AECC, the Department of Defense, and Kroger. In addition to TEP's proposal, production cost allocations based on the 4-CP and Average and Excess Demand methods were introduced into the record and advocated by other parties. Ultimately, most parties to the case (including AECC, the Department of Defense, Kroger, and TEP) entered into a settlement agreement that was approved by the Commission in Decision No. 70628. In that decision, the Commission approved an across-the-board 6 percent rate increase for all customer classes (except low income customers) recommended by the settling parties. Significantly, nowhere in the settlement agreement is there any mention – let alone endorsement – of TEP's proposed production cost allocation methodology. Indeed, AECC would not have agreed to a settlement agreement that provided such an endorsement. Similarly, Decision No. 70628, which approved the settlement agreement, makes no mention whatsoever of TEP's proposed production cost allocation method. Simply put, TEP's assertion that the Commission approved the Company's production cost methodology in the last general rate case is without any support in the record and is without merit.

Q. Does the Average and Excess Demand method used by APS and SRP avoid the double-weighting of average demand costs?

A. Yes. The Average and Excess Demand method avoids the problem of double-weighting while using the same allocation treatment of energy, or average demand, as the Peak and Average Demand method: the difference is in the treatment of the incremental capacity requirements above average demand.

The Average and Excess Demand method is described in the NARUC Manual in its section entitled "Energy Weighting Methods." This method has the virtue of meeting the Commission's stated objective in Decision No. 69663 with respect to allocating a portion of production plant based on energy. As stated in the NARUC Manual, this method "effectively uses an average demand or total energy allocator to allocate that portion of the utility's generating capacity that would be needed if all customers used energy at a constant 100 percent load factor."[8] At the same time, the incremental amount of production plant that is required to meet loads that are above average demand is properly assigned to the users who create the need for the additional capacity.

Q. How does the Average and Excess Demand method apportion responsibility for incremental production plant that is required to meet loads that are above average demand?

A. The Average and Excess Demand method allocates the cost of capacity above average demand in proportion to each class's <u>excess</u> demand, where excess demand is measured as the difference between each class's individual peak demand[9] and its average demand. By focusing on excess demand, this method

[8] NARUC Electric Utility Cost Allocation Manual, January 1992, p. 49.
[9] A class's individual peak demand is often referred to as "Class Non-Coincident Peak Demand" or "Class NCP."

avoids the double-weighting of average demand that occurs in the Peak and Average Demand method.

Q. How would the Average and Excess Demand method allocate the capacity above average demand in your illustrative example?

A. The capacity above average demand would be allocated in proportion to each class's share of excess demand. In this example, the peak demand of the Flat class is the same as its average demand; that is, its excess demand is zero. The peak for the Peaky class is 800 MW, which translates into a class excess demand of 300 MW (i.e., 800 MW - 500 MW), which, of course, is also the entirety of the excess demand on this system. Thus, the Peaky class is allocated all of the cost associated with incremental capacity above average demand. Put another way, the Average and Excess Demand method properly assigns the cost of the incremental amount of production plant used to serve system requirements above average demand.

Q. Have you prepared a cost-of-service analysis that allocates TEP's production and transmission plant using the Average and Excess Demand method?

A. Yes, I have. The results of this analysis are presented in Exhibit KCH-17. I have also prepared a cost-of-service analysis that allocates production and transmission plant using the 4-CP method that TEP uses for jurisdictional purposes. The results of this analysis are presented in Exhibit KCH-18. These results are summarized in Table KCH-4, which is presented later in my testimony, following a discussion of other problems I have identified in TEP's cost-of-service study.

Q. What is your recommendation to the Commission regarding the appropriate methodology for allocating TEP's production and transmission plant?

A. TEP's proposal to use the Peak and Average Demand method to allocate production plant should be rejected. Rather, the Commission should require TEP to allocate production and transmission plant using the Average and Excess Demand method, consistent with the Commission's findings in Decision No. 69663, and consistent with the methodology for allocating production plant used by APS and SRP. The Commission should also give consideration to the cost allocation produced by the 4-CP method, which is consistent with TEP's jurisdictional allocation.

Q. Aside from the choice of methodology for allocating production plant, do you have any other concerns with the cost-of-service study prepared by TEP?

A. Yes. There are several analytical flaws in TEP's study, completely aside from the choice of methodology for allocating production and transmission costs, and distinct from certain errors that TEP has acknowledged in discovery. These analytical flaws are so significant that the results presented by TEP cannot reasonably be relied upon for drawing inferences about class cost causation.

Q. Before discussing the analytical flaws you have identified, what errors in its cost-of-service study has TEP acknowledged in discovery?

A. I am aware of four errors in TEP's cost-of-service study that the Company has acknowledged:[10]

[10] TEP's Responses to AECC Data Request 3.3, DOD Data Request 3.2, Supplemental Response to UDR 1.01, dated October 5, 2012.

(1) Inadvertently allocating distribution costs based on class coincident peak demand rather than class non-coincident peak demand;

(2) Entering the incorrect coincident peak demand for the LLP class;

(3) Entering incorrect class non-coincident peak demands for the LGS-TOU and LLP customer classes; and

(4) Entering incorrect class non-coincident peak and coincident peak data for the Lighting class.

Q. Has TEP corrected these errors in its filing?

A. Not at this time. My understanding is that the first two errors listed above were corrected in an update to TEP's cost-of-service study, but have not been included as part of TEP's filing, at least at this time. To my knowledge, the third error has neither been included in an update to TEP's cost-of-service study nor to its filing, and the fourth error was only discovered several days before this testimony was filed. For ease of discussion, I have prepared an updated cost-of-service study that corrects all four TEP-acknowledged errors listed above. A summary of the results of this analysis is presented in Exhibit KCH-19. I have denoted this corrected TEP cost-of-service study as "AECC COS Adj. 1." This baseline is the point of departure for my subsequent criticism of the remaining problems with TEP's study.

Q. Do you make any other corrections to TEP's cost-of-service study in AECC COS Adj. 1?

A. Yes. I make one other correction in AECC COS Adj. 1. TEP's cost-of-service study excludes the forward component of pro forma PPFAC revenues from present rates – even though these revenues are included in TEP's calculation of income tax expense at current rates in the Company's revenue requirement model. The omission of pro forma PPFAC revenues understates the rates of return for all classes. To correct both for this understatement and for TEP's inconsistent treatment with the revenue requirement model, I have included pro forma PPFAC revenues in AECC COS Adj. 1.

Q. Has TEP admitted that omitting the pro forma PPFAC revenues from present revenues is an error?

A. No. TEP concedes that it has made the omission, but does not acknowledge that it is an error. I have reviewed TEP's explanation for the omission and have concluded that the Company's explanation does not justify the omission.[11] Consequently, I am classifying the omission as an error and including the correction in AECC COS Adj. 1.

Q. What analytical flaws have you identified in TEP's class cost-of-service study?

A. I have identified the following analytical flaws in TEP's cost-of-service study:

1. TEP improperly allocates income tax expense to classes in both its treatment of class returns at present rates and class returns at proposed rates.

2. In allocating the cost of production plant, TEP fails to reflect line loss differentials among customers of different voltages.

3. TEP improperly assigns the errors in measuring class coincident peak attributable to its load research program to customer classes whose coincident

[11] TEP's explanation is provided in TEP Response to AECC 5.1.

peak is measured by census data, grossly overstating the coincident peak properly allocable to the census-measured classes.

4. TEP's weighting of average demand (compared to peak demand) in its use of the Peak and Average Demand method is inconsistent with the weighting prescribed in the NARUC Cost Allocation Manual.

Q. Please describe your concerns with the allocation of income tax expense.

A. In its analysis of class returns at present rates, TEP *allocates* income taxes to classes based on plant in service. While this approach may have some intuitive appeal, it is incorrect. The income tax expense for a given class should be *calculated* based on the operating income produced by that class. TEP's practice of allocating income taxes rather than calculating them overstates the expenses for a class that is earning below the overall average return, and vice versa. Consequently, it distorts rates of return at current revenues: the rate of return is overstated for classes earning above the average return and it is understated for classes earning below the average return.

This very issue was addressed by the Utah Public Service Commission several years ago and its findings on the subject are instructive on this point:

> In the interjurisdictional allocation model, income taxes are calculated based on taxable income. In its class cost of service study, [PacifiCorp] allocates to classes Utah's income taxes based on relative rate base rather than taxable income. UAE recommends income taxes be calculated on taxable income, similar to the approach taken in the interjurisdictional model.
>
> The Company's approach mixes income taxes incorporating the effect of the change in revenue requirement for a specific class with the earned income and rate base components of the class. The approaches of both the Company and UAE can be used to determine the change in revenues required to achieve an allowed rate of return, and moreover, both will provide the same revenue change. *However, the Company's approach tends to overstate the rates of return for classes earning above Utah's overall earned rate of return and understates the*

rates of return for classes earning below Utah's overall earned rate of return. The use of taxable income to calculate income taxes was recently ordered in the recent rate case for Questar Gas Company, Docket No. 07-057-13.

Therefore we accept UAE's proposal as a matter of policy to calculate income taxes based on taxable income in the class cost-of-service study.[12] [Emphasis added]

Q. Does TEP acknowledge that its approach is incorrect?

A. No. In discovery, TEP asserted that its approach was reasonable, implying that the allocation of income taxes to classes was a matter of the analyst's discretion. I disagree. Income taxes are a function of operating income. An integral part of a standard cost-of-service study is to identify operating income by class. This information should then be used to *calculate* each class's income tax expense. This is the conventional treatment nationwide – and with good reason. Failure to adhere to this convention not only distorts class returns at current rates, it can lead to errors in determining class revenue requirements at equalized returns. In this case, TEP's failure to adhere to the conventional treatment of apportioning class income tax expense has resulted in the Company using different income tax allocators for present rates and proposed rates. At present rates, TEP allocates income tax to classes based on plant in service, as noted above. At proposed rates, TEP allocates income tax to classes based on class total retail proposed sales revenue – including fuel. These allocation approaches are obviously inconsistent with one another. Moreover, there is no reasonable basis for TEP to be allocating income taxes based on proposed sales revenue. These

[12] Utah Public Service Commission, Docket No. 09-035-23. Report and Order on Revenue Requirement, Cost of Service and Spread of Rates at 131-132. February 18, 2010.

inconsistent and unreasonable allocation approaches are a consequence of TEP's ad hoc treatment of income tax expense in its cost-of-service study.

Both income tax allocation approaches used by TEP should be rejected. Instead, TEP should be required to adopt the standard utility convention of calculating each class's income tax expense based on the operating income produced by that class.

Q. Have you prepared a cost-of-service adjustment that calculates each class's income tax expense at present rates based on the operating income produced by that class?

A. Yes, I have. This adjustment is denoted as AECC COS Adj. 2 and is presented in Exhibit KCH-20. AECC COS Adj. 2 also incorporates all of the corrections in AECC COS Adj. 1.

Q. Please describe your concerns with the treatment of line losses in the class cost of service study.

A. In general, a customer that takes delivery at higher voltage causes the utility to incur fewer line losses for every kilowatt-hour of electricity delivered to the customer's meter than a customer taking delivery at a lower voltage. As a result, in general, the greater voltage at which a customer takes delivery, the fewer the kilowatt-hours required to be produced at input to deliver a given amount of kilowatt-hours to the customer's meter.

This difference in the cost of energy production should be recognized in a utility cost-of-service study. The typical voltage levels that are recognized for this purpose are secondary, primary, and transmission. (Sub-transmission is also sometimes recognized). However, TEP recognizes energy cost differentials only for customers taking service at 138 kV and above, i.e., transmission voltage – and this recognition is limited to the proposed PPFAC rate. That is, voltage differentiation is not recognized at all in the allocation of production plant, even though this allocation is based on average demand (i.e., energy) and coincident peaks, each of which is affected by line losses. In this fundamental sense, TEP's cost-of-service study is deficient and is not commensurate with good ratemaking practice.

Q. How does TEP treat line losses in its allocation of production plant?

A. In its original "Average and Peaks" summary workpaper, TEP included a column entitled "Losses" that scaled up each customer class's monthly coincident peak demand. While the proportion that was scaled up varied every month, the same proportion was applied to each class for a given month. Simply reviewing the workpaper would give the analyst the impression that the scaling was intended to capture line losses. However, the proportion being scaled up made that supposition implausible: the increase applied to each customer class ranged from 1.7% in December 2011 up to 30.4% in July 2011. Certainly, something else besides line losses is being captured in this adjustment.

