

# Current Developments in Retail Rate Design: Implications for Solar and Other Distributed Energy Resources

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## Executive Summary

Retail electricity pricing is evolving in the context of broader shifts in how electricity customers pay for grid services and how they are compensated for customer-sited generation. This evolution has been prompted by a broad set of factors, chief among them being: widespread adoption of advanced metering infrastructure (AMI), increased customer investment in solar and other distributed energy resources (DERs), concerns about utilities' fixed cost recovery and revenue sufficiency in an era of flat or declining load growth, and significant changes to utilities' hourly net load profiles and operational needs as greater amounts of variable renewable energy (VRE) resources connect to the grid.

This report discusses five current retail rate design trends among residential and commercial customer classes that have emerged, at least in part, in response to those drivers, and uses case studies to illustrate key motivations, variations in rate design, and aspects of implementation experience.

Highlights from our review of these rate design trends include the following:

- **Increased pursuit of residential time-based rates:** Though the federal government enacted legislation over forty years ago asking states to consider the appropriateness of time-based rates, currently only around 3% of residential electricity customers see any temporal variation in the price of electricity (Hledik et al., 2017). As advanced metering infrastructure (AMI) deployment progresses, broader and stronger regulatory support for the adoption of time-based rate options is beginning to emerge. For example, based on the results of their two-year residential pricing pilot, the Sacramento Municipal Utility District (SMUD) is currently transitioning all of its residential customer to a default time-of-use (TOU) rate, which has a peak-period shifted to late afternoon and early evening hours (5-8 PM) (SMUD, 2017). Starting in 2010, Oklahoma Gas & Electric (OG&E) began to test with its residential and small commercial customers a variant of a TOU rate, where the peak price changed daily to better reflect contemporaneous market conditions. That pilot was so successful that the utility gained authorization from its regulators to offer the rate starting in 2013 on a voluntary basis to all its residential customers, with the goal of enrolling 20% of them within three years. As of December 2016, OG&E had enrolled about 107,000 residential customers in its SmartHours Variable Peak Pricing (VPP) rate, representing 19% of its residential customer base (AEG, 2017).
- **Development of rates and programs to promote midday load building:** Utility system planners and system operators in some regions are anticipating, if not already observing, steep declines in load during the morning and steep inclines in late-afternoon/early-evening periods, due to solar PV resources on the bulk power system. This may result in wholesale power costs dropping precipitously during midday hours and curtailment of renewable generators (Seel et al., 2018). One strategy utilities have considered to assist in grid management employs TOU rates designed with very low priced ("super off-peak") periods that coincide with these low cost midday hours (sometimes referred to as *matinee pricing*). California's investor-owned utilities are currently testing whether residential customers will increase their usage in response to such super-off peak

prices as well as reduce or shift usage away from higher-priced peak periods that primarily cover late afternoon and early evening hours, year-round (CPUC, 2015). Alternatively, a utility could pursue programs that provide direct financial incentives for customers to use more load when there is excess generation on the system. Arizona Public Service (APS) recently filed a proposal to implement a reverse demand response program to promote load building during certain periods of time in order to avoid curtailing renewable energy production (APS, 2017). This proposal was filed in September 2017, and is currently awaiting decision from the Arizona Corporation Commission.

- **Increased application of residential three-part rates:** While three-part rates (i.e., demand charges, along with volumetric energy charges and fixed customer charges) have been largely confined to commercial and industrial customers, utilities have become increasingly interested in extending demand charges into the residential sector as well, with the stated purpose of better aligning rate design with underlying cost causation and stabilizing fixed-cost recovery. Within the residential sector, demand charges have been offered mostly on a voluntary basis, but several utilities have implemented or proposed such rates on a mandatory basis, at least for customers with rooftop PV or other DERs. APS has perhaps the longest running experience among investor-owned utilities (IOUs) with voluntary demand charge rates for residential customers and recently launched a new set of tariff options, with 17% of customers opting onto one of the demand charge rates. Analysis of a previous APS tariff offering found that customers on the demand charge rate reduced their billing demand by roughly 11%, on average. Salt River Project (SRP) also recently introduced a mandatory demand charge rate for new rooftop solar customers. Customers on SRP's new demand-charge rate have reduced their billing demand by 11% on average, potentially enabled by the sizeable contingent of recent solar adopters that also installed storage. Despite those demand management efforts and opportunities, new solar applications are roughly 20% below their level prior to implementation of the new tariffs.
- **Development of new net-metering alternatives:** Many states have undertaken reforms of existing net energy metering (NEM) tariffs, driven chiefly by concerns about cost-shifting between NEM participants and other ratepayers, and to incentivize customer DER investments that provide greater benefits to the broader electric system. Among states that have adopted an alternative to NEM, *net billing* has been, by far, the most common approach—whereby customers can continue to offset contemporaneous usage with DERs, but any exported energy is compensated at some designated grid-export rate. New York's Value of Distributed Energy Resources (VDER) tariff represents a relatively sophisticated form of net billing, with grid export rates that vary by time and location, and a phased implementation schedule for different market segments. Hawaii has also moved to net billing, with a range of transitional tariff options, and has seen a sizeable portion of applications in the past year opt for solar+storage configurations in order to qualify for more-favorable grid export prices and other terms.
- **Development of new electric vehicle-specific rates:** States and utilities with some of the highest growth and interest in supporting electric vehicle (EV) adoption are introducing retail rates specific to EVs. In addition, some EV-specific rates are designed to potentially better direct charging

behaviors in ways that minimize the grid impacts and also potentially benefit the grid from such electric-intensive end-uses. EV-specific rates primarily differ as to whether they include demand-based or time-based energy charges, a potentially contentious detail that may incentivize or de-incentivize certain forms of EV charging (e.g., demand charges may particularly impact public charging by penalizing fast chargers, which are demand intensive). Georgia Power’s rate offers EV-owners a time-based (TOU) energy charge applicable to the entire household consumption. This contrasts with Austin Energy’s residential fixed, monthly fee limiting EV charging to off-peak hours only. San Diego Gas and Electric (SDG&E)’s rate for EV charging at multi-unit dwellings and workplaces includes locational costs based on California ISO day-ahead market prices and distribution feeder load.

Each of the five rate design trends entails potentially significant implications for solar and other DERs, in terms of both the quantity and type of deployment that may occur in the future. As shown in Table ES - 1, the potential near-term impacts on DER deployment (which, in some cases, have already been observed) vary significantly depending on the particular rate design and type of DER: either accelerating or constraining deployment, and to varying degrees. These near-term impacts also depend critically on specific tariff design details (e.g., the timing of TOU peak periods or the type of demand charge adopted), as indicated by the ranges shown in the table for any particular rate reform and DER.<sup>1</sup>

**Table ES - 1. Potential Impacts on Near-Term DER Deployment Levels**

Rate Design Trend	PV	Energy Efficiency	EV & Electrification	Storage & Demand Response
Time-Based Rates	●●●●●	●●●●●	●●●●●	●●●●●
Load Building Rates	●●●●●	●●●●●	●●●●●	●●●●●
3-Part Rates	●●●●●	●●●●●	●●●●●	●●●●●
NEM Alternatives	●●●●●	●●●●●	●●●●●	●●●●●
EV-Specific Rates	●●●●●	●●●●●	●●●●●	●●●●●

Key: ●=Highly constrained, ●=Slightly constrained, ●=No impact, ●=Slightly accelerated, ●=Highly accelerated

In considering how these various rate reform trends may impact DER deployment, three broad themes emerge:

- **DER impacts depend critically on the specifics of the tariff structure.** Even if obvious, it cannot be over-stated how important are the specifics of any particular rate design in assessing the potential impacts on DER deployment. Among the rate design trends discussed in this report, this includes details such as: the timing and peak-to-off-peak pricing differential under time-based rates, the choice between intermittent vs. continuous incentives to increase midday load, the use of coincident vs. non-coincident demand charges, the specific price paid for grid exports under net billing rates, and whether or not EV-specific rates are sub-metered vs. applied on a whole-house

<sup>1</sup> Our assessment of the implications is based on rate design variations identified and discussed in this report. Of course, one could conceive of designs that further broaden the range of possible impacts. Over the long run, the range of potential impacts becomes even wider, as DER technologies themselves may evolve in response to new rate structures.



basis. Details such as these dictate not only the magnitude, but in some cases also the directionality of impact for certain DERs.

- **Flexible DERs generally benefit more under emerging rate design trends.** DERs exist along a continuum of flexibility, ranging from those with largely fixed load shapes (energy efficiency (EE) and PV), to those with some level of discretion in how they are operated (EVs and certain other forms of electrification), to fully dispatchable resources (storage and certain forms of demand response (DR) and electrification). As evident by a quick glance at Table ES - 1, most emerging rate reforms tend to support greater deployment of flexible DERs (e.g., storage and DR), while often constraining adoption of less-flexible resources (e.g., PV and EE). This outcome is driven by the general movement towards rate structures with greater temporal granularity, which naturally tends to encourage price-responsive resources.
- **Emerging rate designs generally encourage load building (during specific times of the day).** Though only one of the five rate design trends discussed in this report is explicitly intended as a tool for load building (“Development of rates and programs to promote midday load building”), most of the other rate design trends also incentivize load building, whether in the form of EVs, other types of electrification, or energy storage (which increases net electricity consumption due to round-trip losses and ancillary loads). The incentives for load building are often concentrated during particular times of the day, though depending on their design, three-part rates may encourage load building across a fairly broad range of hours. In contrast, the emerging rate designs discussed in this report generally tend to constrain growth of DERs that reduce consumption of grid-supplied electricity (EE and, especially, PV). This outcome is driven partly by the general movement toward greater levels of attribute unbundling and temporal granularity that better reflects marginal costs. Load building is also a natural response on the part of electric utilities to slowing sales growth and ongoing concerns about revenue erosion from EE and PV, and electrification is a strategy that some state policymakers and regulators have endorsed for addressing their greenhouse gas abatement goals.

Regulators engaged in retail rate reform efforts may wish to consider explicitly how new rate designs may impact deployment trends among different types of DERs, weighing those impacts against the many other considerations and stakeholder perspectives that regulators must balance in establishing utility rate structures.

# 1. Introduction

Retail electricity pricing is evolving in the context of broader shifts in how electricity customers pay for grid services and how they are compensated for customer-sited generation. These retail rate reforms are occurring mostly (though not exclusively) among the residential customer class and are driven by trends in energy technology deployment; by policy and legislative directives; and by concerns among utilities, regulators, and customer groups about fairness and equity. These drivers are also tempered and shaped by the broader set of considerations and stakeholder perspectives that utility regulators must balance when establishing utility rate structures. As has been often noted, rate design is part science, whereby the utility must recover its costs and regulators set just and reasonable rates based on voluminous administrative proceedings, and part art, in that it must satisfy certain principles and objectives (e.g., Bonbright, 1961), many of which may stand counter to each other.<sup>2</sup>

This report identifies current trends in retail rate design and uses case studies to describe key design elements and implementation experience. While numerous changes to retail rates have occurred across the U.S. in recent years, we focus on five particularly salient trends:

- increased pursuit of residential time-based rates,
- development of rates and programs to promote midday load building,
- increased application of residential three-part rates (i.e., rate structures with demand charges),
- development of new net-metering alternatives, and
- development of new electric vehicle (EV)-specific rates.

