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IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. RE-00000C-94-0165 **TEP'S EXCEPTIONS TO THE PROPOSED ORDER ADOPTING AMENDMENTS TO THE ELECTRIC COMPETITION RULES**

On August 26, 1999, the Arizona Corporation Commission's ("Commission") Hearing Division issued a Proposed Order adopting amendments to the Retail Electric Competition Rules, R14-2-1601, *et seq.* ("Rules"). Tucson Electric Power Company ("TEP" or "Company"), through undersigned counsel, hereby submits the following Exceptions to the Proposed Order. These Exceptions are modeled after the comments that TEP previously filed. Although the Concise Explanatory Statement indicates why TEP's comments were not incorporated into the Rules, TEP will respond to the explanations.

ARTICLE 2. ELECTRIC UTILITIES

R14-2-210. Billing and Collection

A.5.c. This provision should be **deleted** as the utility or billing entity does have the ability to do this and such bills can be estimated in accordance with R14-2-209A.8. and R14-2-1613.K.14. It is unclear why as a general rule, direct access customers' bills should not be estimated.

R14-2-213. Conservation

Although TEP supports this concept, this Rule should be **deleted** at this time for the following reasons: (i) it is premature to make this requirement at this time while the Commission and the Legislature (because of SRP) need to work together to accomplish these goals on a statewide basis; (ii) the Commission will be revisiting the Integrated Resource Planning Rules in light of the move to competition (these concepts and filing requirements should be explored in the context of that proceeding); (iii) to achieve these goals, they should be applied to *all* utilities and ESPs (not just Class A and B utilities) and should be considered in the context of the System Benefits Charge; and (iv) this requirement should be delayed until after 100 percent statewide competition has commenced and the market structure has been developed. The fact that this Rule has been in effect for several years (as the reason for the rejection of the chanage) does not address the reasons for its deletion as put forth by TEP above.

<u>ARTICLE 16. RETAIL ELECTRIC COMPETITION</u>

<u>R14-2-1601. Definitions</u>

39. "Stranded Cost." The insertion of "*net original cost*" should be **deleted** and "<u>value</u>" should remain. Utilization of this term may be inconsistent with assets held under lease arrangements and various regulatory assets. Since the amendment may cause problems later, there is no reason why the original term should be changed. This recommended change was not included in the Rules because it was determined that this definition "will not preclude TEP from recovering appropriate stranded costs." There does not appear to be any basis for this determination and as use of the word "value" may avoid potential problems in the future, the change should be adopted.

40. "System Benefits." The word "<u>non-nuclear</u>" should be **added** after "nuclear." This is because coal and generation plants, other than nuclear generating plants, will have decommissioning costs in the future. This change was rejected because there are NRC requirements for nuclear utilities and because of the great magnitude of the costs. This does not address the issue. Non-nuclear generating facilities were built under the Affected Utilities obligation to serve and their construction and recovery was approved by the Commission. Despite the move to competitive retail access, those plants will have decommissioning costs in the future and should be included in definition of Systems Benefits.

<u>R14-2-1604. Competitive Phases</u>

A.1. TEP believes that utilizing a single "non-coincident" peak has unintended consequences. Only customers with a 1 MW **minimum** demand should be eligible for direct access. Given TEP's customer base, the non-coincident peak criterion could expand the direct access eligibility from the 1 MW customer base to well beyond 20 percent of TEP's 1995 system retail peak demand. It would also have the effect of making the 40 kW aggregation meaningless, as well as impose additional burdens with respect to administration. As the 20 percent cap could be easily reached, there will be customers who have loads in excess of 1 MW and who will not be able to access the competitive market during the transition period. TEP suggests **deleting** "*non-coincident*" each time it is referenced in A.1 and **substituting** "minimum demand."

TEP also suggests **deleting** "*months*" and **adding** "six months." Doing so will better characterize a customer whose load or usage is more consistently at least 40 kW or 16,500 kWh. The sentence would then read: "If peak load data are not available, the 40 kW criterion shall be determined to be met if the customer's usage exceeded 16,500 kWh in any six months within the last 12 consecutive months."

