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Editorial

Dispelling the myths of residential rate reform: Why an evolving grid requires a modern approach to residential electricity pricing

1. Introduction

One cannot read the trade press these days without coming across articles discussing advancements in behind-the-meter energy technology and its associated impact on the U.S. electric grid. Rooftop solar is the technology leading the way, with battery storage, electric vehicles, load control devices, and other innovations looming close on the horizon. As customers adopt these technologies, they change the way that they use the electric grid. Where once customers took power only from the grid, they now use the grid both to import and export electricity, resulting in a two-way flow of power: from the utility to the customer and the customer to the utility. These changes require electric utilities to play a different role in the generation and delivery of electricity than they historically have. Reliability will always be a paramount consideration for America's technology-savvy and energy-dependent population. Ensuring reliability in an era of two-way power flows requires power companies to evolve the grid into an integrating platform that invites the adoption of customer-sided technologies while maintaining the fundamental physics that keeps the system functional. The utility's role as a network integrator and system balancer will become increasingly important. And as the utility's functions evolve, so must its pricing structure.

2. What are the alternatives to the traditional kilowatt-hour unit of pricing?

Electricity costs are driven by various factors. Costs that vary with a customer's kilowatt-hour (kWh) energy consumption, such as fuel, are appropriately priced based on the kWh unit of measurement. However, most utility infrastructure costs do not vary with the amount of energy consumed. Rather, infrastructure is sized to serve peak consumption, which is the maximum amount of energy used over a short period of time, such as a 15-min period or a single hour, versus the energy consumed over an entire monthly billing period. These costs, which include such items as power plants, transmission and distribution lines and poles, are often described as being driven by demand or capacity and are measured on a maximum kW basis. Other costs of providing electric service are based on the needs of a single customer, such as a billing meter and service connection, and do not vary with either energy or demand. These are described as "per customer" costs, which are also fixed.

For the most part, the rate designs used for the various customer classes have depended upon the available metering technology. Before the advent of cost-effective meters, customers were charged a flat fee or by the number of light bulbs installed at a residence. Over time, meters were developed that were capable of measuring both demand and energy. Demand meters were more costly and typically did not make sense for residential customers who were considered reasonably homogenous as a class; that is, most residential customers used energy the same way and were viewed as lacking the disparities in system usage that would justify a more complex rate design and the corresponding cost of the more expensive metering infrastructure.[1] For that reason, traditional residential electric rates were based on the billing measurements that could be taken by cost-justified energy meters: the customer and kWh components. While easy to understand, an energy-only rate design does not reflect the difference in cost among customers who have different levels of demand. Two customers may have the same energy usage, but their usage patterns may be such that one requires more generation, transmission, and distribution infrastructure than the other. An energy-only rate undercharges the more demand-intensive customer, and overcharges the customer who uses the grid more efficiently.

As it always will, technology has evolved and the metering economics has now changed. Advanced metering can be implemented at a reasonable cost for residential customers, thereby making three-part residential rates a viable option. Three-part rate designs reduce the billing disparity caused by energy-only rates and are increasingly appropriate as the once-homogenous residential class diversifies with respect to how they use electricity, given such factors as the adoption of distributed generation and other customer-sided energy technology.

Recognizing the policy benefit of three-part residential rates, utilities throughout the country are seeking to reform residential rate designs to include a demand component. Some utilities in the U.S., including Arizona Public Service Company (APS), have had an optional residential demand rate for decades, and the approach is gaining traction. The gravitation to demand-based rates has

[1] Commercial customers, on the other hand, did use the system differently, thereby justifying a more sophisticated rates design and the corresponding investment in demand meters. For decades, commercial customers' electric bills have been based on kW, kWh, and per-customer charges.