These trends all embody some incremental evolution from current rate structures, in terms of increased attribute unbundling, increased temporal granularity, and/or increased locational granularity (Glick et al., 2014). They also entail potentially significant implications for both the type and quantity of distributed energy resources (DERs) that may be deployed in the future.<sup>3</sup>

This report is primarily intended to provide a current snapshot and reference point for state utility regulators, policymakers, electric utilities, and DER technology providers about the motivations, design, and implications of recently adopted retail rate designs. The report is organized as follows: Section 2 briefly highlights several key drivers for the retail rate design trends featured in this report. Section 3 describes and presents case studies for each of the five recent trends in retail rate design noted above, along with their key motivations and design elements, and describes any lessons learned from implementation experience to-date. Section 4 discusses the implications of these retail rate trends for DER adoption and customer economics. Finally, Section 5 offers brief concluding remarks, calling out several overarching themes.

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<sup>2</sup> For example, economically efficient rates like time-based pricing may not be perceived as simple for residential customers as a flat, average rate.

<sup>3</sup> Though DER compensation need not always occur via retail rates (e.g., it can happen through aggregation programs or utility procurement), retail rates are often the most convenient mechanism for smaller resources on the customer-side of the meter.

## 2. Key Drivers for Recent Retail Rate Reforms

Current trends in retail rate design are a response to a variety of technology- and policy-related drivers. Four drivers have been particularly instrumental to prompting and shaping the rate designs trends discussed in this report (though these are by no means an exhaustive set of drivers).

First, many utilities across the country have deployed residential advanced metering infrastructure (AMI), allowing for two-way communication and more granular recording of energy consumption. Until roughly the year 2000, the standard meter for residential customers was an electromechanical meter that simply recorded accumulated electricity consumption read on a relatively infrequent basis (e.g., monthly) for billing purposes. Installation of meters capable of recording usage over specific blocks of hours, as would be needed to participate in a time-of-use (TOU) rate, required special requests and often a monthly meter fee. This generally resulted in quite low enrollment (i.e., less than 1% of residential customers) in residential TOU rates for most utilities. Over the past 15 years, however, utility investments in AMI have resulted in mass deployment of digital meters that measure electricity consumption on an hourly (or sub-hourly) basis. According to a recent industry report, over 55% of U.S. households now have advanced meters (Institute for Electric Innovation, 2017). One of the key rationales justifying AMI deployment has been its potential for reducing overall utility system costs by enabling more widespread application of and participation in time-based rate designs.

Second, residential and commercial electricity customers continue to increase their investment in DERs. For example, U.S. residential solar photovoltaic capacity has grown by 50% per year, on average, since 2010, spurred by substantial installed-cost declines, as well as by favorable incentive policies and electric utility rate designs, such as net energy metering (NEM) (Barbose et al., 2017; NCCETC, 2017). Adoption of other DERs, such as storage and electric vehicles, though less advanced, has also accelerated in recent years (DOE, 2018). Increased DER adoption has put pressure on regulators and utilities to revise retail rate designs in order to optimize the size, location, and operation of DERs.

Third, utilities have increasingly raised concerns about fixed cost recovery and revenue sufficiency—an issue partly associated with increased DER deployment, but related more generally to flat or declining load growth, and compounded by increasing costs to modernize the grid (Satchwell et al., 2015). This has motivated some utilities and states to re-examine their historically heavy reliance on volumetric energy charges to cover both fixed and variable utility costs, and has also prompted efforts to revise net metering tariffs (Satchwell and Cappers, 2018). In the latter case, many regulators, utilities, and consumer advocates have raised concerns specifically about cost-shifting from customers with DERs to other ratepayers and have expressed a desire to ensure that DER owners cover their fair share of embedded utility costs (Satchwell and Cappers, 2018). In some states, these kinds of concerns are implicit in statutory limits to net metering enrollment or on the period of time over which such tariffs can be offered; as those limits have been reached, a number of states have initiated rate reforms (Satchwell and Cappers, 2018).

Fourth, at the bulk power system level, utility system planners and operators are experiencing or anticipating significant changes to hourly net load as a result of broader deployment of utility-scale, community-scale, and customer-sited variable renewable energy resources (Cappers et al., 2012). In particular, surplus generation of electricity by these resources during the middle-of-the-day is causing significant declines in energy supply prices (Seel et al., 2018). This creates an opportunity for customers to capture value in shifting load to those periods and away from morning and/or afternoon peaks, provided rate designs reflective of these price profiles are implemented (Satchwell and Cappers, 2018).

### 3. Current Trends in Retail Rate Design

Below, we describe five current trends in retail rate design, with case studies that illustrate the motivations, key design variations, and implementation experience. The depth and longevity of experience across these five rate designs varies significantly (as do the discussions below), but each one represents some incremental progression along the three continuums described by Glick et al. (2014): greater attribute unbundling, temporal granularity, and locational granularity. Historically, rate designs—especially in the residential sector—have been fully bundled, whereby customers pay all energy services in a single volumetric rate. Residential rates have also often been flat, representing average utility costs. Last, rates have typically been based on costs across the entire utility system regardless of locationally varying costs. All the rate design trends featured below, in some form, represent movement away from those characteristics: e.g., paying or being compensated for energy and demand separately, hourly or sub-hourly pricing that better reflects marginal costs, and pricing that reflects grid-specific locations.

#### 3.1 Increased pursuit of residential time-based rates

Nearly forty years ago, the Public Utility Regulatory Policies Act<sup>4</sup> (PURPA) (Subtitle B) asked state regulatory authorities and non-regulated electric utilities to consider the appropriateness of TOU rates, among other issues. In response to the subsequent state regulatory investigations, the vast majority of U.S. investor-owned utilities began to offer TOU on a voluntary, opt-in basis. Despite this long history, currently only around 3% of residential electricity customers are on a time-based rate (Hledik et al., 2017). As AMI deployment increases, however, a greater range of time-based rate options is beginning to emerge.<sup>5</sup>

The implementation of time-based rates is primarily motivated by economic efficiency concerns (i.e., to better align electricity prices with marginal system costs). Regulators and utilities are also interested in using time-based rates to lower peak demands and improve system load factor by encouraging customers to shift electricity consumption from peak to off-peak periods. These potential benefits, in terms of utility system cost savings, have been one of the central rationales used to justify investments in AMI (Satchwell and Cappers, 2018).

Residential time-based rates have a range of design elements that mostly differ in terms of the timing of the peak and off-peak periods and magnitude of peak to off-peak pricing ratio. The three options

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<sup>4</sup> Subtitle B asked state regulatory authorities and non-regulated electric utilities to determine whether or not it is appropriate to implement time-of-use rates and other ratemaking policies.

<sup>5</sup> AMI is not, by itself, necessarily a prerequisite for certain time-based rates.

with the highest customer enrollment levels to-date are TOU, critical peak pricing (CPP)<sup>6</sup>, and variable peak pricing (VPP).<sup>7</sup> Most utilities offer such rates on a voluntary (i.e., opt-in) enrollment basis, but a few offer time-based rates as the default residential rate (Cappers et al., 2016a).

We detail two case studies highlighting enrollment and design issues for residential time-based rates. First, the Sacramento Municipal Utility District (SMUD) case study describes voluntary (opt-in) versus default (opt-out) customer enrollment. Second, the Oklahoma Gas and Electric (OG&E) case study describes a VPP rate design approach.

### 3.1.1 Case Study: Sacramento Municipal Utility District Default Time-of-Day Rate

In 2009, SMUD received funding as part of the Department of Energy's Smart Grid Investment Grant (SGIG) program. A portion of that funding supported a consumer behavior study of time-based rates for residential customers that was in effect from June through September in both 2012 and 2013. The study employed experimental designs (i.e., randomized control trial, randomized encouragement design) to expose residential customers to one of three different rate designs (TOU, CPP, and TOU with a CPP overlay) under one of two different enrollment approaches (voluntary or default) where a subset of customers also received an offer of in-home display (IHD) that presented real-time (or slightly delayed) home energy consumption data and/or current electricity price data (Cappers et al., 2013).<sup>8</sup>

According to the study's interim evaluation report (Jimenez et al., 2013), the utility wanted to understand several factors:

- Electric energy and demand impacts of each of the seven treatments (e.g., income, home ownership, central air conditioning ownership),
- Customer characteristics associated with behavior,
- The role of IHDs in customers' daily electricity management,
- Program impacts on customer bills and satisfaction,
- Expected value of rate and IHD programs to the utility as well as to customers,
- Expected market penetration for rate and enabling technology programs, and
- Effective educational and marketing strategies for customers.

The results from SMUD's consumer behavior study showed markedly higher enrollment in default TOU (upwards of 90%) relative to the voluntary TOU offering (less than 20%). Many reasons have been

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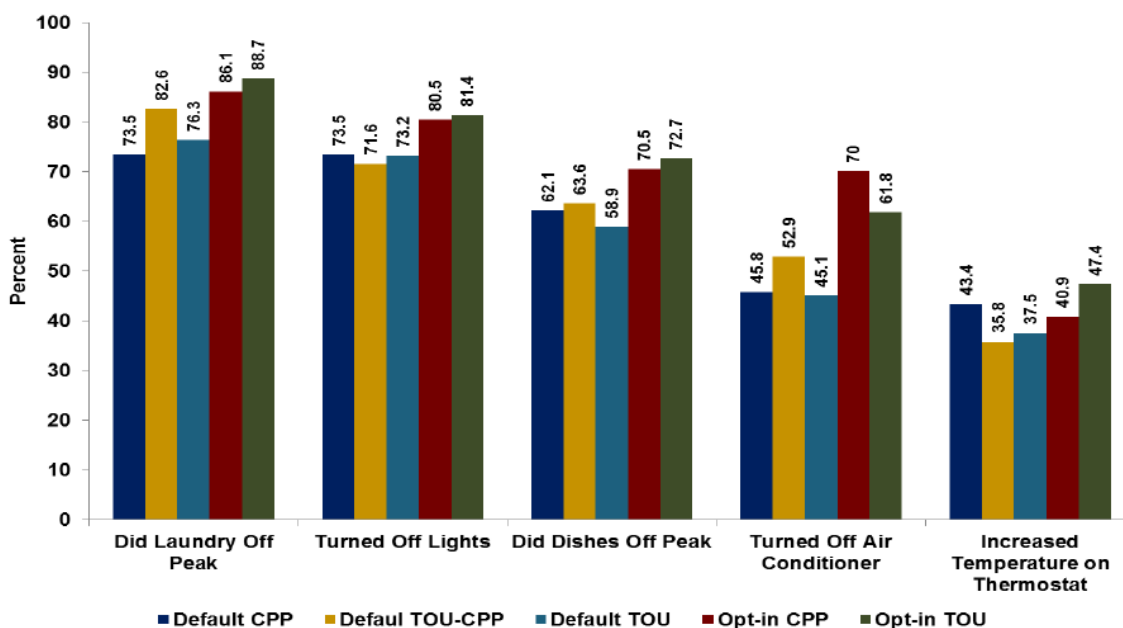
<sup>6</sup> It is important to differentiate CPP, which is a time-based rate intended to induce episodic energy and ideally demand reductions, with critical peak rebate (or peak-time rebate), which is an incentive-based program that seeks to accomplish the same goal. Here we are focusing on time-based rates, not incentive-based programs, so we do not discuss the various jurisdictions which have defaulted their residential customers onto critical peak rebate programs (e.g., Delaware, Maryland).