With respect to the above suggestions, they were rejected because minimum demands should not be used to determine eligibility. TEP disagrees. The purpose of the phase-in is to open up competition to those customers that meet the *minimum* criteria of 1 MW or 40 kW for aggregation. To the extent that a customer hits 1 MW one time on a non-coincident peak basis should not make that customer eligible during the phase-in to the exclusion of other 1 MW customers who might be precluded if the cap is reached. Further, consistent usage in six out of the last twelve months is also a reasonable minimum criteria as opposed to having customers who hit 16,500 kW as little as one out of 12 months be eligible.

R14-2-1606. Services Required to be Made Available

B. TEP maintains that the provision should include a statement that all purchased power costs shall be recovered through a purchased power adjustment mechanism approved by the Commission. TEP disagrees with the position that a purchased power adjustment mechanism will have the opposite effect of securing the lowest prices for standard offer customers because the UDC would have no incentive to do this if it was just a pass-through. This rationale negates the fact that the Commission will oversee the signing of any long-term power purchases by the UDC and will have significant oversight over such transactions. The requirement for the UDC to procure standard offer power in the market (as it will be unable to favor its competitive generation affiliate) with standard offer rates being fixed under regulation, regardless of how prudent management might be, is inherently unfair to the UDC as market risks and market price fluctuations cannot be mitigated as suggested by the amended language. A purchased power adjustment mechanism negates the need for the UDC to have to file for rate changes that could take many months to process and is an unnecessary waste of time and resources. TEP's proposed language is: "After January 1, 2001, power purchased by an investor-owned Utility Distribution Company to provide Standard Offer Service shall be acquired through an open, fair and arms-length transaction. The Commission shall utilize a purchased power adjustment mechanism to facilitate such transactions."

R14-2-1607. Recovery of Stranded Cost of Affected Utilities

A. **Delete** "*expanding wholesale or retail markets or offering a wider scope of permitted regulated utility services for profit, among others.*" As is, this language suggests that the Affected Utility use profits from "expanding [its] wholesale or retail markets" or a "wider scope of permitted regulated utility services" to mitigate stranded costs. TEP anticipates that most, if not all, new products and services in the electric industry will develop in the unregulated, competitive marketplace. The very nature of "unregulated" means that the Commission will not require that profits from such activities be used to offset costs in the regulated arena. With respect to mitigating with regulated utility profits, this is inconsistent with cost-based, rate-of-return regulation. The provision should be **replaced** with: "The Affected Utilities shall take every reasonable, cost-effective measure to mitigate or offset Stranded Cost by reducing costs."

F. TEP disagrees with the self-generation exclusion. If the Rule is not modified to ensure that customers who choose to self-generate are responsible for stranded costs just as any other existing customer, a potentially large and improper economic incentive for self-generation will be created. This is due to the ability of such customers to avoid stranded cost charges. The result of the Rule as written will be to significantly increase uneconomic self-generation, while increasing stranded cost burdens on customers who purchase their power in the competitive marketplace. Therefore, the word "*self-generation*" should be **deleted** from the second sentence. Although Staff indicated that cost-shifting has not developed, self-generation is something that will become more feasible in the future (as opposed to what has occurred in the past.) Because TEP is already seeing self-generation become an option at the commercial level, this Rule needs to look forward and not backward. For this reason, TEP urges the Commission to adopt TEP's recommended change.

G. TEP requests that the following language be **inserted** at the end: "Subject to Commission approval, neither Section F or G of this Rule shall preclude an Affected Utility from implementing stand-by tariffs that recover appropriate stranded costs or from providing other opportunities to recover such resultant stranded costs." This language is necessary to ensure that Affected Utilities have the opportunity to request approval of tariffs to ensure stranded cost shortfalls resulting from conditions completely outside the control of the Affected Utility. Although nothing precludes an Affected Utility from filing such tariffs, the language provides for Commission recognition at this juncture that stand-by tariffs that recover appropriate stranded costs will be considered.

R14-2-1609. Transmission and Distribution Access

D. TEP recommends that the language be **amended** as follows: "The Commission believes that an Independent Scheduling Administrator is necessary in order to provide non-discriminatory retail access to facilitate a robust and efficient electricity market. Therefore, those Affected Utilities that own or operate Arizona transmission facilities shall participate in the formation of an Arizona Independent Scheduling Administrator ("AISA"), which shall file with the Federal Energy Regulatory Commission, within 60 days of this Commission's adoption of final rules herein, for approval of an Independent Scheduling Administrator, which may have the following characteristics if the AISA determines such characteristics are appropriate. The purpose of these changes is because Affected Utilities cannot form an independent entity without participation of others who are not under Commission jurisdiction. Further, the AISA, with its independent Board and broad stakeholder representation, should determine what functions it must carry out as these functions may change over time as circumstances warrant. Therefore, with respect to **1, 2, 3,** and **4** of **D.**, wherever the word "*shall*" is used, it should be **replaced** with "may."