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Misunderstanding the derivation and implementation of a residential demand-based rate

In the November 2015 Issue of *The Electricity Journal*, Scott J. Rubin's article entitled "Moving Toward Demand-Based Residential Rates" evaluated several rate design options and hypothesized that a rate with seasonal consumption charges would make significant progress toward a more efficient rate design (as measured by the correlation between costs and revenues). Mr. Rubin also concluded that a demand rate based on monthly billed demand was inefficient at aligning a utility's cost drivers with revenue collection.

Mr. Rubin's analysis of a demand charge assumes that a demand charge is theoretically set by the single peak hour. That, however, is a gross misunderstanding of the derivation and implementation of a residential demand-based rate (at least here at Arizona Public Service). Mr. Rubin's flawed assumptions led him to the flawed conclusion that demand rates, and the revenues they will produce, are not well correlated to the cost of providing service.

Mr. Rubin may also misunderstand the cost allocation process and proof of revenue concept that ensures the test-year costs and revenues are in alignment.

APS allocates its cost of providing service for generation, transmission, and distribution based on the appropriate cost drivers. Rates are then developed, using a proof of revenue and monthly billing information to recover the allocated cost. Empirically, the very nature of this process creates a very high correlation between the cost of service study and the rates that customers pay.

A single demand does not drive all infrastructure costs; rather, those costs are driven by a series of demands that vary by the infrastructure category and likely time of day, month or year during which they are incurred (for example, generation and transmission costs for APS are driven by the summer peak season; substations and distribution primary costs are driven by class peaks and secondary distribution is driven by individual demands). The cost allocation process follows this complexity.

While these infrastructure costs are driven by various configurations of demand, they are not driven by a home's monthly kWh energy consumption. A TOU energy rate will not provide a higher correlation between costs and revenues. If the cost allocation is done properly (using the various demand cost drivers) and a valid proof of revenue is developed for the rate design, it is not possible for a TOU energy rate design to have a higher correlation than a demand rate design.

generated much conversation in the industry and conceptual arguments both for and against the rate design is now a common dialogue. This article uses real data and relies on the decades of experience that APS has with residential demand rates to debunk the myths associated with demand pricing and replace what have been hypothetical suppositions with reality.

3. APS: a case study in residential demand rates

APS first offered residential demand rates in 1981 and presently has over 117,000 residential customers voluntarily on a time-of-use (TOU) demand rate. APS also has more than 427,000 residential customers on a TOU energy rate. Given this long duration and significant adoption of both TOU energy and demand rates, APS has significant data that provides insight into the effectiveness of each approach in shaping a customer's energy usage. APS data shows that customers on TOU energy rates reduce their peak demand by approximately 5% compared to customers on inclining block rates, primarily due to the enhanced focus on the on-peak pricing period. In addition, data shows that customers on a TOU demand rate have significant potential to further reduce their peak demand compared to those on a TOU energy rate.

APS has data from 977 customers on its system that took service under a TOU energy rate for the 2012 calendar year and then switched to a demand-based rate in 2013 and remained on a demand rate through 2014. That data evidences that customers respond to demand rates, reducing peak demand and saving money. Of those 977 customers, 60% saved an average of 12.5% on their peak demand in the summer peak season. And the most engaged customers (the top 5% savers) reduced their peak demand by approximately 39%. This results in savings that will add up and translate into real capacity deferrals and corresponding system savings – all from sending more precise price signals through rate design. Of those customers that did not actively respond to the price signals sent by the demand rate, 75% still actually saved money simply by subscribing to the three-part rate.

4. Using this data to debunk the myths about residential demand rates

Myth one: residential demand rates will allow the utility to collect for the same infrastructure twice and recover more revenue than authorized.

