An Evaluation of SRP’s Electric Rate Proposal for Residential Customers with Distributed Generation

PREPARED FOR
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PREPARED BY
Ahmad Faruqui, Ph.D.
Ryan Hledik, M.S.

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About the Authors

Ahmad Faruqui is a principal with The Brattle Group who leads the firm’s practice in understanding the changing needs of energy consumers. This work encompasses rate design, distributed generation, energy efficiency, demand response, demand forecasting and cost-benefit analysis of emerging technologies. During his 35 year career, he has analyzed and evaluated a wide range of rate designs for more than three dozen utilities and government agencies in the United States and in Australia, Canada, Egypt, Hong Kong, Jamaica, Philippines, Saudi Arabia, Thailand and Vietnam. He has filed testimony or appeared before state commissions, government agencies, or legislative bodies in Alberta (Canada), Arizona, Arkansas, California, District of Columbia, Illinois, Indiana, Kansas, Maryland, Michigan and Ontario (Canada). And he has addressed regional, national and international conferences in Australia, Bahrain, Brazil, Egypt, France, Germany, Ireland, Jamaica, and the United Kingdom. His work has been cited in publications such as The Economist, The New York Times, USA Today, and The Wall Street Journal. He has appeared on Fox News and National Public Radio. The author, co-author or editor of four books and more than 150 articles dealing with energy issues, he holds a doctorate in economics and a master’s degree in agricultural economics from The University of California at Davis, a master’s degree in economics and a bachelor’s degree in economics, with minors in mathematics and statistics, from the University of Karachi, Pakistan.

Ryan Hledik is a principal in The Brattle Group’s San Francisco office. His expertise is in assessing the economics of demand-side policies, programs, and investments. He has consulted with utilities, policymakers, technology firms, government labs, research organizations, and wholesale market operators. A frequent presenter on the economics of the smart grid, he has recently spoken at events throughout the United States, as well as in Brazil, Canada, Korea, Saudi Arabia, and Vietnam. Mr. Hledik holds a master’s degree in Management Science and Engineering from Stanford University and a bachelor’s degree in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics.
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Section 1: Introduction

1.1 Background

Residential customers are adopting distributed generation (DG), consisting largely of rooftop mounted solar panels, at a rapid rate, spurred on by income tax credits, falling prices of solar photovoltaic (PV) panels and a practice of electricity pricing referred to as net energy metering (NEM). Under NEM, DG customers only pay for their net purchases of electricity, i.e., their gross purchases net of their local generation of electricity.

While renewable energy sources such as rooftop solar are a vital part of the nation’s energy supply, NEM embodies a latent subsidy between DG and non-DG customers. NEM credits DG customers for each unit of power they produce at the same retail rate at which they would otherwise buy it.

This creates two complications:

- The utility’s retail rates include not only the cost of generating the electricity but also the cost of delivering the electricity, consisting of transmission lines, substations, distribution circuits, feeders and lines, line drops, and meters. When a DG customer installs solar panels on his rooftop, he reduces the utility’s cost of generating electricity, and should be compensated for that at the utility’s avoided generation cost. But the customer still requires a connection to the grid for those hours when his solar panels are not generating all of his electricity and for those hours when he over-generates. He still requires power be available from the grid in case the sun is not shining. He still requires a meter, a call center to answer questions about monthly bills, and other vital services. The DG customer, like all other customers, should still pay the utility for those services. But under NEM, the DG customer does not pay for these services.

- Someone else is forced to pay for these costs. It is the non-DG neighbor of the DG customer. Thus NEM amounts to the imposition of a hidden levy on the neighbors who don’t own DG, creating a gross inequity between customers. In the end, it is not the utility that loses in this transaction but the customers without DG. These are often the less affluent customers, who are far less likely to have or be able to afford rooftop solar in the first place, and not the DG customers, who own single-family homes.

As a simplified example to illustrate this problem, suppose the retail rate for power is 11 cents/kWh, and that this rate has been set to cover the combined costs of energy and capacity (inclusive of generation, transmission and distribution). Suppose that the charge for energy is 4 cents per kWh, generation capacity is 2 cents per kWh, the charge for transmission is 3 cents/kWh and the charge for distribution is 2 cents per kWh. Only the energy component is a true variable cost that is sensitive to the volume of sales. The other three components are fixed
or demand-related costs that are often embedded in the volumetric portion of the rate, based on the load profile of an average customer. When a DG customer installs solar equipment on his roof and generates a unit of electricity, the fair compensation for the DG customer is 4 cents/kWh. The customer has not offset the cost of staying connected to the electric grid, which provides transmission and distribution functions and backup generation.