<sup>7</sup> VPP is a form of TOU where the on-peak price can change daily, either based on a pre-set schedule of prices or tied to wholesale market electricity prices.

<sup>8</sup> Regardless of the enrollment approach, a participating customer was able to leave the study at any time throughout its duration.

suggested for these high enrollment levels, but the most compelling and simplest reason may just be status-quo bias (Cappers et al., 2016a).<sup>9</sup> SMUD also pursued extensive market research efforts to develop marketing, education, and outreach materials (Jimenez et al., 2013) that yielded substantially higher voluntary enrollments levels than have generally been experienced in other pilots (Cappers and Scheer, 2016). Although the average load-shifting response from customers defaulted onto TOU was lower than from those who volunteered, SMUD nevertheless determined that rolling out a default TOU rate was more cost-effective than continuing with a voluntary TOU rate (Jimenez et al., 2013).

Through survey research, SMUD also examined the discrete actions customers took to alter their electricity consumption in response to the various rate designs included in the study (see Figure 1).



Source: Potter et al. (2014)

**Figure 1. Actions Taken by SMUD’s Study Participants to Alter Electricity Consumption**

As a result of the high customer enrollment and customer satisfaction results, as well as the economic justification, SMUD is currently transitioning all its residential customers to a default Time-of-Day (TOD) rate by the end of 2019 (SMUD, 2017). SMUD’s residential TOU rate (R-TOD) is seasonal, with three periods (Peak, Mid-Peak, and Off-Peak) and two periods during non-summer months (Peak and Off-Peak, see Table 1). Of some note is the timing of the peak-period, which is shifted to late afternoon and early evening hours (5-8 PM) on weekday non-holidays. The summer season has a peak to off-peak price ratio of 2.4 while the non-summer season has a peak to off-peak price ratio of 1.4. The rate is fully bundled (including all costs for transmission, distribution, and generation) and has no locational

<sup>9</sup> “Status-quo bias” refers to the phenomenon where people disproportionately remain with the option provided to them as the default (DellaVigna, 2009).

granularity. As the default, there will be no bill protection<sup>10</sup>, and it is for single family homes only (but customers may elect to be served under a seasonal flat-rate that is approximate 4% higher than R-TOD).

**Table 1. SMUD Default Residential TOU Rate Design (R-TOD)**

Season	Period	2019 Price (\$/kWh)	Notes
<b>Summer (Jun 1 - Sep 30)</b>	Peak	\$0.2835	Weekdays between 5 p.m. and 8 p.m.
	Mid-Peak	\$0.1611	Weekdays between noon and midnight except during Peak hours
	Off-Peak	\$0.1166	All other hours, including weekends and holidays
<b>Non-Summer (Oct 1 - May 31)</b>	Peak	\$0.1338	Weekday between 5 p.m. and 8 p.m.
	Off-Peak	\$0.0969	All other hours, including weekends and holidays.

Source: SMUD (2017)

According to SMUD’s website (SMUD, 2018), the rate design will result in most customers in their residential class seeing a bill reduction during the eight non-summer months and a bill increase during the four summer months based on historical consumption patterns.<sup>11</sup> On an annual basis, SMUD’s own historical billing analysis shows that, without making any changes to how they use energy:

- 6% of customers will save about \$8 per month on average,
- 37% will save about \$1.65 per month,
- 49% of customers will pay about \$2 more per month on average, and
- 8% of customers will pay about \$6.80 more per month on average.

Low-income customers, as well as those on special medical rates, should see bill impacts that are about the same as other customers. To help these more vulnerable customers manage their electric bills under this new rate, SMUD is working to develop new programs and services that will be offered coincident with the transition to default TOU in 2019.<sup>12</sup>

More generally, SMUD will provide tips for how customers on the default TOD rate can shift certain electric end-uses to off-peak times and reduce their overall usage to better control their bills. The utility is marketing this rate to reduce overall system costs by deferring the need for new power plants, as well as to be more environmentally and community friendly.

<sup>10</sup> Bill protection ensures that a customer will pay no more on their bill under a new rate than they would have if the same monthly usage was applied to their old rate.

<sup>11</sup> SMUD developed bill impact estimates for every residential customer in order to more readily identify which customers might have an increased risk for higher bills due to the transition to default TOU.

<sup>12</sup> For further discussion of issues related to the application of time-based rates for low-income and other vulnerable populations, see Cappers et al. (2016b).



### 3.1.2 Case Study: Oklahoma Gas & Electric Voluntary SmartHours Rate

OG&E also received SGIG program funding that an 18-month CBS of residential time-based rates. OG&E’s study started in July 2010 and extended through September 2011. The study employed a quasi-experimental design (i.e., randomized offer of treatment with a separate randomized control group) to expose residential customers to one of two different rate designs (i.e., TOU and VPP) under a voluntary enrollment approach where a subset of customers were randomly offered one of three different technologies (i.e., IHD, programmable communicating thermostat (PCT)<sup>13</sup>, web portal)<sup>14</sup> (Cappers et al., 2013). According to the study’s final evaluation report, the primary goal of the study was to assess the impact of multiple levels of enabling technology combined with different dynamic pricing rates on a customer’s energy consumption (GEP, 2012).

The OG&E results showed nearly a four-fold increase in load reductions of customers exposed to either TOU or VPP when a PCT was present (GEP, 2012). Despite the higher cost to procure, install, and maintain the PCT, OG&E determined that rolling out a voluntary VPP rate with a PCT was cost-effective because of the utility cost savings. In testimony seeking regulatory authority to offer the VPP rate (among other time-based rate options) to all residential customers, the utility calculated it would defer the need to build 210 MW of new peaking capacity if 20% of its residential and small commercial customer populations were enrolled in the program within three years (Brooks, 2012). The Corporation Commission of Oklahoma approved the rate and it was subsequently offered as the SmartHours VPP rate in January 2013. By the beginning of 2016, OG&E had enrolled 19% of its customers onto the rate, falling just 1% point short of meeting its enrollment goal.

OG&E’s SmartHours VPP rate design has several novel design elements (see Table 2). The peak period is defined as 2-7 PM weekdays between June 1 and September 30; all other hours are considered off-peak. OG&E provides day-ahead notice via email or text of which level (standard, high, or critical) the peak period will be the following day. However, in the event of a system emergency, OG&E can declare a critical event in-day with at least 2 hours advance notice, thereby raising the price of electricity in the peak to the critical level. Finally, OG&E offers customers bill protection for the first subscription year.

**Table 2. OG&E Voluntary SmartHours VPP Rate Design (R-VPP)**

Season	Period	Price Level	2019 Price (\$/kWh)	Notes
<b>Year Round</b>	Peak	Low	\$0.05	Weekdays between 2 p.m. and 7 p.m.
		Standard	\$0.10	Weekdays between 2 p.m. and 7 p.m.
		High	\$0.22	Weekdays between 2 p.m. and 7 p.m.
		Critical	\$0.41	Weekdays between 2 p.m. and 7 p.m.
<b>Year Round</b>	Off-Peak		\$0.05	All other hours, including weekends and holidays.

<sup>13</sup> The PCT was able to receive a price signal from OG&E and execute a change in the thermostat’s setpoint to a level pre-programmed by the customer.

<sup>14</sup> OG&E sought to understand if any of these enabling technologies in isolation or in concert would produce any statistically significant improvement in the average customer’s response to the tested rates.

As of December 2016, OG&E enrolled about 107,000 residential customers in its SmartHours VPP rate, which represented about a 9% increase in participation from the previous year (AEG, 2017). About 64% of these customers accepted a free PCT (AEG, 2017). The utility used a variety of methods to increase enrollment including: TV, radio, print, online advertising, digital outdoor advertising, bus wraps, public events, and targeted direct contact such as email and direct mail (AEG, 2017). In addition, when customers called to enroll in Smarthours VPP rate, the customer service system flagged customers who were ideal candidates to receive the free PCT based on an analysis of their interval meter data.

According to the 2016 program evaluation report, the SmartHours VPP customers with PCTs provided average load reductions of 1.45 kW/customer during the top 3 days, while customers without PCTs provided about one-fourth as much (0.38 kW/customer) (AEG, 2017). During the system peak day (August 11, 2015), customers with PCTs provided a combined 104 MW of demand reductions while those without PCTs reduced demand by 12 MW (AEG, 2017).

### **3.2 Development of rates and programs to promote midday load building**

Utility system planners and system operators are expecting, and in some cases observing, profound effects of variable renewable energy (VRE) on the bulk power system and wholesale power markets. Among several concerns about the ability of bulk power systems and markets to handle these changes is a steep decline and incline in load during the morning and late-afternoon/early-evening periods, respectively. This “duck curve” may result (or in some cases is already resulting) in wholesale power costs dropping precipitously during midday hours and curtailment of renewable generators (Seel et al., 2018).

Utilities and grid operators are developing novel and innovative approaches to assist in grid management. One strategy employs utility pricing and/or programs to increase electricity consumption by end-use customers at times of peak solar production when marginal system prices are particularly low or generation curtailment might otherwise be required. Specific to pricing, a few utilities have designed TOU rates with very low-priced periods (i.e., super off-peak) to coincide with times of low system costs (sometimes referred to as *matinee pricing*). The intent is to drive customers to consume more electricity during these super off-peak price periods, either by shifting load from other parts of the day or by adding load more generally. Utilities have likewise sought to increase electricity consumption during these same time periods by providing some form of a customer bill rebate (i.e., partial or full) that offsets the commodity share of the volumetric energy component of the retail rate (sometimes referred to as a *reverse demand response program*).

Incentivizing increased electricity consumption runs contrary to the more typical aim of time-based rates and demand response programs—namely, to *reduce* load during certain high-cost or supply-constrained hours. Partly as a result, these new approaches are somewhat unproven. Several utilities are, therefore, in the process of testing and evaluating energy pricing and programs to shift load in pilot settings. We detail two case studies: the first focuses on California statewide pilots that employ

matinee pricing, and the second is a proposal, not yet implemented, for a reverse demand response program in Arizona.

### 3.2.1 Case Study: California Statewide Residential Pricing Pilots: Matinee Pricing

The California Public Utility Commission ordered the implementation of a series of pricing pilots at the state’s investor-owned utilities (IOUs) between 2016 and 2018 to support applications filed in December 2017 proposing the implementation of default TOU rates for all residential customers (CPUC, 2015). The study parameters and pilot designs were developed through a working group process, but were required to include the following:

- Opt-in pilots for immediate implementation (2017);
- Opt-out pilots for delayed implementation (2018);
- TOU rate designs with a baseline credit (i.e., a credit on customers’ bills reflecting monthly allocation of baseline energy usage) for at least one rate offering per IOU to make it a viable alternative to existing tiered rates;
- TOU rate designs with at least two periods in any given day, but can have periods that apply only to particular seasons; and
- All rate designs with bill protection for a customer’s first year in the pilot.