Reality: this myth reveals a fundamental misunderstanding about the ratemaking process. During rate proceedings, utilities are required to demonstrate a "proof of revenue" that shows the regulatory body charged with approving rates and tariffs that the proposed rate designs will collect the authorized amount of revenue – no more and no less. How costs are divided between customers is determined through a detailed process during which utilities allocate costs to the appropriate customer classes based on the demand, energy, and customer cost drivers in proportion to their use of infrastructure and energy. The allocated cost responsibility is then divided by the class billing determinants (actual demand, energy and customer information) to develop the specific rates. This allocation process and proof of revenue method ensures that rates do not over- or under-collect revenue. Indeed, commercial customers – typically the most sophisticated customers to participate in utility rate proceedings and actively engage in the proof of revenue and rate design process – have been on demand-based rates for decades. Had the design resulted in duplicative recovery, it would not have lasted long.

Myth two: customers cannot understand residential demand rates.

Reality: customers can learn to manage and understand rates. APS has 34 years of experience with residential demand rates and presently over 11% of APS's residential customers voluntarily subscribe to a three-part rate structure. The additional level of understanding can be communicated at a high level: put simply, do not turn on all of your electric-intensive appliances at the same time. Because APS measures demand for residential customers over a one-hour period of time and most appliances do not run continuously for an hour, there is some built-in forgiveness of a short-term overlap of multiple appliances. The demand reductions presented in the case study above validate that residential customers grasp and engage in the demand management concept, since there is a noticeable demand savings once a customer switches to a demand rate.

Further, approximately 65% of new customer growth for APS over the last five years has selected the residential demand rate, increasing from less than 90,000 customers in 2010 to over 117,000 customers today. Because APS is fully deployed with advanced metering, customers can use rate tools available on the utility's Web site to get a detailed rate comparison, and many are finding that a demand rate is actually the best rate for them in terms of overall cost. Both the bill savings and understanding of the demand charge grows further if the new rate design is coupled with technology that will help him or her manage load, gaining practical experience in how to reduce demand and save money under the new rate design.

Myth three: demand rates will increase customer bills and particularly harm low-income customers.

Reality: whether a customer's bill will increase under demand rates depends entirely on their load factor – that is, the relationship between the customer's peak demand and their overall energy consumption. As discussed above, the existing energy-only rate structure subsidizes customers who do not use the grid efficiently. Whether or not those customers experience rate increases will depend on whether and how they respond to the price information that encourages load management at peak periods.

In a transition to demand rates, any adverse impact to low-use or low-income customers will depend on the ultimate rate design