However, under NEM, the DG customer is over compensated at 11 cents/kWh, even though he has not avoided the 7 cents/kWh cost for staying on the grid. The utility is then forced to make up its revenue shortfall by raising rates for all its customers. The problem is aggravated by the fact that today’s rate designs for residential customers are largely volumetric in nature. The majority of the fixed costs of running the grid are recovered through a volumetric formula.

The best way for restoring fairness in rate design for DG customers is to move the fixed costs out of the volumetric charge and recover them through a fixed charge (i.e., dollars per month) and a demand charge (i.e., dollars per kilowatt of maximum demand per month). Smart meters are being rapidly deployed across the country, allowing the utility to measure not only the energy that customers consume per month, but the customer’s demand on the grid as well. Furthermore, the 4 cents/kWh component for avoided energy costs could vary by time of day, as these costs are higher-than-average during afternoon and evening hours (often when the sun is shining) and lower-than-average during nighttime hours.

### 1.2 Purpose of Our Report

To address the issues of inequity and fixed cost recovery described above, SRP has proposed to introduce a new rate for residential customers who are planning to install DG capability. This paper presents an evaluation of this proposal, using the pricing principles laid out by SRP’s Board.

The paper does not address related policy issues such as decoupling, new regulatory models, caps on NEM participation, or changes to solar incentives like rebates and tax credits. It does also not address rate design issues for non-residential customers. It is focused entirely on residential DG rate design.

### 1.3 Principles of Rate Design

The SRP Board of Directors has laid out the principles against which rate designs should be evaluated. These principles provide the backdrop against which SRP’s rate proposal for DG customers is evaluated.

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1. These customers are often referred to as self-generation customers.
• Gradualism – to enhance sound, economic decision-making by customers of all types through stabilizing price levels and smoothing the impact of cost movements that may be caused by temporary factors

• Cost Relation – to establish prices in relation to costs and SRP’s stewardship to its water constituents, and thus not to pursue the maximization of “profit”

• Choice – to constantly improve customer satisfaction through the creative design of pricing structures that reflect customers’ different desires or abilities to manage the consumption, assume more price control, or demand differentiated products and services, among others

• Equity – to treat customers of all types in an economically fair manner

• Sufficiency – to recover the cost of, and to invest and reinvest in a system of assets to perform its policy obligations, including its obligation to store and deliver water to the owners of land within the boundaries of the Salt River Reservoir District, to maintain SRP’s financial well-being, and to follow the foregoing principles.

1.4 Organization of the Report

The rest of this report is organized as follows: Section 2 presents a conceptual menu of rate reform options, Section 3 reviews which of these options have found traction around the country, and Section 4 evaluates SRP’s DG rate proposal.
Section 2: The Menu of Rate Reform Options

DG rates can be redesigned in a variety of ways to address the shortcomings described in Section 1. As background for the discussion of SRP’s DG rate proposal, this section draws upon utility experiences in other regions of the country to present a variety of options for reforming rates for DG customers. It also discusses key decisions that must be made by utilities as they make the rate transition for future DG customers.

2.1 Rate Reform Options

Rates for DG customers can be redesigned to address the cross-subsidy discussed in Section 1 in a variety of ways. These include the following:

**Introduce a demand charge.** Utilities can introduce a demand charge ($/kW) for customers with DG, in addition to collecting from them a monthly fixed charge ($/month) and a variable energy charge ($/kWh). A demand charge is a charge based on a customer’s maximum kW demand over a specified time period – typically the monthly billing cycle. It is typically based on the customer’s maximum demand across all hours of the month or on their maximum demand during peak hours of the month, or sometimes on both. Since most capital grid investments are driven by demand, the idea is that demand charges will better align the price that customers pay with the costs that they are imposing on the system. Such a rate is also called a three-part rate and is commonly used for commercial and industrial customers.

**Raise the fixed monthly charge.** Most residential rates currently offered in the U.S. include a fixed monthly charge (sometimes called a customer charge or a customer service charge) that is approximately in the range of $5-$15/month along with an energy charge. While the size of the customer charge is generally consistent with the magnitude of fixed customer costs like metering, billing, customer care and other administrative services, it typically does not account for the fixed costs of generation, transmission, and distribution capacity that must be recovered by the utility over time. Increasing the fixed charge allows some or all of that capital investment to be recovered with relative certainty for the utility.

**Impose a minimum bill.** An alternative to a higher fixed monthly charge is a minimum bill. The minimum bill ensures that all customers will pay a minimum threshold amount each month. For instance, with a minimum bill of $50/month, a customer whose bill would have been $30 under the existing rate for a given month would be billed $50 for that month. In a different month, if the customer’s bill under the existing rate would be $60, then the minimum bill feature would not come into play and their bill would remain unchanged. The theory is that the minimum bill amount can be associated with the average customer’s cost of using the grid and therefore guarantee that amount to be recovered on a monthly basis.

