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Transcript Exhibit(s)

Docket #(s): E-01933A-02-0345

E-01933A-98-0471

Exhibit # : TEP1 - TEP3, DOD1, S1

EXHIBIT
TEP-1
TEP-1
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF NEW PARTIAL REQUIREMENTS SERVICE TARIFFS, MODIFICATION OF EXISTING PARTIAL REQUIREMENTS SERVICE TARIFF 101, AND ELIMINATION OF QUALIFYING FACILITY TARIFFS.	DOCKET NO. E-01933A-02-0345
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471 **DIRECT TESTIMONY OF LELAND R. SNOOK**

AUGUST 30, 2002

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INTRODUCTION.

Q. Please state your name and business address.

A. My name is Leland Snook. My business address is 4350 E. Irvington Road, Tucson, AZ 84714.

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

A. I am the Manager of Customer and Regulatory Services.

Q. What are your duties and responsibilities as Manager of Customer and Regulatory Services?

A. My responsibilities include the supervision of regulatory services and customer care for TEP's retail customers. This involves helping TEP's large commercial and industrial customers find solutions to their energy needs. I am also responsible for the TEP Customer Care Center that primarily resolves issues for TEP's residential customers. Additionally, I have strategic responsibility for TEP's Pricing and Economic Forecasting groups, which are responsible for modeling cost of service, tariff design and development, load research and forecasting load by customer class.

Q. Please summarize your educational background.

A. I received a Bachelor of Science Degree in Electrical Engineering from Texas Tech University and I am a registered Professional Electrical Engineer in the State of Arizona.

Q. Please summarize your professional experience.

A. From 1986 through 1990, I was employed by TEP as a Project Engineer in Substation Design and also in Communications. From 1990 through 1994, I was employed as a Planner and as a Supervisor in TEP's Supply Side Planning Department. In that capacity, I utilized sophisticated electric system production cost and planning tools such as PROMOD™ and PROSCREEN™ to prepare (a) production cost studies in support of fuel contract renegotiations; (b) marginal cost studies in support of wholesale marketing efforts; and (c) TEP's 1992 and 1995 Integrated Resource Plans. From March 1994 to July 1998, I was employed by TEP as a Contract Negotiator, Bulk Power, in the Contracts and Wholesale Marketing Department, where I participated in the negotiations of wholesale power contracts with entities such as Texas-New Mexico Power, Navajo Tribal Utility Authority, Morenci Water & Electric and the City of Farmington, among others. I also participated in the negotiations of TEP's electric service agreements ("ESA's") with its large retail customers, such as Phelps Dodge Sierrita (formerly Cyprus Sierrita) and ASARCO. From July 1998 to July 1999, I was employed by NEV Southwest, L.L.C. as the Director of Product Development and Pricing, where I performed economic and pricing analysis for direct access retail energy sales opportunities. Since July 1999, I have been employed by TEP in my current position as the Manager of Customer and Regulatory Services.

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

A. I am sponsoring "Tucson Electric Power Company's Application" filed with the Arizona Corporation Commission ("Commission") on May 10, 2002 (the "TEP Application"). I am also sponsoring the TEP Motion for Clarification of Settlement Agreement filed with the Commission on March 14, 2002 ("TEP Motion for Clarification"). The TEP

Application and TEP Motion for Clarification were joined by the Presiding Administrative Law Judge.

BACKGROUND.

Q. Please provide some background as to why TEP has filed the TEP Application?

A. TEP currently has in place tariffs pursuant to which customers who generate their own power (sometimes called "self-generation customers" or "distributed generation" ("DG") customers) can receive back-up/standby and supplemental service (collectively "partial requirements service" or "PRS"). These tariffs, referred to as "QF" tariffs, require the customers to be "Qualifying Facilities", as that term is defined by The Public Utility Regulatory Policies Act of 1978 ("PURPA"). However, circumstances have changed since the implementation of the QF tariffs. TEP realizes that there are potential self-generation customers who would need PRS but would not qualify for that service pursuant to TEP's QF tariffs because they are not PURPA-designated Qualifying Facilities. So, TEP has re-designed its tariffs to make PRS service available to QF <u>and</u> non-QF self-generation customers.

Q. Please explain back-up/standby service.

A. DG customers need to obtain electric power from a reliable source (such as TEP) when their DG unit is not running due to either a maintenance outage or an unplanned outage. In order to provide back-up/standby service, TEP must be able to obtain and deliver capacity and energy to the DG customer at any time.

Q. Please explain supplemental service.

A. DG customers need to obtain additional electric power, again from a reliable source, when their power needs are greater than what the DG unit is able to generate. In these instances, supplemental service would be provided by TEP even though the DG unit is operating.

Q. Why does TEP believe that the existing QF tariffs do not meet the needs of potential DG customers?

A. TEP does not believe that the absolute requirement that a PRS customer be a QF is needed anymore. Technology and economics have developed to the point where there are many viable potential DG customers whose facilities are not, and in fact, need not be QFs. These non-QF DG customers should be able to receive PRS service pursuant to tariffs that are specifically designed for their circumstances. PURPA standards define how much waste heat must be used or how much useful power must be produced in terms of fuel conversion efficiency. Many DG customers who utilize a "cogeneration" system (one that produces both useful electrical power as well as useful thermal energy, such as heat or steam) do not meet either PURPA's operating or efficiency standards.

Q. Why doesn't TEP just provide PRS service pursuant to TEP's full service requirements tariffs?

A. There are several problems with that approach. First, the terms and conditions of TEP's full service requirement tariffs do not provide for PRS. By definition, a DG customer, whether a QF or not, simply is not a full requirements customer. Also, TEP believes that if it tried to apply full requirements service tariffs to DG customers it would create an economic mismatch of costs and revenues that would result in a revenue shortfall. The installation of a DG unit by a customer reduces the number of hours an incumbent utility's distribution and transmission systems are used by that customer. TEP's full-requirements tariffs were designed based on assumptions of full-requirement utilization by customers. If only the underlying assumptions for full customer utilization are changed, the cost to TEP of providing the transmission and distribution service will be the same, but there will be less customer usage from which TEP can recover the cost of the service.

TEP also believes that providing PRS tariffs designed for full-requirements service would provide a DG customer with a unilateral "discounted call" on generation from TEP at fixed prices—but TEP's generation costs are not fixed. TEP's generation costs vary depending upon system configuration, unit availability, load requirements, time-of-day, season, and the price of market power.

Q. Why does TEP believe that the new PRS tariffs are in the public interest?

A. As I have indicated, PRS customers are different than full requirement service customers. So, PRS tariffs should reflect that difference. PRS customers tend to require service at times when it is most costly for TEP to serve them. TEP believes that it is in the public interest for PRS customers to pay their fair share of the cost of providing service to them—and not be subsidized by full service requirements customers.

As you can tell from my testimony regarding back-up/standby and supplemental service, a PRS customer often requires service immediately (or on short notice) and at times when power costs are high. For example, supplemental service is frequently needed during peak power supply periods when full requirement service customers also need additional power. The cost of electric power tends to be higher than during off-peak periods. Thus, the cost of providing service to a PRS customer with periodic system needs is higher than that of a full requirements customer. So, in order to maintain fair rates for full requirements customers and to avoid PRS customers reaping a windfall at the expense of the full requirements customer, TEP has designed new PRS rates that accurately reflect the cost of service for PRS customers. Establishing tariffs that provide for safe, efficient, reliable and fairly priced electric service is in the public interest. I believe that the new PRS tariffs accomplish that goal for PRS customers.

THE TEP APPLICATION.

Q. Mr. Snook, please explain what is being requested in the TEP Application.

A. The TEP Application seeks Commission approval for those tariffs that will provide PRS to a broadened scope of customers. Specifically, TEP is requesting Commission approval of new PRS tariffs, PRS-10, PRS-13 and PRS-14, and modified existing tariff PRS-101. The new PRS tariffs are designed to replace the existing QF tariffs, so TEP is also requesting that the Commission cancel existing QF tariffs 102, 103, 104, 105, 106, 107 and 108.

Q. Please discuss the new PRS tariffs for which TEP is seeking approval.

A. PRS-10 for General Service provides PRS for customers with loads up to 200 kW. PRS-13 for Large General Service provides PRS for customers with loads from 200 kW - 2,999 kW. PRS-14 for Large Light & Power Service provides PRS for customers with loads of 3,000 kW or greater. A copy of each of these tariffs was submitted as Exhibit 1 to the TEP Application.

Since the TEP Application was filed, the tariff for PRS-13 (Back-up/Standby Service) has been revised. The "Customer Charge" provision now reads "Customer Charge (first 200 kW)"and the "Standby Demand Charge per kW" provision has been changed to read "Standby Demand Charge (all additional kW)". These revisions will ensure that DG customers will only pay the Standby Demand Charge for their demand in excess of 200 kW and that the first 200 kW of demand will be included in the Customer Charge. I have attached a revised tariff sheet to my direct testimony as Exhibit 1.

These new tariffs will apply to any non-residential DG customer requiring PRS, under either a standard offer or direct access service arrangement.

Q. Did TEP rely upon any industry input in designing the new PRS tariffs?

A. Yes. The new PRS tariffs reflect input from the Commission-sponsored Distributed Generation Interconnections Investigation ("DGI") Advisory Committee. On June 28, 2000, the DGI Advisory Committee issued the "DGI Workgroup Final Report" (Docket No. E-00000A-99-0431). Therein, the DGI recommended that the Commission, "design fair and reasonable tariffs considering proper recovery of utility costs, back-up power or partial-requirements tariffs, and PURPA Qualifying Facilities while providing consistent treatment of DG relative to other consumer services."

I believe that TEP's new PRS tariffs are designed consistent with the DGI Advisory Committee's recommendation to recover costs incurred by TEP to provide PRS. In the new PRS tariffs, TEP matched "cost recovery" with the "cost to serve" DG customers. TEP achieved this by appropriately (a) allocating fixed and variable costs for the transmission and distribution system between customer, demand and energy charges based on lower system utilization by partial requirements customers; and (b) separating distribution and transmission cost ("delivery costs") from generation costs.

Q. Will the new PRS tariffs send the proper price signals to DG customers?

A. Yes, I believe they will. TEP uses market-based pricing for generation costs to send the correct price signal to customers. DG customers can benefit from "peak-shaving" due to the price differences that likely will occur between the on-peak and off-peak components of the market-based pricing. Market price signals will also encourage DG customers to schedule maintenance during low priced periods and promptly repair the unit when a forced outage occurs during a high priced period.

Customers will benefit from market-based pricing under the new PRS tariffs because they will only pay for generation when it is used as opposed to the QF tariffs where generation capacity must be reserved. Market pricing will allow DG customers to receive the benefits of low energy market prices as well as bear the risk of high energy market prices.

Q. Please explain how TEP developed the new PRS tariffs.

A. The charges in the new PRS tariffs were developed for each customer rate class (General Service, Large General Service and Large Light and Power). In order to separate transmission and distribution from generation tariff components, the starting points for designing the PRS tariffs were the average unbundled rates for each customer rate class on a per kWh basis using TEP's approved unbundled tariff components, customer and sales data.

The new PRS tariffs were designed to recover delivery costs through a combination of customer, energy, and demand charges. Generation costs are to be recovered through a "Market Generation Charge" ("PRS MGC") as an energy charge component. A revised calculation schedule of the PRS MGC is included in my testimony as Exhibit 2, which includes a change in the terminology of "futures" to "forward" and elimination of the reference to "hourly" prices in the Dow Jones definitions in the Glossary.

TEP designed the PRS tariffs to recover the costs of providing PRS by reallocating the fixed and variable cost components for full-requirements service, based on lower usage levels for back-up/standby service and supplemental service charges. Cost recovery for full-requirements customers is primarily achieved through energy charges. Costs not recovered through energy charges are recovered through customer and demand charges. To appropriately recover the transmission and distribution costs, the back-up/standby service has higher customer and demand charges and lower energy charges than does supplemental service.

Since TEP provides a smaller portion of a DG customer's total energy requirements, the DG customer will have a lower load factor than it would have had if it was a full-requirements customer, which is another way to describe the lower utilization of TEP's system. Because of this, TEP assumed an average ten-percent (10%) load factor for PRS customers, which was applied to the average unbundled rates for each customer rate class to arrive at average unbundled rate components for DG customers. A PRS revenue requirement for the cost of transmission and distribution facilities was developed by multiplying these rate components by the average use per customer. This resulting revenue requirement was the basis for the rate design for both the back-up/standby and supplemental service charges for each new PRS tariff, which were then designed into customer, demand and energy components.

Q. Please explain the load factor that TEP used in the new PRS tariffs.

A. Load factor is a ratio that illustrates the relationship between a customer's average load and its peak load or demand. Load Factor is calculated by the following formula:

LF = (kWh)/(peak load x total hours) where "(kWh)" equals the actual energy consumed and "(peak load x total hours)" equals the maximum energy consumption that would have occurred if, at all times during the cycle, the load was equal to the peak.

Load Factor was used in the development to represent a PRS customer's lower utilization of TEP's distribution and transmission system.

Q. Are the methods that TEP used to develop the PRS tariffs consistent for each customer class?

A. Yes, the methods used to arrive at the rates for the new PRS tariffs are consistent. Any differences among the calculations for each of the new PRS tariffs are the result of variations in customer characteristics such as load patterns, demand levels and energy consumption.

