ORIGINAL

TO: Arizona Corporation Commission
FROM: The Solar Alliance
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The Solar Alliance appreciates this chance to address the Arizona Corporation Commission (Commission) with regard to Tucson Electric Power's (TEP) "Draft Pricing Plan PRS-100S Partial Requirements Service for Solar Facilities > 100 kW." To begin, TEP should be commended for proactively seeking to replace their current partial requirement service (PRS) rate schedule. The current PRS[1] was designed to provide TEP with ample cost recovery for providing Backup/Standby as well as Supplemental Service to customers who use primarily fossil fuel co-generators to produce some or all of their electricity on site.

This rate schedule was not designed to accommodate non-residential distributed generation (DG) solar photovoltaic (PV) systems. Accordingly, it is prohibitively expensive[2] and to date no customer-owned PV system over 200kW of capacity has been installed in TEP service territory. In fact, this tariff has been a principal roadblock toward the development of a multi-megawatt solar system at Davis-Monahan Air Force Base.

The new Draft PRS is a great improvement. It does much to address the financial feasibility of non-residential DG projects. TEP has also done an excellent job of reaching out to the renewable energy community, and has held two well-attended stakeholder meetings to address this topic. This being said, the Solar Alliance still strongly disagrees with some of the fundamental assumptions that TEP makes with regard to the technical nature of these projects, as well as the costs and benefits of non-residential solar PV DG.

The first issue has to do with Standby demand charges. It is useful here to imagine a hypothetical solar PV system with a capacity over 200 kW. Imagine that during the course of a month the meter on the customer's property to which the solar system is connected to registers a maximum demand of 679 kW. Imagine also that during this same period of peak demand the PV system had an output of 71 kW. TEP is proposing to charge roughly $3.07 for every kW of output from the PV system during peak demand. Essentially TEP is proposing that there should be a $218.04 PV capacity charge[3] (71kW*$3.07= $218.04). In other words, the customer is being charged for the energy they are generating during peak demand. To be fair, this charge is significantly lower than comparatively similar charges proposed by APS. However, the Solar Alliance opposes these types of charges in general, because they are unnecessary and do not take into account the positive attributes that distributed generation makes to the grid.

TEP often contends that standby charges should be imposed on a DG customer in order to cover the costs of building and maintaining adequate capacity to handle the customer's

[1] "Pricing Plan PRS-13 (experimental) Partial Requirements Service From 200kW to Less than 3,000 kW"
[2] PRS-13 charges a minimum of $1,675.88 per month for the first 200 kW of demand.
[3] See Appendix A

load should the customer's generating facility fail. The problem with this argument is that utilities typically do not procure standby generation specifically to account for the possibility of DG system failure. Thus, they incur no such costs. Factors such as weather have a much greater impact on the amount of generation capacity a utility must be able to dispatch to serve load on any given day. Even if a very large DG system went down, the impact on a utility's system load would be negligible compared to the impact of weather fluctuations.

Looking at this with a macro lens, if all of the DG on a utility's system accounted for even a large percentage of the utility's peak demand, for instance 1-2%, then even if every one of those systems was to go down simultaneously it would only impact the utility's load service requirements by 1-2%. Daily and seasonal weather fluctuations are likely to have a far greater impact on the load served by a utility.

For this reason, the Solar Alliance believes standby charges for DG customers should be prohibited absent a specific cost/benefit analysis demonstrating that additional charges are actually incurred when utilites provide standby service. Such analysis should not only take into account any costs associated with providing standby service but should also take into account the transmission and distribution costs that are avoided by the implementation of distributed generation.

Moreover, standby demand charges represent the third charge that customers with intermittent DG must pay to build and maintain adequate capacity. DG customers with intermittent resources pay for capacity a first time when they purchase a DG system. They pay a second time through the monthly demand charges they pay to a utility. Standby demand charges therefore represent a third charge that such customers must pay for maintaining adequate capacity to serve their load. We elaborate on this point below.

Most of a utility's cost for providing standby service is associated with the fixed cost of building and maintaining its transmission and distribution system. Generally, a utility customer will pay for these costs in the form of a monthly demand charge per kW. This is in addition to any electrical generation charges for actual electricity used.

Standby rate schedules - such as the current PRS TEP is attempting to replace - were designed for large cogeneration facilities that were expected to generate almost continuously. As a result, a cogeneration facility would incur no demand charges if the facility ran continuously during the month, shifting capacity costs to other ratepayers. The standby tariff ensured that the cogeneration facility incurred the minimum costs required to maintain capacity for the system.