The pricing pilots across the three IOUs are collectively tested nine different TOU rate options. Over 50,000 households enrolled and were assigned to one of the TOU rates or remained on their standard tiered rate as a control (George et al., 2017a). For our purposes, we focus on the three “matinee pricing” options with very low (“super”) off-peak prices that apply during midday hours (see Figure 2 through 4). One objective of these pilots was to test whether customers will expand their usage in response to these super-off peak prices. The TOU rates also had peak periods that primarily covered late afternoon and early evening hours, year-round. These were the first pilots to meaningfully test customer response to peak pricing periods that extend into the evening hours, and were also the first pilots to meaningfully test and measure customer response to such very low super off-peak prices.

Tariff	Season	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Weekday	Summer	Off-Peak (28.59¢)																Peak (57.19¢)							
	Winter	Off-Peak (27.08¢)																Peak (28.97¢)							
	Spring	Off Peak (26.74¢)										Super Off-Peak (18.02¢)				Peak (36.05¢)									
Weekend	Summer	Off-Peak (28.59¢)																							
	Winter	Off-Peak (27.08¢)																							
	Spring	Off Peak (26.74¢)										Super Off-Peak (18.02¢)													

Source: George et al. (2017a)

**Figure 2. PG&E Opt-in Pilot Matinee Pricing Design**

Rate 3	Season	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Weekday	Summer	Off-Peak (16.39¢)											On-Peak (22.64¢)				Super On-Peak (37.03¢)								
	Winter	Off-Peak (18.24¢)											Mid-Peak (20.96¢)												
	Spring	Off-Peak (18.24¢)											Super Off-Peak (9.94¢)				On-Peak (24.86¢)								
Weekend	Summer	Off-Peak (16.39¢)											Mid-Peak (18.77¢)												
	Winter	Off-Peak (18.24¢)											Super Off-Peak (10.39¢)				Mid-Peak (20.96¢)								
	Spring	Off-Peak (18.24¢)											Super Off-Peak (9.94¢)				Mid-Peak (20.96¢)								

Source: George et al. (2017a)

**Figure 3. SCE Opt-in Pilot Matinee Pricing Design**

Tariff	Season	1:00	2:00	3:00	4:00	5:00	6:00	7:00	8:00	9:00	10:00	11:00	12:00	13:00	14:00	15:00	16:00	17:00	18:00	19:00	20:00	21:00	22:00	23:00	24:00
Weekday	Summer	Super Off Peak (29.71¢)						Off Peak (34.91¢)						Peak (56.57¢)				Off Peak (34.91¢)							
	Winter	Super Off Peak (35.12¢)						Off Peak (36.2¢)						Peak (37.31¢)				Off Peak (36.2¢)							
Weekend	Summer	Super Off Peak (29.71¢)											Off Peak (34.91¢)		Peak (56.57¢)				Off Peak (34.91¢)						
	Winter	Super Off Peak (35.12¢)											Off Peak (36.2¢)		Peak (37.31¢)				Off Peak (36.2¢)						

Source: George et al. (2017a)

**Figure 4. SDG&E Opt-in Pilot Matinee Pricing Design**

An evaluation for the first complete year of data assessed how customers responded to seasonally differentiated rates (George et al., 2017b). Customers responded to TOU super off-peak price signals by modestly increasing load by 1.6% on average during summer weekdays, by 2.1% on average during winter weekdays, and 0.7% to -0.3% (i.e., decreasing load by 0.3%) on spring weekdays. Customer response to super-off peak prices on weekends varied considerably by season and rate offerings: with the largest increase in load (2.0% on average) coming from SCE customers in the winter versus the largest decrease in load (-1.5% on average) coming from PG&E customers in the spring. The average study participant saw a reduction in their bill associated with transitioning and responding to the matinee pricing design that ranged from 0.3% (SCE) to 1.6% (SDG&E) (George et al., 2017b).

### 3.2.2 Case Study: Arizona Public Service Reverse Demand Response Pilot

Arizona Public Service (APS) is expecting to see an increased need for greater mid-day electricity demand in non-summer periods, in order to better balance system load when there is surplus generation from renewable resources (APS, 2017). The utility is considering several different demand response opportunities to address these issues. Recently, it filed a proposal with the Arizona Corporation Commission (ACC) to implement a reverse demand response program to promote load building during certain periods of time in order to avoid curtailing renewable energy production (APS, 2017).<sup>15</sup>

<sup>15</sup> This proposal was filed in September 2017 and has not yet been decided by the ACC.

APS proposed a reverse demand response pilot that was scheduled for implementation in 2018, or as soon as possible after the Commission approves the proposal. Based on the filing (APS, 2017), APS plans to work with qualifying non-residential customers to identify dispatchable loads that could produce an increase in electricity consumption during times of “negatively priced wholesale energy market” conditions (APS, 2017). Participating customers would identify non-essential loads that could be remotely operated in response to an event signal sent from APS. In exchange, these customers would receive no-cost energy for such loads during event periods. As such, there would be no additional incentive payment for participation. To qualify, these loads would need to be sub-metered, which APS would provide along with communications infrastructure, to enable the load to receive the event signal. The customer would also need to have a minimum demand level of 30 kW. Participation is planned to be voluntary, but limited, based on a total proposed program budget of \$200,000 in 2018.

### **3.3 Increased application of residential three-part rates**

The majority of electric utilities in the United States rely primarily on volumetric energy charges to collect both fixed and variable costs from residential customers. “Three-part” rates that include demand charges, along with volumetric energy charges and fixed customer charges, are common for commercial and industrial customers, but have historically had much more limited application among residential customers, due to the relatively high cost of metering equipment for measuring peak demand (Hledik, 2014). With recent AMI deployment efforts, however, demand charges have been increasingly considered for more widespread use among residential customers, in some cases specifically targeting residential customers with behind-the-meter PV or other DERs (Satchwell and Cappers, 2018).

The interest in broader adoption of residential demand charges has been driven by several inter-related factors (see Satchwell and Cappers, 2018 for more details). First, as a means of fixed-cost recovery, demand charges may be more palatable than increased fixed customer charges, which do not support energy conservation and customer energy management. Second, demand charges are often portrayed as better aligned with cost causation, as coincident (and to a lesser degree non-coincident) peak demand drives system capacity requirements and costs (e.g., installation of new distribution system transformers). As such, three-part rate designs are often motivated by a desire to increase economic efficiency and improve system load factors, by giving customers a financial incentive to manage not just overall electricity consumption but also maximum demand levels.

Although relatively few IOUs<sup>16</sup> currently offer residential demand charge rates (Faruqui, 2018), those that are in place exhibit several key variations in design. All three-part rates include some measurement of maximum demand, but utilities vary in whether it is based on each customer’s “non-coincident” demand (i.e., the maximum demand, irrespective of when it occurs) or is instead based on the customer’s maximum demand during the distribution or transmission system peak period (i.e., “coincident” demand). An important design consideration is whether the billing demand unit is consistent with the cost driver (e.g., coincident costs should be collected via a coincident demand billing

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<sup>16</sup> Faruqui (2018) identified 16 investor-owned utilities with voluntary residential demand charges.

unit) (Lazar and Gonzalez, 2015). In addition, the interval of time over which the maximum demand is measured can vary from 15 to 60 minutes. Finally, while the vast majority of residential demand charge rates are currently offered on a voluntary opt-in basis, several utilities have proposed or implemented such rates on a mandatory basis, though the latter case has generally been limited to residential customers with behind-the-meter PV (Faruqui, 2018).

Stakeholders have raised several concerns about expanding the application of three-part rates to residential customers, given the limited number of offerings and low customer enrollment (see Satchwell and Cappers, 2018 for more details). In cases of insufficient knowledge of basic energy concepts, such as the difference between electricity demand and energy, there are concerns that residential customers may be unable to effectively manage their electricity bills (Hledik, 2014). Furthermore, it is unclear if customers are able to gauge the benefits associated with energy management and appliance control equipment, in order to determine if such investments are cost effective (Cappers et al., 2016b).

We detail two case studies: The first describes Arizona Public Service (APS)'s three-part tariffs offered on a voluntary basis to all residential customers, and the second describes Salt River Project (SRP)'s mandatory demand charge rate for distributed solar customers.

### 3.3.1 Case Study: Arizona Public Service Residential Demand Rates

Arizona Public Service (APS) has offered voluntary residential demand charges for more than a decade. A 2015 load and bill savings analysis of APS' residential demand rate showed that 60% of customers in the sample reduced monthly demand and energy in summer and winter seasons (10.7% reduction in demand and 8.5% reduction in energy)<sup>17</sup> (APS, 2015). Similarly, 90% of residential demand-rate customers experienced bill savings during the summer season (9% bill savings, on average).

Due in part to its historical success, as well as the utility's belief that broad rate reform is necessary to create a more sustainable and equitably financed grid system, APS filed a proposal in June 2016 to make demand charges a mandatory element of all residential and small commercial customer rates (APS, 2016). Several stakeholders raised a myriad of concerns with the proposal, ultimately resulting in a settlement agreement approved by the Arizona Corporation Commission that included several rate options for residential customers (ACC 2017). The demand rate options include a time-differentiated energy charge and one of the demand rate options has a different demand charge for summer and winter seasons. Starting in 2018, customers were transitioned to one of these alternative rate designs and, as of March 2018, about 17% of APS residential customers had opted in to demand rates.<sup>18</sup>

As part of the transition, APS is supporting customer decision making by providing bill comparisons based on historical consumption. Not surprisingly, customers with higher load factors do better on

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<sup>17</sup> 40% of customers in the sample increased on-peak energy, off-peak energy, and/or peak demand.

<sup>18</sup> Each customer must either select one of the two new rate plans, or APS will move the customer to the rate offering most similar to their current plan.

demand charge rates than those rates that use time-based energy charges. The APS designs also suggest other important design decisions around seasonal differentiation and layering demand charges with a TOU energy charge. For example, one residential demand charge option differentiates the on-peak demand charge by summer and winter seasons where the summer season demand charge is higher. The APS residential demand charge options also include a TOU energy charge with a peak to off-peak ratio that is less than APS' residential TOU rate without a demand charge option.

### **3.3.2 Case Study: Salt River Project Residential Distributed Generation (DG) Demand Rate**

In December 2014, management of SRP, a municipal utility serving the Phoenix metropolitan area, proposed to its governing Board of Directors a broad set of changes to its electricity pricing plans.<sup>19</sup> Among those changes, SRP proposed a new three-part rate implemented exclusively for residential customers with on-site generation (e.g., solar PV).

Several studies were conducted in conjunction with or in support of the rate proposal including a quantification of the shift in fixed cost recovery that was occurring under the existing net energy metering compensation approach. Chamberlin and Lyons (2015) estimated that the 15,000 customers who had installed solar PV systems were shifting \$9-10 million/year to non-solar customers (i.e., ~\$50/month per solar customer).<sup>20</sup> To help inform its decision on whether or not to approve this specific element of the proposed changes to SRPs pricing plans, the SRP Board of Directors engaged the Brattle Group to evaluate the proposal relative to five pricing principles laid out by the Board (Faruqui and Hledik, 2015).