Q. Are there any other reasons TEP believes the new PRS tariffs are an improvement over the existing QF tariffs?

A. Yes, TEP believes that the new PRS tariffs better reflect the intention of PURPA than the existing QF tariffs. All similarly situated DG customers will receive the same service regardless of QF status. Section 292.305 (a) of the Code of Federal Regulation states:

> (1) Rates for sales: (i) Shall be just and reasonable and in the public interest; and (ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customer served by the electric utility. (2) Rates for sales which are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

Q. TEP is also requesting that QF-102, for buyback of power from QF's less than 100 kW on a firm basis, be cancelled. Why is TEP seeking this?

A. TEP believes that these customers cannot feasibly provide <u>firm</u> power to TEP from a single generation unit. By definition, the buyback power provided to TEP is unit contingent. If the single generation unit is out of service due to either a planned or unplanned outage, there is no alternative source of generation to ensure that TEP receives firm power.

Q. How will new TEP's PRS tariffs be more favorable to DG customers than TEP's existing QF tariffs?

A. One important way is that TEP's new PRS tariffs will be applicable to customers utilizing <u>any</u> type of DG, whereas TEP's existing QF tariffs only apply to DG that meets the PURPA requirements.

Q. Do you believe that TEP's new PRS tariffs will be more readily understood by customers than TEP's existing QF tariffs?

A. Yes, I do. I believe that the new PRS tariffs present the pricing, terms and conditions of service in a manner, which makes it easier for customers to estimate their electric service costs. The new PRS tariffs provide back-up/standby (and/or maintenance) and supplemental service under one tariff. Under TEP's QF tariffs, a customer would potentially have to take comparable service under three (3) separate tariffs.

Q. Please explain how the new PRS tariffs are consistent with ongoing discussions regarding electric competition and competitive wholesale generation markets.

A. As I understand the discussions regarding electric competition in Arizona, parties are indicating that it may be beneficial to the development of wholesale generation markets for utilities to separate generation service charges from transmission and distribution service charges, which is achieved by TEP's new PRS tariffs. In this way the cost recovery of transmission and distribution services can be more accurately matched to the cost of providing those services. In addition, I believe that TEP's new PRS tariff design sends the appropriate price signals to customers by passing through the market cost of providing generation service at the time energy is used. The difference between on-peak and off-peak energy prices should provide customers with an incentive to "peak shave."

THE MODIFICATION OF EXISITING TARIFF PRS-101.

Q. Has TEP revised PRS-101 from how it was originally filed?

A. Yes. TEP has raised the limit for net metering of any single solar electric system to 10 kW, from 5 kW and to also make net metering available for small wind generation of 10 kW and below. A revised PRS-101 tariff sheet is attached to my direct testimony as Exhibit 3.

Q. Why is TEP proposing to make changes to existing PRS-101?

A. In general terms, existing PRS-101 is offered to any QF with certified capacity of 100kW or less which generates other than firm power. TEP is requesting that PRS-101 be modified so that it will be exclusively available to any DG with certified capacity of 100kW or less generating through the use of renewable energy resources. TEP currently has thirty (30) DGs participating under PRS-101. The proposed changes to PRS-101 will affect only nineteen (19) of those DGs.

TEP is proposing to make two changes to existing the PRS-101 tariff. First, while the existing PRS-101 tariff is applicable to renewable generators and co-generators, TEP is proposing PRS-101 only apply to renewable generators. Second, the price at which TEP will buy back power from a renewable customer is proposed to change from a fixed price to a market price.

Q. Why does TEP believe it is necessary to revise existing tariff PRS-101 at this time?

A. TEP does not believe it should be required to purchase excess energy from a customer with a self-generation unit in a competitive wholesale generation market. Rather, TEP believes that in a competitive wholesale generation market, market based pricing is appropriate. Although TEP will continue to evaluate the appropriateness of purchasing excess generation from customers with self-generation on a case-by-case basis, this modification to existing tariff PRS-101 will continue to be an incentive for those customers who generate electricity through the use of renewable energy resources.

THE TEP APPLICATION IS PERMISSIBLE UNDER THE 1999 TEP SETTLEMENT AGREEMENT.

Q. Is the TEP Application permissible under The 1999 TEP Settlement Agreement?

A. Yes, I believe it is. The 1999 TEP Settlement Agreement was approved by the Commission in Decision No. 62103. The 1999 TEP Settlement Agreement provides for subsequent tariff filings. For example, Section 13.6 of the 1999 TEP Settlement Agreement states:

> This Settlement Agreement shall not preclude TEP from requesting, or the Commission from approving, changes to specific rate schedules or terms and conditions of service, or the approval of new rates or terms and conditions of service, that do not significantly affect the overall earnings of the Company or materially modify the tariffs or increase the rates approved in the Settlement Agreement. Nothing contained in this Settlement Agreement shall preclude TEP from filing changes to its tariffs or terms and conditions of service, which are not inconsistent with its obligation under this Settlement Agreement.

Q. Will the replacement of TEP's existing QF tariffs with the new PRS tariffs and the modification of existing PRS-101 significantly affect TEP's earnings?

A. No. The transition of customers to the PRS tariffs would not significantly affect the earnings of TEP. This is because the design more appropriately recovers the cost of providing the service as compared to the QF tariffs. Presently, TEP only has one customer on any QF tariff that we propose to eliminate, which will be frozen for that customer.

Q. Were the QF tariffs frozen under TEP's Settlement?

A. No.

Q. How is the replacement of QF tariffs 107 and 108 with new PRS-14 consistent with the 1999 TEP Settlement?

A. This is a good example of how the TEP Application is consistent with the TEP Settlement. TEP is proposing to replace QF tariffs 107 and 108 with new PRS-14. PRS-14 is broader in scope than QF tariffs 107 and 108 and provides consistent terms, conditions and pricing for similarly situated customers. Also, PRS-14 provides customers with back-up/standby, maintenance, and supplemental service while 107 and 108 provides only back-up/standby and maintenance services, respectively, while the customers' supplemental service needs are not addressed.

Q. Are you aware of any other Arizona utilities that have filed tariffs similar to the new PRS tariffs that have been approved by the Commission?

A. Yes. In 2001, APS received approval for its tariff E-36 (Station Use Service), which has a pricing structure similar to TEP's new PRS tariffs.

THE MODIFICATION OF TEP'S MARKET GENERATION CREDIT.

Q. Please review the development of the TEP Market Generation Credit.

A. TEP, Arizonans for Electric Choice and Competition, the Residential Utility Consumer Office and the Arizona Community Action Association were all signatories to the 1999 TEP Settlement Agreement. The 1999 TEP Settlement Agreement authorized TEP the opportunity to recover its stranded costs through the implementation of a Competition Transition Charge ("CTC"). Since the commencement of the implementation of the 1999 TEP Settlement Agreement, the parties concluded that some clarification of the provisions relating to the calculation of the Market Generation Credit ("MGC") is required to insure complete and full implementation of the 1999 TEP Settlement Agreement as intended by the signatories.

Q. Why is TEP seeking to modify the MGC?

A. In simple terms, due to changed circumstances, TEP's current MGC is obsolete. Since the effective date of the 1999 TEP Settlement Agreement two (2) indices that were used in the calculation of the MGC are no longer available. One index was provided by the California Power Exchange ("CALPX"), which ceased operation in January 2001. The other index was the New York Mercantile Exchange ("NYMEX") Palo Verde Electricity Futures, which were de-listed from NYMEX in April 2002. A revised calculation schedule of MGC-1 is attached hereto as Exhibit 4, which includes a change to the terminology of "futures" to "forward" and elimination of the reference to "hourly" prices in the Dow Jones definitions in the Glossary.

Q. Were modifications to the MGC methodology contemplated in the 1999 TEP Settlement Agreement?

A. Yes, changes of this type were contemplated. The TEP 1999 Settlement Agreement Section 2.1 (d) states, in part:

> [I]f the nature of the Palo Verde NYMEX changes such that it no longer accurately reflects the intent of the Settlement, the Company, Staff or any other interested party may request that an alternative index by utilized to the extent such index is consistent with Settlement.

Q. Have all signatories to TEP's Settlement agreed to TEP's proposed method of calculating the MGC?

A. Yes. All signatories have agreed to the proposed method.

Q. What new component indices is TEP proposing to use?

A. TEP is proposing the following changes to the MGC calculation:

Previous Index Component	Proposed Index Component
CALPX	Dow Jones Daily Palo Verde Index ("DJPVI")
NYMEX – Palo Verde electricity prices	Platts "Long-term Forward Assessments" Energy Prices for Palo Verde ("Platts Energy")

For definitional purposes: (1) DJPVI contains an on and off peak daily calculation of actual firm on-peak and firm off-peak weighted average prices for electricity traded at Palo Verde, Arizona switchyard. DJPVI is used to develop the off-peak component; (2) Platts Energy is a McGraw-Hill publication that provides an independent daily evaluation of on-peak forward market prices of electricity at the Palo Verde, Arizona switchyard. Platts Energy prices are used to determine the on-peak generation prices for the MGC.

Q. Did TEP consider other market priced indices?

A. Yes, but no other publicly available indices were found.

Q. Were there other changes that were made to the MGC calculation, and if so, why were they made?

A. Yes. The timing and scope of the calculation was also modified. The previous calculation for the MGC was computed using the 45th, 46th, and 47th days prior to the start of a quarter, which set the MGC for each month in the coming quarter. The new calculation computes the MGC from the 30^{th}, 31st, and the 32^{nd} days prior to the beginning of each month and sets the MGC only for the coming month. The parties to TEP's Settlement concurred that using market prices closer to the delivery month provides more certainty and less risk for all market participants.

Q. What is TEP currently using for the MGC since both component indices have been discontinued?

A. After discussing alternatives with the Commission Staff, TEP agreed to calculate the MGC as it had proposed in its Application, beginning with the delivery month of January 2002.

CONCLUSION.

Q. Please summarize how granting the relief requested in TEP's Application would benefit TEP's customers?

A. TEP believes that the relief requested in the TEP Application will benefit its customers, and is in the public interest, in the following ways: First, the new PRS tariffs broaden the scope of those customers who will be eligible for partial requirements service. Second, the generation pricing for the new PRS tariffs provides an incentive for self-generating customers to peak-shave due to the nature of the on-peak and off-peak generation prices. Third, the PRS tariffs will allow customers to obtain back-up/standby, maintenance and supplemental generation service from a competitive electric service provider through direct access, while acquiring distribution and transmission services for delivery from TEP. Fourth, PRS customers continue to remain eligible to participate in TEP's GreenWatts program. And finally, by modifying the MGC as requested in the TEP Application, the Commission will appropriately update the Settlement Agreement to reflect changed circumstances.

Q. Does this conclude your testimony?

A. Yes.

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Tucson Electric Power

A UniSource Energy Company

Pricing Plan PRS-13
Partial Requirements Service
From 200 kW to Less Than 3,000 kW

AVAILABILITY

This Pricing Plan is available in all territory served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the premises served and when all applicable provisions described herein have been met.

APPLICABILITY

This Pricing Plan is applicable to any non-residential customer requiring partial requirements services, including backup energy, standby capacity, maintenance energy, or supplemental energy and capacity, in addition to regular electric requirements obtained from any service other than the Company. This Pricing Plan is applicable to customers with an aggregate partial requirements service load from 200 kW to less than 3,000 kW. This Pricing Plan is not applicable to resale service or where on-site generation is used only during a utility outage.

CHARACTER OF SERVICE

The service shall be single- or three-phase, 60 Hertz, at one standard nominal voltage as mutually agreed and subject to availability at the point of delivery. Primary metering may be used by mutual agreement between the Company and the Customer.

BUNDLED PRICES

The total monthly bill will be the sum of the delivery charges plus the market-based generation charges.

Delivery Charges – monthly

	Summer Billing Months (May – October)	Winter Billing Months (November – April)
Backup/Standby Service		
Customer Charge (first 200 kW)	$ 1,675.88	$ 1,675.88
Standby Demand Charge (all additional kW)	$ 4.47	$ 4.47
Backup Energy Charge per kWh	$ 0.010458	$ 0.008557
Supplemental Service		
Demand Charge per kW	$ 1.97	$ 1.97
Energy Charge per kWh	$ 0.052290	$ 0.042783

Market-based Generation Charges

Generation-related charges will be billed at a monthly market-based price dependent upon time of day. The price will be based upon a modified Market Generation Credit mechanism plus an additional procurement charge of 10% of the total generation-related charges. See Schedule MGC-2 for details.

Power Factor Adjustment

The above rate is subject to a discount or a charge of 1.3 cents per kW of billing demand for each 1% the average monthly power factor is above or below 90% lagging to a maximum discount of 13.0 cents per kW of billing demand per month.

Three-phase Service

An additional monthly charge of $7.43 shall apply to customers receiving three-phase service.

Arizona Independent Scheduling Administrator (AISA) Charge

A charge of $0.00004473 per kWh shall, subject to Federal Energy Regulatory Commission authorization, be applied for costs associated with the implementation of the AISA in Arizona. Direct access customers will be billed the AISA charge by their scheduling coordinator.

Minimum Bill

The Minimum Bill for Backup/Standby Service is equal to the sum of the greater of the Minimum Contract Demand or the Backup/Standby Service Billing Demand times the Standby Demand Charge per kW plus the Backup/Standby Service Customer Charge per month.