**Levy a capacity charge.** A charge can be levied on DG owners based on the installed capacity of their DG systems. This results in an additional fixed monthly charge for DG owners, with the size of that charge being determined by the customer’s generation capability. The reasoning
behind this design is that customers with larger systems will self-generate more electricity, thereby avoiding paying a larger portion of their grid costs and justifying a larger offsetting incremental monthly charge on their bill.

**Collect a DG output fee.** Somewhat similar in concept to the capacity charge, a DG output fee would charge DG owners based on the total amount of electricity that they produce from on-site generation each month. In other words, the DG owners would still be paid for the electricity that they generate, but some of this payment would be offset by the DG output fee. Whereas the capacity charge is a dollars-per-kilowatt charge, the DG output fee is a dollars-per-kilowatt-hour charge. The DG output fee reflects the customer’s cost of using the distribution system. This approach has also been referred to as a “bidirectional distribution rate.”

**Collect a connection fee.** DG owners could be charged a one-time grid connection fee at the time that they install on-site generation. The fee would be levied to recover the cost of the sunk investment in the grid that would still be used to serve these customers but which would otherwise no longer be recovered through their rates (under net energy metering conventions) once the DG system is installed.

**Streamline the tiered rate structure.** Some utilities currently offer a variable charge that increases with usage, commonly referred to as a tiered or inclining block rate (IBR) structure. For example, a customer might pay 10 cents/kWh for the first 300 kWh of electricity in a month, 15 cents/kWh for the next 300 kWh of consumption, and 20 cents/kWh for all additional consumption. In some regions, the price differential between the tiers bears no relationship to the underlying cost structure of electricity supply. Customers are motivated to install DG systems to avoid the non-cost based upper tier rates, creating an economic inefficiency. In these cases, the prices in the upper tiers could be reduced and the prices in the lower tiers could be increased to reduce the price differential between tiers. This “flattening” of the rate structure would reduce economic inefficiencies by bringing the incentive to install DG systems in line with the utility’s cost structure.

**Introduce time-varying rates.** The variable charge can also be modified to include time-differentiated prices, with a higher price being charged during on-peak hours and a lower price during off-peak hours, reflecting the corresponding variation in utility capacity and energy costs by on-peak and off-peak periods. While this change by itself would not eliminate the cross-subsidies created by net energy metering, it would be consistent with the idea of modifying rates to better reflect the underlying cost structure.

**Introduce a buy-sell arrangement.** Many net energy metering policies compensate DG owners at the full variable charge in the retail rate. As discussed previously, when rates disproportionately collect revenue through that variable charge, DG owners are overcompensated for the electricity they generate. Under a “buy-sell” arrangement, DG owners would pay for all of the electricity

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that they consume at the full retail rate, and would separately be compensated for all of the electricity that they generate at a price that more accurately reflects the value of the electricity being generated. This approach is also commonly referred to as a “value of solar” model, a feed-in-tariff (or “FIT”), or a dual meter tariff.4

2.2 Key Decisions in the DG Rate Transition

In addition to determining the specific design elements to be included in the reformed DG rate, there are a number of policy decisions to consider. The following are key questions that should be answered in a new DG rate proposal.

Should the new rate be offered only to DG owners or to all residential customers? Modifying the rate only for DG customers has the advantage of restricting the immediate bill impacts of the rate change to a small subset of the utility’s customers. This limits the number of customer considerations that must be made when evaluating the rate. Since DG owners have a different load profile than other customers and are acting both as consumers and as generators, their unique status warrants the creation of a specific rate class. Offering special rates to DG customers is analogous to the development of “standby rates” for “partial requirements” customers in the commercial and industrial classes. Alternatively, if the proposed rate changes are cost-based and represent an overall improvement upon the existing rate structure according to sound principles of rate design, then it could be argued that only making these changes for DG customers is a missed opportunity to improve the rate design of the entire residential class.

Should current owners of DG be subject to the new rate design or should they be allowed to “grandfathered” onto the existing pricing policy? Typically, significant changes to the DG rate and/or the net energy metering policy have been accompanied by a grandfathering rule that allows existing DG owners to continue to be billed under the old pricing policy. The argument for this approach is that those customers made the decision to purchase their DG systems under a pre-established pricing agreement with the utility – or at least with the expectation that the existing arrangement would continue to be honored in the future. The grandfathering policy avoids placing an unexpected financial burden on those customers under the new pricing structure. The counterargument to such a grandfathering policy is that all investments are subject to the risk that future policies can change, and that DG investments are no different in this regard and should therefore not be given any special treatment.

Will the new DG rate be offered on a mandatory, opt-out, or opt-in basis? A mandatory rate offering ensures that all applicable customers will be enrolled in the newly designed rate. If it is desired to offer a choice of rates, then the new rate can be introduced on either an “opt-out” or “opt-in” basis. With an opt-out (or “default”) offering, all customers are moved over to the new rate and then presented with the option to enroll in an alternative rate (or rates) if they choose.