One of the more contentious issues with the new solar rate structure was the grandfathering period – namely, the length of time pre-existing solar PV systems would qualify to continue receiving service under the standard residential tariff, after which point they would move to the new three-part rate. SRP's original proposal grandfathered existing solar customers under the pre-existing rate structure for 10 years. A subsequent revision extended that period, but only for host-owned systems that received an SRP incentive. Ultimately, the Board decided to extend the grandfathering period to 20 years for all pre-existing systems (both host-owned and third-party owned, regardless of whether they received an incentive), and also specified that grandfathering would transfer with the sale of a home (out of concern that the rate change could create difficulties for customers selling their homes).

Other alterations were made to the original proposal based on negotiations with stakeholders. For example, SolarCity/Tesla sued SRP based on “anticompetitive and tortious conduct designed to eliminate solar competition” (Randazzo, 2015). SRP appealed to the US Supreme Court to dismiss the case. Ultimately, the suit was settled and the appeal was dropped, with SRP agreeing to purchase a 25

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<sup>19</sup> Since SRP is not an investor-owned utility, but rather a municipal entity, the process for altering its rates includes proposing changes to its Board of Directors, which then adjudicates the proposal.

<sup>20</sup> To be sure, studies that investigate cost-shifts from solar customers or that estimate the value of solar can vary widely in terms of the set of costs and benefits considered, and assumptions made about each, potentially leading to quite divergent results.

MW battery from Tesla and launch an incentive program for residential storage (\$1,800 rebate per customer, for up to 4,500 customers over 3 years). The settlement also required SRP to create its “Demand Assurance Program”, a limited-term bill protection program.<sup>21</sup> Negotiations with other stakeholders resulted in changes to the demand charge measurement interval. Originally it was specified as a 15-minute measurement, but the final proposed rate was based on 30-minute intervals (on the basis that it would be easier for customers to manage).

After four months of negotiations, SRP put forward an updated portfolio of rates, including the E-27 tariff (see details in Table 3) that gained approval from its Board in February 2015 and went into effect two months later. As ultimately approved, the demand charge is structured as a seasonally differentiated inclining block rate, applied to the customer’s maximum on-peak demand (kW).<sup>22</sup> In addition to the demand charge, the rate design includes a fixed monthly customer charge to collect billing, meter, customer service, and a portion of distribution facility costs, as well as a seasonally varying time-of-use rate for energy (kWh).

**Table 3. Summary of SRP Customer Generation Price Plan for Residential Service (E-27)**

Rate Design Elements		Summer Peak (May, June, Sept, Oct)	Summer (July, August)	Winter (All other months)
<b>Customer Charge</b>	0-200 Amp Service	\$32.44	\$32.44	\$32.44
	200+ Amp service	\$45.44	\$45.44	\$45.44
<b>Demand Charge</b> <i>30-min On-Peak</i> <i>Demand (kW)</i>	First 3 kW	\$9.59	\$8.03	\$3.55
	Next 7 kW	\$17.82	\$14.63	\$5.68
	All Add'l kW	\$34.19	\$27.77	\$9.74
<b>Energy Charge (kWh)</b>	On-Peak <sup>23</sup>	\$0.0633	\$0.0486	\$0.0430
	Off-Peak	\$0.0423	\$0.0371	\$0.0390

SRP initially estimated that demand charges would average \$80/month for a typical solar customer, if no efforts were made to alter usage patterns for the purposes of managing demand, and that the customer’s total bill would be roughly \$50/month higher than if the customer instead took service under the previous rate structure. Following implementation of the new rates, SRP analyzed solar customer bills from May 2015 to April 2016 and found that, on average, customer bills under the new rate were only \$19/month higher than they would have been under the previous rate structure (Carroll 2018). This reduced impact, relative to prior expectations, is attributable to load shifting behavior by customers under the new rate, who reduced their on-peak demand by about 0.9 kW (11%), on average under the new rate (Carroll 2018).

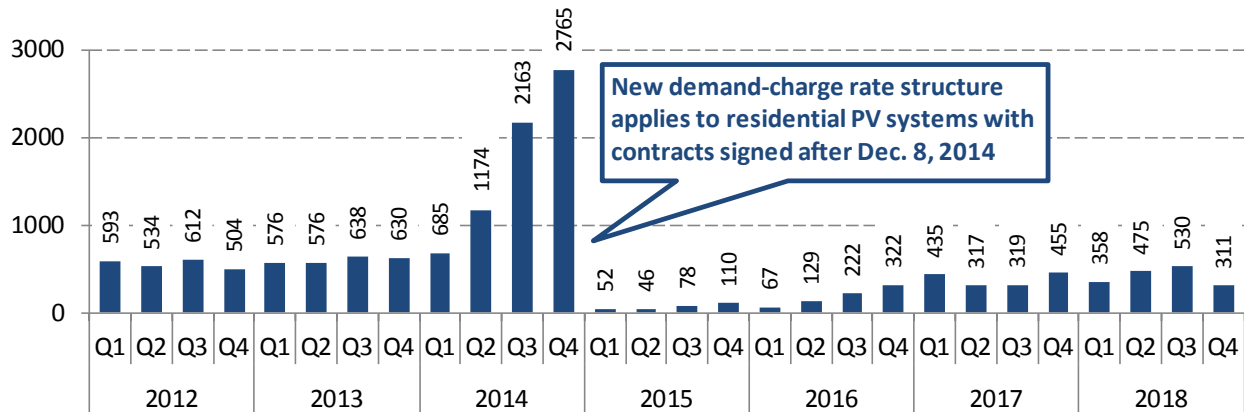
<sup>21</sup> Customers may enroll (free of charge) in the demand charge assurance option, which caps the billing demand at 3 kW above the maximum billing demand over the prior 12 months. This program is available through April 2021 and is limited to 10,000 customers.

<sup>22</sup> Distribution service costs represent only about 33% of the total demand charge, while generation and transmission together represent over 50%; most of the remainder is an “environmental programs adjustment”.

<sup>23</sup> On-peak is defined as 1-8 pm during summer and summer peak months, and 5-9 am and 5-9pm in winter months.



### Salt River Project: Number of Residential PV Interconnection Applications



Source: Data downloaded from <http://www.arizonaqoessolar.org>

**Figure 5. Number of Residential PV Interconnection Applications to SRP**

Since implementation in early 2015, the new rates have slowed the pace of residential solar development in SRP’s solar territory, though perhaps not as dramatically as initially seemed to be the case. As shown in Figure 5, solar applications rose dramatically in 2014, as proposals for the new DG rate were under discussion. Applications dropped off precipitously in 2015, immediately after the new rate went into effect. Since mid-2016, however, new residential solar applications have rebounded, though still remain below the average prior to the run-up in advance of the new rates (averaging roughly 400 new applications per quarter over the 2017-2018 period, or about 50% below the average of roughly 600 applications per quarter over the 2012-2013 period). This rebound is no doubt partly an artifact of the run-up in new solar applications in late 2014, in order to qualify for grandfathering under the previous rate structure, effectively accelerating some of the applications that might otherwise have occurred in 2015. At the same time, it is also plausible to assume that the local market has adapted in certain ways to the new rate structure, as discussed further below.

In terms of broader market impacts, one clear trend associated with SRP’s new DG rate has been a dramatic shift from third-party ownership (TPO) to host-owned systems. Based on our analysis of SRP application data, TPO represented roughly 80% of SRP residential applications during the three years preceding the new rate, while virtually all new applications since then have been for host-owned systems.<sup>24</sup> This trend has been driven, in a proximate sense, by the exit from SRP’s service territory of several large national solar PV installers who represented the vast majority of all TPO installations in the region during prior years. More fundamentally, though, TPO may be more difficult to pencil out as cash-flow positive under the new rate structure, given the additional financing and other business costs associated with third-party ownership.

<sup>24</sup> In comparison, our analysis of installation data in the neighboring service territory of APS shows a TPO market share of roughly 60% in 2018. APS and SRP application data are posted online at <http://www.arizonaqoessolar.org>.

The change in rate design has also impacted the characteristics of new PV installations. Most notably, PV systems installed under the new rate structure are considerably smaller than under the previous rate. Our own analysis of SRP installation data revealed that the average system size dropped from 8.2 kW under the old rate to 6.7 kW under the new rate, as PV systems tend to exhibit diminishing returns to scale for demand charge reductions (Darghouth et al., 2017). Carroll (2018) found that systems installed under the new rate structure have a 15% higher capacity factor during the 5-7 pm period, compared to systems installed under the previous rate structure—suggesting that the new rates have driven customers to install systems with a more westerly orientation, which better coincides with the timing of customer peak demand.

Some installers have also begun marketing demand management technologies bundled with PV. For example, Sun Valley currently sells a demand manager in conjunction with its PV system, which controls air conditioning units and other appliances (Dyreson et al., 2017). PV companies have also been increasingly marketing battery storage as a tool for managing peak demand under the new three-part rates. Although initial uptake was slow, our analysis of SRP interconnection data indicates that roughly 20% of residential installations in 2018 included battery storage.

### **3.4 Development of new net-metering alternatives**

Net energy metering (NEM) is a billing method that applies specifically to electricity exported from customer-sited distributed generation (DG) systems, allowing that exported generation to be netted against consumption from the grid at other times (e.g., exported generation during the middle of the day is credited against consumption during evening hours). In effect, NEM thereby compensates exported generation at the full retail rate. NEM tariffs can vary in important ways, particularly related to how net excess generation at the end of each billing period is credited. However, the common fundamental feature of NEM is the netting of exported generation against consumption at other times within, if not across, billing periods.

Many states have sought reforms to NEM tariffs (see Satchwell and Cappers, 2018 for more details). In some cases, these actions were ostensibly prompted by the state having reached some previously established cap on NEM enrollment. More generally, the reforms have been driven by concerns about cost-shifting between NEM participants and other ratepayers, and by a desire to develop more-efficient price signals for customer investments in DERs. In addition, NEM was in some cases initially envisioned to supporting an emerging technology (i.e., solar PV); but given the substantial cost declines for solar PV over the past decade, the strength of that initial rationale has diminished.

There are effectively two alternatives to NEM:

1. *Net billing*, whereby the customer continues to be able to offset its own usage with contemporaneous solar generation (as under NEM), but any generation exported to the grid is compensated at some specified price other than the retail rate. Those exports may be measured instantaneously or over intervals of up to an hour.<sup>25</sup>
2. *Buy-all/sell-all*, whereby the customer purchases 100% of its consumption from the utility at the retail rate and sells 100% of the generation back to the grid at some other specified price; compensation for all DG generation is thus settled completely separate from charges for consumption.<sup>26</sup> This method typically requires two meters.

Among states that have adopted an alternative to NEM, net billing has been, by far, the most common approach (Satchwell and Cappers, 2018). At least one state (Maine) has moved entirely to a buy-all/sell-all structure, but individual municipal utilities in several other states have also done so, and one state (Minnesota) has created a buy-all/sell-all rate that utilities can choose to offer in lieu of NEM. Many states have adopted NEM alternatives on a provisional basis with plans to further refine their tariffs in the near future. The transition from NEM to alternative compensation schemes has frequently been accompanied by some parallel effort to reform the underlying rate structure for DG customers, affecting the compensation for solar generation consumed behind the meter (which net billing otherwise leaves untouched).