For intermittent resources such as solar and wind, standby charges are much more punitive, imposing significant extra costs on the owners of these resources. This is due to the fact that an intermittent resource, such as a solar facility, only produces electricity when it receives sufficient sunlight. At other times of the day, a solar DG customer must purchase energy from the grid. In doing so, the DG customer incurs both commodity charges commensurate with its usage and demand charges associated with the demand

such customer places on the utility system. Thus, unlike cogeneration systems, which may avoid demand charges entirely, DG customers continue to pay significant demand charges even when a DG system is operating smoothly and as intended.

The second and perhaps more troublesome issue with regard to the Draft PRS is that it introduces a novel "Standby Demand Charge." Essentially, TEP is proposing to charge $.007 for every kWh that a customer with a PV DG system over 200 kW produces. While seven tenths of a cent doesn't sound like much, for a 200kW PV system this would be a charge of over $2,240 per year.[4] This charge is unprecedented and unjustified regardless of how one feels about the validity of utility arguments for the need for standby demand charges. DG systems, no matter their level of intermittency, year in and year out, reliably reduce the amount of fossil fuels need for utilities to produces energy. A per kWh charge seems to be a charge for energy production avoided.

The Solar Alliance recognizes that after a customer installs solar, TEP loses revenue because, the customer is no longer purchasing as much energy as they previously had been. However, TEP's 2008 Renewable Energy Standard (RES) Implementation Plan creates a mechanism for the full recovery of the costs associated with their DG program.

> REST funding is intended to cover the cost of utility-scale renewable generation in excess of the market cost of conventional resource alternatives, incentive payments for distributed energy resources, marketing expenses and program implementation, and administration costs.[5]

The 2008 TEP RES agreement was the result of a lengthy stakeholder process where a tariff for cost recovery for DG programs was approved after lengthy debate. Any cost recovery associated DG PV systems should have been included in this tariff and it is inappropriate for TEP to attempt to implement "backdoor" cost recovery. Such actions undermine the validity of the stakeholder process and the finality/continuity of Commission decisions.

The Solar Alliance asks the Commission to help us work with TEP to create a Draft Partial Requirement Service schedule that is devoid of redundant and punitive standby energy and demand charges.

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[4] Conservatively assumes PV production of 1600 kWh per kW in Arizona

[5] TEP 2008 REST Implementation Plan (E-01933A-07-0594)

APPENDIX A
PARTIAL REQUIREMENTS SOLAR BILLING EXAMPLE FROM POWERPOINT PRESENTATION DISTRIBUTED AT TEP'S AUGUST 4 2008 STAKEHOLDER MEETING.

PRS LGS -13	SDCF	70.24%				
Billing Determinants	Customer	TEP	TEP No Solar			
Demand	71	679	750	kW		
Energy	25,784	340,384	366,168	kWh		
Unbundled Components	Supplemental Rate	Supplemental Revenue	Standby Rate	Standby Revenue	Supplemental plus Standby Revenue	All TEP Supplied - Full Requiremen
Demand Charge (kW):						
Generation Capacity	$6.9110	$4,696	$2.0570	$145	$4,841	$5,183
Transmission	$2.6850	$1,824	$0.7990	$56	$1,881	$2,014
System Control & Dispatch	$0.0360	$24	$0.0110	$1	$25	$27
Reactive Supply and Voltage Conti	$0.1430	$97	$0.0430	$3	$100	$107
Regulation and Frequency Respor	$0.1390	$94	$0.0410	$3	$97	$104
Spinning Reserve Service	$0.3770	$256	$0.1120	$8	$264	$283
Supplemental Reserve Service	$0.0610	$41	$0.0180	$1	$43	$46
Energy Charges (kWh):						
Delivery Charge						
Summer	$0.0124	$4,220	$0.0037	$95	$4,315	$4,539
Generation Capacity	$0.0095	$3,241	$0.0028	$73	$3,315	$3,487
Fixed Must-Run	$0.0033	$1,121	$0.0010	$25	$1,146	$1,206
System Benefits	$0.0004	$151	$0.0004	$11	$162	$162
Fuel & Purchased Power	$0.0326	$11,081	$0.0000	$0	$11,081	$11,920
					$27,270	$29,079
	Estimated REST Payment to Customer:				$4,641	n/a
			Net Cost:		$22,628	$29,079