In discovery, TEP clarified that the column in the workpaper that was labeled "Losses" was actually the difference between TEP's actual system peak demand and the sum of the class peak demands as estimated from TEP's load research program.[13] In other words, the "Losses" column was actually comprised of average line losses *plus* the variance (or error) between TEP's load research <u>prediction</u> of system coincident peak demand and <u>actual</u> system coincident peak

[13] Source: TEP Response to AECC 6.1.b.iv.

demand. Significantly, in the summer period (corresponding to the 4-CP used in the Peak and Average demand method used by TEP), the estimation error was very large, with the total "adder" applied to each class's coincident peak ranging from 21.4% in August to 27.9% in July.[14] Whereas some portion of this "adder" is accounting for line losses, a very substantial portion of it is truing up for estimation error.

Q. Why is there an estimation error in the first place?

A. Identifying class coincident peak demands requires identifying each class's aggregate demand at the time of the system monthly peak demand. For certain customer classes (e.g., LLP, LGS), this is relatively straightforward, because every customer in the class has a demand meter, so their demands at the time of the system peak can be directly measured. We can refer to these classes as "census-measured" classes – because their coincident demands in the cost-of-service study are based on the measured demand for the entire population of the class.

In contrast, smaller customers, such as Residential and SGS, typically do not have demand meters. Consequently, the class demands at the time of the coincident peaks for these classes cannot be directly measured, but rather are estimated using statistical samples of customers that have demand meters assigned to them for this purpose. Through statistical sampling, the usage patterns of a relatively small number of customers are used to estimate the coincident peak demands for the entire classes to which these customers belong.

[14] These adders were calculated from TEP's workpaper: "Average and Peaks Allocation 12-31-11(Revised 11-01-12)", column N.

Some error in estimation is inevitable. TEP is aware that an estimation error exists because TEP knows the actual system peak and TEP realizes that the sum of the individual class demands does not match the system peak. To compensate for this difference, in the cost-of-service study, TEP "trues up" the class coincident peak data to force it to match the actual system peak demands by applying the "adder" (labeled "Losses") that I described above. Some portion of this difference is attributable to line losses, but a large portion of it is attributable to estimation error.

Q. Is there a problem with the way that TEP accounts for the variation between predicted coincident peak and actual coincident peak?

A. Yes. TEP spreads the estimation error to all classes – even the census-measured classes whose coincident demands are directly measured. This means the census-measured classes are being assigned a pro rata share of the estimation error attributable to the statistically sampled classes. Because the estimation errors are very substantial during the 4-CP summer period, the census classes end up being assigned a much greater amount of peak demand than they actually cause. This is easy to see in the case of the Mining class, which consists of only two customers. The non-coincident peak ("NCP") for this class during July 2011 was 141 MW. That is, the maximum demand of these two customers at the same time (irrespective of the hour) during that month was 141 MW. Logically, coincident peak demand (after accounting for line losses) cannot exceed the NCP. Yet the July coincident peak assigned to these two customers in TEP's cost-of-service study was 173 MW. This amount was derived by scaling up by approximately 27% the measured July coincident peak of these two customers of

136 MW. I estimate that approximately 10 MW of the additional 37 MW assigned to this class was attributable to line losses. The remainder is simply "phantom load" – the share of estimation error assigned to the Mining class – even though the coincident demand of this class was already known and not subject to estimation error.

Q. How should this problem be corrected?

A. Each class's measured (or estimated) coincident peak demand should be adjusted for losses. Then, the estimation error (i.e., the difference between the sum of the loss-adjusted predicted class coincident peak demands and actual system peak demand) should be assigned pro rata to the sampled classes only, because these classes are the source of the estimation error. Class NCP and energy should also be adjusted for losses.

Q. Have you prepared a cost-of-service adjustment that performs this correction?

A. Yes, I have. This adjustment is denoted as AECC COS Adj. 3 and is presented in Exhibit KCH-21. AECC COS Adj. 3 also incorporates all of the corrections in AECC COS Adj. 1 and Adj. 2.

Q. What is the basis of your line loss estimates?

A. I requested line loss data from TEP by voltage but the Company indicated that it has not completed an engineering study on line losses in the last two rate cases.[15] TEP further indicated that it does not have line loss information differentiated by the voltage levels I requested (secondary, primary, non-EHV,

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[15] Source: TEP Response to AECC 3.1.c.

EHV).[16] In the absence of this standard information, I estimated TEP's line losses by estimating the *differences* in line losses between secondary and primary voltage levels provided by APS in its last rate case, and incorporated these differentials into TEP's average system line losses. I believe that using the line loss differentials on the APS system is a reasonable proxy for the TEP system and is preferable to ignoring these differentials altogether, as TEP has done.

Q. Please describe your concerns with TEP's weighting of average demand compared to peak demand in its use of the Peak and Average Demand method.

A. When using the Peak and Average method, a proportion of production costs must be assigned to average demand (i.e., energy) and the remaining proportion must be assigned to peak demand. The proportions used by TEP are inconsistent with the proportions prescribed in the Electric Utility Cost Allocation Manual, published by the National Association of Regulatory Utility Commissioners ("NARUC Manual"), which is the standard reference manual for this subject. Specifically, TEP weighted average demand by the system load factor, whereas the NARUC Manual prescribes that the proportion of plant classified as energy-related is calculated by dividing average demand by the sum of average demand and the average of the monthly peak demands used in the analysis (in this case, the four summer months).[17] Mathematically, this ratio will almost always be less than system load factor.[18] By giving a stronger weight to

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[16] Source: TEP Response to AECC 3.2.e.
[17] NARUC Manual, pp. 57-58.
[18] Since, by definition, system load factor is equal to (AD / CP), TEP's weighting of average demand, under most conceivable scenarios, will produce a classification percentage for energy that is greater than the weighting of (AD / (AD + 4 CP)) prescribed in the NARUC Manual.

average demand (or energy) than the NARUC Manual prescribes, TEP has further biased the results of its analysis to the disadvantage of higher-load factor customers. As discussed above, the Peak and Average Demand method already contains an undue bias against higher-load-factor customers; by giving average demand an even greater weighting than prescribed in the NARUC Manual TEP has arbitrarily exacerbated that bias.

Q. Have you prepared a cost-of-service adjustment that substitutes the weightings prescribed by the NARUC Cost Allocation Manual for those used by TEP?

A. Yes, I have. This adjustment is denoted as AECC COS Adj. 4 and is presented in Exhibit KCH-22. AECC COS Adj. 4 also incorporates all of the corrections in AECC COS Adj. 1, Adj. 2, and Adj. 3.

Q. Have you prepared an overall summary of the cost-of-service analyses you have conducted?

A. Yes. This summary is presented in Table KCH-4, below.

Table KCH-4

SUMMARY OF TEP CLASS COS STUDY RESULTS
(Class Rates of Return at Present Rates)

	P&A AECC Adj 4	AECC A&E	AECC 4CP
RESIDENTIAL SERVICE	0.12%	0.52%	-1.38%
SMALL GENERAL SERVICE	13.77%	9.97%	15.33%
LARGE GENERAL SERVICE	5.08%	8.05%	6.87%
LARGE LIGHT & POWER	-0.71%	1.24%	2.41%
MINING	-1.53%	2.55%	4.84%
LIGHTING	-0.73%	-10.18%	-0.08%
TOTAL	3.45%	3.45%	3.45%

Q. What conclusions do you draw from the cost-of-service analyses you have prepared in this case?

A. As I discussed above, the Peak and Average Demand method is rarely adopted by utility regulatory commissions because of its structural bias that unreasonably disadvantages higher-load factor customers. As implied by the classification of this method in the NARUC Manual as a "Judgmental Energy Weighting" approach, shifting costs to higher-load factor customers in this manner is a matter of subjective judgment, one with which I strongly disagree, and which I encourage the Commission to reject, in favor of the Average and Excess Demand method, or alternatively, the 4-CP Method.

To the extent that the Peak and Average Demand method is considered at all, it should be a version that is cured of the various analytical flaws committed by TEP, as discussed in my testimony above. For purposes of this case, that corresponds to the results produced by AECC COS Adj. 4.

Across the various methodologies, some inferences can be drawn. Under each of the methodologies, the Residential class performs best under the Average and Excess Demand method, but even under this method, this class produces a rate of return that is materially below average. Similarly, the returns for Lighting are significantly below par under all three methods. Conversely, the returns for SGS and LGS are above average under all three methodologies.

The results for LLP and Mining are mixed. Mining, which is not its own rate schedule but actually pays LLP-TOU rates, produces below average returns under the corrected Peak and Average Demand method, near average returns under Average and Excess Demand, and above-average returns under the 4-CP. LLP (excluding Mining) produces below average returns under the corrected Peak and Average Demand method, improves to moderately below average returns under Average and Excess Demand, and produces near average returns under the 4-CP.

RATE SPREAD

Q. What general guidelines should be employed in spreading any change in rates?

A. Rate spread allocates the revenue requirement to each of TEP's customer classes. Rate spread should recognize that rates must be just and reasonable and not cause undue discrimination. To this end, revenue responsibility for any class should be informed by the cost to serve the class, but should also take into account other factors such as economic conditions and the magnitude of rate impacts.

Q. What is your rate spread recommendation in this case?

A. I am recommending an across-the-board equal percentage increase for each of the major customer classes, subject to a number of qualifications discussed below. The equal percentage increase should be calculated using present revenues equal to current base rates plus the Forward Component of the 2012 PPFAC, as this is most representative of current going-forward rates. Within the LGS and LLP classes (including Mining), I am recommending retaining the same relationship between time-of-use ("TOU") and non-TOU rate schedules as proposed by TEP. That is, within these groupings, TEP has proposed a smaller rate increase for the TOU rate schedules than for the non-TOU rate schedules. This relationship should be retained, while holding the overall rate increase for the grouping equal to the average percentage increase for the system.

Q. Have you prepared an exhibit that illustrates your recommended rate spread at TEP's requested revenue requirement?

A. Yes. Those results are presented in Exhibit KCH-23.

Q. Have you also prepared an exhibit that illustrates your recommended rate spread at the adjusted revenue requirement presented by AECC in its direct testimony?

A. Yes. Those results are presented in Exhibit KCH-24.

Q. Why are you recommending an equal percentage increase for the major customer classes in this case?

A. The cost of service results using the Average and Excess Demand, 4 CP, and even Peak and Average Demand methods all suggest that the Residential and Lighting classes should be assigned rate increases that are *above* the system average and that SGS and LGS should be assigned increases *below* the system average. However, the proposed rate increase in this case is very large and moving in the direction of cost of service would be impactful on the classes that would be assigned above-average increases. Consequently, if the final overall rate increase is greater than 10 percent, an equal percentage change would be reasonable. On the other hand, to the extent that the final rate increase is less than 10 percent, the Commission should give consideration to allowing the Residential/Lighting percentage rate increase to be somewhat above the system average and the SGS/LGS rate increase to be somewhat below the system average. For every one percentage point that the SGS/LGS percentage rate increase is set below the system average, the Residential/Lighting increase would need to be 0.91 percentage points above the system average. The remaining classes should continue to receive the system average increase.

<u>RATE DESIGN</u>

Q. What rate design issues do you address?

A. My rate design testimony is the primarily concerned with the LGS and LLP rate schedules, along with their TOU counterparts. Specifically, I address TEP's proposed change to the demand ratchet, TEP's proposed changes to the TOU rate design, the representation of unbundled rate components in the tariff, the proper treatment delivery charges for customers taking service at 138 kV or above, and interruptible rates.

Q. What is a demand ratchet?

A. A demand ratchet is a tariff provision that locks in a customer to a minimum billing demand going forward based on the demand level in a prior month. For example, TEP currently has a demand ratchet for LLP-90N, which is a TOU rate schedule, that requires the demand charge to be no less than 50% of the maximum on-peak billing demand in the preceding eleven months. TEP's demand ratchets range from 50% to 66.7%, depending on the rate schedule.

Q. What change to the demand ratchet is TEP proposing in this case?

A. TEP is proposing to increase the demand ratchet for LGS and LLP customers to 100%. This means that a customer will be billed for demand at the highest demand level that the customer experienced over the prior eleven months.

Q. What justification does TEP offer for increasing the ratchet to 100%?

A. In a footnote on page 26 of his direct testimony Mr. Jones states that the "mechanism minimizes [the] risk of not recovering fixed costs and properly compensates for the year-round expenses incurred to provide service to a customer."

Q. Do you concur that a 100% demand ratchet is warranted?

A. No. I agree with Mr. Jones that a 100% demand ratchet provides great assurance of fixed-cost recovery to a utility, but it comes at the expense of considerable risk-shifting to customers: just one hour of unusually high demand and the customer's demand charge would be locked in for the next eleven months. While it is reasonable for the customer to pay the demand charge corresponding to the unusually high demand for the month in question, locking in that level for the next eleven months is an extreme consequence. In my experience, I am not aware of another utility with a demand ratchet of 100% applied to generation.