D.5. This should be **deleted** in its entirety because within the AISA, there has been no discussion of taking on such a responsibility, which is very different from all other AISA activities to ensure fair access to the transmission system. The existing FERC-sanctioned Regional Transmission Associations have created such a process.

It is not TEP's position that participation in the AISA should be made optional instead of mandatory. The suggested changes stem from TEP's participation in the AISA process and the need for all transmission owners to be involved and to give the AISA latitude to address changing circumstances.

R14-2-1612. Service Quality, Consumer Protection, Safety and Billing Requirements

K.6. TEP strongly objects to the inclusion of the last two sentences that permit the use of load profiling for predictable loads. All accounts greater than 20 kW or 100,000 kWh annually should be required to have interval meters to be eligible for direct access. TEP has consistently maintained that there are many reasons why load profiling fails to adequately address various issues including economic efficiency, system reliability, proper allocation of costs to customers and proper allocation of costs to third-party suppliers. These issues were explained in detail in the Commission Report submitted by the Unbundled Services and Standard Offer Working Group on November 3, 1997 ("Report").[1] Section VII.F. of the Report titled "Unresolved Issues Regarding Load Profiling" provides as follows:

> The consensus of the Working Group was that the development of a load profiling methodology would require considerably more time to resolve than was available. There are four principal interrelated issues surrounding load profiling: (1) Economic efficiency; (2) System reliability; (3) Proper allocation of energy cost responsibility to customers; and (4) Proper allocation of energy cost responsibility to third party suppliers.[2]

To date, these issues remain unresolved. Load profiling should most properly be viewed as a temporary and expedient approach for small customers less that 20 kW or 100,000 kWh. There is no justification to avoid the use of interval metering in favor of load profiling.

Moreover, the proposed amendment assumes that load profiles exist for hourly consumption data, which is not true in many cases. As loads are determined by an Affected Utilities' unmetered tariffs, only the Affected Utility (and not the ESP or other Load-Serving Entity) is in a position to determine whether the load is predictable. For these reasons, TEP requests that the following language be **deleted**: "*Predictable loads will be permitted to use load profiles to satisfy the requirement of hourly consumption data. The Load-Serving Entity developing the load profile shall determine if a load is predictable.*" Alternatively, "Load-Serving Entity" should be **replaced** with "Affected Utility."

<u>**R14-2-1615.C. Separation of Monopoly and Competitive Services**</u>

The proposed changes to the Rule includes the deletion of the following sentence: "*A Generation Cooperative shall be subject to the same limitations to which its member Distribution Cooperatives are subject.*" This sentence was originally inserted into the Rules at the suggestion of TEP to ensure that a generation cooperative (through a competitive affiliate) is prevented from

[1] The section of the Report relating to load profiling is attached hereto as Attachment A.
[2] These four principal issues are discussed in greater detail in Attachment A.

competing in the retail electric market while its distribution cooperatives are allowed to offer competitive services (which no other UDCs are allowed to do) to their members. If under the Rules and the Stranded Cost Decisions, AEPCO, through a competitive affiliate such as Sierra Southwest, is precluded from serving competitively in any other retail service territories, including those of their affiliated distribution cooperatives, until such territories are opened up to other ESPs, TEP does not object to the deletion. If, however, this is not the case, TEP believes that the language should not be deleted to avoid this competitive advantage.

R14-2-1618. Disclosure of Information

TEP believes that, in theory, disclosing a load-serving entity's resource mix may be a worthy goal from society's perspective. However, from a practical standpoint, the costs and efforts required to track and administer such things as composition of the resource portfolio, the fuel mix of that portfolio and its emission characteristics are at least substantial, and more than likely burdensome, from the customer's, as well as the load-serving entity's, perspective. If, in the future, technological advances regarding developing and tracking such information make it readily available, the costs of disclosing it may not be prohibitive, but such is not the case at present. Therefore, the Rule should be **deleted**.