As to be expected, the specific rate design details of individual net billing and buy-all/sell-all rates can vary significantly from case to case (see Satchwell and Cappers, 2018 for more details). The most significant difference relates to the price paid for DG generation (the “sell-rate”) and the basis for establishing that price. In some cases, it is based on an estimate of the value of solar, though the details of how that estimate is performed and what is included can vary (e.g., whether the value is simply based on avoided utility procurement costs or includes a broader set of costs and benefits). In other cases, the sell-rate may be stipulated based on some assessment of what level of compensation is required to support a desired level of market growth (as is commonly the case under a feed-in tariff), or it may simply be a political compromise (e.g., a fixed discount off the retail rate). Two other key design issues related to the PV generation sell-rate are whether the price includes any temporal or locational variability and the term over which the price remains fixed for any given project.

Finally, a key aspect of many states’ implementation of NEM alternatives is whether and how they manage that transition for solar customers. In particular, grandfathering of existing solar customers under pre-existing NEM rates has been a hotly contested issue in several states. This was discussed in

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<sup>25</sup> This is distinct from some NEM tariffs where net excess generation over the course of the entire billing period is credited at some specified price (often below retail rates), rather than rolled over as a kWh-credit to the next billing period.

<sup>26</sup> The sale of electricity under buy-all/sell-all arrangements is often compensated via bill credits, rather than as a separate payment. This distinction may be important from a tax perspective, in terms of whether the sale is treated as taxable income. As such, this arrangement is also sometimes called “buy-all/credit-all”; we treat these terms as synonymous.

more detail in the case study on SRP's demand charge DG rate (see Section 3.3.1). Aside from grandfathering, states have also sought to smooth the transition to NEM alternatives through incremental adjustments to the price paid for solar generation or to other terms of service over the course of some period of time.

We detail two case studies of NEM alternatives tariff offerings: the first describes New York's Value of Distributed Energy Resources tariff, and the second describes Hawaii's recently developed suite of tariff options for customer-sited solar. Both illustrate approaches to net billing, using different methods for establishing grid export prices and with other important differences in design features. Currently, there are relatively few examples in the U.S. of recently developed buy-all/sell-all tariffs.

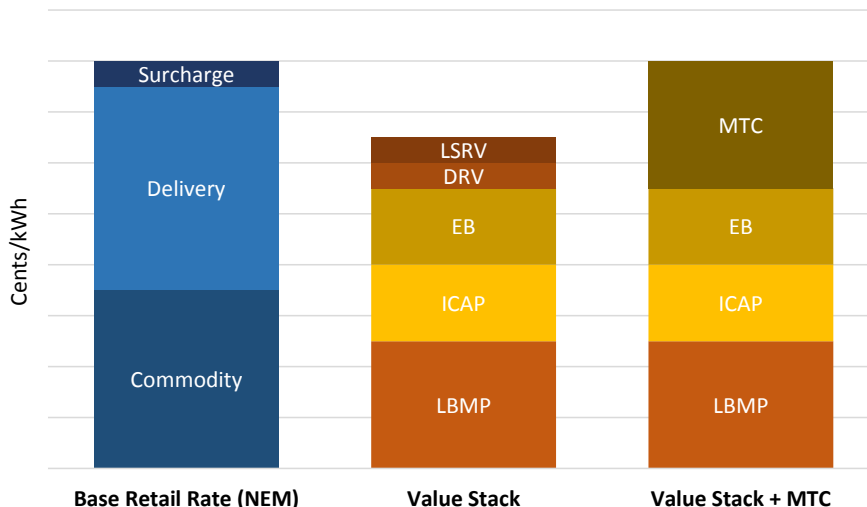
### **3.4.1 Case Study: New York Value of Distributed Energy Resources Tariff**

On December 26, 2013 the New York Public Service Commission (NYPSC) ordered a comprehensive reconsideration of its regulatory paradigm and retail electricity market designs, as they pertain to the state's objectives of achieving clean energy, system efficiency, and greater resilience (NYPSC, 2013). Four months later, the NYPSC commenced its "Reforming the Energy Vision" (REV) proceeding (NYPSC, 2014), kicking off a series of subsequent dockets with the goal of greatly expanding the use of demand-side resources, including demand response, distributed generation, and energy efficiency.

In one of these dockets, the NY Commission sought to work with stakeholders on a successor tariff to the existing NEM compensation approach that would support the broader framework of the REV proceeding (NYPSC, 2015). Throughout 2016, an extensive public process was undertaken to collaboratively identify the design elements of this new compensation methodology. The NYPSC adopted the proposed methodology in March 2017 (NYPSC, 2017a) and began implementation of the first phase of the novel DG compensation mechanism in September of that same year to "enable a distributed, transactive, and integrated electric system" (NYPSC, 2017b). The Value of DER tariff, as it is known (or VDER), includes five pricing components based on the range of benefits DERs provide to the New York utilities' distribution networks (see Figure 6). These are:

1. Location-Based Marginal Price (LBMP) – The day-ahead wholesale market hourly price for the energy commodity being produced by the resource, grossed up for line losses;
2. Installed Capacity (ICAP) – The wholesale market average monthly price for the capacity provided by the resource;
3. Environmental Benefits (EB) – An environmental adder that is fixed at the time of interconnection for the entire 25-yr term of service and set equal to the greater of the Tier 1 REC price or a social cost of carbon (SCC)-derived value; alternatively, customers can opt to retain their REC in which case they forfeit this value element;
4. Demand Reduction Value (DRV) – Utility-specific \$/kW-year value (recalculated every 3 years) distributed across the 10 highest usage hours; projects are compensated based on performance during those hours; and

5. Locational System Relief Value (LSRV) – Utility-specific and only available in designated locations; a \$/kW-year value identified by the distribution utility, locked-in and paid for the first 10 years of the project.<sup>27</sup>



Source: NYPSC (2017c)

**Figure 6. Comparison of NEM and VDER Tariffs**

This value stack pricing applies only to exports to the grid (i.e., an example of net billing). Exports are calculated on an hourly basis, which is somewhat unique among net billing rates (which typically compute exports instantaneously). Compensation for excess DER production is provided as a bill credit only (with indefinite roll-over, but no payouts). As noted above, the tariff applies for a 25-year term of service and requires an advanced meter capable of measuring hourly electric exports and imports.<sup>28</sup>

One of the unique elements of this NEM successor tariff is that it applies to a wide array of different distributed energy resource technologies including: solar PV, wind, hydroelectric, farm waste generation, fuel cells up to 2 MW, and combined heat and power systems up to 10 kW. Storage is likewise qualified but only when paired with an eligible generation technology as listed above. Stand-

<sup>27</sup> The NYPSC is currently considering revisions to the VDER tariff, including a potential phase out of the LSRV component. See NYPSC Staff “Whitepaper Regarding Future Value Stack Compensation Including For Avoided Distribution Costs,” December 12, 2018 in Docket 15-E-0751.

<sup>28</sup> As of this publication date, full-scale AMI rollouts had not yet happened in any investor-owned utility in New York; however, several utilities have ongoing AMI pilots, and Consolidated Edison will shortly be starting its AMI rollout. Timing of full AMI technology deployment varies by utility. Consolidated Edison’s AMI Plan was approved in March, 2016 (docket 15-E-0050) and it will complete full deployment by 2022. Orange & Rockland’s AMI Plan was approved in November, 2017 (docket 17-M-0178) and will complete full deployment by 2020. Long Island Power Authority received approval of its AMI Plan in December, 2018 and it will complete full deployment by 2023. National Grid and Avangrid have plans pending before the NY PSC. All utilities have hourly meters for their largest C&I customers (demand greater than 300 kW) since the mid-2000s. For customers without interval meters, VDER Order requires metering workaround by the end of 2019.

alone storage systems will be considered as part of Phase 2 of the proceeding, which is currently underway.

The tariff is only mandatory for new large commercial projects (i.e., demand-metered or mandatory hourly pricing customers) and for new mass market projects once utility-specific caps are reached. All existing NEM projects are grandfathered indefinitely, though any NEM-eligible project can opt-in to the Value Stack rates if they so choose.

Utility tariffs were issued in late 2017 and a Phase 2 of this proceeding was initiated in July 2017 addressing a range of issues, including: rate design, refinement of “value stack” elements, the application to a broader set of technologies/applications (e.g., >2 MW projects), and transitioning of mass market customers from NEM to VDER. Likewise, the NY PSC Staff filed two whitepapers in 2018 suggesting changes and improvements to the VDER tariff. As such, experience with this new form of DER compensation is still very much emerging.

### **3.4.2 Case Study: Hawaii Tariff Options for Customer-Sited Solar**

Hawaii has reached distributed solar penetration levels far beyond any other state. As of year-end 2017, roughly 36% of all single family residential homes in the state had rooftop PV systems; by comparison, the next highest was California (12% of single family homes), followed by Arizona (8%).<sup>29</sup> Such high penetration levels have prompted concerns about not only the financial consequences of continued reliance on net metering, but also the physical infrastructure impacts, as increasing numbers of distribution network circuits reach or approach their hosting capacity limits.<sup>30</sup>

Recognizing these issues, the Hawaii Public Utilities Commission (HPUC) opened a wide-ranging proceeding in 2014 “to investigate the technical, economic, and policy issues associated with DER” (HPUC, 2014). Among other things, the proceeding sought to transition away from “a DER market structure that exclusively facilitates the uncontrolled export of electrical energy onto the grid” and toward new forms of compensation that “accurately value the provision of energy and grid services and compensate customers based on the relative value these DER systems provide to the electrical grid at the time of delivery” (HPUC, 2017).

As an initial step in that direction, the HPUC closed the net metering program in October 2015, and directed the utilities to file two interim successor tariffs: the Customer Self Supply (CSS) option and the Customer Grid Supply (CGS) option. Both options allow customers to offset their own consumption with contemporaneous solar generation, but differ in their treatment of exported generation. Under CSS,

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<sup>29</sup> These adoption rates are based on calculations performed by Berkeley Lab, using data from GTM and SEIA (2018) for the number of residential installations by state and data from the U.S. Census Bureau's 2015 American Community Survey (ACS) for the number of single family homes in each state.

<sup>30</sup> See, for example, the Hawaiian Electric Companies' “Locational Value Maps”, which show numerous regions within the utilities' primary distribution networks within 5% of their respective hosting capacity limits: <https://www.hawaiianelectric.com/clean-energy-hawaii/integration-tools-and-resources/locational-value-maps>.

customers are prohibited from exporting any solar generation (aside from incidental exports), effectively requiring onsite storage. Under CGS, customers can export generation (as under NEM), but unlike NEM, exported generation is compensated at a fixed price, based on the utility's historical 12-month average on-peak avoided cost. For customers on Oahu, for example, the grid-export price was initially set at roughly 15 cents/kWh and remains fixed for 5 years, after which the HPUC may update it. As a point of comparison, the volumetric element of residential retail rates is roughly 25 cents/kWh; the CGS tariff therefore represented roughly a 10 cent/kWh reduction in the price paid for exported PV generation relative to how the CSS tariff values solar production that must remain on site.