Q. Do you have an alternative proposal?

A. Yes. I recommend that the demand ratchet be set at 75%. This is midway between TEP's proposed 100% ratchet and the 50% ratchet currently in place for the LGS and LLP-TOU rate schedules. A 75% ratchet balances the need to compensate the Company for year-round expenses with reasonable variability in a customer's usage. Moreover, it is comparable to the 80% ratchet that APS has in place for certain demand-billed rate schedules.

Q. What changes in TOU rate design has TEP proposed for LGS and LLP customers?

A. TEP has proposed a large number of changes in rate design for TOU rates. Among the proposed changes are:

- Elimination of the shoulder peak period.
- The summer on-peak period is expanded from the current 2:00 p.m. - 6:00 p.m. to 10:00 a.m. - 9:00 p.m.
- Summer months are changed from May - October to May - September.
- Winter months are changed from November - April to October - April.
- Elimination of the on/off-peak differentiation in demand charges.
- Weekends and holidays are designated as off-peak.
- Elimination of the on/off-peak differentiation and seasonality in unbundled transmission and ancillary services charges.
- A flattening of the differential between on-peak and off-peak charges for base power rates.

Not all of these changes are objectionable. However, several of them cause very significant concerns and should not be adopted.

Q. What are your concerns regarding TEP's proposed rate design for TOU rates for LGS and LLP customers?

A. In the last general rate case, the settling parties, including TEP, made a concerted effort to encourage customers to shift energy and capacity usage into off-peak periods. This was implemented, in significant part, by adopting TOU rates that sent an energy price signal that off-peak usage would be materially less expensive than on-peak usage, and by setting demand charges that were tied to on-peak usage. In my opinion, the TOU rates negotiated by the parties and approved by the Commission sent the right message, because shifting energy usage to the off-peak periods allows TEP to utilize lower-cost fuel, and shifting capacity to the off-peak period allows for more efficient utilization of TEP's generation and transmission plant.

Indeed, customers have responded to this message. I am aware of at least one major industrial customer than has organized its production schedule to fit the time-of-day parameters in the LLP-TOU rate schedule. This response is good for the TEP system because it makes better use of system capacity, good for the customer because it gives the customer the opportunity to reduce its energy costs by acting in the best interest of the system, and good for the local economy because the availability of opportunities to reduce costs is particularly important during challenging economic times.

In this case, TEP is proposing to undo much of this good work. With respect to the LGS-TOU and LLP-TOU rate schedules, TEP is proposing to significantly flatten the TOU differentials for fuel and purchased power costs, watering down the price signal for customers to use power off-peak. Similarly, TEP is proposing to abandon the relationship between demand charges and on-peak usage, and instead is proposing that the demand charge for LGS-TOU and

LLP-TOU be based on maximum demand irrespective of what time of day this demand occurs. In other words, TEP is proposing to completely eliminate the incentive for TOU customers to shift their demand usage to the off-peak period.

Q. Under the current tariff is an LLP-TOU customer able to use unlimited amounts of capacity off-peak at no charge?

A. No, not at all. An LLP-TOU customer is billed for its demand during the on-peak period. The customer can then use up to 150 percent of its billed demand off-peak before incurring any additional demand charges. For off-peak demand that is greater than 150 percent of the (on-peak) billed demand, the customer is billed an additional demand charge equal to approximately 50 percent of the on-peak demand charge. And of course, the customer must pay the energy charge for the off-peak usage as well. The off-peak demand is not free; rather, the customer has a well-structured economic incentive to shift its demand to the off-peak period.

Q. What is your recommendation to the Commission regarding the rate design treatment of off-peak demand for the LLP-TOU rate schedule?

A. TEP's proposal to abandon the price signal to shift capacity usage to off-peak periods should be rejected. Instead, TEP should be required to retain the current rate design in which the demand charge is limited to the on-peak period and incremental off-peak demand charges are not incurred until the off-peak demand reaches 150% of the on-peak billing demand. Moreover, the same pricing relationship between on-peak and incremental off-peak rates should be retained. Finally, TEP has also proposed to extend the weekday on-peak period in the summer by two hours in the morning and one hour in the evening. With respect to the on-peak demand charge, this change will adversely impact customers who have scheduled their production processes in reliance on the current tariff. Consequently, for purposes of continuing the current practice of encouraging load-shifting to off-peak periods, the definition of the weekday on-peak period (as applicable to on-peak demand) should remain unchanged.

Q. What is your recommendation to the Commission regarding the rate design treatment of base power rates?

A. Base power rates correspond to the fuel and purchased power costs that are eligible for recovery in the PPFAC. As discussed in my direct revenue requirements testimony, TEP has proposed separating these costs from base rates. As a preliminary matter, I recommend that the separation that TEP has requested be rejected and these costs continue to be recovered in base rates as a separately stated "base power rate" component, as occurs in current rates.

With respect to rate design, TEP's proposal to flatten the base power rates for TOU customers in the LGS and LLP classes (LGS-85N and LLP-90N, respectively) should be rejected. Rather, the rate design should retain the current price signal for customers to shift energy usage to the off-peak periods. I have prepared an alternative rate design for these two rate schedules that builds upon the current design. It was constructed by increasing the summer and winter on-peak prices for LLP-90N by the overall increase in fuel and purchased power costs since the last general rate case and then solving for off-peak prices that retain the proposed pricing relationships between LLP-90N and LGS-85N while simultaneously recovering the combined revenue requirement. AECC's proposed base power rates are presented in Table KCH-5 below. The proof of revenues is presented in Exhibit KCH-25.

Table KCH-5

AECC Recommended Base Power Rate Design for LGS-85N and LLP-90N

	LGS-85N		
	Current Rate	TEP Proposed Rate	AECC Recommended Rate
Summer On-Peak	$0.059253	$0.038739	$0.050669
Summer Shoulder Peak	$0.033588		
Summer Off-Peak	$0.025299	$0.030187	$0.026679
Winter On-Peak	$0.036088	$0.034305	$0.032893
Winter Off-Peak	$0.027799	$0.030599	$0.027092

	LLP-90N		
	Current Rate	TEP Proposed Rate	AECC Recommended Rate
Summer On-Peak	$0.041786	$0.034837	$0.045568
Summer Shoulder Peak	$0.041786		
Summer Off-Peak	$0.026872	$0.027146	$0.023985
Winter On-Peak	$0.027126	$0.030849	$0.029581
Winter Off-Peak	$0.019542	$0.027517	$0.024356

Q. Does your proposed rate design produce reasonable results?

A. Yes, it does. The average fuel cost at TEP's Luna generating plant in 2012 was $.043 per kWh. The summer peak rate I have proposed for LLP-90N of $.045568 per kWh is close to the fuel cost of this facility plus losses. At the same time, the off-peak rates are well above TEP's lowest-cost base-load plants.

Q. Did TEP file its tariff in a manner that is identifies the unbundled components?

A. TEP's proposed tariff purports to identify unbundled components. However, the structure of the unbundled portion of the tariff suffers from ambiguity, inconsistency, and numerous typographical errors – even in the corrected version of the tariff that was filed August 17, 2012. It does not meet the minimum standard of a well-structured unbundled tariff. I recommend that the Commission order TEP to re-file the unbundled sections of its tariff in a manner that responds to the issues I discuss below.

Q. Before addressing the problems with the unbundled sections of TEP's proposed tariff, please explain the significance of an unbundled tariff.

A. An unbundled tariff is one in which utility rates are separated according to function, in particular, generation, transmission, and distribution (or delivery service).

In the late 1990s, the Commission adopted rules implementing retail competition, or direct access service. While direct access activity is currently suspended, it remains an open issue, and it is my understanding that the Commission intends to revisit this issue in the future. For direct access to work, it is essential that utility rate schedules be unbundled because direct access customers are not generally required to pay utility generation rates, as they are purchasing their generation elsewhere. The Commission's rules carefully prescribe the requirements for filing an unbundled tariff.

Q. Please describe the ambiguity and inconsistencies in TEP's proposed unbundled tariff.

A. Consider proposed Tariff Sheet 302-2, which presents the unbundled components for LLP-90N, and which I have reproduced as Exhibit KCH-26.

Note the first entry below "Demand Charges": it simply restates "Demand Charges" without any indication as to <u>function</u>. That is, the entry does not indicate whether these demand charges are for generation service, delivery service, or some combination of the two. As a component in an unbundled tariff, this label is useless: it gives no indication to a prospective direct access customer whether this is a delivery charge or a bypassable generation charge. TEP should be required to restate this charge by function and fully document the source of the charge by function. TEP's workpapers filed with the case do not appear to provide sufficient documentation to verify whether these charges derive from generation or distribution (i.e., delivery) service.

Q. What is an example of inconsistency in the unbundled portion of the tariff?

A. Consider proposed Tariff Sheet 301-2, which presents the unbundled components for LLP-14, and which I have reproduced as Exhibit KCH-27. Note that unlike proposed Tariff Sheet 302-2, the first entry below "Demand Charges" states "Delivery Charges," which is a clear indication of function. However, continuing down the list of "Demand Charges" we find the entry "Fixed Must-Run Charges (in kW)." Yet, the charge itself is expressed not as a demand charge, but as an energy charge. Properly, Fixed Must-Run Charges *should* be recovered as a demand charge, and it is recovered through a demand charge in the current tariff, but it does appear that TEP intends to convert this charge arbitrarily into an energy charge – yet continues to list it among the demand charges. Turning back to proposed Tariff Sheet 302-2 we see a further inconsistency with respect to this charge: for LLP-90N customers the Fixed Must-Run Charge is listed among the energy charges (although it is expressed as a demand charge). Further note that all of the "Energy Charges" on this tariff sheet are expressed as demand charges.

Here I have highlighted the ambiguities, inconsistencies, and extensive typographic errors just between two pages of the proposed tariff. I have not done an exhaustive review of every page in the tariff, but I have little doubt that similar problems abound. The entire document needs to be re-filed and restated in accordance with industry standards. As part of that re-filing, the base power charges should be incorporated back into each rate schedule, rather than separately stated in the PPFAC, as TEP as proposed.

Q. As part of your review of the unbundled tariff components, do you have any additional rate design recommendations?

A. Yes. A portion of the Delivery Charges for demand-billed customers is stated as an energy charge. This is not good rate design. The cost of delivery service is exclusively a function of customer-related costs and demand-related costs; consequently, recovery of these costs should occur exclusively through fixed customer charges and demand charges, not energy charges. The fact that TEP has proposed partial recovery of distribution charges through an energy charge is particularly ironic in light of the fact that TEP has gone through great lengths in this case to emphasize its concern with fixed cost recovery; yet by proposing to recover delivery service costs through an energy charge TEP is undermining that very objective. TEP should be required to restate its proposed energy charges for distribution service as demand charges for demand-billed classes.

In addition, I believe there is a serious problem in the relationship between TEP's proposed delivery charges and the proposed charges to recover fixed generation costs. Note that for LLP-14 customers (proposed Tariff Sheet 301-2), the proposed demand charge Delivery Service is $10.18 per kW-month, whereas the proposed demand charge for Generation Capacity Service is $8.25 per kW-month. This pricing relationship is entirely inconsistent with the results of TEP's cost-of-service study (flawed as it is), which shows generation demand costs for the LLP class to be $27.7 million and distribution demand costs to be just $8.0 million.[19] In other words, the cost-of-service study TEP presumably relied upon in designing rates shows that generation demand costs are more than three times as great as distribution demand costs, yet TEP proposes to price generation demand more cheaply than distribution demand. This is a serious problem.

Q. Why is this a serious problem?

A. It is a serious problem because direct access customers are able to bypass generation charges. If the rate design shifts cost recovery from generation charges to distribution charges, then the ability of customers to shop competitively for power will be thwarted. Based on the proposed unbundled rate components, it appears that is exactly what TEP is attempting to achieve.

Q. What is your recommendation to the Commission on this issue?

A. TEP's proposed relationship between delivery charges and generation capacity charges in its unbundled tariff should be rejected. Instead, TEP should be ordered to re-file its unbundled rate components such that the relationships among the functions correspond to the underlying cost relationships using the cost-of-service methodology approved by the Commission in this case.

Q. Does TEP's proposed tariff adequately address the rate design for customers taking service at 138 kV or above?

[19] TEP Schedule G workpaper (Revised 10-05-12).

A. No. Retail customers taking service at 138 kV do not use the primary and secondary distribution systems and thus should not be charged for the costs of those systems, which comprise the lion's share of delivery costs. Excluding high-voltage customers from these costs is fundamentally reasonable and is the norm across the United States, yet TEP's tariff fails to clearly state that customers taking service at high voltage are not subject to delivery charges.

