

# **Arizona Public Service Company Comments**

## **Draft NARUC Manual on Distributed Energy Resources Compensation**

### **Introduction**

Arizona Public Service Company (APS) appreciates the opportunity to provide comments to NARUC on the Draft NARUC Manual on Distributed Energy Resources Compensation. This is an important and timely effort. APS believes NARUC has taken a broad, comprehensive and useful approach to the subject. APS supports DERs and has a vision of the future where the modern grid is enabled by a modern approach to rates for the energy product and the other grid and infrastructure services provided for the benefit of customers. APS believes the true potential of a modern distributed grid cannot be realized without robust complementary rate design that levels the playing field between technologies and sends accurate price signals to better align customer incentives with actual infrastructure cost savings that could result from DER technologies.

### **APS's Experience With Residential TOU and Demand Rates**

Today, APS has over 120,000 residential customers on TOU Demand rates and another 450,000 on TOU Energy rates. In a recent study of customers who switched from TOUE to TOUD, 60% of customers saved 12.5% (average) of their summer demand and 9% (average) of their summer energy, and 90% of customers saved on their bill. APS's extensive experience with both TOUE and TOUD rate structures has led APS to conclude that TOU Energy rates, at least in the Arizona climate, cannot adequately provide an accurate price signal to DERs because TOU Energy rates still improperly recover demand costs through an energy charge. Today, with DERs, the electric grid has evolved to a system of two-way power flow: customers take energy from the system at times, and send it back at others. Given this fundamental change in how the system operates, the difference between the energy product that the utility sells and the grid services it provides has become critical. Most of what it takes to provide reliable service to customers depends on utility infrastructure, but the bulk of a customer's electric bill reflects how much of the energy product they bought - a function of the fuel cost to produce the energy. Rate design must evolve to reflect the distinction between the utility's energy product and grid services. Customers should pay for what they use. Three-part rates are the best solution to adequately address this pricing problem because a three-part rate design better matches charge types to cost drivers by recognizing that much of the utility's infrastructure investment is driven by the customer's maximum usage, or kW demand, rather than the total monthly usage, or kWh energy.

Given APS's history with residential demand rates, APS would also disagree with the notion that demand charges should necessarily be used sparingly. APS's generally available demand rate for residential customers recovers a significant portion of generation and distribution demand driven costs. And, under this type of design, APS has seen customers thrive on a demand rate. As referenced earlier, APS has also observed additional energy conservation on a demand rate<sup>1</sup>, even with necessarily lower energy prices,

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<sup>1</sup>This is in contrast to an inclining block rate, which raises the conservation price signal, but only for larger homes with high monthly kWh usage. Inclining block rates actually lower the conservation price signal for smaller homes with lower kWh usage. This inherent flaw makes energy efficiency work better for large users and worse for small users.

## Arizona Public Service Company Comments Draft NARUC Manual on Distributed Energy Resources Compensation

which APS attributes to the customer's more focused attention on how, when and how much energy is used under a demand rate. Some of the results from APS's analysis of customers who switched from a TOU energy rate to a TOU demand rate are depicted below.

### Demand Rates are Not New

APS has offered residential demand rates since 1981 and today...

120,000

residential customers choose a rate plan combining time-of-use and peak usage.

90%

of customers saved money on their summer bill.\*

Among the highest savers

42% are small to mid-size customers.\*



33%

increase in residential customers adopting our demand-based rate plan since 2010, making it our fastest-growing plan.

60%

reduced their peak usage by an average of 12.5% during the summer peak season.\*

\*Based on data from 977 APS customers who switched to a time-of-use demand rate plan in 2013 and stayed on the plan for at least one year.

## Arizona Public Service Company Comments

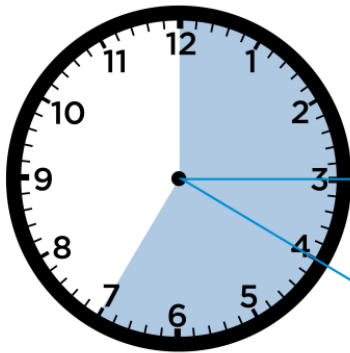
### Draft NARUC Manual on Distributed Energy Resources Compensation

With respect to assessing a demand charge on a coincident peak or non-coincident peak, APS believes the method should match the cost allocation methods used in the approved cost of service study, which is the basis for rate design. For residential customers at APS, demand rates are all time-of-use rates that only measure the demand during the defined on-peak period today. APS believes this presently strikes the right balance between sending an appropriate price signal and also being relevant and useful to the customer. APS has also found it appropriate thus far to measure residential demand over a 1-hour period rather than 15 minutes as it does for business customers. While technology and rate design will continue to evolve, both the on-peak only and 1-hour measurement have proven to be a balanced way to ensure the price signal is accurate and to provide some built in moderation for residential customers.