The Minimum Bill for Supplemental Service is equal to the sum of the Minimum Bill for Backup/Standby Service plus the greater of the Minimum Contract Demand or the Supplemental Service Billing Demand times the Supplemental Demand Charge per kW.

TERMS AND CONDITIONS

1. Service Requirements

This Pricing Plan consists of rates charged for two general types of service--Backup/Standby Service and Supplemental Service. The use of Backup/Standby Service occurs when the Customer's total generating resources covered under PRS-13 are unavailable, such as during forced generator outages (when the Customer's generator is not operational) and unforced or planned outages (when the Customer's generator requires maintenance). The use of Supplemental Service occurs when the Customer requires power in addition to that generated by the Customer to meet the Customer's total energy requirements.

The Customer may elect to take Backup/Standby service only, or Supplemental Service in addition to Backup/Standby service. However, when the Customer's Partial Requirements Usage Percentage (PRUP) in any given billing period exceeds 5%, the Customer's Energy Charge per kWh under Backup/Standby Service will be converted to the Energy Charge per kWh under Supplemental Service for all kilowatt-hours in excess of 5% for the billing period.

The PRUP is calculated as follows:

$$PRUP = \frac{\textit{Backup Energy Purchased under Backup/Standby Service}}{\textit{Billing Demand for Backup/Standby Service} \times \textit{Hours in Billing Period}}$$

2. Contract

The Customer shall contract for a Term and a Minimum Contract Demand (for either Backup/Standby and Supplemental Service as applicable) and shall conform to all applicable interconnection requirements as mandated either by government or by the Company.

3. Direct Assignment of Interconnection Costs

Prior to construction, the Customer will advance to the Company the total amount of the estimated interconnection construction costs directly related to distribution and transmission service. For each of the first five years of metered use up to the amount of the advance, the Company will refund to the Customer 40% of the annual revenue received based on the unbundled charges under this tariff that are associated with the facilities installed (e.g. revenue from the distribution secondary charge for 13.8 kV facilities). The refund, without interest, will be made one month after each full year of service.

The Customer will furnish, install, and maintain incremental non-distribution system or non-transmission system equipment at his expense. The equipment must meet the standards of the Company's Electric Service Requirements.

Direct Assignment of Incremental Interconnection Costs
In the event that either the fifteen (15) minute demand in the billing month or the maximum fifteen (15) minute demand in the preceding 23 billing months exceeds the Maximum Contract Demand and the Company must expand facilities to meet the additional load, the Customer shall pay for the cost of the incremental facilities.

4. Billing Demand

Backup/Standby Service and Supplemental Service have separate demand charges. For both services, the Billing Demand in any month is the greater of (i) the maximum fifteen (15) minute demand in that month or (ii) the maximum fifteen (15) minute demand in the preceding 23 billing months, or (iii) the Minimum Contract Demand as set forth by mutual agreement. The Minimum Contract Demand for Backup/Standby Service shall be based on the measured kW output of each generating unit at the time of the start-up test.

5. Additional Equipment

Service under this Pricing Plan shall require the appropriate interval metering equipment to allow identification of accurate inbound load flows from the Company. This equipment shall require a dedicated telephone line that is to be installed and maintained by the Customer.

ADDITIONAL NOTES

1. There shall be a $13.50 charge for the initial establishment of each new service for each customer. There shall be a $13.50 charge for the re-establishment of each service for each customer.

2. The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where consistent with this Pricing Plan.

3. To the charges computed under the above Pricing Plan, including any adjustments, shall be added the applicable proportionate part of any taxes, governmental impositions, or ACC-mandated assessments which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

4. Energy Imbalance service is currently charged pursuant to the Company's Open Access Transmission Tariff, which is subject to change pursuant to AISA protocols. A loss factor adjustment (5.4%) shall be made for Transmission and Ancillary Services.

RELATED SCHEDULES

- Schedule MGC-2 – Market Generation Credit (MGC) Calculation for Partial Requirements Services
- Environmental Portfolio Surcharge – Rider No. 6
- Tucson Electric Power Company – Rules and Regulations

2

Tucson Electric Power

A UniSource Energy Company

Schedule MGC-2
Market Generation Credit (MGC) Calculation For Partial Requirements Services

Introduction

The purpose of the Market Generation Credit (MGC) for Partial Requirements Services is to establish a price at which TEP's partial requirements customers will purchase backup/standby and supplemental energy under Rates PRS-10, PRS-13, and PRS-14. The Market Generation Credit for Partial Requirements Services is consistent with the MGC methodology per TEP's Settlement Agreement, Section 2.1(d), as amended MM DD, 2002:

> The monthly MGC amount shall be calculated in advance and stated as both an on-peak value and an off-peak value. The monthly on-peak MGC component shall be equal to the Market Price multiplied by one plus the appropriate line loss (including unaccounted for energy ("UFE")) amount. The Market Price shall be equal to the Platts Long-Term Forward Assessment for the Palo Verde Forward price, except when adjusted for the variable cost of TEP's must-run generation. The Market Price shall be determined fifteen (15) days prior to each calendar month using the average of the most recent three (3) business days of Platts Long-Term Forward Assessment for Palo Verde settlement prices. The off-peak MGC component shall be determined in the same manner as the on-peak component, except that the Platts Long-Term Forward Assessment for the Palo Verde Forward price will be adjusted by the ratio of off-peak to on-peak hourly prices from the Dow Jones Palo Verde Index of the same month from the preceding year.

Calculations

The Customer will be charged adjusted on-peak MGC multiplied by kWh consumption for On-peak hours, and adjusted off-peak MCG multiplied by kWh consumption for Off-peak hours. Three steps are outlined below for the calculation of the MGC. None of the steps are excludable for any customer type. Acronyms are defined in the Glossary at the end of this document.

1. Calculating the on-peak MGC

Fifteen (15) days prior to each calendar estimation month, the Forward prices for the three (3) most recent business days are used. The simple average (or arithmetic mean) is calculated for these three days for the estimation month.

$$MGC_{ON,i} = \frac{\sum(PLATTS)_i}{3} \qquad \text{(Equation 1)}$$

The calculation is illustrated in the table below.

Forward Prices per MWh	Apr 2002
3/13/2002	$25.80
3/14/2002	$26.90
3/15/2002	$27.75
Average	$26.82

2. Calculating the off-peak MGC

The off-peak MGC is determined by multiplying the on-peak MGC value by the off-peak price weighting factor (WEIGHT). The WEIGHT is equal to the simple average of all off-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year, divided by the simple average of all on-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$\mathrm{MGC}_{\mathrm{OFF},i} = \mathrm{MGC}_{\mathrm{ON},i} * \mathrm{WEIGHT}_i \quad \text{(Equation 2)}$$

where

$$WEIGHT_i = \frac{DJPVI_{OFF,i}}{DJPVI_{ON,i}} \quad \text{(Equation 3)}$$

3. Loss-adjusting the MGC

The on-peak MGC and the off-peak MGC must be adjusted for line losses. The appropriate line loss adjustment factor (LLAF) for the large industrial customer class is 1.0515; for all other customer classes, the appropriate factor is 1.0919.

$$MGC_{LOSS-ON,i} = MGC_{ON,i} * LLAF \quad \text{(Equation 4)}$$

$$MGC_{LOSS-OFF,i} = MGC_{OFF,i} * LLAF \quad \text{(Equation 5)}$$

This calculation produces the final value for the on-peak and off-peak Market Generation Credits.

GLOSSARY

$DJPVI_{OFF}$	Simple average of off-peak prices on the Dow Jones Palo Verde Index.
$DJPVI_{ON}$	Simple average of on-peak prices on the Dow Jones Palo Verde Index.
Dow Jones Palo Verde Index	Daily calculation of actual firm on-peak and firm off-peak weighted average prices for electricity traded at Palo Verde, Arizona switchyard.
LLAF	Line-loss adjustment factor.
MGC	Market Generation Credit.
MGC_{OFF}	MGC_{ON} weighted by the ratio of off-peak to on-peak daily prices on the Dow Jones Palo Verde Index.
MGC_{ON}	Average of the Platts prices on days appropriate for the calculation of the MGC.
$MGC_{LOSS\text{-}ON}$	MGC_{ON} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
$MGC_{LOSS\text{-}OFF}$	MGC_{OFF} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
NERC	North American Electric Reliability Council. A voluntary not-for-profit organization established to promote bulk electric system reliability and security. Membership include investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.
Off-Peak Hours	Number of total monthly off-peak hours as defined by NERC. Off-peak hours are hour ending 0100 – hour ending 0600 and hour ending 2300 – hour ending 2400, Monday through Saturday, Pacific Prevailing Time (PPT). All Sunday hours are considered off-peak. PPT is defined as the current clock time in the Pacific time zone.
On-Peak Hours	Number of total monthly on-peak hours as defined by NERC. On-peak hours are hour ending 0700 – hour ending 2200 Monday through Saturday, Pacific Prevailing Time (PPT). PPT is defined as the current clock time in the Pacific time zone.

Tucson Electric Power

A UniSource Energy Company

Schedule MGC-2
Market Generation Credit (MGC) Calculation For Partial Requirements Services

PLATTS — A McGraw-Hill publication that provides an independent daily evaluation of on-peak Long Term Forward Assessment of market prices of electricity at the Palo Verde, Arizona switchyard. The forward product is "6 x 16," power is for 16 hours a day for six days a week (Monday through Saturday) for the delivery period, excluding NERC holidays.

Stranded Costs — The difference between revenues under competition and the costs of providing service, including the inherited fixed costs from the previous regulated market.

TEP — Tucson Electric Power Company, a subsidiary of UniSource Energy Corp.

TEP Settlement Agreement — An agreement between TEP, the Arizona Residential Utility Consumer Office, members of the Arizonans for Electric Choice and Competition, and Arizona Community Action Association regarding TEP's implementation of retail electric competition, implementation of unbundled tariffs, and recovery of stranded costs.

WEIGHT — Ratio of off-peak to on-peak hourly prices on the Dow Jones Palo Verde Index.

3

Tucson Electric Power
The Energy People

Pricing Plan PRS-101
Power Purchase from Renewable Energy Resources

AVAILABILITY

Available throughout Company's entire electric service area to any Customer with certified capacity of 100 kW or less generating through the use of renewable energy resources.

PRICE

For all energy billed which is supplied by the Customer to the Company, the price shall be the Company's Market Generation Credit (MGC) as specified in Schedule MGC-1.

CONDITIONS OF PURCHASE

1) The Customer shall be responsible for all interconnection costs unless otherwise indicated by the Company. In addition, Customer shall conform to all applicable interconnection requirements as mandated either by government or by the Company.

2) The Customer shall operate its electric generating equipment in accordance with Company rules, regulations, and service requirements.

3) The Customer shall, at its option, operate in one of the following two system configurations:

   a) Parallel Mode – The Customer's self-generation facilities first supply its own electric requirements with any excess power being sold to the Company at the MGC. The Company shall sell power to the Customer as required by the Customer under the Company's applicable Pricing Plan.

   b) Simultaneous Buy/Sell Mode – The Customer's total generation output is sold directly to the Company and the Customer's total electric requirements are met by sales from the Company. Billing for purchases and sales shall be calculated, at the Customer's option, in either of three methods:

      i) Net bill method: The kWh sold to the Company shall be subtracted from the kWh purchased from Company. If the kWh calculation is net positive, the Company will sell the net kWh to the Customer under the applicable Pricing Plan. If the kWh calculation is net negative, the Company will purchase the net kWh from the Customer at the MGC. Time of use bi-directional metering is not available.

      ii) Separate bill method: All purchases and sales shall be treated separately with revenues from sales to the Customer calculated under the applicable Pricing Plan, and the purchase of power from the Customer at the MGC.

      iii) Net metering method: Applicable only where the Customer has a single solar to electricity or wind to electricity conversion system of AC electrical peak capability of 10 kW or less and meets all qualifications. The kWh sold to the Company shall be subtracted from the kWh purchased from the Company. If the kWh calculation is net positive, the Company will sell the net kWh to the Customer under the applicable Pricing Plan. If the kWh calculation is net negative, Company will carry the kWh forward and credit the net kWh of the next billing cycle. All negative kWh credits will be zeroed out anually after the January billing cycle.

<u>Separate Qualifications for Net Metering</u>

(a) Service under this method shall be limited to 500 kWp (p=peak) aggregate Customer per calendar year.
(b) Installed solar to electricity or wind to electricity conversion system shall meet IEEE-929 standard, local, and National Electrical Code requirements.
(c) Installation shall be complete six months from pre-installation approval; thereafter, Customer must re-apply.
(d) Time of use net metering is not available.

4) The applicable Pricing Plan shall apply for all energy billed which is supplied by the Company to the Customer.

5) The Company may require a written contract and a minimum term of contract.

6) This Pricing Plan is not applicable for Customers with certified renewable generating capacity of over 100 kW. However, for such capacity the Company shall enter into individual agreements.

7) The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this Pricing Plan.