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4 There are nuanced differences in these approaches, mostly revolving around how to determine the price that is paid to DG owners for their power generation. But at a basic level, all of these approaches include a bifurcation of power purchases from the grid from power sales to the grid.
Research has found that with this approach most customers will continue to remain on the new rate. With an opt-in offering, customers are presented the new rate as a voluntary option in which they must proactively enroll. Enrollment in the new rate will be the lowest with an opt-in approach.

**Will the DG rate include a surcharge or will all modifications be revenue neutral?** As discussed earlier in this section, DG rates may be modified to include a surcharge that is incremental to the rate that the DG owners would otherwise pay. This surcharge is intended to offset the DG owners’ underpayment for their use of the grid. While this may have a cost basis, it is often met with resistance and characterized by some as a special “tax” on DG owners. An alternative approach is to modify the DG rate structure to better reflect system costs, but to make the changes in a way that is revenue neutral for the residential class. In other words, for the average residential customer, the new rate would produce the same bill as the old rate in the absence of any change in electricity consumption behavior.

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Section 3: The National Landscape of DG Rate Reforms

There is widespread recognition in the US among regulators and utilities of the major issue raised in Section 2, that NEM creates unsustainable cross-subsidies from non-DG customers to DG customers. Efforts to reform residential rates to eliminate this NEM cross-subsidy are underway with varying degrees of success. This section presents a survey of recent state and utility DG rate reform activity. These case studies illustrate the broad variety of approaches to rate reform. They are meant to be illustrative of the national landscape and not necessarily be exhaustive in coverage.

Each of the cases studies reflects its unique circumstances, metering capabilities and regulatory milieu. But there is a common element in many of the case studies. Just about all of them are proposing to raise the fixed charge in a two-part rate design construct. Some utilities are willing to proceed with the three-part rate design which includes a demand charge. Some feature a time-varying volumetric charge while others have decided to stay, at least for the time being, with a flat energy charge.

In some cases, the volumetric charge has an inclining block rate structure. While it is not always clear, it seems that existing DG customers will be grandfathered on the old NEM provisions for several years. That is how the issue of transition is being dealt with.

Some utilities are considering eventually extending the three-part for all residential customers. It is noteworthy that this is already the case for at least 10 utilities in a dozen states. But the offerings are optional unlike the practice for medium to large commercial and industrial customers where the offerings are mandatory or default (as in restructured markets). The issue of whether to make the three-part rate the standard rate for all residential customers continues to be debated. While there is universal agreement that that would be the optimal rate from an efficiency and equity perspective, the transition would create winners and losers with the attendant controversies.

Finally, some utilities are compensating DG customers using a “value of solar” construct rather than the retail rate. This is similar to the buy-sell arrangement being used by some utilities. In some cases, this involves compensating the DG customer at the wholesale power rate which is considerably lower than the retail rate. In other cases, it involves the inclusion of externalities that could result in a number that is higher than the retail rate.

Given the large volume of activity in DG rate reform, it is likely that these initiatives will continue to develop and evolve at a rapid pace.

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6 While utilities are frequently proposing a variety of changes to their rates, in this section we have focused specifically on those aspects of recent proposals that are designed to address fixed cost recovery.
**Arizona:** In July 2013, Arizona Public Service (APS) proposed a new NEM policy for DG owners. APS proposed two options. The first option would put DG owners on a three-part rate and continue to compensate them for their generation at the full retail rate. The second option was a buy-sell arrangement under which DG owners would have all consumption billed under one of the existing rate options, but they would be paid a lower wholesale rate for the electricity that they generate. In November 2013, the Arizona Corporation Commission instead voted to implement a $0.70/kW capacity charge for DG owners, equating to a surcharge of roughly $5/month for a typical residential rooftop solar installation.7

Additionally, APS offers the most highly subscribed three-part rate in the United States. Offered on an opt-in basis since the early 1980’s, approximately 10 percent of APS’s residential customers are enrolled in the rate, representing roughly 20 percent of residential sales.8 Participants face a demand charge of $13.50/kW in the summer and $9.30/kW in the winter, as well as a $16.68/month fixed charge and a time-varying energy charge.9 The rate option is available to all residential customers including DG owners.

**California:** In California, two of the three investor owned utilities (IOUs) currently do not have a fixed charge in their residential rate (San Diego Gas & Electric and Pacific Gas & Electric) and the third (Southern California Edison) has a nominal fixed charge of $0.94/month10. All three utilities have very small minimum bill requirements. Additionally, the residential rate is an inclining block rate with four tiers. The gap in prices has grown over time and now exceeds a ratio of 2:1.11 In ongoing proceedings on redesigning residential rates, the utilities have proposed to reduce the number of tiers from four to two and to significantly reduce the price differential. They have also proposed a fixed charge of $10/month.12 These changes would be phased in over a four-year period, and customers would also have the option to enroll in a variety of alternative time-differentiated rates.