See the example below of how peak usage is calculated over an entire hour, rather than a moment in time. In this illustrative example, it is 6:00 p.m. on a Friday and the customer gets a call from friends who want to stop by for a quick visit. Being a gracious host, the customer turns on the oven for 10 minutes to heat up some snacks. At the same time, their daughter realizes her jersey is not quite dry enough to wear to practice and throws it in the dryer for 10 minutes. Because it is summertime, the air conditioner is on while all this is happening. So, what would the customer's peak usage be for that hour? Let's assume that the customer's energy use during the 10 minutes that the oven, the dryer and the air conditioner are in use is 7 kW. For the remaining 50 minutes of the hour, the customer's energy use is 4 kW because they go back to using energy the way they normally do. In this example, the customer's peak usage would be 4.5 kW, because the energy use would be averaged over the full hour.

## How Peak Usage is Calculated

Current on-peak hours  
(noon–7 p.m.)



### Example

$$7 \text{ kW} \mid \text{for 10 minutes} \quad (7 \times 10) = 70 \text{ kW}$$

$$4 \text{ kW} \mid \text{for 50 minutes} \quad (4 \times 50) = 200 \text{ kW}$$

$$70 \text{ kW} + 200 \text{ kW} = 270 \text{ kW}$$

$$270 \text{ kW} \div 60 \text{ min.} = 4.5 \text{ kW}$$

## **Arizona Public Service Company Comments**

### **Draft NARUC Manual on Distributed Energy Resources Compensation**

#### **Are Unique Rates Appropriate for DERs?**

One question the Manual asks, do DERs avoid utility infrastructure costs? Some forms of DER will do a better job of this than others. APS suggests that rates with a sound price signal that aligns customer incentives with utility cost savings will provide the right incentives to reward DER technologies that are more effective at avoiding utility infrastructure costs.

APS has also performed two cost-of-service-studies (COSS) with rooftop solar customers analyzed as a unique customer sub-class. The results of these studies strongly support separate treatment for customers with some forms of DERs, if the service, load or cost characteristics are significantly different than other customers within the broader customer class. The COSS conclusions were definitive that within APS's service territory, residential rooftop solar customers have significantly different characteristics than residential customers without rooftop solar.

While DER's reduce the customer's bill, they can also reduce the utility's costs. Cost shifting occurs when the DER reduces the customer's bill more than it reduces the utility costs. When this happens, the DER customer is actually using services from the utility and not paying for them, or not paying the full cost for that service. Because the revenue goes away, but not the cost, the costs are eventually shifted to other customers in the form of higher rates. APS believes one goal of DER rate design should be to recover the appropriate amount of cost from various customers, or customer classes, in addition to recovering the entire revenue requirement.

APS believes we should discuss the unpaid for cost in a precise way rather than using the term "stranded costs," which typically occur when a customer stops paying for, and stops using, certain infrastructure investments that were made by the utility on behalf of the customer. In the case of some DERs, like rooftop solar, the customer may stop paying for grid infrastructure investments, but they nonetheless continue to use them. The investment is not stranded - it cannot be moved to serve another customer, resold or salvaged - rather the investment is merely unpaid for. The Manual should distinguish between "Unpaid Assets," and "Stranded Assets."

#### **When Should a Jurisdiction Act to Address DERs?**

The Manual indicates states may need to wait for a critical mass of adoption before acting. While this can often be true, APS would caution against being too cautious. The longer a jurisdiction waits to implement modern rate design, the bigger the potential grandfathering issue that will need to be addressed and the more difficult crafting a solution will become. Starting to address the potential issues sooner rather than later also allows more time for a gradual transition.