<u>RELATED SCHEDULES</u>

- Schedule MGC-1– Market Generation Credit (MGC) Calculation
- Tucson Electric Power Company – Rules and Regulations

4

Schedule MGC-1
Tucson Electric Power Company
Market Generation Credit (MGC) Calculation

Tucson Electric Power

A UniSource Energy Company

Introduction

There are two purposes of the Market Generation Credit (MGC). The first purpose is to establish a price to which TEP's energy customers can compare to the prices of competitors. The second purpose is to enable the calculation of the variable or "floating" component of TEP's stranded cost recovery. Shown below are the terms of the MGC methodology per TEP's Settlement Agreement, Section 2.1(d), as amended MM DD, 2002:

> The monthly MGC amount shall be calculated in advance and stated as both an on-peak value and an off-peak value. The monthly on-peak MGC component shall be equal to the Market Price multiplied by one plus the appropriate line loss (including unaccounted for energy ("UFE")) amount. The Market Price shall be equal to the Platts Long-Term Forward Assessment for the Palo Verde Forward price, except when adjusted for the variable cost of TEP's must-run generation. The Market Price shall be determined thirty (30) days prior to each calendar month using the average of the most recent three (3) business days of Platts Long-Term Forward Assessment for Palo Verde settlement prices. The off-peak MGC component shall be determined in the same manner as the on-peak component, except that the Platts Long-Term Forward Assessment for the Palo Verde Forward price will be adjusted by the ratio of off-peak to on-peak hourly prices from the Dow Jones Palo Verde Index of the same month from the preceding year. The MGC shall be equal to the hours-weighted average of the on-peak and off-peak pricing components and shall reflect the cost of serving a one hundred percent (100%) load factor customer.

To reflect the cost of serving a 100% load factor customer, the actual MGC used for billing calculations will be a loss adjusted average price that is weighted by the ratio of on-peak and off-peak hours. This process is illustrated in equations 4 and 5 below and will be posted to TEP's website http://partners.tucsonelectric.com thirty (30) days prior to each calendar month. This composite price will be credited to all energy consumption, regardless of the time period in which it is consumed.

Calculations

Five steps are outlined below for the calculation of the MGC. None of the steps are excludable for any customer type. Acronyms are defined in the Glossary at the end of this document.

Schedule MGC-1
Tucson Electric Power Company
Market Generation Credit (MGC) Calculation

1. Calculating the on-peak MGC

For the calendar estimation month, the Platts Long-Term Forward Assessment for Palo Verde Forward prices for the 30th, 31st, and 32nd business days prior to the start of the new month are used. The simple average (or arithmetic mean) is calculated for these three (3) days for the estimation month (see Equation 1).

$$MGC_{ON,i} = \frac{\sum (PLATTS)_i}{3} \qquad \text{(Equation 1)}$$

The calculation is illustrated in the table below.

Forward Prices per MWh	Apr-2002
3/1/2002	$25.50
2/28/2002	$25.50
2/27/2002	$24.75
Average	$25.25

2. Calculating the off-peak MGC

The off-peak MGC is determined by multiplying the on-peak MGC value by the off-peak price weighting factor (WEIGHT). The WEIGHT is equal to the simple average of all off-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year, divided by the simple average of all on-peak prices from the Dow Jones Palo Verde Index in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$\mathrm{MGC_{OFF,i}} = \mathrm{MGC_{ON,i}} * \mathrm{WEIGHT_i} \qquad \text{(Equation 2)}$$

where

$$WEIGHT_i = \frac{DJPVI_{OFF,i}}{DJPVI_{ON,i}} \qquad \text{(Equation 3)}$$

3. Weighting the MGC for hours in the month

The on-peak and off-peak MGCs are combined to form an average MGC by computing a weighted average of the two time periods. This is done by multiplying the on-peak MGC by the percentage of on-peak hours in the same month of the previous year and then adding the product of the off-peak MGC and the percentage of off-peak hours in the same month of the previous year. Off-peak, on-peak and holiday hours are defined by NERC in the estimation month.

$$MGC_{WEIGHT,i} = MGC_{ON,i} * \left(\frac{ONHOURS}{ONHOURS + OFFHOURS} \right) + MGC_{OFF,i} * \left(\frac{OFFHOURS}{ONHOURS + OFFHOURS} \right)$$

(Equation 4)

4. Loss-adjusting the MGC

The average MGC must be adjusted for line losses. The appropriate line loss adjustment factor (LLAF) for a large industrial customer is 1.0515. For all other customers, the appropriate factor is 1.0919.

$$MGC_{LOSS,i} = MGC_{WEIGHT,i} * LLAF$$ (Equation 5)

5. Adjusting the MGC for variable must-run

The MGC will be adjusted for variable must-run as defined in TEP's Stranded Cost Settlement Agreement and AISA protocols. Fifteen (15) days prior to each month, TEP forecasts a ratio of its variable must-run generation to retail system demand for the following month. The MGC is determined by adding the product of MGC_{LOSS} and one minus the ratio of variable must-run generation to total retail system demand to the product of \$15/MWh and the variable must-run ratio.

$$MGC_i = \left[MGC_{LOSS,i} * (1 - VMR_i)\right] + (\$15 * VMR_i)$$ (Equation 6)

This calculation produces the final value for the Market Generation Credit.

GLOSSARY

$DJPVI_{OFF}$	Simple average of off-peak prices on the Dow Jones Palo Verde Index.
$DJPVI_{ON}$	Simple average of on-peak prices on the Dow Jones Palo Verde Index.
Dow Jones Palo Verde Index	Daily calculation of actual firm on-peak and firm off-peak weighted average prices for electricity traded at Palo Verde, Arizona switchyard.
AISA	Arizona Independent Scheduling Administrator, a temporary entity, independent of transmission-owning organizations, intended to facilitate nondiscriminatory retail direct access using the transmission system in Arizona. Required by the Arizona Corporation Commission Retail Electric Competition Rules.
LLAF	Line-loss adjustment factor.
MGC	Market Generation Credit.
MGC_{OFF}	MGC_{ON} weighted by the ratio of off-peak to on-peak hourly prices on the Dow Jones Palo Verde Index.
MGC_{ON}	Average of the Platts prices on days appropriate for the calculation of the MGC.
MGC_{LOSS}	MGC_{WEIGHT} adjusted for line losses (including unaccounted for energy) on TEP's generation and energy delivery systems.
MGC_{WEIGHT}	A weighted average of MGC_{ON} and MGC_{OFF} by ONHOURS and OFFHOURS.
Must-run Generation	The cost associated with the running of local generating units needed to maintain distribution system reliability and to meet load requirements in times of congestion on certain portions of the interconnected grid.
NERC	North American Electric Reliability Council. A voluntary not-for-profit organization established to promote bulk electric system reliability and security. Membership includes: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers.

Schedule MGC-1
Tucson Electric Power Company
Market Generation Credit (MGC) Calculation

A UniSource Energy Company

OFFHOURS	Number of total monthly off-peak hours as defined by NERC. Off-peak hours are hour ending 0100 – hour ending 0600 and hour ending 2300 – hour ending 2400, Monday through Saturday, Pacific Prevailing Time (PPT). All Sunday hours are considered off-peak. PPT is defined as the current clock time in the Pacific time zone.
ONHOURS	Number of total monthly on-peak hours as defined by NERC. On-peak hours are hour ending 0700 – hour ending 2200 Monday through Saturday, Pacific Prevailing Time (PPT). PPT is defined as the current clock time in the Pacific time zone.
PLATTS	A McGraw-Hill publication that provides an independent daily evaluation of on-peak Long Term Forward Assessment of market prices of electricity at the Palo Verde, Arizona switchyard. The forward product is "6 x 16," power is for 16 hours a day for six days a week (Monday through Saturday) for the delivery period, excluding NERC holidays.
Stranded Costs	The difference between revenues under competition and the costs of providing service, including the inherited fixed costs from the previous regulated market.
TEP	Tucson Electric Power Company, a subsidiary of UniSource Energy Corp.
TEP Settlement Agreement	An agreement between TEP, the Arizona Residential Utility Consumer Office, members of the Arizonans for Electric Choice and Competition, and Arizona Community Action Association regarding TEP's implementation of retail electric competition, implementation of unbundled tariffs, and recovery of stranded costs.
VMR	Ratio of variable must-run generation (MW) to total retail system demand (MW) in TEP's service territory.
WEIGHT	Ratio of off-peak to on-peak hourly prices on the Dow Jones Palo Verde Index.

EXHIBIT
TEP-2
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION RECEIVED

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AZ CORP COMMISSION
DOCUMENT CONTROL

WILLIAM A. MUNDELL
CHAIRMAN
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COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF NEW PARTIAL REQUIREMENTS SERVICE TARIFFS; MODIFICATION OF EXISTING PARTIAL REQUIREMENTS SERVICE TARIFF 101; AND ELIMINATION OF QUALIFYING FACILITY TARIFFS.	Docket No. E-01933A-02-0345 **NOTICE OF FILING REVISED PAGE OF DIRECT TESTIMONY OF LELAND R. SNOOK**

Tucson Electric Power Company, through its undersigned counsel, hereby files a revised page 13 (a copy of which is attached) to the Direct Testimony of Leland R. Snook that was originally filed on August 30, 2002. The revisions to page 13 are underlined.

DATED: October 9, 2002.

ROSHKA HEYMAN & DEWULF, PLC

By ______________________

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Q. Why is TEP proposing to make changes to existing PRS-101?

A. In general terms, existing PRS-101 is offered to any QF with certified capacity of 100kW or less which generates other than firm power. TEP is requesting that PRS-101 be modified so that it will be exclusively available to any DG with certified capacity of 100kW or less generating through the use of renewable energy resources. TEP currently has thirty (30) DGs participating under PRS-101. The proposed changes to PRS-101 will affect only nineteen (19) of those DGs.

TEP is proposing to make two changes to existing the PRS-101 tariff. First, while the existing PRS-101 tariff is applicable to renewable generators and co-generators, TEP is proposing PRS-101 only apply to renewable generators. Second, the price at which TEP will buy back power from a renewable customer is proposed to change from a fixed price to a market price.

Q. Why does TEP believe it is necessary to revise existing tariff PRS-101 at this time?

A. TEP does not believe it should be required to purchase excess energy from a customer with a self-generation unit in a competitive wholesale generation market. Rather, TEP believes that in a competitive wholesale generation market, market based pricing is appropriate. Although TEP will continue to evaluate the appropriateness of purchasing excess generation from customers with self-generation on a case-by-case basis, this modification to existing tariff PRS-101 will continue to be an incentive for those customers who generate electricity through the use of renewable energy resources.

<u>Q. How will the revised Tariff PRS-101 affect TEP's purchases from Qualifying Facilities (QFs) under Public Utilities Regulatory Policy Act (PURPA)?</u>

<u>A. As to QFs, it is TEP's corporate policy to honor all of its obligations to such actual or prospective customers as those obligations may exist from time to time under the provisions of PURPA, and any regulations or decisions of the Federal Energy Regulatory Commission and this Commission implementing the same.</u>

EXHIBIT TEP-3 TEP-3 Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
CHAIRMAN
JIM IRVIN
COMMISSIONER
MARC SPITZER
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF NEW PARTIAL REQUIREMENTS SERVICE TARIFFS, MODIFICATION OF EXISTING PARTIAL REQUIREMENTS SERVICE TARIFF 101, AND ELIMINATION OF QUALIFYING FACILITY TARIFFS.	DOCKET NO. E-01933A-02-0345
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471

REBUTTAL TESTIMONY OF LELAND R. SNOOK

On Behalf of
TUCSON ELECTRIC POWER COMPANY

OCTOBER 11, 2002

INDEX TO TESTIMONY

LELAND R. SNOOK

INTRODUCTION

Q. Please state your name and business address.

A. My name is Leland R. Snook. My business address is 4350 E. Irvington Road, Tucson, Arizona 84714.

Q. Did you file direct testimony in this proceeding?

A. Yes, I did.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the testimony filed by Commission Staff and intervenors in this proceeding. In particular, I will address portions of the Direct Testimony of Ms. Barbara Keene on behalf of Commission Staff, the Direct Testimony of Mr. Peter Chamberlain on behalf of the Arizona Cogeneration Association, and the Direct Testimony Mr. Dan Neidlinger on behalf of the Department of Defense.

Q. Mr. Snook, is it TEP's intention to impose a burden on distributed generation, cogeneration or QF customers, by revising its PRS and QF tariffs?

A. No, not at all. TEP believes that contrary to being a burden, the revised tariffs will be a benefit to those customers. The new PRS tariffs and the modified PRS-101 are designed to be an improvement of the QF tariffs and to better match the changing electric utlity industry. The new PRS tariffs are broader in scope and are designed to recover only those costs actually incurred by TEP to provide partial requirements service. I think that my position is fully supported by the fact that the Commission authorized the Distributed

Generation and Interconnections Investigation (ACC Docket No. E-00000A-99-0431) to look into the viability of existing tariffs to meet the needs of the evolving distributed generation segment of the electric industry. As I will detail later, I did not read anything in the testimony of Commission Staff or the intervenors that justified staying with the outdated PRS and QF tariffs, nor did I see anything that supported rejecting the proposed tariffs.

Q. Mr. Snook, will the proposed tariffs violate any state or federal laws?

A. No, they will not. If TEP believed that any of the proposed tariffs were contrary to state or federal law, or any rule or regulation of the Federal Energy Regulatory Commission ("FERC") or this Commission, it would not have filed the Application. I would add that if the Commission determines that its decisions or rules and regulations must be changed in order to implement any portion of the Application, TEP will work with the Commission to bring about such changes.