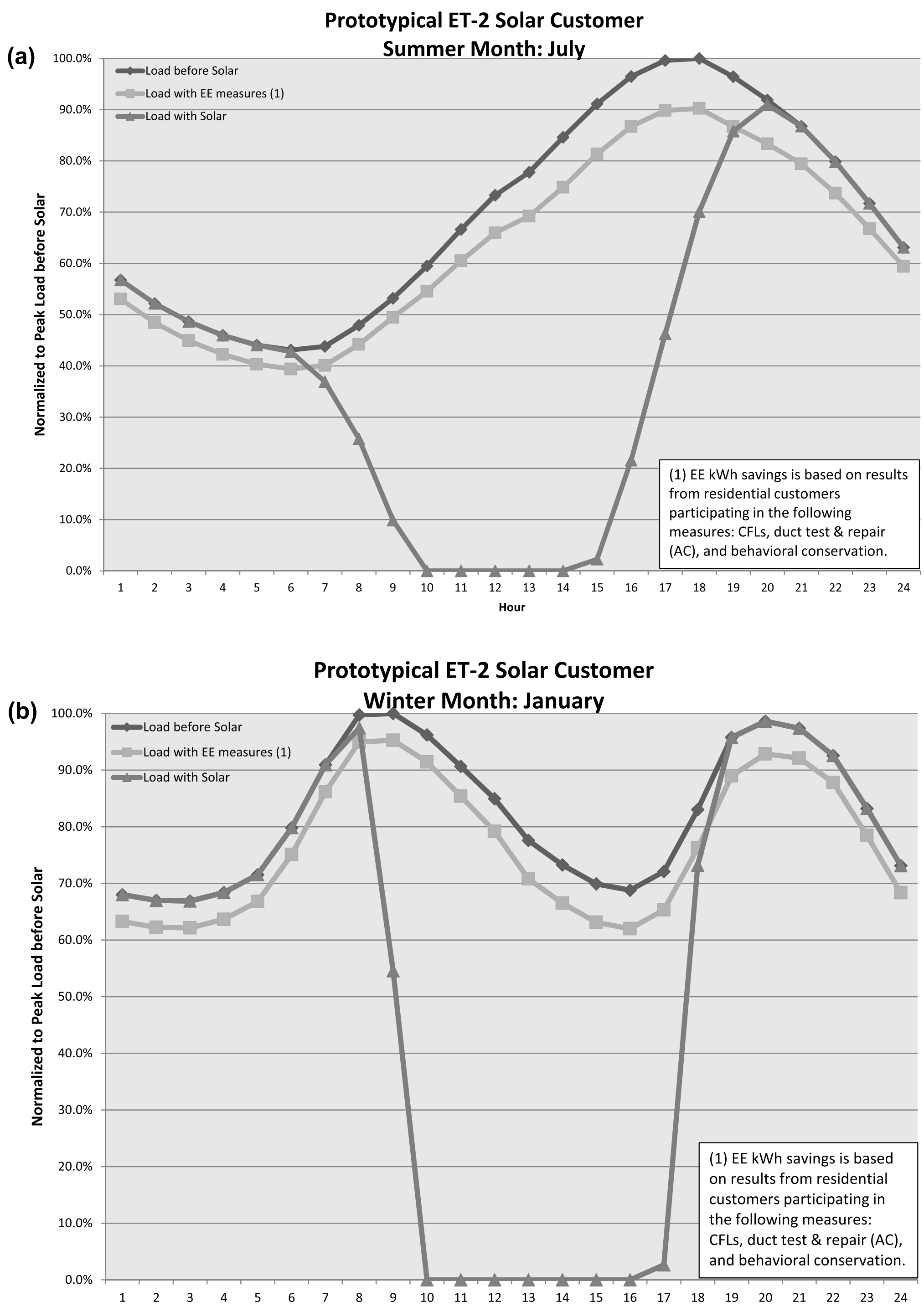

Fig. 1. (a) Prototypical ET-2 Solar Customer Summer Month: July. (b) Prototypical ET-2 Solar Customer Winter Month: January.

Table 1
The change in kW, kWh and monthly bill from Switching from a two-part to a three-part rate.

Summer load change (weather normalized – temp, humidity)									Summer bill	
% Customers	Total kWh	On-Pk kWh	Off-Pk kWh	On-Pk kW	% Total kWh	% On-Pk kWh	% Off-Pk kWh	% On-Pk kW	$ Change	% Change
5%	(617)	(234)	(383)	(3.0)	−27%	−40%	−22%	−39%	$ (93.94)	−35%
10%	(444)	(134)	(310)	(1.8)	−19%	−24%	−17%	−24%	$ (66.07)	−25%
15%	(386)	(139)	(247)	(1.6)	−15%	−21%	−13%	−19%	$ (64.35)	−22%
20%	(364)	(117)	(246)	(1.3)	−14%	−17%	−13%	−16%	$ (62.67)	−21%
25%	(358)	(89)	(269)	(1.1)	−14%	−14%	−14%	−13%	$ (58.15)	−20%
30%	(196)	(76)	(120)	(0.9)	−8%	−11%	−7%	−11%	$ (45.61)	−16%
35%	(99)	(48)	(51)	(0.7)	−4%	−8%	−3%	−9%	$ (37.68)	−14%
40%	(162)	(66)	(96)	(0.7)	−6%	−9%	−5%	−8%	$ (45.06)	−14%
45%	(40)	(29)	(11)	(0.5)	−2%	−5%	−1%	−6%	$ (29.43)	−11%
50%	(78)	(41)	(38)	(0.4)	−3%	−6%	−2%	−4%	$ (30.38)	−10%
55%	(31)	(25)	(6)	(0.2)	−1%	−4%	0%	−2%	$ (29.28)	−10%
60%	7	(12)	19	(0.1)	0%	−2%	1%	−1%	$ (22.88)	−9%
65%	2	(4)	6	0.1	0%	−1%	0%	1%	$ (17.45)	−6%
70%	68	8	60	0.2	3%	1%	4%	3%	$ (14.64)	−5%
75%	3	7	(4)	0.3	0%	1%	0%	4%	$ (17.65)	−6%
80%	181	25	156	0.5	8%	4%	9%	6%	$ (7.49)	−3%
85%	200	45	155	0.7	8%	7%	8%	9%	$ (1.01)	0%
90%	144	52	92	0.9	6%	9%	5%	12%	$ (3.11)	−1%
95%	256	63	193	1.2	11%	10%	11%	16%	$ 7.82	3%
100%	519	166	353	2.1	25%	34%	22%	33%	$ 41.43	18%
Average	(70)	(32)	(37)	(0.31)	−2.9%	−5.2%	−2.1%	−3.9%	$ (29.88)	−11%