CSS and CGS were intended as interim solutions while parties in the proceeding worked toward a longer term DER market structure. Accordingly, the HPUC placed enrollment caps on CGS, in order to manage the various technical and economic issues associated with uncontrolled exports. However, virtually all new PV applications were initially submitted under the CGS program, rather than CSS, leading to concerns that the CGS enrollment caps would be reached before new tariffs could be developed. In response, the HPUC raised the enrollment caps in December 2016 (HPUC 2016).

As the next incremental step toward a longer-term DER market structure, the HPUC directed the utilities to submit two new PV compensation tariffs in October 2017, representing essentially the next generation of the CSS and CGS options. CSS will continue to be available, offering customers an option for expedited interconnection approval. These tariff options are summarized in Table 4, along with the original CGS tariffs, which was fully subscribed as of November 2017.

The first of the two new tariffs is the Smart Export rate, which allows PV grid exports only during the hours of 4 pm to 9 am—effectively requiring onsite storage—with a fixed grid-export price based on the utility's historical average marginal costs during the export period (roughly 15 cents/kWh for customers on Oahu).

The second of the two new tariffs is Customer Grid Supply Plus (CGS+), which is similar to the earlier CGS tariff—allowing grid exports at any time—but with the critical additional provision allowing the utility to install controls to curtail PV output if required for grid reliability. The CGS+ tariff was thus intended as something of a compromise: recognizing that battery storage costs had not yet declined to the point where storage should be made a requirement for new rooftop PV installations, while also providing a mechanism for managing the most critical reliability-related issues associated with uncontrolled grid exports. As with the original CGS rate, the grid export price under CGS+ is based on the utility's 12-month average on-peak avoided cost, but was updated based on more-recent (and lower) avoided costs (e.g., roughly 10 cents/kWh for customers on Oahu). The HPUC also established enrollment limits for the CGS+ rate, given its intended transitional purpose.

In establishing these new tariff options, the HPUC made clear their desire to offer customers a spectrum of options, and that the current set of tariffs are intended to serve as “foundational building blocks” that could be supplemented or amended later to compensate other types of grid services provided by customer DERs (HPUC, 2017).

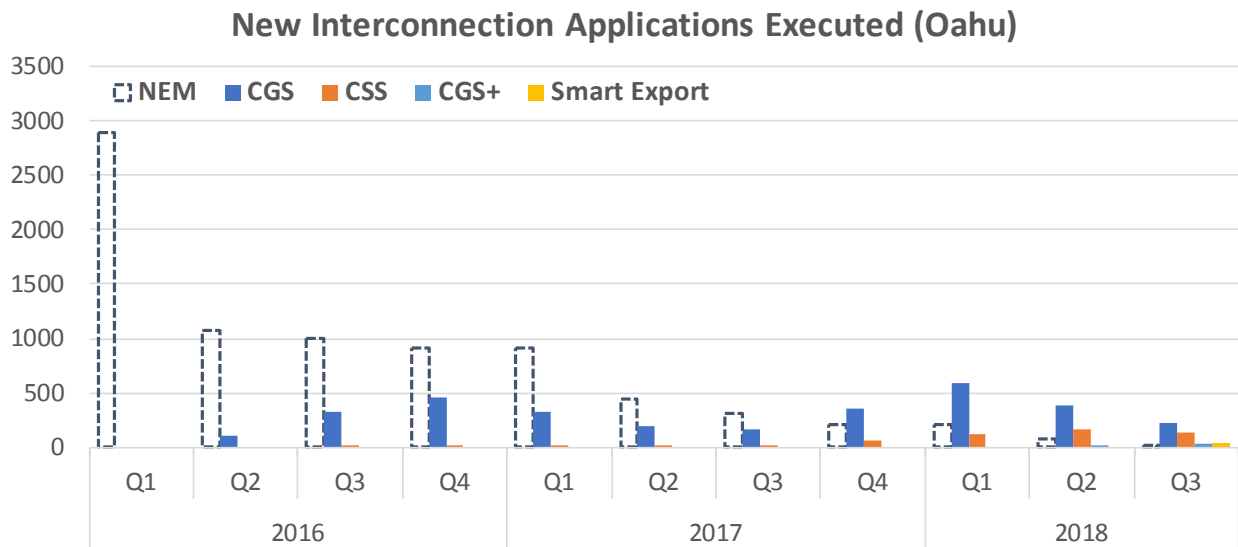
**Table 4. Hawaii’s Tariff Options for Customer-Sited Solar**

Tariff Name	Grid Exports Allowed	Grid-Export Price (Oahu)*	Storage Likely Needed	Other Key Provisions
<b>Customer Self-Supply</b>	No	n/a	Yes	Expedited interconnection approval
<b>Customer Grid Supply</b>	Any time	\$0.15/kWh	No	Legacy rate available only until enrollment limits are reached
<b>Smart Export</b>	Only 4 pm – 9 am	\$0.15/kWh	Yes	-
<b>Customer Grid Supply Plus</b>	Any time	\$0.10/kWh	No	Utility can curtail for grid reliability; tariff subject to enrollment limits

\* Grid-export prices are fixed for 5 years and vary by island. Under the Smart Export rate, grid exports outside of the designated grid export window are technically allowed, but receive zero compensation.

The transition in PV tariff structures has noticeably impacted the residential solar market in Hawaii, though the effects have been lagged due to the large number of wait-listed NEM projects installed following NEM phase-out. On a statewide basis, residential solar installations fell by roughly half, from 9,000-10,000 installations per year over the 2014-2016 period, to roughly 5,000 installations in 2017 (and 2018 on pace for about 4,000 systems) (GTM and SEIA, 2018). As can be seen from interconnection application data for the island of Oahu, in Figure 7, almost all non-NEM applications have occurred under CGS tariff (roughly 3,000 applications, compared to only 500 applications for the CSS tariff, which effectively requires energy storage). However, that balance has clearly begun to shift, with an increasing fraction of new applications in 2018 occurring under the CSS tariff, as battery storage costs have fallen and an increasing number of installers have developed bundled solar-plus-storage product offerings. An analysis of 2017 building permit data for the island of Oahu, for example, found that roughly 27% of permits issued for PV over the course of the year also included battery storage (Hawaii DBECT, 2018). That percentage likely increased in 2018, given continuing declines in battery storage costs.





Source: Data compiled from the Hawaiian Electric Company's quarterly compliance filings submitted in docket number 2014-0192.

Figure 7. New Interconnection Applications Executed for Each PV Tariff Option (Oahu)

### 3.5 Development of new electric vehicle-specific rates

States and utilities with some of the highest growth and interest in driving further EV adoption are beginning to introduce retail rates specific to EVs. By creating either a unique customer class for those with EVs or rates in which only EV owners can enroll, utilities can potentially better direct charging behaviors in ways that minimize the system impacts from such electric-intensive end-uses, and encourage EV adoption.

Although these rates are relatively new and thus implementation experience has been quite limited, they have attracted scrutiny. Specifically, the debates have centered on the role of demand-based charges versus time-based energy charges (RMI, 2017). One concern is that demand charges may impact public charging by penalizing fast chargers, which are demand intensive. However, some utilities counter that demand charges more closely align with cost causation principles, given the impact on the system infrastructure from such intermittent but intense draws of electricity.<sup>31</sup> EV supporters, as well as utilities, believe TOU rates provide financial incentives for customers to more efficiently use the grid by charging when prices are low, as well as improved customer economics for EV investment decisions, and can be designed consistent with cost causation principles.

However, a number of other factors may have even greater impact on customer adoption than retail rates, including customer characteristics (e.g., number/type of cars owned, early adopter profile), travel distance, and location and prevalence of charging stations (Coffman et al., 2015). In addition, the

<sup>31</sup> At the same time, there are several utilities temporarily or permanently eliminating demand charges in order to encourage EV adoption (e.g., see Whited et al., 2018).

differential between gasoline prices and electricity prices in some jurisdictions may be large enough that the particular rate design does not matter as much for customer economics as one might expect (or early adopters simply may not be that price sensitive to begin with). These dynamics may change, though, depending on how rate designs for EV customers evolve, and as the EV market moves to more price-conscious customers.

We detail three case studies of EV-specific tariff offerings: the first describes Georgia Power’s residential “whole home” TOU rate, the second describes Austin Energy’s EV-only rate, and the third describes San Diego Gas and Electric (SDG&E)’s multi-unit dwelling EV rate.

### 3.5.1 Case Study: Georgia Power Plug-In Electric Vehicle Rate

Georgia Power filed an Advice Letter with the Georgia Public Service Commission in 2014 describing the details of its Electric Transportation Initiative, which included an education campaign, utility-owned charging infrastructure, and rate offerings to support broader adoption of electric vehicles (GPC 2014). The rate proposal, a voluntary TOU rate (TOU-PEV-6), was based on the design of an offering that had been around since 2011, but the utility updated the rate levels and basic service charge while keeping the period definitions the same (see Table 5).

**Table 5. Summary of GP Residential TOU EV Rate**

Rate Design Elements	Rate Period	Definition	Rate Level
<b>Customer Charge</b> (\$/Month)	N/A	Fixed charge per meter per month	\$10.00
<b>Energy Charge</b> (\$/kWh)	Super Off-Peak	11PM-7AM every day	\$0.014164
	Off-Peak	7AM-2PM weekday and 7PM-11PM weekdays, weekends and holidays from June-September; and every day October-May	\$0.065865
	On-Peak	2-7PM weekday non-holidays from June-September	\$0.203217

The utility is actively marketing the rate to all private EV owners. According to its website, Georgia Power claims participants can expect to save \$88 dollars a month in vehicle fuel costs (as compared to gasoline) by investing in an electric vehicle and charging it during the super off-peak period relative to filling up the tank on a gasoline fueled car (Georgia Power, 2018). In addition, the utility offers rebates on the purchase of electric vehicles and incentives for the installation of different types of EV chargers.

### 3.5.2 Case Study: Austin Energy Plug-In Electric Vehicle Rate Pilot Program

Austin Energy rolled out its electric vehicle initiative in 2012, with its Plug-In EVerywhere<sup>SM</sup> program supported by a DOE grant placing 113 charging stations at retail, multi-family, parks, libraries, and other locations in the City of Austin. The utility then incentivized the growth of charging infrastructure in its service territory to broaden EV adoption in the city. This has expanded the Plug-In EVerywhere<sup>SM</sup> program to over 700 level-2 public charging ports including a DC Fast charger in the downtown Austin

area. However, the utility’s marketing studies showed that ~90% of their customers wanted or preferred to charge their electric vehicles at home. Accordingly, in 2016, the utility rolled out its EV360 rate pilot program.

Participating customers in EV360 pay a flat monthly subscription fee and can charge their electric vehicles at any of the utility’s Plug-In EVERYwhere<sup>SM</sup> stations or at their homes between 7 PM and 2 PM on weekdays or anytime on weekends (see Table 6). The program is advertised as a home-and-away program allowing drivers to have flexibility when it comes to charging. The utility will charge the customer for any energy used during weekdays on peak hours from 2 PM to 7 PM at the applicable energy rate (see Table 6). There is also a one-time enrollment fee of \$150 for a 12-month commitment to the pilot to help offset the additional sub-metering cost. Should a participant leave the program before the 12-month period is up, there is an early termination fee of \$200.