Modern rate design should ideally reflect the cost structure to provide service in order to send the proper price signal to customers. Customers with DERs may not always rely on the utility for electricity supply, but they still require grid services every hour of every day of the year. The intermittency of DERs and the dynamic nature of two-way power flow makes managing the electric system more challenging. In many cases it also requires additional grid infrastructure in order to keep the lights on and power

## Arizona Public Service Company Comments Draft NARUC Manual on Distributed Energy Resources Compensation

quality high. A two-part rate design inherently over-compensates a customer that avoids a significant quantity of kWh, but does not reduce their peak demand, which indicates the use of grid infrastructure is still high. A three-part rate design would split the prices for these two distinct categories of services being provided and remove this mismatch resulting from two-part rates (even TOU) which inevitably shift costs to other customers.

APS supports the Manual's conclusion that unique solutions may very well be appropriate based on a variety of factors and given the unique characteristics from jurisdiction to jurisdiction.

### Is A Demand Charge An Extra Charge on the Customer's Bill?

APS wants to emphasize, while it would be an additional line item on a customer's bill, this is absolutely not the case, despite some of the rhetoric. As regulators know, electric utilities are required to perform a proof of revenue using billing determinants (number of customers, kWh energy consumption (on-peak and off-peak if TOU), and kW demand) from a test period. A demand rate proposal for residential customers would be revenue neutral with the test-year billing determinants used to produce the revenue allocated to the customer group in the revenue allocation process. The rate design produces an equal amount of revenue to the allocated revenue requirement, no more, no less, based on the test period data, regardless of the rate design ultimately chosen. In APS's recently filed rate case, the proposal is also revenue neutral as shown below.

## Your Electric Bill: Before & After

	Current Bill of an Average Residential Customer	Same Customer's Bill with the Proposed Changes (on 1 of 3 demand rate plan options)
	Before	After
Basic Service Charge	\$17.00	\$24.00
Energy Charge	\$122.32	\$90.11
Demand Charge	N/A	\$36.30
Rate Increase	\$11.09*	INCLUDED
<b>TOTAL</b>	<b>\$150.41</b>	<b>\$150.41</b>

\*APS's proposed rate increase would add \$11.09 to the bill.

# **Arizona Public Service Company Comments**

## **Draft NARUC Manual on Distributed Energy Resources Compensation**

### **What Weight to Give the Notion That All Fixed Costs Are Variable in the Long Run**

The issue of fixed versus variable costs in rate design has very little to do with how costs change over time. All utility costs vary in magnitude and price over time as utilities constantly replace old infrastructure and build new infrastructure for the future. APS believes some parties misapply this thought to rate design and erroneously conclude that because all costs vary over time, all costs should therefore be recovered through a volumetric kWh charge, which is a variable charge. This is flawed logic. The relevant question for rate design is: does the cost vary with the customer's monthly kWh usage? Not, does the cost vary over time? While they do vary over time, utility assets are long-lived assets and the variation over time is a slow process. A well designed rate should match charge types such as service charge, demand charge, energy charges, time-of-use, and others, with cost drivers including fixed service costs, demand-driven infrastructure costs and variable energy costs. APS also points out that a kW demand charge is a variable charge, but one that is more precisely aligned with the costs driven by demand.

### **Demand Response – Primarily an Operation Tool**

The manual discusses demand response (DR) programs like Critical Peak Pricing and Peak Time Rebates. APS also has experience with these types of DR programs. While these types of programs can be useful as operational tools, APS wants to stress CPP and PTR are not a replacement for the precision of a three-part rate in providing price signals to customers that would result in sustained demand reductions over time that could be counted on for planning purposes. In the harsh Arizona climate, CPP and PTR offers too limited a number of event days to effectively manage the large number of peak days that result from the long summer season, although it can still be valuable for operational flexibility. APS acknowledges CPP and PTR may be more effective in other regions of the United States that have a better match between event days and peak days.

### **Negative Market Prices**

Negative market prices have also occurred in the western US as a result of excess solar production during mid-day in low load periods, which also is accompanied by the resulting steep ramp period as solar production declines as the sun sets and loads remain relatively constant or even increase. APS has begun to develop protocols and has the ability to curtail its own utility scale "free" renewable generation to take advantage of periods where negative prices exist. APS believes this phenomenon will occur more frequently as the western US continues to add renewable generation, much of it solar, without adequate storage capability to address the excess solar production.

### **Additional Information**

APS provides the attached article, *Dispelling the myths of residential rate reform: Why an evolving grid requires a modern approach to residential electricity pricing*, which was published in the April 2016 issue of The Electricity Journal 29 (2016) 72-76, that discusses the study mentioned above.