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RESPECTFULLY SUBMITTED this 7th day of September, 1999.

TUCSON ELECTRIC POWER COMPANY

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purposes of billing required services (i.e., transmission and ancillary services). If it is found tha a Affected Utility's current FERC open access tariff requires modification to facilitate data access and to fully accommodate retail access, then the Arizona Corporation Commission may have to cooperate or concur with the incumbent utilities for an unbundled retail transmission tariff to the FERC.

13. ISSUE: **Data Access Frequency and Timeliness.** The consensus was that access to meter data should be at a minimum on a monthly basis for validated meter reads necessary for billing purposes. Such information should be made available to the electronic mailbox within 24 hours of the actual meter read date for customers who have untimed meters and within 48 hours for customers who have hourly interval meters.

14. ISSUE: **Metering Certification Process.** The consensus was that all metering personnel should be subject to a certification process. All metering agents and their individual service personnel must be certified to insure the safe and reliable operation of the metering system. Since the ESPs and the MAs must obtain a CC&N for doing metering and meter-reading in Arizona, the consensus was that all parties are certified as part of their compliance with their CC&N. As part of their CC&N filings, Staff will require the ESP's and the MA's to present the procedure used to verify the certification of their metering personnel.

15. ISSUE: **Should Load Profiling Be Allowed?** Load profiling is the process of estimating a customer's hourly load shape based on an appropriate sample of historical usage patterns for similarly situated customers. There was consensus that load profiling should be allowed as an economic alterna[illegible] to hourly meter reading. A proposal was made that customers under 20 kW, at least initially, be permitted to use load profiling to satisfy the requirements for hourly consumption data. Such a load profiling provision should include the requirement for a statistically significant metered load sampling basis to meet scheduling and settlement requirements. The method for allocating cost responsibility to ESP's for any irreconcilable energy imbalance charges resulting from the inaccuracies introduced by load profiling remains to be determined. Ultimate implementation of hourly metering for customers under 20 kW will be determined by the experience gained with the application of load profiling as well as the economics of system-wide hourly metering implementation. The Mines and the Coalition note that the appropriate minimum level for requiring hourly metering may be in the 20-50 kW range, as has been determined in California. APS suggests that consideration should be given to equating kW to kWh to facilitate the identification of customers eligible for load profiling.

Load profiling methodologies need to be periodically reviewed by the Commission to determine whether it is appropriate to continue their use. The inaccuracies inherent in load profiling may disadvantage some customers by requiring that they pay based on a load profile that is different than their own. ACAA suggests that customers should be held harmless from any negative consequences as a result of the design and implementation of load profiling. It is essential that the load profiling methodology be reviewed and updated regularly by the LDC and the ESP's to ensure that the profile adequately reflects the usage patterns of the customer it is modeling. Ultimately, dynamic load profiling should be the goal, if load profiling continues. This would permit the ESP's to modify the load profiles of its customers based on the most current usage information and will help reduce variations between the load profile and ac[illegible] usage and will reduce any misallocation of costs.

F. UNRESOLVED ISSUES REGARDING LOAD PROFILING. The consensus of the Working Group was that the development of a load profiling methodology would require considerably more time to resolve than was available. There are four principal interrelated issues surrounding load profiling: (1) Economic efficiency; (2) System reliability; (3) Proper allocation of energy cost responsibility to customers; and (4) Proper allocation of energy cost responsibility to third party suppliers.

1. ISSUE: **Economic Efficiency**. One of the fundamental overriding objectives of competition in any industry (including the electric industry) is the attainment of greater economic efficiency. The prevailing wisdom on the subject dictates that in order to achieve this goal it is imperative that consumers receive appropriate pricing signals that accurately reflect the cost of the product they are consuming or the service they are receiving. Electric energy is a commodity which all suppliers recognize has a cost that varies depending on a number of possible factors including the nature of the fuel source for the generation, the time of year and the time of day in which it is supplied. Accordingly, the unresolved issue involves how to best ensure that consumers receive price signals consistent with their individual usage.