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8 Based on FERC Form-1 Data from 2013 and 2014.
In contrast, Sacramento Municipal Utility District (SMUD) has proposed to transition all of its residential customers to a rate with a time-varying volumetric charge and a $16/month fixed charge. The transition will occur over a multi-year period.\textsuperscript{13}

**Connecticut:** Connecticut Light and Power (CL&P), a subsidiary of Northeast Utilities, recently requested an increase in its fixed charge from $16 to $25.50.\textsuperscript{14} A December 17, 2014 decision by the Public Utilities Regulatory Authority (PURA) approved a smaller increase, raising the fixed charge to $19.25/month.

**Georgia:** In its 2013 rate case, Georgia Power proposed a new tariff for DG customers in all classes. Specifically, the utility proposed to introduce a monthly capacity charge of $5.56/kW. For a 4 kW rooftop solar system, this translates into $22.24/month. The charge would have been entirely incremental to the existing rate. DG customers could avoid the capacity charge if they took service on a demand or RTP rate. However, in November 2013 Georgia Power withdrew its proposal as part of a settlement agreement with interveners. Residential rooftop solar owners continue to be billed under the utility’s tiered rate structure, which has inclining tiers in the summer and declining tiers in the winter, and includes a $10/month fixed charge.\textsuperscript{15} In that rate case, however, Georgia Power received approval for an optional three-part tariff with a time-varying energy charge for residential customers.

**Hawaii:** Hawaiian Electric Company (HECO) filed a Power Supply Improvement plan (PSIP) and a Distributed Generation Improvement Plan (DGIP) before The Hawaii Public Utilities Commission on August 26, 2014. The plan includes an illustrative $55/month fixed charge for all residential customers and an additional $16/month charge for DG owners, accounting for standby generation and capacity requirements. The filing also describes a “gross export purchase model” which compensates net energy metered customers at wholesale rates for the power they contribute to the grid.\textsuperscript{16} However, this one of several possible scenarios described in the plans, and no formal request for a rate change has yet been filed with the commission. Both the PSIP and DGIP are under review by the Hawaii Public Utilities Commission.

**Idaho:** In late 2012, Idaho Power proposed to increase the fixed charge for residential net metering customers from $5/month to $20.92/month. With this proposal, Idaho Power would have also established a “basic load capacity charge” of $1.48 per kilowatt that would be applied to the average of the two highest billing demands for each customer’s most recent twelve month

\textsuperscript{14} FOX CT news \texttt{http://foxct.com/2014/12/01/pura-proposal-cuts-clp-customer-increase-by-6mo/}, accessed 12/19/2014.
\textsuperscript{15} Georgia Power Residential Service Schedule: “R-20”, p.1
period. These new charges would be offset by a reduction in the energy rates paid by net metering customers. The Idaho Public Utilities Commission rejected the rate design proposal in July 2013, stating these changes could be raised again in the context of a general rate case.\(^{17}\)

**Louisiana**: Entergy proposed to reduce the net metering payment to DG owners, in recognition that solar-powered homes aren’t paying for their full use of the grid. The Louisiana Public Service Commission rejected the proposal in June 2013, but agreed to conduct a detailed study on the costs and benefits of solar, and to revisit the issue when the enrollment cap on the state’s net metering policy is reached.\(^{18}\)

**Minnesota**: Minnesota has passed legislation that will allow its utilities to use a “Value of Solar” tariff (or buy-sell arrangement) as an alternative to traditional net metering. The measures of value that will ultimately determine the payment to DG generators are energy and its delivery, generation capacity, transmission capacity, transmission and distribution line losses, and environmental value.\(^{19}\)

**Nevada**: In 2013, NV Energy received approval for an increase in its fixed charge for all residential customers in its northern service territory. The fixed charge was increased from $9.25/month to $17.50/month,\(^{20}\) citing a desire by the PUC to adhere to a “cost follows causation” principle. Additionally, an initial proposal in the utility’s southern territory included an increase in the fixed charge from $10/month to $15.25/month. However, the utility has since modified its proposal as part of a settlement process and is now seeking a $2.75/month increase, which the Nevada PUC is considering.\(^{21}\) The increase in the fixed charge would be offset by a decrease in the volumetric charge, resulting in no net change in revenue.