COMMISSION STAFF

Q. Please summarize Commission Staff's position regarding the Application.

A. Let me start by saying that TEP and Commission Staff have worked together over the years to develop sound policy regarding the integration of PRS, QF and DG into the TEP system. TEP and Commission Staff have participated in the DGI Working Group, whose recommendations are in line with the proposals in the Application.

I was surprised, however, that Commission Staff's position now is that TEP should be required to keep its existing PRS and QF tariffs. It seems that Commission Staff is now taking a position that is contrary to the recommendations of the DGI Working Group. Let me point to the key findings by the DGI Working Group to illustrate my point. Section 1.4 of the DGI Working Group Final Report dated June 28, 2000 set forth some key findings and recommendations. The first such recommendation listed included the following:

> Design fair and reasonable tariffs considering proper recovery of utility costs, backup power or partial-requirements tariffs, and PURPA Qualifying Facilities (QF) tariffs while providing consistent treatment of DG relative to other consumer services.

The Application is consistent with the intent of this recommendation. Also, in contrast to Commission Staff's position in this case, the DGI Working Group Final Report states:

> DG Providers suggested that existing partial requirements tariffs were developed under the "bundled regime" of the past. These tariffs should be reviewed and revised, where appropriate, to ensure conformance with an "unbundled" world. Id. at 14.

In other words, even the DG Providers recognize that the existing tariffs were developed under a regime that may no longer meet their needs. In keeping with the spirit of the DGI Working Group's findings and recommendations, TEP filed the Application.

Q. Mr. Snook, Commission Staff witness Ms. Barbara Keene states in her testimony that Decision No. 56271 and Decision No. 52345 set forth the appropriate policies to address cogeneration and small power production today. Do you agree?

A. No, I do not agree and I do not believe that the DGI Working Group would agree. Ms. Keene references two decisions (Decision No. 52345 and Decision No. 56271) issued in the 1980s for rates and policies related to cogeneration and small power production facilities. However, even Decision No. 56271 recognized that these issues were evolving and would need to be updated:

> During the last few years, several issues have evolved which were not explicitly addressed in the Commission's 1981 policy statement.

The evolution did not stop in 1988. Since the issuance of Decision No. 56271 other issues and circumstances have come about such that the policy set forth in those Decisions is obsolete on many issues. Some of the significant changes that have occurred since 1988 include (a) changes in transmission pricing and access policies due to the implementation of FERC Orders 888 and 889; (b) the advent of Retail Access Programs; (c) unbundling of rates; and (d) pending legislation to change existing PURPA requirements.

I believe that the Commission authorized the DGI Working Group in recognition of these changes as well as the possibility that other circumstances may require changes to be made in the policies of Decision No. 56271.

Q. Do the charges in the existing QF tariffs accurately reflect TEP's costs?

A. No. Supplemental service at the full-requirements terms and conditions does not recover TEP's costs. The backup/standby service does not accurately reflect the cost recovery of TEP's facilities. For example, for the first year of backup service under PRS-106 a QF customer will be billed $2.20 per kW-month for all facilities including distribution, transmission, and generation. However, TEP's transmission and ancillary service costs total $3.886 per kW-month, without considering recovery of distribution and generation cost.

Under the scenario when a customer's DG unit does not experience forced outages or does not operate for purely economic reasons, the customer would be not be charged for service under PRS-106. In these situations, the appropriate costs of TEP's transmission and distribution facilities would not be recovered. Under an opposite scenario, a customer's DG unit would not operate but the customer would be billed $22 per kW-month. The $22 per kW-month represents only TEP's embedded transmission and generation costs, without considering TEP's cost of distribution facilities.

For these reasons TEP believes that the customer who chooses to put in DG units should pay for the distribution and transmission facilities on the same basis as other customers (based on customer class characteristics). This would be accomplished through TEP's new PRS tariffs. Generation does not have to be reserved by the DG customer since it is a cost to the customer only when it requires generation. Again this is accomplished through TEP's new PRS tariffs by the market generation price. To sum this up, TEP's new PRS tariffs better match expenses with costs than TEP's existing QF tariffs.

Q. Are there additional concerns with the existing QF tariffs?

A. Yes. TEP's existing QF tariffs provide DG customers with an opportunity to take fixed price energy in inappropriate circumstances. For example, when the costs of operating the customer's DG unit exceed the fixed tariff price, the customer may reduce output, schedule maintenance or shut down operation of the DG unit and exercise the purchase power option available in the QF tariff. With the volatility that has been experienced in the market in the recent past, there is the potential that TEP could incur purchase power costs that exceed TEP's fixed tariff prices.

Q. Mr. Snook, did Staff present any evidence of how TEP's proposed tariffs would harm customers?

A. No, Staff did not. Ms. Keene's testimony only raised hypothetical concerns about what might occur without stating that negative results would, in fact, occur. Let me give you a few examples:

At page 7, lines 15-18 of her Direct Testimony, Ms. Keene says, with regard to elimination of PRS-103:

> Although no customers are currently being served under PRS-103, customers **may** be planning facilities while relying on the fact that PRS-103 is available.

At page 8, lines 23-25 of her Direct Testimony, Ms. Keene says, with regard to elimination of PRS –103,104, 105 and 106:

> Even though only one customer is currently being served on these tariffs, **there may be other customers** planning facilities while relying on the fact that these tariffs are available.

At page 9, lines 22-24 of her Direct Testimony, Ms. Keene says, with regard to elimination of PRS-107 and 108:

> Even though no customers are currently being served on these tariffs, **there may be other customers** planning facilities while relying on the fact that these tariffs are available.

But, there is no evidence that any customers are planning facilities in reliance on PRS-203, 104, 105, 106, 107 or 108. Moreover, TEP notified all customers of TEP's PRS tariff application through a direct mailing starting on the billing cycle July 10, 2002. Customers relying on the QF tariffs have had the opportunity to intervene in this process. It is also TEP's experience that customers make contact with TEP in the planning stages of a project to develop pricing and interconnection policies and procedures.

Q. Commission Staff that TEP retain the PRS-102 tariff. Do you agree with this recommendation?

A. As stated in my direct testimony, TEP believes that PRS-102 customers cannot feasibly provide firm power to TEP from a single generation unit. However, TEP would be willing to offer PRS-102 modified to reflect the changes that have been proposed (and agreed to by Staff) for PRS-101.

Q. Commission Staff recommends PRS-103 stay in place because residential QFs will not have a tariff to provide service. Do you agree with this recommendation?

A. No. Residential customers with renewable applications take service under PRS-101 not PRS-103. Currently TEP provides service for 30 renewable customers under PRS-101 and the applicable full-requirements residential pricing plan is used for all energy billed which is supplied by TEP to the customer.

Q. Are the tariff proposals in the Application similar to partial requirement tariffs of any other Arizona utility?

A. Yes, the proposals are consistent with APS' existing tariffs. In Decision No. 59759 the Commission approved APS' PRS tariffs and at the same time "froze" APS' QF tariffs for customers with loads over 100 kW. And, in 2001, APS received approval (outside of a rate case) for its E-36 tariff (Station Use Service), which has a pricing structure similar to TEP's new PRS tariffs.

Q. Ms. Keene states at page 8 of her testimony, with reference to TEP's QF tariffs, "If the rates on these tariffs are no longer reflective of TEP's costs to provide such services, TEP should include revised rates in its next general rate case filing." Do you agree with Ms. Keene's assessment?

A. No, I do not for two reasons. First, all of the tariffs that TEP is seeking to "freeze" (PRS-103, PRS-104, PRS-105, PRS-106, PRS-107, and PRS-108) were designed and became effective "outside" of a general rate case and, therefore, were not included in TEP's cost of service at that time. Second, TEP's succeeding rate cases did not include these rates in the class cost of service studies because no customers were on those tariffs.

Q. Do you agree with Ms. Keene's testimony that PRS-107 and PRS-108 should remain in effect?

A. No. The existence of PRS-107, PRS-108, and PRS-14 complicate the process by having multiple tariffs available. PRS-14 was designed to replace PRS-107 and PRS-108. TEP believes that all similarly situated customers should have consistent terms, pricing and conditions. Under PRS-107 and PRS-108, however, customers are not able to receive supplemental service. PRS-14 is broader in scope and provides maintenance, supplemental and backup service for generators greater than 3 MW.

Q. Do you agree with Ms. Keene's suggestion at pages 10-11 of her testimony that "Supplemental Service" should be priced at no more than the otherwise applicable tariff?

A. No, I do not. The reality is that customers who receive supplemental service do so at a reduced load factor compared to full-requirements customers. These PRS Supplemental Service customers actually increase TEP's cost of service without any corresponding compensation, because TEP's full requirements tariffs were developed with full-requirement customer benefits.

Q. Does TEP agree with Ms. Keene's proposed modifications to MGC-1 and MGC-2?

A. Yes, TEP does agree with Ms. Keene on these points and, subject to Commission approval, will incorporate her proposed modifications.

THE ASSOCIATION

Q. At page 3 of Mr. Chamberlain's testimony, he suggests that TEP proposes to eliminate PRS- 105 and 106 based on " a generator's own heat rate is inextricably linked to the cost of providing backup and supplemental service to that generator." Do you agree with Mr. Chamberlain's characterization of TEP's basis for eliminating those tariffs?

A. No, I do not. First, PRS-105 and 106 relate to maintenance and backup service, not supplemental service. Second, I make no reference to a generator's heat rate in my testimony and, in fact, it was not considered in the development of the rates for maintenance and backup service. In reality, the backup rates in PRS-106 are not based on the fixed transmission and distribution costs of TEP's system, rather they are based on the forced outage rate of a DG unit.

Q. Mr. Chamberlain states at page 3 of his testimony that small renewable solar and wind generators would be adversely impacted by the elimination of existing PRS tariffs. Do you agree?

A. No, I do not agree. Our experience is that solar and wind generators in the Tucson area are of a size of 100 kW or less. Existing small renewable generators and future generators of this type would operate under our proposed modified PRS-101 tariff. Under PRS-101, the applicable full-requirements pricing plan is used for all energy that is billed which is supplied by TEP to the customer.

Q. Mr. Chamberlain also contends at page 4 of his testimony that the proposed tariffs are not based on cost of service principles and that assumptions used in the derivation of the rates are inconsistent. What is your response to that claim?

A. As I stated in my direct testimony, TEP's PRS rates are designed to recover the costs of providing PRS by reallocating the fixed and variable costs of full requirements service. Since a PRS customer takes less energy from TEP than its full requirements counterpart, the PRS tariffs are designed accordingly. TEP was consistent in assuming a ten percent (10%) load factor in PRS-10, PRS-13, and PRS-14.

Q. Mr. Chamberlain believes that TEP's rates allocate more Transmission and Distribution costs to back up customers than it does to full requirements customers. Do you agree?

A. No. I believe that the rates allocate an equitable share of the Transmission and Distribution costs to PRS customers. TEP must provide adequate transmission and distribution capacity whether a customer has a ten percent (10%) or a one hundred percent (100%) load factor.

Q. Mr. Chamberlain contends that it is not necessary for TEP to reserve, and thus not charge, a backup customer for a constant firm transmission reservation all of the time. Do you agree?

A. No. In order to provide the services described in our tariffs, it is necessary for TEP to reserve firm transmission all of the time. Mr. Chamberlain correctly understands that TEP's OATT provides for the purchase of firm transmission for a period of less than all 8,760 hours of a calendar year. However, a utility will purchase weekly or daily firm transmission with an expectation of scheduling power during a stated period. In addition, the rates for weekly and daily service are higher than the rates for monthly service. In the case of a utility reserving transmission in order to provide backup service, there is no predetermination of when the power will be scheduled, only that upon an outage of the generator the customer expects to be able to call on the full level of backup power to maintain its load. Therefore, if TEP is obligated to provide firm backup service, it must reserve firm transmission during all hours. Without such reservation, there is no assurance that transmission would be available when the forced outage occurs.

Q. Mr. Chamberlain challenges the use of ratchets as applied in TEP's proposed PRS tariffs. What is your response?

A. I believe that 23-month ratchets are recognized as appropriate mechanisms to recover the costs of TEP facilities that must be in place, but are seldom used. In fact, the Commission recently approved contracts between TEP and DG customers, which contain similar ratchet provisions.

Q. At page 7 of Mr. Chamberlain's direct testimony he states, "back up customers woul pay over 22% more fixed and variable T & D costs than a full requirements customer". He then states., "Under TEP's proposed rates, a customer would pay over two times as much for supplemental service (at a 65% load factor) as the same load would pay under the direct access rate for a full requirements customer." What is Mr. Chamberlain's basis for these statements?

A. I do not know and I certainly do not agree with his statements. TEP sent Mr. Chamberlain a data request seeking support for his statements. We have not yet received his response. Accordingly, I would like to reserve my right to supplement my rebuttal testimony after I have reviewed Mr. Chamberlain's response.

DEPARTMENT OF DEFENSE

Q. Mr. Neidlinger states several times throughout his testimony that the cost information used to develop the PRS rates is outdated. How do you respond?