and the transition plan. Rate design is an art as much as a science, and any policy in favor of subsidizing low-income customers can be fostered through a demand-rate construct as much as it can through an energy-only design. While low-use customers would be hit harder than average-use customers through a one-size-fits-all fixed monthly customer charge, that is not true in a three-part rate approach. Indeed, in most instances, low-use customers also have a lower peak demand. Because a kW demand charge is a variable charge, lower demand will also translate into a lower cost.

Myth four: diversity in the residential class limits the usefulness of infrastructure price information intended to result from demand charges.

Reality: "Diversity" refers to whether and how customers use energy differently over the 24 h in a day. The concept underlying this "myth" is that because residential customers use energy at different times, a demand charge will not change the way the residential class overall uses energy sufficient to save utility investment in system infrastructure needed to serve peak demand. That concept is fundamentally flawed in states, like Arizona, in which weather and temperature drive peak demand. In APS's territory, for example, peak demand is primarily driven by air conditioning load to keep homes cool during the hot summer months. This naturally causes a fairly high level of coincidence between residential customers – everyone cranks their air conditioning units at about the same time. For other states, a demand charge focused on a discrete time period can force the coincidence that will result in system savings. If a demand charge is applied only to peak time periods, the resulting price information will cause customers to be aligned in when they reduce usage. In other words, the price information will incentivize conduct that decreases diversity in the residential class and increases the likelihood of achieving a coincident system benefit.

Myth five: TOU rates can resolve the customer cost-shift that results from an energy-only rate design.

Reality: TOU rates alone cannot adequately resolve the cost-shift. APS has 34 years of experience with TOU rates, and 60% of APS's net metering customers are on TOU rates. Still, the cost shift continues. At their core, even TOU energy rates attempt to collect infrastructure costs that are driven by demand, not monthly energy consumption. In an energy-only TOU rate, a customer can shift a portion of his or her energy consumption to non-peak periods but still have a high level of demand. In that case, the customer receives a large level of savings, but the infrastructure needed to serve him or her is unchanged. A demand rate structure encourages customer behavior that will actually save the infrastructure investment, which is the ultimate goal. Demand rates can also have a TOU component, leveraging the benefits of a TOU rate with the benefits of a demand rate.

Myth six: demand response (DR) will do a better job of reducing customer peak demand than demand rates.

Reality: DR programs have the potential to result in high demand savings for participating customers, but are limited with respect to the amount of overall system savings that are likely to result. This is because DR programs typically have a limit to the number of events that can be called – perhaps 14 events over a summer billing season – and have stringent customer notification requirements. Demand rates, which incentivize customers to change their behavior day in and day out, will have a more sustained system benefit than a DR program which may or may not change a customer's behavior only a handful of times each year. For example, APS's summer season includes more than 100 days at temperatures of above 100 degrees, and APS's peak period is broad, from 3 pm to 10 pm. Therefore, for APS, the limited number of opportunities to reduce demand under a typical DR program has a limited benefit. The hour or day after a DR program event may very well also be a peak hour or day, and APS would likely get no demand reduction from the very same customer. A demand rate rewards a customer for reducing demand consistently – and that consistency delivers real demand savings to APS.