Q. What is your recommendation to the Commission on this issue?

A. TEP should be ordered to state clearly in its tariff that customers taking service at 138 kV or above are not subject to the Delivery charges stated in the unbundled portion of the tariff.

Q. Does TEP have interruptible rates for industrial customers in its current tariff?

A. No.

Q. Has TEP proposed interruptible rates for industrial customers in this case?

A. No.

Q. Is TEP required by Commission order to offer such rates?

A. Yes. Section XVIII of the settlement agreement approved by the Commission in the last general rate case required TEP to file an interruptible tariff within 90 days of the effective date of the Commission's approval of the agreement. The interruptible tariff was to be developed in consultation with Staff and interested stakeholders and was required to provide "a range of options with respect to notice requirements, duration, and frequency, and that will provide credits to participating customers based on avoided capacity costs."

On behalf of AECC, I had several rounds of communications with TEP during 2009 in an attempt to jointly develop an interruptible tariff. While we reached agreement on the basic structure of the tariff, several items remained unresolved. On October 26, 2009, the Company filed in Docket No. E-01933A-07-0402 its proposed interruptible tariff, Rider 5-ISCC, which I have attached as Exhibit KCH-28.[20] AECC filed an Objection two days later, indicating its support for many of the elements in the structure of the proposed tariff, but expressing strong objections to a "shared savings factor," which would allow the interruptible customer to retain just 25% of the benefit of the value provided by the interruption, while transferring 75% of the benefit to non-participating customers. AECC requested that the Commission set the matter for hearing to resolve this and other differences.

In 2010, I met with Staff and TEP in an attempt to work through the several differences between AECC and TEP on the design of the interruptible tariff. We made progress on several technical issues, but the disagreement over the shared savings factor remained. On July 22, 2010, I provided data responses to Staff clarifying AECC's positions on areas of disagreement. I supplemented the data responses on July 28, 2010, a copy of which is attached as KCH Exhibit-29.

My understanding is that following the three-party meeting and follow-up communication, Staff intended to file a proposed order. However, to my knowledge, no further action has been taken on this matter.

[20] TEP also filed a proposed Rider 6, which AECC does not believe is useful and is not discussed in this testimony.

Q. What is your recommendation to the Commission with respect to an interruptible tariff for industrial customers?

A. I recommend that the Commission approve TEP's proposed Rider 5-ISCC filed in Docket No. E-01933A-07-0402, but with the removal of the "shared savings factor" and subject to the modifications recommended by AECC as explained in Exhibit KCH-29.

Q. Why should the shared savings factor be removed?

A. The economic premise behind the proposed interruptible tariff is that it would be tied to the market value of capacity purchased by TEP to serve customers. The "shared savings factor" proposed by TEP is simply an unjust diminution of the benefit that would be available to interruptible customers from participating in the program, such that program participants would be paid a fraction of the adjusted market value of the interruptible capacity. Such an approach to interruptible customers is unduly discriminatory relative to other suppliers of capacity. It would also be disadvantageous to non-participating retail customers, as TEP would wind up paying more for generation capacity in the market when interruptible capacity was available. There is no reason why customers who are providing capacity should be treated on a discriminatory basis relative to generation suppliers who are providing capacity. If the type of "shared savings factor" proposed by TEP is adopted, I believe the interruptible service program envisioned by Rider 5 would be certain to fail due to lack of participant interest.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT KCH-17

Class Cost of Service Results at Present Rates
Using Average & Excess Demand Methodology
(For the 12 Months ending December 31, 2011)

SUMMARY AT PRESENT RATES

LINE NO.		TOTAL TEP	RESIDENTIAL	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$3,199,453,192	$1,712,344,202	$777,824,282	$308,398,638	$192,190,015	$152,059,690	$56,636,364
3	RESERVE FOR DEPRECIATION	1,411,638,679	751,500,365	344,169,978	137,123,281	85,448,828	67,996,529	25,399,698
4	CASH WORKING CAPITAL	(19,358,886)	(10,206,723)	(4,646,861)	(1,883,406)	(1,182,043)	(1,154,597)	(285,257)
5	FUEL INVENTORY	25,307,037	12,812,322	6,259,902	2,605,687	1,640,428	1,636,534	352,163
6	MATERIALS & SUPPLIES	42,837,160	22,926,406	10,414,212	4,129,119	2,573,213	2,035,912	758,299
7	PREPAYMENTS	4,537,991	2,428,728	1,103,238	437,422	272,595	215,676	80,331
8	CUSTOMER ADVANCES FOR CONSTRUCTION	(8,923,750)	(4,614,433)	(1,791,248)	(1,118,969)	(565,143)	(659,708)	(174,249)
9	CUSTOMER DEPOSITS	(23,743,247)	(9,901,609)	(12,408,985)	(480,953)	0	(947,000)	(4,700)
10	DEFERRED CREDITS - ASSET RETIREMENT	(15,832,308)	(8,879,823)	(3,710,414)	(1,411,797)	(877,103)	(693,884)	(259,287)
11	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
12	REGULATORY ASSESTS	11,088,732	5,877,140	2,809,799	1,111,289	685,149	317,418	287,937
13	ACCUM DEFERRED INCOME TAXES	(284,653,881)	(152,346,477)	(69,202,669)	(27,438,085)	(17,099,057)	(13,528,681)	(5,038,911)
14								
15	TOTAL RATE BASE	$1,519,073,362	$818,939,368	$362,481,279	$147,225,664	$92,189,227	$71,284,831	$26,952,992
16								
17	DEVELOPMENT OF RETURN							
18	ADJUSTED SALES OF ELECTRICITY - NON-PPFAC	$544,748,189	$248,139,394	$169,348,655	$63,509,759	$30,353,523	$30,374,675	$3,022,183
19	ADJUSTED SALES OF ELECTRICITY - PPFAC	268,653,221	115,433,127	61,692,507	37,178,047	24,171,504	29,264,219	913,817
20	PRO FORMA PPFAC REVENUE	23,536,480	7,381,000	7,682,673	3,269,209	2,271,394	2,664,699	267,506
21	OTHER OPERATING REVENUE	29,181,969	15,594,150	7,166,657	2,852,137	1,665,580	1,783,358	120,086
22	TOTAL OPERATING REVENUE	$866,119,859	$386,547,671	$245,890,492	$106,809,153	$58,462,001	$64,086,951	$4,323,592
23								
24	OPERATING EXPENSES							
25	OPERATION & MAINTENANCE	$674,132,594	$323,067,905	$160,621,917	$77,247,594	$50,383,125	$55,856,517	$6,955,536
26	DEPRECIATION & AMORT EXPENSE	97,310,414	52,309,751	23,417,935	9,218,329	5,742,996	4,854,551	1,766,852
27	INTEREST ON CUSTOMER DEPOSITS	45,852	19,122	23,964	929	0	1,829	9
28	TAXES OTHER THAN INCOME TAX	35,141,489	18,850,039	8,537,087	3,377,703	2,103,980	1,645,065	627,614
29	STATE & FEDERAL INCOME TAX	7,018,371	(11,953,778)	17,144,635	5,111,743	(910,927)	(91,151)	(2,282,150)
30	TOTAL OPERATING EXPENSES	$813,648,719	$382,293,039	$209,745,538	$94,956,297	$57,319,173	$62,266,812	$7,067,861
31								
32	OPERATING INCOME	$52,471,140	$4,254,632	$36,144,954	$11,852,856	$1,142,828	$1,820,140	($2,744,270)
33								
34	RATE OF RETURN (PRESENT WITH PRO FORMA PPFAC)	3.45%	0.52%	9.97%	8.05%	1.24%	2.55%	-10.18%

Data Sources: AECC Class Cost of Study Workpaper, TEP Schedule H-2, p. 2 & 6. 2012 TEP Proposed Rates (Revised).xls.

EXHIBIT KCH-18

Class Cost of Service Results at Present Rates
Using 4CP Demand Methodology
(For the 12 Months ending December 31, 2011)

SUMMARY AT PRESENT RATES

LINE NO.		TOTAL TEP	RESIDENTIAL	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$3,199,453,192	$1,835,147,472	$682,922,813	$318,930,268	$184,703,597	$141,599,332	$36,149,710
3	RESERVE FOR DEPRECIATION	1,411,638,679	807,857,593	300,617,524	141,956,486	82,013,140	63,196,032	15,997,904
4	CASH WORKING CAPITAL	(19,358,886)	(11,382,348)	(3,738,346)	(1,984,227)	(1,110,373)	(1,054,457)	(89,134)
5	FUEL INVENTORY	25,307,037	14,521,065	4,939,398	2,752,229	1,536,259	1,490,984	67,102
6	MATERIALS & SUPPLIES	42,837,160	24,570,607	9,143,586	4,270,126	2,472,978	1,895,859	484,005
7	PREPAYMENTS	4,537,991	2,602,908	968,633	452,359	261,977	200,839	51,273
8	CUSTOMER ADVANCES FOR CONSTRUCTION	(8,923,750)	(4,614,433)	(1,791,248)	(1,118,969)	(565,143)	(659,708)	(174,249)
9	CUSTOMER DEPOSITS	(23,743,247)	(9,901,609)	(12,408,985)	(480,953)	0	(947,000)	(4,700)
10	DEFERRED CREDITS - ASSET RETIREMENT	(15,832,308)	(9,439,773)	(3,277,688)	(1,459,819)	(842,967)	(646,188)	(165,873)
11	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
12	REGULATORY ASSESTS	11,088,732	5,877,140	2,809,799	1,111,289	685,149	317,418	287,937
13	ACCUM DEFERRED INCOME TAXES	(284,653,881)	(163,272,228)	(60,759,329)	(28,375,079)	(16,432,994)	(12,598,028)	(3,216,223)
14								
15	TOTAL RATE BASE	$1,519,073,362	$876,251,209	$318,191,108	$152,140,737	$88,695,343	$66,403,020	$17,391,945
16								
17	DEVELOPMENT OF RETURN							
18	ADJUSTED SALES OF ELECTRICITY - NON-PPFAC	$544,748,189	$248,139,394	$169,348,655	$63,509,759	$30,353,523	$30,374,675	$3,022,183
19	ADJUSTED SALES OF ELECTRICITY - PPFAC	268,653,221	115,433,127	61,692,507	37,178,047	24,171,504	29,264,219	913,817
20	PRO FORMA PPFAC REVENUE	23,536,480	7,381,000	7,682,673	3,269,209	2,271,394	2,664,699	267,506
21	OTHER OPERATING REVENUE	29,181,969	15,594,150	7,166,657	2,852,137	1,665,580	1,783,358	120,086
22	TOTAL OPERATING REVENUE	$866,119,859	$386,547,671	$245,890,492	$106,809,153	$58,462,001	$64,086,951	$4,323,592
23								
24	OPERATING EXPENSES							
25	OPERATION & MAINTENANCE	$674,132,594	$345,610,868	$143,200,880	$79,180,882	$49,008,845	$53,936,312	$3,194,807
26	DEPRECIATION & AMORT EXPENSE	97,310,414	56,577,524	20,119,831	9,584,334	5,482,821	4,491,023	1,054,881
27	INTEREST ON CUSTOMER DEPOSITS	45,852	19,122	23,964	929	0	1,829	9
28	TAXES OTHER THAN INCOME TAX	35,141,489	20,156,198	7,527,697	3,489,719	2,024,353	1,533,807	409,714
29	STATE & FEDERAL INCOME TAX	7,018,371	(23,703,222)	26,224,520	4,104,108	(194,649)	909,665	(322,049)
30	TOTAL OPERATING EXPENSES	$813,648,719	$398,660,489	$197,096,892	$96,359,972	$56,321,369	$60,872,635	$4,337,362
31								
32	OPERATING INCOME	$52,471,140	($12,112,818)	$48,793,600	$10,449,181	$2,140,631	$3,214,316	($13,770)
33								
34	RATE OF RETURN (PRESENT WITH PRO FORMA PPFAC)	3.45%	-1.38%	15.33%	6.87%	2.41%	4.84%	-0.08%

Data Sources: AECC Class Cost of Study Workpaper, TEP Schedule H-2, p. 2 & 6. 2012 TEP Proposed Rates (Revised).xls.