A. I am not sure what Mr. Neidlinger is referring to. The cost information that TEP used to develope the proposed PRS rates is consistent with the types of data used to develop TEP's other rates and tariffs. I believe that the rates that TEP is proposing are supported by relevant data and information.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT
DOD-1
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

TUCSON ELECTRIC POWER COMPANY

Docket Nos. E-01933A-02-0345 & E-01933A-98-0471

DIRECT TESTIMONY OF DAN L. NEIDLINGER

ON BEHALF OF

THE DEPARTMENT OF DEFENSE

SEPTEMBER 27, 2002

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BEFORE THE ARIZONA CORPORATION COMMISSION
TUCSON ELECTRIC POWER COMPANY
Docket Nos. E-01933A-02-0345 & E-01933A-98-0471

<u>Direct Testimony of Dan L. Neidlinger</u>

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, ADDRESS AND OCCUPATION.

A. My name is Dan L. Neidlinger. My business address is 3020 North 17th Drive, Phoenix, Arizona. I am President of Neidlinger & Associates, Ltd., a consulting firm specializing in utility rate economics.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS AND EXPERIENCE.

A. A summary of my professional qualifications and experience is included in the attached Statement of Qualifications. In addition to the Arizona Corporation Commission ("ACC or the "Commission"), I have presented expert testimony before regulatory commissions and agencies in Alaska, California, Colorado, Guam, Idaho, New Mexico, Nevada, Texas, Utah, Wyoming and the Province of Alberta, Canada.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the United States Department of Defense ("DOD"). Two major DOD installations, Fort Huachuca located near Sierra Vista, Arizona and Davis-Monthan AFB located in Tucson, are served by Tucson Electric Power Company ("TEP"or "Company") under its Large Light & Power rate, Rate Schedule 14.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to comment, in general, on TEP's proposed partial requirements service ("PRS") tariffs and recommend certain changes to the Company's pricing proposals for partial requirements customers. My testimony does not address TEP's proposed modification to the calculation of the Market Generation Credit ("MGC") under Docket No. E-01933A-98-0471.

II. TEP'S JUSTIFICATION FOR NEW PRS TARIFFS

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF MR. LELAND R. SNOOK, MANAGER OF CUSTOMER AND REGULATORY SERVICES FOR TEP?

A. Yes. Mr. Snook discusses the Company's rationale for filing new PRS tariffs at this time. He states many distributed generation ("DG") customers do not qualify for service under TEP's QF tariffs under PURPA and that the Company's full requirements tariffs are not designed to accommodate service to partial requirements customers.

Q. WHAT'S WRONG WITH PROVIDING SERVICE TO DG CUSTOMERS UNDER THE COMPANY'S CURRENT BUNDLED RATE SCHEDULES?

A. Mr. Snook states that the terms and conditions of TEP's full service requirement tariffs do not provide for PRS. He then states, starting on line 26, page 4 of his direct testimony, that providing service to DG customers under current rate schedules "would create an economic mismatch of costs and revenues that would result in a revenue shortfall". He continues on line 3, page 5, "If only the underlying assumptions for full customer utilization are changed, the cost to TEP of providing the transmission and distribution service will be the same, but there will be less customer usage from which TEP can recover the cost of service."

Q. DO YOU AGREE?

A. I do agree with the general proposition that full requirements tariffs are probably not appropriate for service to PRS customers. However, the economic mismatches that Mr. Snook discusses are largely the result of years of faulty ratemaking at TEP. PRS customers taking service under full requirements tariffs are merely taking advantage of inherent flaws in TEP's rates.

Q. PLEASE EXPLAIN.

A. TEP's current rates are the product of the incorrect costing and pricing methods used in past rate proceedings. As a result, the Company's commercial and industrial customers have been required to pay rates that exceed the cost to serve them. Price signals to these customers have been further blurred by improper rate designs; excessive amounts of demand costs are included in the energy component of TEP's commercial and industrial rates. Accordingly, customers with lower-than-average load factors, such as PRS customers, tend to under-recover demand related costs. Now, TEP is seeking to correct these rate design errors as related to PRS service.

Q. WHAT IS THE MAGNITUDE OF THE "WINDFALL" CURRENTLY REALIZED BY TEP'S PRS CUSTOMERS?

A. I don't know. The magnitude of the alleged windfall, in terms of dollars currently under-recovered, was not quantified by Mr. Snook. An estimate by TEP of current and future revenue shortfalls attributable to partial requirements customers would be helpful to the Commission in deciding this matter.

III. PROPOSED PRS TARIFFS

Q. HAVE YOU REVIEWED TEP'S PROPOSED PRS TARIFFS, PRS-10, PRS-13 AND PRS-14?

A. Yes. The Company is proposing three new rate schedules: PRS-10 for partial requirements service less than 200 kilowatts ("KW"), PRS-13 for partial requirements service from 200 KW to less than 3,000 KW and PRS-14 for partial requirements service of 3,000 KW and greater. In addition, the Company has proposed modifications to existing rate schedule PRS-101. The new PRS rate schedules include proposed customer, demand and energy charges for backup and/or standby service and separate demand and energy charges for supplemental service.

Q. HOW DOES THE COMPANY DETERMINE WHETHER A CUSTOMER SHOULD BE PLACED ON ONE OF THESE NEW TARIFFS?

A. The tariffs are silent on this issue. A definition of partial requirements is needed, expressed either as a percentage of maximum customer demand or, for larger customers, a defined level of self-generation capacity. Fort Huachuca, for instance, has a variety of experimental sources of energy generation that have been in operation for some time. These include a fuel cell and solar energy sources that provide an extremely tiny portion of the Fort's power requirements. Accordingly, the Fort should not, under any measure, be deemed a partial requirements customer.

Q. WHAT IS YOUR OVERALL REACTION TO THE PROPOSED PRS TARIFFS?

A. There are a number of problems, in my view, with the Company's proposals. First, the proposed rate design for the PRS tariffs is overly complicated with respect to small customers (less than 200 KW) and overly broad and economically unrealistic with respect to larger customers. Second, the proposed rates are based on load and cost information that is outdated. Finally, the method used to develop the rates does not accurately reflect, for certain cost components, the costs imposed by PRS customers on TEP's system.

Q. WHY IS THE PROPOSED TARIFF FOR SMALL CUSTOMERS, PRS-10, OVERLY COMPLICATED?

A. The proposed PRS-10 rate is comprised of customer, demand and seasonal energy charges for backup/standby service, demand and seasonal energy charges for supplemental service and a complicated market calculation for all generation-related charges. In addition, a variety of other calculations must be made (ratchets and PRUP) before a bill can be rendered. While appropriate for larger customers, these rate design elements represent "overkill" for the customers that would qualify for PRS-10 service. Full requirements customers in this class use, on average, only 3,880 kilowatt-hours ("KWH") per month. A simpler three-part rate, such as a seasonal time-of-use rate, is suggested as an alternative to PRS-10.

Q. WHAT ABOUT THE PROPOSED PRS-13 AND PRS-14 TARIFFS?

A. The scope of these tariffs, in my view, is too broad. These two rate schedules, and their common provisions, do not properly reflect the cost to service PRS customers with widely varying demands (200 KW to 20,000 KW), load profiles and self-generation configurations. I suggest that partial requirements rates, with relevant terms and conditions, be developed on a case-by-case basis for these larger customers. This will ensure that the self-generation projects that are built by these customers are mutually beneficial to both the customer and the Company.

Q. HOW WERE THE PRS TARIFFS DEVELOPED?

A. The rates were developed using the Company's GS Rates 10, 13 and 14, bundled and unbundled. Average customer load factors for full requirements customers were used to calculate average unbundled costs, expressed as a percentage of the total average bundled rate. To develop the PRS rates, the unbundled component costs were increased, proportionately, based upon a bundled rate calculation assuming an average load factor of 10% for PRS customers. As a final step, 80% of energy costs were allocated to customer and demand costs (in contrast to the Company's traditional cost of service practice of allocating approximately 50% of demand costs based on energy).

Q. DO YOU HAVE ANY CONCERNS WITH RESPECT TO THIS RATE DESIGN PROCESS?

A. There are two. First, the information used to develop the rates is woefully outdated. The bundled and unbundled rates are based upon a 1996 cost of service study and the rate class load factor data is based upon load research from 1994. Accordingly, the Company's proposed rates should be revised based on updated cost of service and load research information. Second, the unbundled transmission demand costs used to calculate PRS rates are based on demand allocators (12CP and 4CP) for customer classes with load factors that are much greater than the assumed 10% load factor for PRS customers. Average load factors used in the Company's calculations for the GS-10, GS-13 and LLP-14 full requirements customers were 48%, 58% and 83%, respectively. A 10% load factor class of customers would exhibit much lower coincident demand factors and, accordingly, lower allocated transmission costs.

Q. WHY UPDATE COST OF SERVICE FOR ONE TARIFF – PRS-10?

A. Updated costing, in the manner I have discussed, is needed not only to revise PRS-10 rates but also to provide better information for setting partial requirements rates for larger customers on a case-by-case basis

IV. SUMMARY CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS WITH REGARD TO TEP'S PROPOSED PRS TARIFFS.

A. My conclusions and recommendations are as follows:

1. The need for TEP to file partial requirements tariffs at this time is largely due to flawed costing and pricing practices for its commercial and industrial customers;
2. The proposed PRS-10 rate schedule for small commercial customers should be simplified;
3. The proposed PRS-13 and 14 rate schedules should be discarded. Partial requirements service for customers with demands greater than 200 KW should be negotiated on a case-by-case basis; and
4. PRS rates should be revised based on updated cost of service and load research data; the updated cost of service analysis should reflect lower coincident transmission demand factors for partial requirements customers.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

DAN L. NEIDLINGER

SUMMARY STATEMENT OF QUALIFICATIONS

I. General:

Mr. Neidlinger is President of Neidlinger & Associates, Ltd., a Phoenix consulting firm specializing in utility rate economics and financial management. During his consulting career, he has managed and performed numerous assignments related to utility ratemaking and energy management.

II. Education:

Mr. Neidlinger was graduated from Purdue University with a Bachelor of Science degree in Electrical Engineering. He also holds a Master of Science degree in Industrial Management from Purdue's Krannert Graduate School of Management. He is a licensed Certified Public Accountant in Arizona and Ohio.

III. Consulting Experience:

Mr. Neidlinger has presented expert testimony on financial, accounting, cost of service and rate design issues in regulatory proceedings throughout the western United States involving companies from every segment of the utility industry. Testimony presented to these regulatory bodies has been on behalf of commission staffs, applicant utilities, industrial intervenors and consumer agencies. He has also testified in a number of civil litigation matters involving utility ratemaking and once served as a Special Master to a Nevada court in a lawsuit involving a Nevada public utility.

Mr. Neidlinger has performed feasibility studies related to energy management including cogeneration, self-generation, peak shaving and load-shifting analyses for clients with large electric loads. In addition, he has conducted electric and gas privatization studies for U.S. Army installations and assisted these and other consumer clients in contract negotiations with utility providers of electric, gas and wastewater service.

Mr. Neidlinger has extensive experience in the costing and pricing of utility services. During his consulting career, he has been responsible for the design and implementation of utility rates for over 30 electric, gas, water and wastewater utility clients ranging in size from 50 to 25,000 customers.

IV. Professional Affiliations:

Professional affiliations include the American Institute of Certified Public Accountants and the Association of Energy Engineers.

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing Direct Testimony of Dan L. Neidlinger on behalf of the United States Department of Defense was sent to the parties on the attached service list either by Federal Express or by first class mail, postage prepaid on September 26, 2002.

Dated at Arlington County, Virginia, this 26th day of September 2002.

Peter Q. Nyce, Jr.

PETER Q. NYCE, JR.

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EXHIBIT
S-1
Admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

WILLIAM A. MUNDELL
Chairman
JIM IRVIN
Commissioner
MARC SPITZER
Commissioner

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF NEW PARTIAL REQUIREMENTS SERVICE TARIFFS, MODIFICATION OF EXISTING PARTIAL REQUIREMENTS SERVICE TARIFF 101, AND ELIMINATION OF QUALIFYING FACILITY TARIFFS	DOCKET NO. E-01933A-02-0345
IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR APPROVAL OF ITS STRANDED COST RECOVERY	DOCKET NO. E-01933A-98-0471

DIRECT

TESTIMONY

OF

BARBARA KEENE

PUBLIC UTILITIES ANALYST

UTILITIES DIVISION

SEPTEMBER 27, 2002

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APPENDICES

INTRODUCTION

Q. Please state your name and business address.

A. My name is Barbara Keene. My business address is 1200 West Washington St., Phoenix, Arizona 85007.

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

A. I am employed by the Utilities Division of the Arizona Corporation Commission (Commission) as a Public Utilities Analyst. My duties include evaluation of electric utility special contracts, review of utility tariff filings, assessment of utility demand-side management programs, and analysis of electric utility production costs and marginal costs. A copy of my résumé is provided in Appendix 1.

Q. As part of your employment responsibilities, were you assigned to review matters contained in Docket No. E-01933A-02-0345?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present the Utilities Division Staff's ("Staff") response to Tucson Electric Power's ("TEP") proposals to eliminate, modify, or introduce tariffs. I will also present testimony regarding the proposed modification of TEP's Market Generation Credit.

BACKGROUND-COMMISSION IMPLEMENTATION OF PURPA

Q. Please describe PURPA.

A. The Public Utility Regulatory Policies Act (PURPA) was enacted on November 9, 1978, as one of five parts of the National Energy Act. Its purpose is to encourage cogeneration and small power production. The Federal Energy Regulatory Commission (FERC) was to promulgate rules to implement PURPA. FERC determined that a small power production or cogeneration facility which meets its ownership and technical requirements is a Qualifying Facility (QF).