Myth seven: residential demand rates will impair energy efficiency.

Reality: there is big difference between the cost-shift that results from distributed generation under an energy-only rate structure and that resulting from energy efficiency. Energy efficiency customers increase or maintain their load factor and are thus more cost-effective to serve. That is not true for distributed generation customers, who, without proactive steps, use less energy but have similar demand profile before and after solar. Consider the load profiles depicted in Fig. 1.

Residential demand rates will not impair energy efficiency, but will encourage a more sophisticated kind of efficiency – one that results in measureable capacity savings in addition to energy savings and one that results in load shaping (moving consumption from high cost periods to lower cost periods) from load management technologies and storage solutions. Residential demand rates will likely sharpen the focus of energy efficiency programs going forward, but will not impede energy efficiency from delivering results. This is supported by the results depicted in Table 1, where customers conserved more energy on a demand rate than when they were on a two-part energy time-of-use rate.

Myth eight: residential demand rates will hurt the solar industry.

Reality: to date, the solar industry has benefitted from a rate design that compensates a customer when they save energy as if they also saved on peak demand, which they do not do without proactive change. Indeed, real data taken from a cost-of-service study[2] performed by APS concluded that the typical residential solar customer on an energy-based rate, after all savings are taken into account, covers only 36% of the cost incurred by APS to serve them. Residential solar customers on APS's demand rate pay for 72% of the cost to serve. This stands in contrast to non-solar residential customers whose bill payments cover approximately 87% of the cost to serve. This disparity under an energy-only rate occurs because that rate structure credits residential solar customers for saving on infrastructure without requiring that infrastructure actually be saved. This approach is not sustainable.

Demand rates will send price signals that will require the solar market to adapt its business models so that peak demand savings actually occur. Changes to the rate structure will encourage an evolution of the solar industry, driving a business model that will endure without deep embedded subsidies. Such evolution is not only possible, but is already being developed by forward-thinking solar companies. To that end, APS is working with third-party partners to develop a Solar Innovation Pilot that studies how a customer with solar, in combination with other technology and focused energy efficiency strategies, can respond to a demand rate price signal. This pilot will use battery storage, load control, and energy efficiency strategies to help customers shape their energy usage to balance lifestyle and savings. The exciting future is one where the use of solar and other behind the meter generation resources is part of an integrated whole home solution.

5. The reality

Residential demand rates have been an effective tool in encouraging customers to reduce their peak demand during the on-peak period for APS for more than three decades. As the electric utility industry rapidly evolves in the 21st century, demand rates will be an increasingly important means of stimulating innovation and helping customers shape how they consume energy.

Author contributions'

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[2] APS's cost-of-service study, based on calendar year 2014, created unique sub-classes for residential solar customers. APS had over 27,000 solar customers on energy rates and almost 1200 on demand rates in 2014. The study included both the costs and the benefits of rooftop solar and only allocated cost to solar customers for the portion of system infrastructure they used. Further, the study used actual 2014 load and solar production data to analyze how residential solar systems produced energy at the time of system and class peaks. The APS peak is broad – system peaks occurred from 5 to 6 pm, but persisted from 3 to 10 pm. Residential customers, including solar customers, peak around 7 pm, with a broad class peak that persisted from 3 to 10 pm. The study credited solar customers for the actual solar energy generated using the actual fuel cost for all solar production, and solar generation capacity was credited based on a combination of system and class peaks. Residential solar customers offset about 19% of their peak demand. Transmission costs and savings were allocated based on system peaks and distribution costs and savings were allocated on class peaks.