EXHIBIT KCH-19

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Class Cost of Service Results at Present Rates
Using TEP's Oct. 5, 2012 4CP Peak and Average Demand Methodology with AECC Adjustment 1
(For the 12 Months ending December 31, 2011)

SUMMARY AT PRESENT RATES

LINE NO.		TOTAL TEP	RESIDENTIAL	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$3,199,453,192	$1,636,011,342	$706,761,817	$368,961,665	$233,406,441	$206,536,870	$47,775,057
3	RESERVE FOR DEPRECIATION	1,411,638,679	717,816,647	311,549,381	164,383,704	103,966,940	92,656,035	21,265,973
4	CASH WORKING CAPITAL	(19,358,886)	(9,798,214)	(3,959,189)	(2,328,885)	(1,479,571)	(1,608,551)	(184,475)
5	FUEL INVENTORY	25,307,037	12,252,400	5,259,691	3,239,172	2,062,753	2,289,006	204,016
6	MATERIALS & SUPPLIES	42,837,160	21,904,393	9,462,764	4,939,991	3,125,056	2,765,302	639,655
7	PREPAYMENTS	4,537,991	2,320,460	1,002,446	523,322	331,055	292,945	67,762
8	CUSTOMER ADVANCES FOR CONSTRUCTION	(8,923,750)	(4,614,433)	(1,791,248)	(1,118,969)	(565,143)	(659,708)	(174,249)
9	CUSTOMER DEPOSITS	(23,743,247)	(9,901,609)	(12,408,985)	(480,953)	0	(947,000)	(4,700)
10	DEFERRED CREDITS - ASSET RETIREMENT	(15,832,308)	(8,531,766)	(3,386,388)	(1,687,949)	(1,065,038)	(942,286)	(218,881)
11	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
12	REGULATORY ASSESTS	11,088,732	5,543,801	2,817,375	1,250,156	785,495	387,476	304,429
13	ACCUM DEFERRED INCOME TAXES	(284,653,881)	(145,555,178)	(62,880,274)	(32,826,350)	(20,766,064)	(18,375,490)	(4,250,525)
14								
15	TOTAL RATE BASE	$1,519,073,362	$781,814,549	$329,328,627	$176,087,498	$111,868,044	$97,082,528	$22,892,117
16								
17	DEVELOPMENT OF RETURN							
18	ADJUSTED SALES OF ELECTRICITY - NON-PPFAC	$544,748,189	$248,139,394	$169,348,655	$63,509,759	$30,353,523	$30,374,675	$3,022,183
19	ADJUSTED SALES OF ELECTRICITY - PPFAC	268,653,221	115,433,127	61,692,507	37,178,047	24,171,504	29,264,219	913,817
20	PRO FORMA PPFAC REVENUE	23,536,480	7,381,000	7,682,673	3,269,209	2,271,394	2,664,699	267,506
21	OTHER OPERATING REVENUE	29,181,969	15,594,150	7,166,657	2,852,137	1,665,580	1,783,358	120,086
22	TOTAL OPERATING REVENUE	$866,119,859	$386,547,671	$245,890,492	$106,809,153	$58,462,001	$64,086,951	$4,323,592
23								
24	OPERATING EXPENSES							
25	OPERATION & MAINTENANCE	$674,132,594	$314,996,640	$147,440,512	$85,888,333	$56,159,537	$64,612,864	$5,034,708
26	DEPRECIATION & AMORT EXPENSE	97,310,414	50,110,555	20,938,394	11,134,708	7,037,994	6,652,707	1,436,056
27	INTEREST ON CUSTOMER DEPOSITS	45,852	19,122	23,964	929	0	1,829	9
28	TAXES OTHER THAN INCOME TAX	35,141,489	18,009,093	7,781,914	4,033,967	2,551,112	2,230,602	534,801
29	STATE & FEDERAL INCOME TAX	7,018,368	3,403,412	1,456,159	838,347	518,850	440,302	361,297
30	TOTAL OPERATING EXPENSES	$813,648,717	$386,538,821	$177,640,943	$101,896,284	$66,267,493	$73,938,303	$7,366,871
31								
32	OPERATING INCOME	$52,471,143	$8,850	$68,249,549	$4,912,869	($7,805,493)	($9,851,352)	($3,043,279)
33								
34	RATE OF RETURN (PRESENT WITH PRO FORMA PPFAC)	3.45%	0.00%	20.72%	2.79%	-6.98%	-10.15%	-13.29%

Data Sources: AECC Class Cost of Study Workpaper, TEP Schedule H-2, p. 2 & 6. 2012 TEP Proposed Rates (Revised).xls.

EXHIBIT KCH-20

Class Cost of Service Results at Present Rates
Using TEP's Oct. 5, 2012 4CP Peak and Average Demand Methodology with AECC Adjustments 1 & 2
(For the 12 Months ending December 31, 2011)

SUMMARY AT PRESENT RATES

LINE NO.		TOTAL TEP	RESIDENTIAL	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$3,199,453,192	$1,636,011,342	$706,761,817	$368,961,665	$233,406,441	$206,536,870	$47,775,057
3	RESERVE FOR DEPRECIATION	1,411,638,679	717,816,647	311,549,381	164,383,704	103,966,940	92,656,035	21,265,973
4	CASH WORKING CAPITAL	(19,358,886)	(9,798,214)	(3,959,189)	(2,328,885)	(1,479,571)	(1,608,551)	(184,475)
5	FUEL INVENTORY	25,307,037	12,252,400	5,259,691	3,239,172	2,062,753	2,289,006	204,016
6	MATERIALS & SUPPLIES	42,837,160	21,904,393	9,462,764	4,939,991	3,125,056	2,765,302	639,655
7	PREPAYMENTS	4,537,991	2,320,460	1,002,446	523,322	331,055	292,945	67,762
8	CUSTOMER ADVANCES FOR CONSTRUCTION	(8,923,750)	(4,614,433)	(1,791,248)	(1,118,969)	(565,143)	(659,708)	(174,249)
9	CUSTOMER DEPOSITS	(23,743,247)	(9,901,609)	(12,408,985)	(480,953)	0	(947,000)	(4,700)
10	DEFERRED CREDITS - ASSET RETIREMENT	(15,832,308)	(8,531,766)	(3,386,388)	(1,687,949)	(1,065,038)	(942,286)	(218,881)
11	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
12	REGULATORY ASSESTS	11,088,732	5,543,801	2,817,375	1,250,156	785,495	387,476	304,429
13	ACCUM DEFERRED INCOME TAXES	(284,653,881)	(145,555,178)	(62,880,274)	(32,826,350)	(20,766,064)	(18,375,490)	(4,250,525)
14								
15	TOTAL RATE BASE	$1,519,073,362	$781,814,549	$329,328,627	$176,087,498	$111,868,044	$97,082,528	$22,892,117
16								
17	DEVELOPMENT OF RETURN							
18	ADJUSTED SALES OF ELECTRICITY - NON-PPFAC	$544,748,189	$248,139,394	$169,348,655	$63,509,759	$30,353,523	$30,374,675	$3,022,183
19	ADJUSTED SALES OF ELECTRICITY - PPFAC	268,653,221	115,433,127	61,692,507	37,178,047	24,171,504	29,264,219	913,817
20	PRO FORMA PPFAC REVENUE	23,536,480	7,381,000	7,682,673	3,269,209	2,271,394	2,664,699	267,506
21	OTHER OPERATING REVENUE	29,181,969	15,594,150	7,166,657	2,852,137	1,665,580	1,783,358	120,086
22	TOTAL OPERATING REVENUE	$866,119,859	$386,547,671	$245,890,492	$106,809,153	$58,462,001	$64,086,951	$4,323,592
23								
24	OPERATING EXPENSES							
25	OPERATION & MAINTENANCE	$674,132,594	$314,996,640	$147,440,512	$85,888,333	$56,159,537	$64,612,864	$5,034,708
26	DEPRECIATION & AMORT EXPENSE	97,310,414	50,110,555	20,938,394	11,134,708	7,037,994	6,652,707	1,436,056
27	INTEREST ON CUSTOMER DEPOSITS	45,852	19,122	23,964	929	0	1,829	9
28	TAXES OTHER THAN INCOME TAX	35,141,489	18,009,093	7,781,914	4,033,967	2,551,112	2,230,602	534,801
29	STATE & FEDERAL INCOME TAX	7,018,371	(7,153,113)	24,001,216	360,597	(4,100,115)	(4,779,947)	(1,310,269)
30	TOTAL OPERATING EXPENSES	$813,648,719	$375,982,297	$200,186,000	$101,418,534	$61,648,529	$68,718,055	$5,695,306
31								
32	OPERATING INCOME	$52,471,140	$10,565,375	$45,704,492	$5,390,619	($3,186,528)	($4,631,103)	($1,371,714)
33								
34	RATE OF RETURN (PRESENT WITH PRO FORMA PPFAC)	3.45%	1.35%	13.88%	3.06%	-2.85%	-4.77%	-5.99%

Data Sources: AECC Class Cost of Study Workpaper, TEP Schedule H-2, p. 2 & 6. 2012 TEP Proposed Rates (Revised).xls.

EXHIBIT KCH-21

Class Cost of Service Results at Present Rates

Using TEP's Oct. 5, 2012 4CP Peak and Average Demand Methodology with AECC Adjustments 1, 2 & 3

(For the 12 Months ending December 31, 2011)

SUMMARY AT PRESENT RATES

LINE NO.		TOTAL TEP	RESIDENTIAL	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$3,199,453,192	$1,704,224,236	$716,524,648	$342,055,632	$213,118,019	$186,217,400	$37,313,257
3	RESERVE FOR DEPRECIATION	1,411,638,679	747,773,927	316,038,174	152,569,245	95,053,168	83,672,283	16,531,882
4	CASH WORKING CAPITAL	(19,358,886)	(10,128,989)	(4,060,025)	(2,205,612)	(1,382,391)	(1,481,597)	(100,273)
5	FUEL INVENTORY	25,307,037	12,699,337	5,406,950	3,074,007	1,931,631	2,111,821	83,292
6	MATERIALS & SUPPLIES	42,837,160	22,817,689	9,593,477	4,579,749	2,853,416	2,493,246	499,583
7	PREPAYMENTS	4,537,991	2,417,211	1,016,293	485,160	302,279	264,124	52,924
8	CUSTOMER ADVANCES FOR CONSTRUCTION	(8,923,750)	(4,614,433)	(1,791,248)	(1,118,969)	(565,143)	(659,708)	(174,249)
9	CUSTOMER DEPOSITS	(23,743,247)	(9,901,609)	(12,408,985)	(480,953)	0	(947,000)	(4,700)
10	DEFERRED CREDITS - ASSET RETIREMENT	(15,832,308)	(8,842,798)	(3,430,904)	(1,565,264)	(972,529)	(849,634)	(171,178)
11	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
12	REGULATORY ASSESTS	11,088,732	5,877,140	2,809,799	1,111,289	685,149	317,418	287,937
13	ACCUM DEFERRED INCOME TAXES	(284,653,881)	(151,624,048)	(63,748,869)	(30,432,533)	(18,961,012)	(16,567,677)	(3,319,743)
14								
15	TOTAL RATE BASE	$1,519,073,362	$815,149,810	$333,872,962	$162,933,261	$101,956,251	$87,226,111	$17,934,968
16								
17	DEVELOPMENT OF RETURN							
18	ADJUSTED SALES OF ELECTRICITY - NON-PPFAC	$544,748,189	$248,139,394	$169,348,655	$63,509,759	$30,353,523	$30,374,675	$3,022,183
19	ADJUSTED SALES OF ELECTRICITY - PPFAC	268,653,221	115,433,127	61,692,507	37,178,047	24,171,504	29,264,219	913,817
20	PRO FORMA PPFAC REVENUE	23,536,480	7,381,000	7,682,673	3,269,209	2,271,394	2,664,699	267,506
21	OTHER OPERATING REVENUE	29,181,969	15,594,150	7,166,657	2,852,137	1,665,580	1,783,358	120,086
22	TOTAL OPERATING REVENUE	$866,119,859	$386,547,671	$245,890,492	$106,809,153	$58,462,001	$64,086,951	$4,323,592
23								
24	OPERATING EXPENSES							
25	OPERATION & MAINTENANCE	$674,132,594	$321,577,325	$149,369,160	$83,425,999	$54,224,873	$62,126,839	$3,408,399
26	DEPRECIATION & AMORT EXPENSE	97,310,414	52,027,558	21,287,593	10,388,008	6,470,305	6,041,632	1,095,317
27	INTEREST ON CUSTOMER DEPOSITS	45,852	19,122	23,964	929	0	1,829	9
28	TAXES OTHER THAN INCOME TAX	35,141,489	18,763,674	7,885,093	3,735,685	2,326,574	2,008,373	422,090
29	STATE & FEDERAL INCOME TAX	7,018,371	(11,176,884)	23,009,598	1,891,543	(2,913,255)	(3,359,257)	(433,374)
30	TOTAL OPERATING EXPENSES	$813,648,719	$381,210,795	$201,575,407	$99,442,164	$60,108,497	$66,819,415	$4,492,441
31								
32	OPERATING INCOME	$52,471,140	$5,336,877	$44,315,085	$7,366,989	($1,646,496)	($2,732,464)	($168,850)
33								
34	RATE OF RETURN (PRESENT WITH PRO FORMA PPFAC)	3.45%	0.65%	13.27%	4.52%	-1.61%	-3.13%	-0.94%

Data Sources: AECC Class Cost of Study Workpaper, TEP Schedule H-2, p. 2 & 6. 2012 TEP Proposed Rates (Revised).xls.