**South Carolina**: A settlement agreement reached in December 2014 between utilities, conservation groups, and solar industry groups in South Carolina outlines key provisions for DG rates. One key provision dictates that rooftop solar owners be credited at the full retail rate. Additionally, charges cannot be levied exclusively on DG owners.\(^{22}\)

**Texas**: Austin Energy began offering a “Value of Solar” tariff in October 2012. The tariff is similar in concept to the buy-sell arrangement offered by other utilities, although the payment to

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\(^{17}\) The Idaho Public Utilities Commission Website  
<http://www.puc.idaho.gov/fileroom/cases/summary/IPCE1227.html>


<https://www.snl.com/InteractiveX/ArticleAbstract.aspx?id=26308183>


DG owners includes a number of components, such as environmental value and avoided fuel hedging costs, that tend to lead to a higher price paid to DG owners. The tariff also includes a floor price that ensures a minimum payment level to DG owners over a future time period.23

**Utah:** After several years of unsuccessful attempts to introduce a customer charge above $5/month, PacifiCorp (through subsidiary Rocky Mountain Power) proposed a surcharge of $4.65/month for DG customers, indicating that the charge would “produce the same average monthly revenue per customer for distribution and customer costs that is recovered in energy charges from all residential customers based on the cost of service study.”24 In its rate case testimony, the utility advised the Utah Commission that the surcharge was an interim measure and that in its next rate case it would be proposing a three-part rate designed specifically for partial requirements DG customers. The Public Service Commission of Utah did not approve the proposal, citing a need for further assessment of the costs and benefits of net metering.

**Washington:** PacifiCorp has proposed to increase its fixed charge from $7.75/month to $14/month. The proposal is packaged with a request for an overall rate increase. As in Utah, the utility advised the Washington Utilities and Transportation Commission that in its next rate case it would be proposing a three-part rate designed specifically for partial requirements DG customers. A decision from the commission is expected by March 2015.25

**Wisconsin:** In June 2014, Madison Gas & Electric (MGE) proposed to eventually transition all of its residential customers to a three part rate. The rate would have included an increased fixed charge, a flat variable charge, and two different demand charges. One demand charge was based on a customer’s maximum demand during any hour (designed to collect distribution costs) and the other was based on a customer's maximum demand during peak hours (designed to collect system peak-driven costs). During the interim period of transition to this three-part rate, MGE proposed a fixed charge that would escalate over a multi-year period and eventually be replaced with the demand charges. MGE ultimately withdrew this proposal, and the Wisconsin Public Service Commission is instead expected to approve a $19/month fixed charge, which is an $8.50 increase over the current fixed charge of $10.50/month.26 The commission is also expected to...

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approve fixed charges of $16/month for We Energies\textsuperscript{27} and $19/month for Wisconsin Public Service Company.\textsuperscript{28}

It should be noted that there are currently at least 10 utilities offering three-part rates to residential customers in a dozen states. Although most of these rates have been offered for years and are not specific to DG customers, they share many characteristics with the rate proposals described above. The utilities currently offering a residential three-part rate are Alabama Power, Alaska Electric Light & Power (“AELP”), Arizona Public Service (“APS”), Black Hills (in South Dakota and Wyoming), Dominion (in Virginia and North Carolina), Duke Energy (in North Carolina and South Carolina), Georgia Power, Westar Energy, and Xcel Energy (in Colorado). The rates vary across characteristics such as the timing of demand measurement, the duration of the demand interval, and whether the energy charge is time-varying.\textsuperscript{29} But all of the rates share the same basic common elements of the three-part rate: A demand charge, a fixed charge, and a variable charge. While these existing three-part from other jurisdictions are not specific to DG customers, they are useful for benchmarking SRP’s proposed three-part rate design, as we do in Section 4.


\textsuperscript{29} For more information, see Ryan Hledik, “Rediscovering Residential Demand Charges,” \textit{The Electricity Journal}, August/September 2014.
Section 4: SRP’s Proposed DG Rate

Against the backdrop of the national experience with pricing electricity to DG customers, this section discusses SRP’s DG rate proposal. It first summarizes the key elements of SRP’s proposal as they relate to the various DG rate design options presented in Sections 2 and 3. It then provides an assessment of the extent to which SRP’s proposal satisfies the ratemaking objectives presented in Section 1.

4.1 Key Elements of SRP’s Rate Proposal

SRP is proposing a new three-part rate for its residential DG customers, referred to as the E-27 Customer Generation Price Plan. The rate is composed of three parts: a fixed monthly charge, a time-varying variable charge, and a demand charge.

The fixed charge varies by a customer’s amperage (i.e., the size of their connection to the distribution system). It is $32.44/month for customers with 200 amps or less and $45.44/month for customers above 200 amps. Relative to the proposed fixed charge of $20/month for residential non-DG customers, that represents an increase in the fixed charge for all DG customers, driven primarily by an increase in the amount of distribution capacity cost that is recovered through the fixed charge.