2. ISSUE: **System Reliability**. As part of the procedures associated with energy supply, third party suppliers will have to furnish energy schedules for their customers, including any that may be load-profiled. In day-ahead planning, the anticipated hourly energy usage of customers along with the resources necessary to meet that demand (plus reserves) is scheduled with the transmission system's control area operator. In a competitive market, the schedules of retail customer loads will be furnished by authorized scheduling entities, such as aggregators. These scheduling entities will be required to submit schedules in which expected hourly loads and resources are in balance and reserves are provided. It is well understood that actual loads and schedules will not match perfectly. For this reason, the control area operator is required by FERC to provide regulation and frequency response service, the cost of which is charged to customers as an ancillary service. In performing this service, the control area operator uses Automatic Generation Control (AGC) to make sure that resources exactly match load in real time, ensuring system reliability.

Some parties are concerned that load profiling will decrease the accuracy of scheduling process, thereby making day-ahead planning more difficult. Others point out that those who submit inaccurate schedules will be subject to monthly energy imbalance charges. These charges will be assessed after monthly energy usage is apportioned in accordance with the customers' respective load profiles. All parties agree that the load profiling protocol should be designed in a way that minimizes the opportunities for taking unfair advantage of the scheduling process

3. ISSUE: **Proper Allocation of Costs to Customers**. An additional unresolved issue with load profiling is how to best ensure that consumers are paying an appropriate amount for their individual contribution to the system peak or to the peak hours. This issue occurs because every customer in a particular class is lumped in with all others of that class and a usage pattern is deduced for the class as a whole. Energy will then be scheduled to cover the generalized estimates for the customer class's needs without any specific consideration of individual customers taking place. (Without hourly meters this is all you can do.) This method has the distinct disadvantages of (a) failing to monitor the hourly use of individual customers, many of whom may be larger users of electricity than those included in their class during the more expensive peak periods, and (b) requiring the control area operator (or the ISO) to supply,

or arrange for the supply of, any additional energy that may be needed above the estimated sched amounts for those customers who are consuming more than anticipated by their generation suppliers without the control area operator (or the ISO) being able to specifically identify those individual customers who are the cause of the energy deficiencies. The inability of the control area operator (or ISO) to identify those individual customers who are these energy "absorbers" leads to the economically distorting effect of costs being incurred without proper assignment to the customers causing them. In the absence of hourly metering, all that can be done is to assign the additional costs over the entire class and build them into the customer charges, probably on an average basis. But this solution cuts against the grain of competition's objectives by failing to link cost responsibility to cost causation.

One way to capture as much allocable efficiency as possible is to require that all time-of-day information captured by an individual customer's meter be used in fitting his or her energy usage into the load profile. Thus, for example, a customer with a time-of-day meter would have his or her known on-peak hours placed within the on-peak portion of the load profile.

4. ISSUE: **Proper Allocation of Costs to Third Party Suppliers.** Another issue is that energy suppliers are not being assessed appropriate cost responsibility for any energy deficiencies that have to be made up by the control area operator (or ISO) to ensure energy deliveries to load-profiled customers. Unless all load-profiled customers are supplied by one energy company, the inability of the control area operator (or ISO) to identify specific customers responsible for unscheduled energy additions during given hours will consequently render that entity unable to specifically identify the energy supplier that should be responsible for the additional cost. Again, some form of averaging or generalized cost will have to spread over all suppliers of that particular customer class; this will, of course, mean that some suppliers will pay more than their customers are actually responsible for and some will pay less. The issue then becomes one of finding the best possible way to ensure that suppliers pay their fair share of the cost.

VIII. BILLING AND COLLECTIONS

A. INTRODUCTION

On April 9, 1997, the first meeting was held of the Unbundled Services and Standard Offer Working Group. The objectives of the Working Group and the key issues were developed at this first meeting. At the next meeting of the Working Group on May 9, 1997, the participants began discussing the key issues. During these discussions, it became apparent that the implementation of the billing and collection issues would involve much more discussion. Thus, the participants agreed to establish a Billing and Collection (B and C) Subcommittee. Representatives from APS, ACAA, Enron, ESI, Tucson Electric Power, Trico Electric Cooperative, Citizens Utilities, Sulphur Springs Valley Electric Cooperative (SSVEC), the City of Mesa and the City of Tucson volunteered to be on the subcommittee. The Residential Utility Consumer Office was also invited to participate in the subcommittee. David Jankofsky, chairman of the Working Group, appointed John Wallace of the Commission Staff to head the Subcommittee.