EXHIBIT KCH-22

Class Cost of Service Results at Present Rates

Using TEP's Oct. 5, 2012 4CP Peak and Average Demand Methodology with AECC Adjustments 1, 2, 3 & 4

(For the 12 Months ending December 31, 2011)

SUMMARY AT PRESENT RATES

LINE NO.		TOTAL TEP	RESIDENTIAL	SMALL GENERAL SERVICE	LARGE GENERAL SERVICE	LARGE LIGHT & POWER	MINING	LIGHTING
1	DEVELOPMENT OF RATE BASE							
2	ELECTRIC PLANT IN SERVICE	$3,199,453,192	$1,736,834,773	$708,155,057	$336,295,535	$206,040,516	$175,103,871	$37,023,439
3	RESERVE FOR DEPRECIATION	1,411,638,679	762,739,648	312,197,178	149,925,804	91,805,140	78,572,031	16,398,878
4	CASH WORKING CAPITAL	(19,358,886)	(10,441,177)	(3,979,901)	(2,150,469)	(1,314,637)	(1,375,204)	(97,498)
5	FUEL INVENTORY	25,307,037	13,153,096	5,290,492	2,993,858	1,833,151	1,957,182	79,260
6	MATERIALS & SUPPLIES	42,837,160	23,254,308	9,481,418	4,502,627	2,758,656	2,344,448	495,703
7	PREPAYMENTS	4,537,991	2,463,465	1,004,422	476,990	292,241	248,361	52,513
8	CUSTOMER ADVANCES FOR CONSTRUCTION	(8,923,750)	(4,614,433)	(1,791,248)	(1,118,969)	(565,143)	(659,708)	(174,249)
9	CUSTOMER DEPOSITS	(23,743,247)	(9,901,609)	(12,408,985)	(480,953)	0	(947,000)	(4,700)
10	DEFERRED CREDITS - ASSET RETIREMENT	(15,832,308)	(8,991,493)	(3,392,741)	(1,539,000)	(940,257)	(798,960)	(169,857)
11	PLANT HELD FOR FUTURE USE	0	0	0	0	0	0	0
12	REGULATORY ASSESTS	11,088,732	5,877,140	2,809,799	1,111,289	685,149	317,418	287,937
13	ACCUM DEFERRED INCOME TAXES	(284,653,881)	(154,525,392)	(63,004,230)	(29,920,059)	(18,331,330)	(15,578,911)	(3,293,958)
14								
15	TOTAL RATE BASE	$1,519,073,362	$830,369,029	$329,966,905	$160,245,044	$98,653,206	$82,039,467	$17,799,711
16								
17	DEVELOPMENT OF RETURN							
18	ADJUSTED SALES OF ELECTRICITY - NON-PPFAC	$544,748,189	$248,139,394	$169,348,655	$63,509,759	$30,353,523	$30,374,675	$3,022,183
19	ADJUSTED SALES OF ELECTRICITY - PPFAC	268,653,221	115,433,127	61,692,507	37,178,047	24,171,504	29,264,219	913,817
20	PRO FORMA PPFAC REVENUE	23,536,480	7,381,000	7,682,673	3,269,209	2,271,394	2,664,699	267,506
21	OTHER OPERATING REVENUE	29,181,969	15,594,150	7,166,657	2,852,137	1,665,580	1,783,358	120,086
22	TOTAL OPERATING REVENUE	$866,119,859	$386,547,671	$245,890,492	$106,809,153	$58,462,001	$64,086,951	$4,323,592
23								
24	OPERATING EXPENSES							
25	OPERATION & MAINTENANCE	$674,132,594	$327,563,633	$147,832,756	$82,368,619	$52,925,657	$60,086,731	$3,355,197
26	DEPRECIATION & AMORT EXPENSE	97,310,414	53,160,870	20,996,726	10,187,828	6,224,342	5,655,404	1,085,245
27	INTEREST ON CUSTOMER DEPOSITS	45,852	19,122	23,964	929	0	1,829	9
28	TAXES OTHER THAN INCOME TAX	35,141,489	19,110,526	7,796,072	3,674,419	2,251,296	1,890,168	419,008
29	STATE & FEDERAL INCOME TAX	7,018,371	(14,296,961)	23,810,375	2,442,652	(2,236,101)	(2,295,948)	(405,645)
30	TOTAL OPERATING EXPENSES	$813,648,719	$385,557,188	$200,459,893	$98,674,447	$59,165,194	$65,338,183	$4,453,814
31								
32	OPERATING INCOME	$52,471,140	$990,483	$45,430,599	$8,134,705	($703,193)	($1,251,232)	($130,222)
33								
34	RATE OF RETURN (PRESENT WITH PRO FORMA PPFAC)	3.45%	0.12%	13.77%	5.08%	-0.71%	-1.53%	-0.73%

Data Sources: AECC Class Cost of Study Workpaper, TEP Schedule H-2, p. 2 & 6. 2012 TEP Proposed Rates (Revised).xls.

EXHIBIT KCH-23

AECC Recommended Revenue Spread At TEP's Requested Revenue Increase
by Customer Classifications

For the 12 Months Ending December 31, 2011
(Thousands of Dollars)

Line No.	Pricing Plans	Adjusted Present Net Revenue (a)	AECC Recommended Net Increase		AECC Recommended Percent Increase	Line No.
1	Residential Service	$370,953,521	$56,626,697		15.27%	1
2	Small General Service	238,723,835	36,441,607		15.27%	2
3	Large General Service	103,957,015	15,869,218		15.27%	3
4	Large Light & Power / Mining	119,100,014	18,180,823		15.27%	4
5	Lighting	4,203,506	641,672		15.27%	5
6	Subtotal	$836,937,891	$127,760,018	(b)	15.27%	6
7	Other Operating Revenue	29,181,969	0		N/A	7
8	Total	$866,119,859	$127,760,018		14.75%	8

Supporting Schedules/Workpapers
(a) TEP Schedule H-1 (p. 1)
(b) 2012 TEP Rev Req Model.xls

EXHIBIT KCH-24

AECC Recommended Revenue Spread At AECC's Revenue Increase
by Customer Classifications

For the 12 Months Ending December 31, 2011
(Thousands of Dollars)

Line No.	Pricing Plans	Adjusted Present Net Revenue (a)	AECC Recommended Net Increase		AECC Recommended Percent Increase	Line No.
1	Residential Service	$370,953,521	$36,891,914		9.95%	1
2	Small General Service	238,723,835	23,741,462		9.95%	2
3	Large General Service	103,957,015	10,338,689		9.95%	3
4	Large Light & Power / Mining	119,100,014	11,844,685		9.95%	4
5	Lighting	4,203,506	418,045		9.95%	5
6	Subtotal	$836,937,891	$83,234,795	(b)	9.95%	6
7	Other Operating Revenue	29,181,969	0		N/A	7
8	Total	$866,119,859	$83,234,795		9.61%	8

Supporting Schedules/Workpapers
(a) TEP Schedule H-1 (p. 1)
(b) Exhibit KCH-1, p. 1 of 7

EXHIBIT KCH-25

AECC Recommended Base Power Rate Design

	LGS-TOU		
	Current Rate (a)	TEP Proposed Rate (a)	AECC Recommended Rate (b)
Summer On-Peak	$0.059253	$0.038739	$0.050669
Summer Shoulder Peak	$0.033588		
Summer Off-Peak	$0.025299	$0.030187	$0.026679
Winter On-Peak	$0.036088	$0.034305	$0.032893
Winter Off-Peak	$0.027799	$0.030599	$0.027092

	LLP-90N		
	Current Rate (a)	TEP Proposed Rate (a)	AECC Recommended Rate (b)
Summer On-Peak	$0.041786	$0.034837	$0.045568
Summer Shoulder Peak	$0.041786		
Summer Off-Peak	$0.026872	$0.027146	$0.023985
Winter On-Peak	$0.027126	$0.030849	$0.029581
Winter Off-Peak	$0.019542	$0.027517	$0.024356

<u>Supporting Schedules/Workpapers</u>

(a) 2012 TEP Proposed Rates (Revised)

(b) TEP PPFAC DFD-8 & Schedule 1 of TEP's 2013 PPFAC Filing

AECC Recommended Base Power Rate Design

Revenue Reconciliation for the LGS-TOU and LLP-90N Rate Classes

	LGS-TOU		
	Proposed Billing Determinants	TEP (a) Proposed Revenues	AECC Recommended Revenues
Summer On-Peak	48,988,303	$1,897,758	$2,482,188
Summer Off-Peak	49,196,404	$1,485,099	$1,312,516
Winter On-Peak	40,905,653	$1,403,254	$1,345,510
Winter Off-Peak	77,700,944	$2,377,587	$2,105,082
Total:	216,791,304	$7,163,697	$7,245,296

	LLP-90N		
	Proposed Billing Determinants	TEP (a) Proposed Revenues	AECC Recommended Revenues
Summer On-Peak	315,295,814	$10,983,960	$14,367,244
Summer Off-Peak	355,641,730	$9,654,250	$8,530,104
Winter On-Peak	308,032,402	$9,502,492	$9,111,851
Winter Off-Peak	616,988,517	$16,977,673	$15,027,437
Total:	1,595,958,463	$47,118,375	$47,036,636

	Combined LGS-TOU and 90N Revenues	
	TEP Proposed Revenues	AECC Recommended Revenues
Summer On-Peak	$12,881,718	$16,849,432
Summer Off-Peak	$11,139,349	$9,842,620
Winter On-Peak	$10,905,746	$10,457,361
Winter Off-Peak	$19,355,260	$17,132,519
Total:	$54,282,072	$54,281,932

Supporting Schedules/Workpapers

(a) 2012 TEP Proposed Rates (Revised)

EXHIBIT KCH-26

Exhibit KCH-26

Excerpt from Proposed Rate Schedule LLP-90N, Tariff Sheet 302-2

Tucson Electric Power Company

Original Sheet No.: 302-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$ 277.50 per month
Meter Reading	$1,586.89 per month
Billing & Collection	$ 63.70 per month
Customer Delivery	$ 271.91 per month
Demand Charges ($/kW)	
Demand Charges (in $/kW)	
Summer	$10.60 per kW
Winter	$ 7.60 per kW
Generation Capacity Charges (in $/kW)	$ 6.76 per kW
Transmission (in $/kW)	$ 3.62 per kW
Transmission - Ancillary Services (in $/kW)	
System Control & Dispatch	$0.0500 per kW
Reactive Supply and Voltage Control	$0.1900 per kW
Regulation and Frequency Response	$0.1900 per kW
Spinning Reserve Service	$0.5100 per kW
Supplemental Reserve Service	$0.0800 per kW
Energy Imbalance Service: currently charged pursuant to the Company's OATT.	
Energy Charges ($/kWh)	
Delivery Charges (in $/kWh)	
Summer On-peak	$0.0061 per kW
Summer Off-peak Excess Demand	$0.0051 per kW
Winter On-peak	$0.0056 per kW
Winter Off-peak Excess Demand	$0.0046 per kW
Fixed Must Run Charges (in $/kW)	$0.0003 per kW

EXHIBIT KCH-27

Exhibit KCH-27

Excerpt from Proposed Rate Schedule LLP-14, Tariff Sheet 301-2

Tucson Electric Power

Tucson Electric Power Company

Original Sheet No.: 301-2
Superseding:

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charges:	
Meter Services	$ 477.35 per month
Meter Reading	$ 111.83 per month
Billing & Collection	$ 487.16 per month
Customer Delivery	$ 923.66 per month
Total	$2,000.00 per month
Demand Charges:	
Delivery Charge (in $/kW)	$10.18 per kW
Generation Capacity Charges (in $/kW)	$8.2500 per kW
Fixed Must-Run Charges (in $/kW)	$0.0016 per kWh
Transmission (in$/kW)	$2.0000 per kW
Transmission Ancillary Services (in $/kW)	
System Control & Dispatch	$0.0300 per kW
Reactive Supply and Voltage Control	$0.1100 per kW
Regulation and Frequency Response	$0.1000 per kW
Spinning Reserve Service	$0.2800 per kW
Supplemental Reserve Service	$0.0500 per kW

Energy Imbalance Service: currently charged pursuant to the Company's OATT.