Q. Please further describe a QF.

A. A QF is either (a) a small power production facility, no greater than 80 MW, that uses biomass, waste, or renewable resources as fuel; or (b) a cogeneration facility that produces both electric energy and steam or heat which is used for industrial, commercial, heating, or cooling purposes. In addition to other requirements, the facility must be owned by a person not primarily engaged in the generation or sale of electric power.

Q. What does PURPA require in regard to utilities buying excess energy from QFs?

A. At times, a QF can produce more electricity than is needed by the operating facility. PURPA requires utilities to purchase this excess electric energy from QFs. PURPA also requires the rates for purchases by electric utilities to (a) be just and reasonable to the electric consumers of the electric utility and in the public interest, (b) not discriminate against qualifying cogenerators or qualifying small power producers, and (c) not exceed the incremental cost to the electric utility of alternative electric energy. The term "incremental cost of alternative electric energy" is defined as "with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source." This incremental cost is also known as "avoided cost."

Q. What does PURPA require in regard to utilities supplying power to QFs?

A. PURPA requires utilities to sell power to QFs to supplement their electrical production and to supply power during scheduled and unscheduled outages at non-discriminatory rates that reflect the costs of supplying that power.

. . .

Q. How did the Commission implement PURPA in Arizona?

A. Sections 201 and 210 of PURPA required state regulatory authorities to implement FERC's rules. The final FERC rules for the implementation of the cogeneration law contained in PURPA became effective on March 20, 1980. On July 27, 1981 (Decision No. 52345), after a hearing, the Commission adopted a Cogeneration and Small Power Production Policy ("Policy"). This policy is intended to encourage the development of cogeneration and small power production, reduce the consumption of non-renewable energy resources, reduce the administrative and bureaucratic barriers to the advancement of cogeneration and small power production, and promote equity, efficiency, and conservation in the production and sale of electricity in Arizona. The Policy is applicable to all electric corporations under Commission jurisdiction.

Q. What does Arizona's Cogeneration and Small Power Production Policy address?

A. Among other provisions, the Policy addresses:

- *Standard rates and contracts for QFs of 100 kW or less.* Each utility was required to file for Commission approval standard rates, based on the utility's avoided costs, for the purchase of power from QFs 100 kW and under.
- *Rates and contracts for QFs over 100 kW.* All of these contracts must be submitted to the Commission for review and approval. No specific rate must be filed prior to the execution of the contract, but the rates would generally be based on the standard rates for QFs 100 kW and under.
- *Rates for supplementary, standby, and maintenance power.* Each utility was required to file rates for supplying this power to QFs. In determining these rates, the utility was not to assume that the QF's requirements for these services would occur simultaneously with the utility's system peak.

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Q. Have any changes been made to the Policy?

A. Yes. The Commission issued Decision No. 56271 on December 15, 1988. That decision required each utility to file tariffs for the provision of supplementary, standby, and maintenance power to QFs over 100 kW with the following guidelines:

- The tariffs were to include a single basic service charge for the three services. The charge would be set at the otherwise applicable rate, reflecting the average demand of the QF, with the standby and maintenance power demand being weighted by the proportion of time that such services are required.
- Supplementary power would be priced at the otherwise applicable retail rate. Any demand charge or minimum kW demand included in the rate would be determined only for supplementary power, without reference to the QF's other power requirements.
- Maintenance power would be priced at an energy charge per kWh equal to the actual incremental cost of providing such service plus an appropriate adder to contribute toward common costs.
- Tariffs for standby service would include an energy charge per kWh equal to the actual incremental cost of providing such service plus an appropriate adder to contribute toward common costs. Demand costs would be recovered through a fixed dollars per kW reservation charge, based on the probability that the QF would have a forced outage at the time of the utility's system peak.

PRICING PLAN PRS-101

Q. Please describe TEP's Pricing Plan PRS-101.

A. The title of Pricing Plan PRS-101 is "Non-Firm Power Purchase from Renewables, Cogeneration, and Small Power Production Service." PRS-101 contains fixed seasonal rates at which TEP would purchase *non-firm* energy from QFs with capacity of 100 kW or less.

Q. What has TEP proposed regarding PRS-101?

A. TEP has proposed changing the title of PRS-101 to "Power Purchase from Renewable Energy Resources." It would apply to customers with generating capacity of 100 kW or less that use renewable energy resources. It would no longer apply to QFs that are cogeneration facilities. The purchase rates would also change from fixed rates to market-based rates using TEP's Schedule MGC-1. In addition, TEP has added a provision that would require the customer to conform to all applicable interconnection requirements as mandated either by government or by TEP. TEP has also proposed that time-of-use bi-directional metering and time-of-use net metering would not be available. TEP further proposed changes to the "Net metering method" section. It would be expanded from being applicable only to solar facilities of 5 kW or less to solar or wind facilities of 10 kW or less. Time-of-use net metering would not be available. There are other minor word changes in TEP's proposal.

Q. What is Staff's recommendation regarding PRS-101?

A. Staff recommends that the applicability of PRS-101 not be changed to exclude cogeneration facilities. All of the other proposed changes are acceptable.

Q. Why is Staff recommending that the applicability of PRS-101 not be changed?

A. As described earlier, Decision No. 52345 required the utilities to file tariffs for purchases from QFs. In addition, Sec. 292.304(c)(1) of FERC's regulations regarding PURPA requires utilities to have in effect standard rates for purchases from QFs of 100 kW or less. Therefore, to remove cogeneration facilities from PRS-101 would be in violation of both FERC's regulations and the Commission's order.

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PRICING PLAN PRS-102

Q. Please describe TEP's Pricing Plan PRS-102.

A. The title of Pricing Plan PRS-102 is "Cogeneration and Small Power Production Service Firm Power Purchase from Qualifying Facilities (QF) with 100 kW or Less Capacity." PRS-102 contains fixed seasonal rates at which TEP would purchase *non-firm* energy from QFs with capacity of 100 kW or less.

Q. What has TEP proposed regarding PRS-102?

A. TEP has proposed to eliminate PRS-102.

Q. What is Staff's recommendation regarding PRS-102?

A. Staff recommends that PRS-102 not be eliminated. Standard rates for purchases from QFs of 100 kW or less must be in place for the same reasons that cogenerators should not be excluded from PRS-101. To eliminate standard purchase rates for QFs of 100 kW or less would be in violation of both FERC's regulations and the Commission's Decision No. 52345.

Decision No. 52345 requires purchase rates to be based on the utility's avoided costs. If the purchase rates on PRS-102 are no longer aligned with TEP's avoided costs, TEP could file an application with the Commission to revise the rates. Decision No. 52345 allows such adjustments to the purchase rates as often as quarterly to reflect variations in fuel and purchased power costs.

PRICING PLAN PRS-103

Q. Please describe TEP's Pricing Plan PRS-103.

A. The title of Pricing Plan PRS-103 is "Supplementary, Backup, Maintenance and Interruptible Service for Cogeneration and Small Power Production Qualifying Facilities (QF) under 100 kW." PRS-103 provides for billing for these services to be in accordance with the General Service Time-of-use Rate GS-76, except that the rate would be reduced by $0.01 per kWh for interruptible service.

Q. What has TEP proposed regarding PRS-103?

A. TEP has proposed to eliminate PRS-103. Non-residential QFs would be served under TEP's proposed Pricing Plan PRS-10 Partial Requirements Service Less Than 200 kW. There would be no tariff to provide partial requirements service for residential QFs.

Q. What is Staff's recommendation regarding PRS-103?

A. Staff recommends that PRS-103 not be eliminated at this time. Renewable energy applications under 100 kW are often located at residential customers. Also, the rates may be higher on the proposed PRS-10 than on the current PRS-103. Comparing the rates on GS-76 with PRS-10 is difficult because one tariff is time-of-use and the other tariff is not. However, the monthly service charge on GS-76 is $6.78, while the monthly charge on PRS-10 is $124.90. Although no customers are currently being served under PRS-103, customers may be planning facilities while relying on the fact that PRS-103 is available. If the rates on PRS-103 are no longer reflective of TEP's costs to provide such services, TEP should include revised rates in its next general rate case filing.

PRICING PLANS PRS-104, PRS-105, and PRS-106

Q. Please describe TEP's Pricing Plan PRS-104.

A. The title of Pricing Plan PRS-104 is "Optional Supplementary Service for Cogeneration and Small Power Production Qualifying Facilities (QF) over 100 kW." PRS-104 provides for billing for supplementary service to be in accordance with the General Service Time-of-use Rate GS-76, Large General Service Time-of-Use Rate GS-85A, or Large Light and Power Time-of-Use Rate LLP-90A. Supplementary service is for electricity purchased from TEP that is in addition to what the QF produces.

. . .

Q. Please describe TEP's Pricing Plan PRS-105.

A. The title of Pricing Plan PRS-105 is "Optional Maintenance Service for Cogeneration and Small Power Production Qualifying Facilities (QF) over 100 kW." PRS-105 contains a monthly service charge and a fixed energy charge for energy purchased from TEP when a QF is out service for scheduled maintenance.

Q. Please describe TEP's Pricing Plan PRS-106.

A. The title of Pricing Plan PRS-106 is "Optional Backup Service for Cogeneration and Small Power Production Qualifying Facilities (QF) over 100 kW." PRS-106 contains a monthly service charge except that customers also taking service on PRS-105 would only pay the service charge once. For energy purchased from TEP during an unscheduled outage of the QF, there is a fixed energy charge. There is also a reservation charge based on the facility's unscheduled outage rate.

Q. What has TEP proposed regarding PRS-104, PRS-105, and PRS-106?

A. TEP has proposed to eliminate these three tariffs. Partial requirements customers would be served under the proposed PRS-10, PRS-13, or PRS-14, depending on the customer's size.

Q. What is Staff's recommendation regarding PRS-104, PRS-105, and PRS-106?

A. Staff recommends that these tariffs not be eliminated at this time. These tariffs were designed in accordance with Decision No. 56271. The rates may be higher on the proposed tariffs than on the current tariffs. Even though only one customer is currently being served on these tariffs, there may be other customers planning facilities while relying on the fact that these tariffs are available. If the rates on these tariffs are no longer reflective of TEP's costs to provide such services, TEP should include revised rates in its next general rate case filing.

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PRICING PLANS PRS-107 and PRS-108

Q. Please describe TEP's Pricing Plan PRS-107.

A. The title of Pricing Plan PRS-107 is "Optional Backup Service for Self-Generation Facilities over 3 MW." Facilities do not have to be designated as QFs to qualify for service under this tariff. The rates to purchase electricity from TEP during an unscheduled outage of the facility consist of a reservation charge and a fixed energy charge.

Q. Please describe TEP's Pricing Plan PRS-108.

A. The title of Pricing Plan PRS-108 is "Optional Maintenance Energy Service for Self-Generation Facilities over 3 MW." Facilities do not have to be designated as QFs to qualify for service under this tariff. The rate to purchase energy from TEP during a scheduled outage of the facility consists of a fixed energy charge. The energy charge is lower if the customer also takes service under PRS-107.

Q. What has TEP proposed regarding PRS-107 and PRS-108?

A. TEP has proposed to eliminate both tariffs. Self-generation facilities over 3 MW would be served under the proposed PRS-14.

Q. What is Staff's recommendation regarding PRS-107 and PRS-108?

A. Staff recommends that these tariffs not be eliminated at this time. The rates may be higher on the proposed tariff than on the current tariffs. Even though no customers are currently being served on these tariffs, there may be customers planning facilities while relying on the fact that these tariffs are available. If no customers have requested service on these tariffs by the time of TEP's next general rate case, the tariffs could be considered for elimination if other applicable tariffs are available.

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PRICING PLAN PRS-10

Q. Please describe TEP's Pricing Plan PRS-10.

A. TEP has proposed the introduction of Pricing Plan PRS-10, titled "Partial Requirements Service Less Than 200 kW." The tariff would be available to any non-residential customer with an aggregate partial requirements load of less than 200 kW. The facility would not have to be a QF.

The rates on PRS-10 consist of fixed delivery charges and market-based generation charges using Schedule MGC-2 plus a 10 percent procurement charge. The delivery charges include a monthly customer charge of $124.90 for backup/standby service, a standby demand charge of $8.34 per kW, a backup energy charge of $0.032612 per kWh in the summer, a backup energy charge of $0.024602 per kWh in the winter, a supplemental demand charge of $4.17 per kW, a supplemental energy charge of $0.068778 per kWh in the summer, and a supplemental energy charge of $0.051885 per kWh in the winter. Backup/standby service is defined in the tariff as service during both planned and unplanned generator outages.

Q. What is Staff's recommendation regarding PRS-10?

A. Staff recommends that PRS-10 be approved with modifications. There is a need for a partial requirements tariff for customers under 200 kW that are not QFs. However, Staff is concerned that the rates on the tariff may be too high and thus discourage the development of these applications. Decision No. 52345 intended to encourage the development of cogeneration and small power production. Staff recommends that TEP revise the delivery rates downward by considering savings to TEP of having self-generation facilities in its service territory, such as reduced need for additional transmission capacity. In addition, Decision No. 56271 requires that supplementary power be priced at the otherwise applicable retail rate. The rates for supplementary power on PRS-10 are not equal to the otherwise applicable rates. The rates on PRS-10 for supplemental service should be adjusted so that a customer would not pay more on PRS-10 than on the otherwise applicable tariff.