The variable charge varies by time of day. There are two pricing periods, an on-peak period and an off-peak period, and the price of each varies by season. In the summer the on-peak period price is 4.86 cents/kWh and the off-peak price is 3.71 cents/kWh.30 In the winter the on-peak price is 4.30 cents/kWh and the off-peak price is 3.90 cents/kWh. Additionally during the on-peak summer months of July and August, the on-peak period price rises to 6.33 cents/kWh and the off-peak period price rises to 4.23 cents/kWh, reflecting the higher cost of providing electricity in these months when air-conditioners are running heavily and demand for electricity is high.

The demand charge is tiered, meaning that the price increases with a customer’s demand. It also varies by season. Demand is measured as the customer’s maximum demand in any 15 minute interval during the on-peak period. In the summer, a customer’s first 3 kW of demand are charged $6.61/kW, the next 7 kW of demand are charged $12.07/kW, and any additional demand is charged $22.98/kW. In the summer peak months (July and August), the demand charges are $8.10/kW, $15.05/kW, and $28.93/kW, respectively. In the winter, they are $2.87/kW, $4.57/kW, and $7.91/kW, respectively.

30 In the summer (May 1 through October 31) the on-peak period is from 1 pm to 8 pm, Monday through Friday, excluding holidays. In the winter (November 1 through April 30) it is from 5 am to 9 am and from 5 pm to 9 pm, Monday through Friday, excluding holidays. The off-peak period is all other hours.
SRP has designed the rate to be revenue neutral for the typical DG customer before the customer has installed DG. The proposal includes a grandfathering clause that would allow existing DG customers to continue to be billed under the current pricing policy for 10 years. The rate applies only to DG owners and is a mandatory rate, meaning that they do not have a choice of alternative rate options.

**4.2 Benchmarking SRP’s Proposal**

Several elements of SRP’s DG rate proposal are similar to the proposals of other utilities discussed in Section 3.

SRP’s decision to offer a three-part rate is mirrored by the proposals and/or existing rates of APS, MGE, and PacifiCorp utilities. APS currently offers an optional residential three part rate that is similar to SRP’s proposal, with a time-varying energy charge and recovery of capacity costs primarily through a demand charge. However, unlike SRP’s proposed rate, APS’s rate is available to DG customers as an option rather than being mandatory. SRP’s proposal is also similar to the DG rates vision that has been established by PacifiCorp. Both SRP’s proposal and the BHE proposal include a three-part rate that applies specifically to DG owners. MGE’s originally proposed three part rate was also similar to SRP’s design, but with the exception that MGE was proposing to make its rate mandatory for all customers rather than just for DG owners.

SRP’s proposal to increase the fixed charge is similar to the recently approved fixed charge increases for Nevada Power and SMUD, as well as the proposal by CL&P, among other utilities. However, SRP’s proposed fixed charge – ranging from $32/month for smaller customers to $45/month for larger customers – while aligned with SRP’s fixed costs, is higher than the fixed charges of these utilities.

SRP’s application of its new rate only to DG customers is also consistent with that of several other proposals. For example, the capacity charges included in the DG rates that were recently approved for Georgia Power and APS apply only to DG customers, as does the incremental fixed monthly charge proposed by HECO. This is in contrast to the recently adopted policy in South Carolina, for example, which dictates that any changes to rates for DG customers will also apply to all other residential customers.

SRP’s proposal to maintain its net metering policy of compensating DG owners at the full variable price in their rate is common to many of the proposals we have reviewed. In fact, at least 32 states have net metering policy that compensates the DG owner at the full retail rate for all electricity produced, including all net excess generation, and many more states credit at least a

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31 APS’s rate is the most highly subscribed three-part residential rate in the United States.
portion of the electricity at the full retail rate. This is in contrast to the buy-sell arrangements of utilities such as Austin Energy and the Minnesota utilities.

There are also some elements of SRP’s proposal that are unique relative to the case studies discussed in Section 3. SRP seems to be the only utility that has proposed a tiered demand charge. It is not clear if any other utility has formally proposed a fixed charge that varies with a customer’s amperage, although this is an idea that is frequently being discussed.

As discussed in Section 3, three-part rates are currently offered to residential customers by a handful of utilities across the United States. These rates are not specific to DG customers and are available to the entire residential class, potentially limiting their comparability to SRP’s proposal. However, the comparison is still relevant for contextual purposes.

A comparison of SRP’s demand charge to that of the other existing three-part rates is shown in Figure 1 and Figure 2. The first two tiers of SRP’s demand charge generally fall within the range of demand charges being offered by other utilities. The third tier price is higher than other rate offerings. For comparability, the charts also show the average demand charge for a customer with 10 kW of monthly demand. On average, an SRP DG customer with 10 kW of demand would pay $10.43/kW in the summer (including the summer peak months of July and August), and $4.06/kW in the winter, prices that are generally within the range of these other rate offerings. Smaller customers, of course, would pay a lower average price for demand and larger customers would pay a higher average price.