Energy Charges:	
Delivery Charges (in $/kWh)	
Summer	$0.0074 per kWh
Winter	$0.0064 per kWh
PPFAC	In accordance with Rider 1 – PPFAC

EXHIBIT KCH-28

Exhibit KCH-28

TEP's Oct 26, 2009 Interruptible Tariff Filing, Docket Nos. E-001933A-05-0605 & E-01933A-04-0402

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE FILING BY TUCSON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650
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-07-0402 **NOTICE OF FILING**

Tucson Electric Power Company ("TEP" or the "Company"), through undersigned counsel and pursuant to the Tucson Electric Power Company Proposed Rate Settlement Agreement, approved by Decision No. 70628 (December 1, 2008) ("2008 Settlement Agreement"), hereby files with the Arizona Corporation Commission ("Commission") two (2) Large Light and Power ("LLP") Interruptible tariffs. In support of its Application, TEP states as follows:

I. TARIFFS.

Section 18.1 of the 2008 Settlement Agreement requires TEP to file Partial Requirements, Interruptible, Demand Response, and Bill Estimation tariffs. TEP previously has filed Partial Requirements, Demand Response, and Bill Estimation tariffs. Pursuant to the Settlement Agreement, TEP has consulted with Commission Staff and Interested Stakeholders prior to filing this Application. TEP hereby files the required Interruptible tariffs applicable to Large Light and Power (LL&P) Customers, as provided below:

- Rider-5 ISCC – Interruptible Service Capacity Constraint (Attachment "A")
- Rider-6 CEP – Experimental Critical Event Pricing Rider (Attachment "B")

Rider-5 ISCC addresses interruptions prompted by anticipated capacity constraints on the TEP system. The establishment of this interruptible program provides benefits to larger customers who are willing and able to reduce loads during periods of capacity constraints. This helps improve system reliability. Rider-6 CEP addresses interruptions prompted by economic considerations, and will provide participating customers an opportunity to receive a certain discount in exchange for a commitment to reduce purchases in periods declared critical by TEP when the cost of supplying power is highest. The reduction in purchases during critical periods helps reduce the cost of electricity that is ultimately recovered through the Purchased Power and Fuel Adjustment Charge ("PPFAC").

TEP favors an "experimental" implementation of these programs, with the tariff sheets accordingly marked as "experimental." This would recognize the need for periodic review of the program, and subject to the Commission's approval, allow adjustments to the tariff's prices, terms, and conditions to help optimize the operation of the interruptible tariffs.

II CONCLUSION.

TEP respectfully requests that the Commission approve its Rider-5 ISCC – Interruptible Service Capacity Constraint and Rider-6 CEP – Experimental Critical Event Pricing Rider.

RESPECTFULLY SUBMITTED this 26th day of October 2009.

Tucson Electric Power Company

By ______________________
Philip J. Dion
UniSource Energy Services
One South Church Avenue, Suite 200
Tucson, Arizona 85701

and

Michael W. Patten
Jason D. Gellman
ROSHKA DEWULF & PATTEN, PLC.
One Arizona Center
400 East Van Buren Street, Suite 800
Phoenix, Arizona 85004

Attorneys for Tucson Electric Power Company

Original and 15 copies of the foregoing filed this 26th day of October, 2009 with:

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

Copy of the foregoing emailed this 26th Day of October 2009 to:

Brian Bozzo
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Janet Wagner, Esq.
Robin Mitchell, Esq.
Chief Counsel, Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
jwagner@azcc.gov
rmitchell@azcc.gov
nscott@azcc.gov
rosorio@azcc.gov
mfinical@azcc.gov

Steven Olea
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007
aigwe@azcc.gov
cbuck@azcc.gov
tford@azcc.gov
solea@azcc.gov
bkeene@azcc.gov

Micheal Grant, Esq.
Gallagher & Kennedy
2575 East Camelback Road
Phoenix, Arizona 85016
mmg@gknet.com
gyaquinto@arizonaic.org

Peter Q. Nyce, Jr.
General Attorney-Regulatory Office
Department of Army
901 North Stuart Street
Arlington, Virginia 22203
peter.nyce@us.army.mil

Dan Neidlinger
Neidlinger & Associates
3020 North 17th Drive
Phoenix, Arizona 85015
dneid@cox.net

Jane Rodda, esq.
Administrative Law Judge
Hearing Division
Arizona Corporation Commission
400 W. Congress
Tucson, Arizona 85701
jrodda@azcc.gov

Daniel Pozefsky, Chief Counsel
Residential Utility Consumer Office
1100 West Washington, Suite 220
Phoenix, Arizona 85007
dpozefsky@azruco.gov
brigsby@azruco.gov
egamble@azruco.gov

C. Webb Crockett
Patrick J. Black
FENNEMORE CRAIG, PC
3003 North Central Avenue, Suite 2600
Phoenix, Arizona 85012-2913
wcrockett@fclaw.com
pblack@fclaw.com
khiggins@energystrat.com

Timothy Hogan
Arizona Center for Law
in the Public Interest
2092 East McDowell Road, Suite 153

Phoenix, Arizona 85004
thogan@aclpi.org

Jeff Schlegel
SWEEP Arizona Representative
1167 West Samalayuca Dr.
Tucson, Arizona 85704

David Berry
Western Resource Advocates
P.O. Box 1064
Scottsdale, Arizona 85252
azbluhill@aol.com

Michael L. Kurtz, Esq.
Kurt J. Boehm, Esq.
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
kboehem@bkllawfirm.com
mkurtz@bkllawfirm.com

By

Nicholas J. Enoch
Lubin & Enoch, PC
349 North Fourth Avenue
Phoenix, Arizona 85003
Nicholas.enoch@azbar.org

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

Thomas Mumaw
Barbara A. Klemstine
Arizona Public Service Company
P.O. Box 53999, Station 9708
Phoenix, Arizona 85072
Barbara.klemstine@aps.com
Meghan.grable@pinnaclewest.com

Robert J. Metli
Snell & Wilmer LLP
One Arizona Center
400 East Van Buren
Phoenix, Arizona 85004
Rmetlie@swlaw.com

Christopher Hitchcock
Law Offices of Christopher Hitchcock
P.O. Box AT
Bisbee, Arizona 85603
lawyers@bisbeelaw.com

Cynthia Zwick
1940 E. Luke Avenue
Phoenix, Arizona 85016
czwick@azcaa.org

Greg Patterson
Arizona Competitive Power Alliance
916 West Adams, Suite 3
Phoenix, Arizona 85007
Gpatterson3@cox.net

William P. Sullivan
Curtis, Goodwin, Sullivan
Udall & Schwab, PLC
501 East Thomas Road
Phoenix, Arizona 85012
wsullivan@cgsuslaw.com

Attachment "A"

Tucson Electric Power
The Energy People

Rider-5 ISCC
Experimental Interruptible Service Capacity Constraint

APPLICABILITY
The Company agrees that interruptions called under the provisions of this Rider-5, Interruptible Service Capacity Constraint ("ISCC"), are limited to interruptions required to ensure system reliability. Interruptions called pursuant to the terms of this Rider will not be made solely for economic reasons.

AVAILABILITY
Available to Customers receiving and qualifying for electric service under pricing plans applicable to service over 3,000 kW, and are willing to subscribe to at least 1,000 kW of Interruptible load at a contiguous facility.

CHARACTER OF SERVICE
Must meet all service requirements for the Customers applicable Standard Offer pricing plan.

COMPANY'S ANNUAL POSTING OF AVAILABLE INTERRUPTIBLE CREDITS AND ASSOCIATED NOTICE REQUIREMENTS AND MAXIMUM HOURS OF INTERRUPTION
The Company will post Market Based Capacity Price MBCP(defined below), and available Interruptible Credits, by Notice Requirement and Maximum Hours of Interruption (Maximum Annual Duration) for upcoming months of May through October of the calendar year by March 15 of the same calendar year. A sample Interruptible Credit Availability Matrix is shown below.

The credits vary by Maximum Annual Duration and Notice Requirement. Typically, as Maximum Annual Duration increases – other factors held constant – the Interruptible Credit increases; and as the Notice Requirement increases (e.g., from ≤ 10 minutes to ≤ 30 minutes) – other factors held constant – the Interruptible Credit decreases. The Shared Savings Factor may also vary, and this will affect the Interruptible Credit.

NOMINATION OF INTERRUPTIBLE LOAD BY CUSTOMER
Nomination will occur before April 15 of the calendar year of each interruption season. Participating Customers shall designate the portion of their load that is Interruptible Load (in kW). A participating Customer also shall designate its choice for the Notice Requirement option and the Maximum Annual Duration option. A Customer may only choose from the available options posted by the Company.

A single Notice Requirement option and a single Maximum Annual Duration option applies to all load nominated at a single service point. A Customer may not split interruptible load at a single service point among multiple options. Customers with multiple service points may designate different Notice Requirement options and different Maximum Annual Duration options for different service points. If the Customer intends to interrupt a specific activity or function at its operation, the Customer should state this activity or function at the time Interruptible Load is nominated. The minimum nomination of interruptible load summed over a participating Customer's service points shall be 1,000 kW.

INTERRUPTIBLE CREDIT
Customers who elect service under this Rider-5 will receive a monthly Interruptible Credit. The credit will be an Interruptible Demand Charge Credit (in $/kW) applied to the Customer's Interruptible Load in kW. The Demand Charge (kW) Credit will be applied to the monthly demand charge for the Customer's Standard Offer Pricing Plan otherwise applicable under full requirements of service.

Tucson Electric Power
The Energy People

Rider-5 ISCC
Experimental Interruptible Service Capacity Constraint

The Demand Charge Credit shall be calculated as follows:

Market Based Capacity Price (MBCP) * A * B * C * D * E * F

(A) The 116% (+/-) Reserves Factor above represents the avoidance of reserves needed to support the interruptible load.

(B) The 103% (+/-) Line Loss Factor above represents the avoidance of transmission line losses by displacing purchased capacity.

(C) The 50% Annualization Factor above represents an annualization of the Demand Charge Credit. Applicable capacity is purchased over a six month summer time frame, while the Demand Charge Credit applies in all twelve months of the year.

(D) The Availability Weighting factor represents a discount applied to Interruptible Load to reflect its reduced availability under the terms of this Rider relative to purchased capacity. TEP recommends an Availability Weighting Factor based on the matrix below for the different hours per year.

(E) Shared Savings Factor:
The 25% Shared Savings Factor awards one-fourth of the interruptible benefit to the Customer subject to interruption and the remaining three-fourths to other system customers. (The Shared Savings Factor initially is set to 25% under this experimental tariff. A change in this factor requires Commission approval. A higher factor would award more benefit to the Interruptible Customer and less benefit to other customers and would provide a greater incentive for Customers to interrupt.)

(F) The Notice Factor of 100% is applicable to load that is interruptible with notice of Less Than or Equal to 10 Minutes and equals 50% for longer notice requirements.

SAMPLE INTERRUPTIBLE CREDIT AVAILABILITY MATRIX:

Maximum Annual Duration	80 Hours Per Year		40 Hours Per Year		20 Hours Per Year	
Notice Requirement	≤ 10 Minutes	≤ 30 Minutes	≤ 10 Minutes	≤ 30 Minutes	≤ 10 Minutes	≤ 30 Minutes
Reserves Factor (%)	116%	116%	116%	116%	116%	116%
Line Loss Factor (%)	103%	103%	103%	103%	103%	103%
Annualization Factor (%)	50%	50%	50%	50%	50%	50%
Availability Weighting Factor (%)	75%	75%	65%	65%	60%	60%
Shared Savings Factor (%)	25%	25%	25%	25%	25%	25%
Notice Factor (%)	100%	50%	100%	50%	100%	50%

Note: Rates and nominated hours for current season will be posted by Company via the Internet on or before March 15 of every year.

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Experimental Interruptible Service Capacity Constraint

Example: Assume a MBCP of $8 per kW-month. Assume a Customer is interruptible on 10 minutes notice or less and selects the 80 hours/year Maximum Annual Duration option. Multiply by 116% for avoided reserves. Multiply by 103% for avoided line losses. Multiply by 50% for Annualization. Multiply by the 75% for Availability Weighting. And multiply by 25% for Shared Savings. Multiply by 1 (no change) for Notice Factor. The resulting Demand Charge Credit for this example is $0.896 per kW month.

The Demand Charge Credit is rounded to the nearest mill (1/10 cent).