PRICING PLAN PRS-13

Q. Please describe TEP's Pricing Plan PRS-13.

A. TEP has proposed the introduction of Pricing Plan PRS-13, titled "Partial Requirements Service From 200 kW to Less Than 3,000 kW." The tariff would be available to any non-residential customer with an aggregate partial requirements load from 200 kW to Less than 3,000 kW. The facility would not have to be a QF.

The rates on PRS-13 consist of fixed delivery charges and market-based generation charges using Schedule MGC-2 plus a 10 percent procurement charge. The delivery charges include a monthly customer charge of $1,675.88 for backup/standby service that includes 200 kW, a standby demand charge of $4.47 per kW for all additional kW, a backup energy charge of $0.010458 per kWh in the summer, a backup energy charge of $0.008557 per kWh in the winter, a supplemental demand charge of $1.97 per kW, a supplemental energy charge of $0.052290 per kWh in the summer, and a supplemental energy charge of $0.042783 per kWh in the winter. Backup/standby service is defined in the tariff as service during both planned and unplanned customer-owned generator outages.

Q. What is Staff's recommendation regarding PRS-13?

A. Staff recommends that PRS-13 be approved with modifications. There is a need for a partial requirements tariff for customers from 200 kW to Less Than 3,000 kW that are not QFs. However, Staff is concerned that the rates on the tariff may be too high and thus discourage the development of these applications. Decision No. 52345 intended to encourage the development of cogeneration and small power production. Staff recommends that TEP revise the delivery rates downward by considering savings to TEP of having self-generation facilities in its service territory, such as reduced need for additional transmission capacity. In addition, Decision No. 56271 requires that supplementary power be priced at the otherwise applicable retail rate. The rates on PRS-13 for supplemental service should be adjusted so that a customer would not pay more on PRS-13 than on the otherwise applicable tariff.

PRICING PLAN PRS-14

Q. Please describe TEP's Pricing Plan PRS-14.

A. TEP has proposed the introduction of Pricing Plan PRS-14, titled "Partial Requirements Service 3,000 kW and Greater." The tariff would be available to any non-residential customer with an aggregate partial requirements load of 3,000 kW and greater. The facility would not have to be a QF.

The rates on PRS-14 consist of fixed delivery charges and market-based generation charges using Schedule MGC-2 plus a 10 percent procurement charge. The delivery charges include a standby demand charge of $4.48 per kW, a backup energy charge of $0.004761 per kWh in the summer, a backup energy charge of $0.003896 per kWh in the winter, a supplemental demand charge of $2.00 per kW, a supplemental energy charge of $0.031743 per kWh in the summer, and a supplemental energy charge of $0.025972 per kWh in the winter. Backup/standby service is defined in the tariff as service during both planned and unplanned generator outages.

Q. What is Staff's recommendation regarding PRS-14?

A. Staff recommends that PRS-14 be approved with modifications. Staff is concerned that the rates on the tariff may be too high and thus discourage the development of these applications. Decision No. 52345 intended to encourage the development of cogeneration and small power production. Staff recommends that TEP revise the delivery rates downward by considering savings to TEP of having self-generation facilities in its service territory, such as reduced need for additional transmission capacity. In addition, Decision No. 56271 requires that supplementary power be priced at the otherwise applicable retail rate. The rates on PRS-14 for supplemental service should be adjusted so that a customer would not pay more on PRS-14 than on the otherwise applicable tariff.

SCHEDULE MGC-1

Q. Please describe TEP's Schedule MGC-1

A. Schedule MGC-1 is titled "Tucson Electric Power Company Market Generation Credit (MGC) Calculation." MGC-1 was established by the 1999 TEP Settlement Agreement (Decision No. 62103) to be used in the calculation of the variable component of TEP's stranded cost recovery.

Q. What has TEP proposed regarding MGC-1?

A. TEP has proposed the following changes to the MGC-1:

- Replace references to the "Palo Verde NYMEX futures price" with the "Platts Long-Term Forward Assessment for the Palo Verde Forward price."
- Replace references to the "California Power Exchange" with "Dow Jones Palo Verde Index."
- Change the determination of the market price from 45 days prior to each calendar quarter to 30 days prior to each calendar month.
- Remove the word "hourly" from the calculation of the off-peak MGC.
- Make other clarifying wording changes.

Q. What is Staff's recommendation regarding MGC-1?

A. Staff recommends that the proposed changes be made. The Palo Verde NYMEX futures price and the California Power Exchange no longer exist. The Platts and Dow Jones indices are the only ones currently available for this area. The word "hourly" should be removed because the Dow Jones Index provides daily figures instead of hourly. Although TEP removed the word "hourly" from some locations in the MGC-1, it appears that a few were missed. To be consistent, the word "hourly" should be removed from the 10th line of the second paragraph on page 1, from the definition for "MGC_{OFF}" on page 4, and from the definition of "WEIGHT" on page 5.

SCHEDULE MGC-2

Q. Please describe TEP's Schedule MGC-2.

A. The title of MGC-2 is "Market Generation Credit (MGC) Calculation For Partial Requirements Services." The purpose of the MGC-2 is to establish the generation price at which customers would purchase electricity for backup/standby and supplemental energy under TEP's proposed PRS-10, PRS-13, and PRS-14. The MGC-2 is based on the MGC-1 with the following differences:

- The determination of the market price is made 15 days prior to each calendar month instead of 30 days.
- The on-peak and off-peak MGCs are not combined to form an average MGC.
- The MGC is not adjusted for variable must-run.

Q. What is Staff's recommendation regarding MGC-2?

A. Staff recommends that MGC-2 be approved. Also, the word "hourly" should be removed from the 10th line of the second paragraph on page 1 and from the definition of "WEIGHT" on page 5.

Q. Does this conclude your testimony?

A. Yes.

RESUME

BARBARA KEENE

Education

B.S.	Political Science, Arizona State University (1976)
M.P.A.	Public Administration, Arizona State University (1982)
A.A.	Economics, Glendale Community College (1993)

Additional Training

Management Development Program - State of Arizona, 1986-1987
UPLAN Training - LCG Consulting, 1989, 1990, 1991
various seminars, workshops, and conferences on energy efficiency, rate design, computer skills, labor market information, training trainers, and Census products

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Public Utilities Analyst V (October 2001-present), Senior Economist (July 1990-October 2001), Economist II (December 1989-July 1990), Economist I (August 1989-December 1989). Conduct economic and policy analyses of public utilities. Coordinate working groups of stakeholders on various issues. Prepare Staff recommendations and present testimony on electric resource planning, rate design, special contracts, energy efficiency programs, and other matters. Responsible for maintaining and operating UPLAN, a computer model of electricity supply and production costs.

Arizona Department of Economic Security, Research Administration, Economic Analysis Unit: Labor Market Information Supervisor (September 1985-August 1989), Research and Statistical Analyst (September 1984-September 1985), Administrative Assistant (September 1983-September 1984). Supervised professional staff engaged in economic research and analysis. Responsible for occupational employment forecasts, wage surveys, economic development studies, and over 50 publications. Edited the monthly **Arizona Labor Market Information Newsletter**, which was distributed to about 4,000 companies and individuals.

Testimony

Resource Planning for Electric Utilities (Docket No. U-0000-90-088), Arizona Corporation Commission, 1990; testimony on production costs and system reliability.

Trico Electric Cooperative Rate Case (Docket No. U-1461-91-254), Arizona Corporation Commission, 1992; testimony on demand-side management and time-of-use and interruptible power rates.

Navopache Electric Cooperative Rate Case (Docket No. U-1787-91-280), Arizona Corporation Commission, 1992; testimony on demand-side management and economic development rates.

Arizona Electric Power Cooperative Rate Case (Docket No. U-1773-92-214), Arizona Corporation Commission, 1993; testimony on demand-side management, interruptible power, and rate design.

Tucson Electric Power Company Rate Case (Docket Nos. U-1933-93-006 and U-1933-93-066) Arizona Corporation Commission, 1993; testimony on demand-side management and a cogeneration agreement.

Resource Planning for Electric Utilities (Docket No. U-0000-93-052), Arizona Corporation Commission, 1993; testimony on production costs, system reliability, and demand-side management.

Duncan Valley Electric Cooperative Rate Case (Docket No. E-01703A-98-0431), Arizona Corporation Commission, 1999; testimony on demand-side management and renewable energy.

Tucson Electric Power Company vs. Cyprus Sierrita Corporation, Inc. (Docket No. E-0000I-99-0243), Arizona Corporation Commission, 1999; testimony on analysis of special contracts.

Arizona Public Service Company's Request for Variance (Docket No. E-01345A-01-0822), Arizona Corporation Commission, 2002; testimony on competitive bidding.

Generic Proceedings Concerning Electric Restructuring Issues (Docket No. E-00000A-02-0051), Arizona Corporation Commission, 2002; testimony on affiliate relationships and codes of conduct.

Publications

Author of the following articles published in the *Arizona Labor Market Information Newsletter*:

"1982 Mining Employees - Where are They Now?" - September 1984
"The Cost of Hiring" and "Arizona's Growing Industries" - January 1985
"Union Membership - Declining or Shifting?" - December 1985
"Growing Industries in Arizona" - April 1986
"Women's Work?" - July 1986
"1987 SIC Revision" - December 1986

"Growing and Declining Industries" - June 1987
"1986 DOT Supplement" and "Consumer Expenditure Survey" - July 1987
"The Consumer Price Index: Changing With the Times" - August 1987
"Average Annual Pay" - November 1987
"Annual Pay in Metropolitan Areas" - January 1988
"The Growing Temporary Help Industry" - February 1988
"Update on the Consumer Expenditure Survey" - April 1988
"Employee Leasing" - August 1988
"Metropolitan Counties Benefit from State's Growing Industries" - November 1988
"Arizona Network Gives Small Firms Helping Hand" - June 1989

Major contributor to the following books published by the Arizona Department of Economic Security:

Annual Planning Information - editions from 1984 to 1989
Hispanics in Transition - 1987

(with David Berry) "Contracting for Power," *Business Economics*, October 1995.

(with Robert Gray) "Customer Selection Issues," *NRRI Quarterly Bulletin*, Spring 1998.

Reports

(with Task Force) *Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees*. Arizona Corporation Commission, 1992.

Customer Repayment of Utility DSM Costs, Arizona Corporation Commission, 1995.

(with Working Group) *Report of the Participants in Workshops on Customer Selection Issues*," Arizona Corporation Commission, 1997.

TEP Proposals

TEP's Proposed Action	Title of Tariff/Schedule	Comments
Modify PRS-101	*current*: Non-Firm Power Purchase from Renewables, Cogeneration, and Small Power Production Service *proposed*: Power Purchase from Renewable Energy Resources	proposal would use Schedule MGC-1 instead of fixed seasonal rate for non-firm buyback rate; would no longer be applicable to cogeneration facilities
Eliminate PRS-102	Cogeneration and Small Power Production Service Firm Power Purchase From Qualifying Facilities (QF) with 100 kW or Less Capacity	fixed seasonal firm buyback rate
Eliminate PRS-103	Supplementary, Backup, Maintenance and Interruptible Service for Cogeneration and Small Power Production Qualifying Facilities (QF) under 100 kW	billing in accordance with General Service Time-of-Use Rate GS-76
Eliminate PRS-104	Optional Supplementary Service for Cogeneration and Small Power Production Qualifying Facilities (QF) over 100 kW	billing in accordance with General Service Time-of-Use Rate GS-76, Large General Service Time-of-Use Rate GS-85, or Large Light and Power Time-of-Use Rate LLP-90
Eliminate PRS-105	Optional Maintenance Service for Cogeneration and Small Power Production Qualifying Facilities (QF) over 100 kW	fixed service and energy charges
Eliminate PRS-106	Optional Backup Service for Cogeneration and Small Power Production Qualifying Facilities (QF) over 100 kW	fixed service, reservation, and energy charges
Eliminate PRS-107	Optional Backup Energy Service for Self-Generation Facilities over 3 MW	fixed reservation and energy charges
Eliminate PRS-108	Optional Maintenance Energy Service for Self-Generation Facilities over 3 MW	fixed energy charge
Introduce PRS-10	Partial Requirements Service Less Than 200 kW	fixed delivery charges with 23-month demand ratchet, market-based generation charges using MGC-2 + 10 %
Introduce PRS-13	Partial Requirements Service From 200 kW to Less Than 3,000 kW	fixed delivery charges with 23-month demand ratchet, market-based generation charges using MGC-2 + 10 %
Introduce PRS-14	Partial Requirements Service 3,000 kW and Greater	fixed delivery charges with 23-month demand ratchet, market-based generation charges using MGC-2 + 10 %

TEP's Proposed Action	Title of Tariff/Schedule	Comments
Introduce Schedule MGC-2	Market Generation Credit (MGC) Calculation For Partial Requirements Services	mechanism for calculating generation charges for proposed tariffs; based on Platts Long-Term Forward Assessment for Palo Verde and Dow Jones Palo Verde Index
Modify MGC-1	Market Generation Credit (MGC) Calculation	This issue was consolidated with the partial requirements docket.