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33 DSIRE database on net metering <http://www.dsireusa.org/summarytables/rrpre.cfm>. We considered the net metering policy for all states and the District of Columbia. Only states where compensation amount was a function of retail rates were included.
Figure 1: Summer Demand Charge in Residential Three-Part Rates

Figure 2: Winter Demand Charge in Residential Three-Part Rates

Notes:
Georgia Power’s rate is a proposed modification to its existing rate and approval is pending.
Xcel Energy’s rate is currently closed to new enrollment.
Rates are from utility tariff sheets as of May 2014.
SRP’s proposed fixed charge is compared to the fixed charge of the other three-part rate offerings in Figure 3. SRP’s fixed charge is similar to that of Xcel Energy but significantly higher than the other rate offerings. This difference is likely explained by the fact that SRP’s rate collects a larger portion of distribution costs (i.e., the Distribution Facilities Charge) than is collected by the other rates.

![Figure 3: Fixed Charge in Residential Three-Part Rates](image)

SRP’s variable charges are lower than around half of those in the three-part rates being offered today. Figure 4 shows this comparison. The height of the bars represents the difference between the peak period price (the top of the bar) and the off-peak period price (the bottom of the bar) for rates with a time-varying energy charge. Rates that do not have a time-varying energy charge are represented with a gray diamond.
4.3 Assessing the Proposal

SRP’s proposed Customer Generation Price Plan has very significant advantages over the current rate offering. Perhaps most importantly, the proposal’s three-part rate structure aligns much more closely with the underlying cost of supplying electricity to customers. By collecting demand-related costs through a demand charge, fixed costs through a fixed charge, and variable costs through a time-varying variable charge, SRP’s proposal satisfies the ratemaking objectives of economic efficiency and “cost causation.” By better reflecting costs, the rate will address the inequities that exist in the current rate designs, particularly as they relate to the under-recovery of fixed costs from DG customers.

The recovery of capacity costs through a demand charge is a particularly attractive feature of the rate. This will credit DG customers for the peak-coincident capacity that they provide to the system. By recovering capacity costs through a demand charge rather than a fixed charge, SRP’s proposal avoids the challenge of automatically increasing bills for small customers, a common argument against high fixed charges. And unlike a fixed charge, the demand charge provides customers with a strong incentive to lower their bills by reducing their kW demands. Finally, since demand charges have been offered to commercial and industrial customers for decades,
there is well established precedent for designing such rates, enrolling customers, handling calls and doing all the other activities that attend to their offering. With smart meters fully deployed across SRP’s service territory, there is no longer a technical barrier to offering these rates to residential customers.

The time-varying and seasonal nature of the volumetric charge is another attractive feature of the rate. Since energy costs vary over the course of the day, capturing this variability in the rate structure helps to ensure that customers face accurate price signals when making decisions about their electricity consumption behavior.

SRP’s NEM policy is also a strong feature of the proposal. With a cost-based three-part rate, it is not necessary for SRP to modify its current NEM arrangement of compensating DG owners for their electricity production at the full variable rate. In other words, SRP has not proposed to implement a buy-sell arrangement, since there is no strong and compelling reason for them to do so. As designed, the rate will sufficiently recover fixed costs from those who impose the costs on the system, while compensating them at a fair rate for the electricity that they generate.

SRP’s plan to allow current DG owners to continue to be billed under their current rate for a period of 10 years is also a positive feature of the proposal. This grandfathering policy will facilitate the transition to the new rate by ensuring that customers will not experience bill increases when the rate is rolled out. Those customers who are considering investing in DG will be able to do so with complete information about their future pricing structure.

Overall, SRP’s proposed rate is well designed and represents a significant improvement over the current offering. A three-part rate is perhaps the most effective way to satisfy the principles of economic efficiency and cost causation, reduce inequities in existing rates, and provide customers with an opportunity to reduce their bills through smarter energy management. It is the ideal DG rate design.34

34 In the future, SRP may wish to further refine its rate offerings. Two are discussed here. First, SRP might want to consider incorporating two demand charges into the rate. In addition to the currently proposed demand charge, which is constrained to the peak hours of the day, a second demand charge would be based on the customer’s maximum demand at any point in the day. Adding the second demand charge could further improve the extent to which the rate reflects SRP’s underlying cost structure, although such a change would need to be made with considerations for the tradeoff with simplicity and a customer’s ability to understand and act on the rate. And, second, SRP might consider making the three-part rate the standard for all of its residential customers, not just its DG customers. This rate design has a number of distinct advantages over the existing residential rate options. Deploying the rate to all residential customers would require that the rate rollout be accompanied by a carefully designed customer education and outreach plan that is informed by market research. Other customer protections, particularly for vulnerable customers, may also be needed.
Additional Resources


http://www.edisonfoundation.net/iei/Documents/IEI_NEM_Subsidy_Issues_FINAL.pdf