MARKET BASED CAPACITY PRICE (MBCP)
The Market Based Capacity Price (MBCP) reflects opportunity cost of capacity as revealed through the Company's resource procurement process. Resource prices are sensitive and confidential information based on competitive bids; however this information will be made available to the Commission Staff and/or an Independent Monitor(s) for review. The MBCP is a price applicable to six summer months only.

PENALTY FOR FAILURE TO INTERRUPT
Customers failing to interrupt contract interruptible load for any interruption event during the billing month forfeits the discount for that billing month. A second failure of the Customer to comply with any mandated Interruption for capacity constraints may, in the Company's sole discretion, result in the Customer being removed from this Pricing Plan for up to a twenty-four month period.

Additionally, a Customers failing to interrupt contract interruptible load for any interruption event shall purchase interruptible power taken during the event at a penalty price calculated as ten (10) times the incremental cost of power (higher of generated cost or market cost) taken in violation of the interruption order. The Customer's penalty payment shall be credited to the PPFAC.

These penalties shall not apply in instances in which the failure to interrupt is due to the failure of the Company or its equipment to communicate or implement the interruption properly.

RECOVERY OF PROGRAM COSTS

ISCC Customers' bills will be credited on a demand basis ($/kW). Recovery of the credits – the cost of the interruptible resource under this Rider - shall be on an energy basis ($/kWh) through the Purchased Power and Fuel Adjustment Clause (PPFAC). The credits shall be treated in the same manner as any other prudent fuel / purchase power cost.

TERMS AND CONDITIONS OF SERVICE

1. The Customer must have sufficient load to qualify for Large Light & Power service (either Time-of-Use or Non-Time-of-Use).

2. The Customer must designate for each service point its choice for the Notice Requirement option among available posted options (typical options that may be available, at the Company's discretion: Less than or Equal to 10 Minutes OR Less Than or Equal to 30 Minutes.)

3. Ten-Minute Notice Provision - Upon receiving an interruption notice, a Customer providing Interruptible Load at a subscribed service point shall reduce its load to a level no greater than its Firm Load. This reduction must occur within ten minutes or Customer will be subject to the Penalty for Failure to Interrupt.

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Experimental Interruptible Service Capacity Constraint

4. Thirty-Minute Notice Provision - Upon receiving an interruption notice, a Customer providing Interruptible Load at a subscribed service point shall reduce its load to a level no greater than its Firm Load. This reduction must occur within thirty minutes or Customer will be subject to the Penalty for Failure to Interrupt.

5. The Customer shall contract for Interruptible Load (sum of all notice options at Customer's contiguous facility) of not less than 1,000 kW.

6. A single interruption event is limited to no more than 4 hours in duration.

7. A Customer receives 4 hours credit for any single interruption event to apply toward the Maximum Annual Duration, even if the duration of the event is less than 4 hours.

10. The Company may call two <u>consecutive</u> interruption events in calendar day (midnight to midnight). The maximum number of back-to-back interruption events over <u>any</u> time period is two. For example, if the Company calls Event 1 from 4 p.m. to 8 p.m. on Day 1, it may also call Event 2 starting at 8 p.m. on Day 1 and continuing for four hours to midnight. However, Company may not call another back-to-back third event staring at the beginning of Day 2 (midnight) and continuing to 4 a.m. on Day 2. This would result in three consecutive back-to-back interruption events, which is not allowed hereunder.

11. The maximum number of interruption events in any calendar day is three.

12. The Customer will provide communication equipment (e.g., telephone line, paging, or wireless service, relays, RTU's (remote transmitting units), meters, recorders, and related software and hardware infrastructure) necessary to-comply with data requirements including verification. The Customer must furnish, install, own, and maintain all Company-approved equipment necessary for the Company to provide interruption notification to the Customer from its master control station.

13. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

14. Nothing herein prevents the Company from interrupting service for emergency circumstances, determined in the Company's sole discretion. Emergency interruptions shall not count as interruption events for purposes of this Rider.

15. The standard Rules and Regulations of the Company, as on file with the Arizona Corporation Commission, shall apply where not inconsistent with this rate schedule.

Attachment "B"

Tucson Electric Power
The Energy People

Rider-6 CEP
Experimental Critical Event Pricing Rider

PURPOSE OF RIDER:
Customer shall receive a discount to the Base Power Supply Charge(s) under the pricing plan applicable to all purchases at a specific delivery point, except during a Critical Event called by the Company, at which time a Critical Event Price shall apply to all delivery point purchases. Customers with multiple delivery points shall designate which points are subject to Rider-6 CEP.

The Company may call a Critical Event for any reason, including for economic considerations under this Rider-6 CEP.

AVAILABILITY
Available to Customers receiving and qualifying for electric service under pricing plans applicable to service over 3,000 kW. The Customer must designate specific delivery point(s) as subject to Rider-6 CEP, with all load at the delivery point subject to this Rider-6 CEP. The Customer must also designate the total duration of Critical Events as either 20 hours (5 events) per year or 40 hours (10 events) per year.

CHARACTER OF SERVICE
Must meet all service requirements for the applicable pricing plan.

CREDITS
Customers that elect service under this Rider-6 CEP will receive a credit to the Base Power Supply Charge for all purchases at the delivery point, except for purchases during Critical Events. This credit shall be:

For Customers choosing to limit the total duration of Critical Events to no more than 20 hours:
0.31 mills per kWh ($0.00031 per kWh)

For Customers choosing to limit the total duration of Critical Events to no more than 40 hours:
0.55 mills per kWh ($0.00055 per kWh)
(1 mill equals 1/10 cent.)

CRITICAL EVENT PRICE
Customer purchases during a Critical Event shall be subject to a surcharge to the Base Power Supply Charge for all purchases at the delivery point. This surcharge shall be the greater of:

a. $0.20 per kWh, or
b. 125% of the incremental cost of power (higher of generated cost or market cost) during the Critical Event.

Payments shall be credited to the Purchased Power and Fuel Adjustment Clause ("PPFAC").

RECOVERY OF PROGRAM COSTS

Customers' bills will be credited on an energy basis ($/kWh) as described above. Recovery of the credits – the cost of the interruptible resource under this Rider - shall be on an energy basis ($/kWh) through the PPFAC. The credits shall be treated in the same manner as any other prudent fuel / purchase power cost.

TERMS AND CONDITIONS OF SERVICE

1. The Customer must have sufficient load to qualify for Large Light & Power service (either Time-of-Use or Non-Time-of-Use).

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Experimental Critical Event Pricing Rider

2. The Customer must designate for each Critical Event Pricing (CEP) service point either 20 hours or 40 hours for its choice of the total duration of Critical Events.

3. A single choice of the total duration of Critical Events (either 20 hours (5 events) or 40 hours (10 events)) applies to all load at a single CEP service point. A Customer may not split load at a single CEP service point among multiple duration options. Customers with multiple CEP service points may designate different choices of the total duration of Critical Events for different service points.

4. A single Critical Event is limited to no more than 4 hours in duration.

5. The sum of the durations of all Critical Events (Maximum Annual Duration) shall be no more than 20 hours for the 5 event option, and 40 hours for the 10 event option.

6. A Customer receives 4 hours credit for any single Critical Event to apply toward the Maximum Annual Duration, even if the duration of the event is less than 4 hours.

7. At least four hours of prior notice shall be provided for each interruption event.

8. The Customer will provide communication equipment (e.g., telephone line, paging, or wireless service, relays, RTU's (remote transmitting units), meters, recorders, and related software and hardware infrastructure) necessary to-comply with data requirements including verification. The Customer must furnish, install, own, and maintain all Company-approved equipment necessary for the Company to provide interruption notification to the Customer from its master control station.

9. Nothing herein prevents the Company from interrupting service for emergency circumstances, determined in the Company's sole discretion. Emergency interruptions shall not count as interruption events for purposes of this Rider-6 CEP.

10. Company shall not be liable for any loss or damage caused by or resulting from any interruption of service.

11. The standard Rules and Regulations of the Company, as on file with the Arizona Corporation Commission, shall apply where not inconsistent with this rate schedule.

EXHIBIT KCH-29

Exhibit KCH-29

AECC's Jul 28, 2010 Supplemental Response to Staff Data Request Regarding TEP's Proposed Rider-5 ISCC

AECC SUPPLEMENTAL RESPONSE TO STAFF DATA REQUEST

1. The Objection indicates that AECC opposes TEP's proposed Rider-5 ISCC Shared Savings Factor (25%). Is this the only objection AECC has to TEP's Rider-5 ISCC? If not, please describe in detail any other objections.

   Supplemental Response:

   AECC supplements its Response with additional information designated as (d), (e) and (f) below.

   No. While the Shared Savings Factor represents the most serious problem with TEP's proposed Rider-5 ISCC, AECC also objects to the terms of several other provisions, as explained below.

   (a) Penalty for Failure to Interrupt
   AECC agrees that it is necessary to have a material penalty for failure to interrupt; however, TEP's proposed penalty of ten times the incremental cost of power is disproportionate to the size of demand credit that TEP is proposing, particularly in light of TEP's proposed "shared savings factor." Specifically, if a shared savings factor is adopted (which AECC opposes, as stated above), then the same "shared savings factor" should be applied to the penalty price. In addition, the "second failure" referenced in the text needs to be defined with respect to a time period, specifically 12 months.

   AECC recommended alternative language for first two paragraphs of "Penalty for Failure to Interrupt" section:

   PENALTY FOR FAILURE TO INTERRUPT
   Customers failing to interrupt contract interruptible load for any interruption event during the billing month forfeits the discount for that billing month. A second failure of the Customer to comply with any mandated interruption for capacity constraints within twelve (12) months of the first failure may, in the Company's sole discretion, result in the Customer being removed from this Pricing Plan for up to a twenty-four month period.

   Additionally, a Customer's failing to interrupt contract interruptible load for any interruption event shall purchase interruptible power taken during the event at a penalty price calculated as ten (10) times the incremental cost of power (higher of generated cost or market cost) taken in violation of the interruption order multiplied by any Shared Savings Factor. The Customer's penalty payment shall be credited to the PPFAC

   (b) Maximum number of interruption events in any calendar day
   AECC recommends that a limit of two interruption events in any calendar day is more reasonable to encourage efficient program participation. AECC recommended alternative language:

11. The maximum number of interruption events in any calendar day is two ~~three~~.

(c) Communication equipment
Proposed Term 12 lists examples of the type of communication equipment that may be necessary to comply with data requirements, including verification. AECC agrees that proper communication and data measurement is essential, but seeks clarification that: (1) TEP will not mandate the use of RTUs; and (2) currently-installed TOU meters are sufficient for data measurement purposes.

Supplemental information:

(d) Nomination of Interruptible Load by Customer

This provision addresses the customer's designation of its Interruptible Load. There is nothing specifically objectionable in this section; however, it requires clarification. It is the experience of AECC's members that an Interruptible Tariff is best implemented through the Interruptible Customer specifying in advance the amount of its *firm* load, and then responding to an interruptible event by shedding all load down to the firm level. Defined in this manner, all load above the firm level is interruptible. AECC recommends the following edit to the first paragraph of this section:

Nomination will occur before April 15 of the calendar year of year interruption season. Participating Customers shall designate the portion of their load that is Firm Load (in kW), which shall not be subject to interruption. All remaining load shall be Interruptible Load ~~(in kW)~~. A Participating Customer shall also designate its choice for the Notice Requirement Option and the Maximum Annual Duration option. A Customer may only choose from the available options posted by the Company.

(e) Interruptible Credit

Item (C) in this section provides that the demand charge will be annualized using a 50 percent factor, i.e., 6 months of capacity value will be spread over 12 months. AECC does not object to the logic of this concept, but suggests that an option be available that allows the full credit to be available for the 6 summer months (with zero credit for the 6 non-summer months).

(f) Terms and Conditions of Service #14

This provision gives TEP the right to interrupt service for emergency purposes. AECC recognizes that occasional system outages may be unavoidable. However, the provision, as drafted, appears unduly open-ended. For example, it does not appear reasonable that an emergency interruption would not count as an interruption event. Further, if an Interruptible Customer has been subject to its maximum number of interruptions per the tariff and an emergency event occurs, the tariff should provide that an Interruptible Customer in this situation will not be treated any differently than a non-interruptible customer (i.e., subject to emergency interruptions on the same basis). AECC recommends the following change to provision 14:

14. Nothing herein prevents the Company from interrupting service for emergency situations, determined in the Company's sole discretion. Emergency interruptions shall ~~not~~ count as interruption events for purposes of this Rider. <u>During an emergency situation, Interruptible Customers that have already been subjected to the Maximum Annual Duration of interruptions will be treated on a non-discriminatory basis relative to non-interruptible customers for the purposes of the Company's determination whether to interrupt the Customer's service.</u>