**Table 6. Summary of AE Residential TOU EV Pilot Rate**

Rate Design Elements		Summer (June - September)	Non-Summer (All other months)
<b>Customer Charge</b> (\$/Month)	Demand < 10 kW	\$30.00	\$30.00
	Demand ≥ 10 kW	\$50.00	\$50.00
<b>Supply Charge</b> (\$/kWh)	Weekday Off-Peak	\$0.00000	\$0.00000
	Weekday On-Peak	\$0.40000	\$0.14000
	Weekend Off-Peak	\$0.00000	\$0.00000

Austin Energy requires that each participating customer install at their expense a separate sub-meter circuit attached to a level-2 plug-in electric vehicle charging station. The customer can receive a 50% rebate for the cost of the charging station and associated installation costs including the sub-meter circuit. The charging station is then connected to a utility-provided meter which registers and reports electricity usage back to Austin Energy.

As of January, 2019, the pilot is fully subscribed out of the goal of 100. Initially to help boost enrollment to meet the goal of 100 participants, Austin Energy used an ArcGIS “Tapestry software” to identify socioeconomic profiles of customers who would be good candidates for the pilot, and then target marketed to them using direct mailers. An installer toolkit and checklist is also available on Austin Energy’s website for electricians and contractors to understand the program and the installation process.

Preliminary analysis of participants’ EV charging station meter data in the fall of 2018, when there is little heating or cooling load, showed substantial overnight charging by participants. Most of the initial subscribers chose the “< 10kW” demand option within the program with a few high mileage users going for the higher demand option. A white paper on Austin Energy’s EV360 program is expected to be released in 2020.

### 3.5.3 Case Study: San Diego Gas & Electric Power Your Drive Program

In 2014, San Diego Gas & Electric (SDG&E) made a rate request to the California Public Utility Commission (CPUC) for the first California investor-owned utility EV infrastructure investment and rate proposal (SDG&E 2014). The utility's focus was long-dwell time locations (i.e., workplaces and multi-unit dwellings (MUDs)), because they were (and remain) underserved with EV chargers but frequently have electric vehicles parked for long periods of time. MUD's also comprise ~50% of San Diego's residential units (CPUC, 2016). SDG&E expanded its EV initiative in April 2017 to include its Power Your Drive program.

The Power Your Drive program has two components. First, SDG&E installs level-2 EV charging stations (with an embedded submeter) to participating employers at office buildings, apartment communities, or condominium associations. Depending on the site type (e.g., MUD versus workplace), the participating customer may pay a one-time participation fee. SDG&E retains ownership of the "make-ready" EV infrastructure and chargers, and funds collected from all ratepayers cover the costs of the Power Your Drive program. Second, the Power Your Drive program chargers apply a rate (\$/kWh) based on that hour's California ISO day-ahead market price for that location on the grid, with an adder at the distribution feeder level based on the likelihood at that time of exceeding the top 200 hours of actual load relative to historical averages. The site host can elect to either pay the monthly bill from use of the Power Your Drive program chargers on their premise, or have individual EV owners create accounts with SDG&E where their use is charged directly to them. The CPUC required SDG&E to file semi-annual reports, including EV charger usage statistics, customer EV adoption surveys, program spending, and observable trends in the deployment of EV charging sites and growth in EV adoption, among others (CPUC, 2016).

## 4. Implications of Rate Design Trends for DERs

The foregoing set of rate reforms have broad implications: for utilities, in terms of their operations, planning, and financial health; for customers, in terms of distributional bill impacts within and across customer classes and their opportunities to manage energy costs; and for society more broadly, in terms of the economic and environmental impacts associated with the provision of energy services. While acknowledging this much broader set of implications, we focus here narrowly on one particular set of implications and stakeholder perspective—namely, the potential impacts on adoption and market development for specific DER technologies.

In discussing these implications, we characterize the likely near-term deployment impacts of each rate reform on different types of DERs (whether deployed on a stand-alone basis or in tandem with other technologies). As shown in Table 7, the potential near-term impacts on DER deployment vary significantly depending on the particular rate reform and type of DER—in some cases helping to accelerate DER deployment and in other cases constraining it, to varying degrees. The implications of any particular rate reform depend critically on specific tariff design details (e.g., the timing of TOU peak periods or the type of demand charge adopted), as indicated by the ranges shown in the table for any particular rate reform and DER.<sup>32</sup> Below, we elaborate upon these dynamics and discuss some of the more qualitative implications for DER deployment trends, in terms of how these rate reforms may impact the particular features and operation of DERs deployed. We caveat this discussion by acknowledging that DER deployment impacts in some cases are somewhat ambiguous or unknown, even in the short-run, and especially over the long-run as the technologies themselves may evolve in response to new rate structures.

**Table 7. Potential Impacts on Near-Term DER Deployment Levels**

Rate Design Trend	PV	EE	EV & Electrification	Storage & DR
Time-Based Rates	●●●●●	●●●●●	●●●●●	●●●●●
Load Building Rates	●●●●●	●●●●●	●●●●●	●●●●●
3-Part Rates	●●●●●	●●●●●	●●●●●	●●●●●
NEM Alternatives	●●●●●	●●●●●	●●●●●	●●●●●
EV-Specific Rates	●●●●●	●●●●●	●●●●●	●●●●●

Key: ●=Highly constrained, ●=Slightly constrained, ●=No impact, ●=Slightly accelerated, ●=Highly accelerated

**Increased pursuit of residential time-based rates.** For both PV and EE, the deployment impacts of time-based rates depend critically on the timing of high vs. low priced periods, and how that coincides with the DER load shape. PV generation profiles and peak prices have historically coincided reasonably well, though TOU peak periods are often centered in afternoon hours, which may motivate more westerly oriented systems. In regions with high solar penetration levels, however, peak prices have increasingly

<sup>32</sup> Our assessment of the implications is based on rate design variations identified and discussed in this report. Of course, one could conceive of designs that further broaden the range of possible impacts.

shifted toward evening hours with very low prices experienced in the middle part of the day. Broader application of time-based rates in these markets, if mandatory or the default for customers with PV, would thus tend to dampen PV deployment.<sup>33</sup> For EE, the coincidence with peak prices is measure-specific and to some extent regional. For example, time-based rates may incentivize greater adoption of EE measures targeting cooling loads in hot-weather climates and heating loads in cold weather climates where electric space heating is prevalent, as those loads often coincide well with system peaks, but may deter investments in other types of EE measures that operate predominantly in low-priced, off-peak hours. Analysis by Baatz (2017), however, found that the impact of time-based rates on EE measure cost-effectiveness tends to be relatively small for most measures.

In the case of EVs and other forms of electrification, residential time-based rates have somewhat ambiguous implications that largely relate to the timing and flexibility of usage behaviors. For customers who need to charge their vehicles in the afternoon to early evening hours, higher prices during these periods could deter adoption of EVs (presuming the EV customer does not use technologies to optimally time EV charging in low price hours). However, for customers willing and able to charge during lower-cost off-peak hours, either because this coincides with their needs or they are flexible, residential time-based rates should boost EV deployment by offering lower-cost charging during off-peak hours. Similarly, other residential electrification measures, such as water heating, would also likely benefit from greater availability of time-based rates, to the extent that such loads can be scheduled during less expensive off-peak periods.

For storage and DR—which we group together in this analysis by virtue of their similar attributes—time-based rates will typically help to accelerate deployment, by providing an opportunity to arbitrage between high and low price periods. In many cases, these arbitrage opportunities may be relatively modest (e.g., if the peak-to-off-peak price ratio is small or if high prices occur only occasionally, as under some CPP or VPP rates). As such, the deployment impacts may be greater for DR than for storage, given the potential for low-tech/low-cost DR strategies (e.g., programmable thermostats and simple behavioral strategies that may not require any technology investments).

**Development of rates and programs to promote midday load building.** As discussed in Section 3, midday load building can be encouraged either through time-based rates with “matinee pricing” (i.e., super off-peak rates during midday hours) that operate on a daily basis or through dispatchable programs (e.g., reverse DR programs) that encourage increased consumption on specific occasions. The implications for DERs depend on which of these two approaches is pursued.

In the case of time-based rates with matinee pricing, the DER-related implications are largely an extension of those discussed above for time-based rates, more generally—albeit with potentially more extreme impacts, given the possibility for larger pricing differentials. For PV, super off-peak prices

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<sup>33</sup> As an illustration, Darghouth et al. (2013) modeled customer bill savings from residential PV in California, and found that bill savings under TOU rates would be 13% *higher* than under flat rates when PV penetration on the grid is low, but would be 20% *lower* than under flat rates once PV penetration reaches 15% of total generation (assuming that TOU period definitions are based solely on the temporal profile of wholesale electricity prices).

during midday hours would likely serve as a strong deterrent to adoption, given the timing of PV production. For EE, matinee pricing would drive investment even further towards those end-uses that operate primarily during on-peak hours and away from other measures. For commercial and industrial customers, in particular, whose operations and loads tend to be more concentrated within midday hours than do residential customers', matinee pricing could serve as a fairly strong deterrent to energy efficiency investments. Instead, matinee pricing could help drive deployment of electrification (e.g., converting from natural gas and other fuels to electricity for various end-uses, such as heating and cooking). For EVs, matinee pricing could substantially reduce charging costs for those with this need in the middle of the day (e.g., public and workplace charging). Electrification of industrial process loads would be incentivized in situations where consumption can be timed to coincide with super off-peak midday periods. For storage and DR, matinee pricing would offer even greater arbitrage opportunities than under standard TOU rates by virtue of super-off peak pricing periods, providing an even stronger incentive for adoption.

In the case of programs with dispatchable events to encourage episodic, midday load building, like a reverse DR program, the implications for DERs are more limited and apply only to dispatchable resources like storage and DR (and, if vehicle-to-grid functionality were widely enabled, EVs as well). The incentives provided under these programs likely provide only a modest inducement for DR that can shift loads and storage adoption, given the infrequency of the dispatch events and, as in the case of time-based rates, may initially provide more stimulus for DR than for storage, given the availability of low-cost DR measures. That said, to the extent that storage and DR technologies require "value stacking" to make the investment case, the incremental revenue opportunity provided through a reverse DR-type program could be pivotal in some instances.

**Increased application of residential three-part rates.** Demand charge rates, which have correspondingly low volumetric energy charges, have diametrical implications for different types of DERs. For PV, three-part rates can potentially be a significant deterrent to adoption depending on the size and structure of the demand charge. PV may be able to modestly reduce residential demand charges under certain types of designs (e.g., if based on the customer's maximum demand during afternoon peak periods, when PV is generating), but in most cases the demand charge savings from residential PV are minimal, at best (Darghouth et al., 2017). That said, experience with SRP's mandatory demand charge rate for residential PV customers has shown that the PV market can adapt and survive under demand charge rates, even if growth is slower than what might otherwise have occurred.<sup>34</sup>

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<sup>34</sup> One other important distinction may be whether the demand charge rate is mandatory for all residential customers or only for residential customers with PV. In the latter case (as exemplified by SRP's rate), a customer's decision to invest in PV is made based on comparison to its utility bill under a standard non-demand charge rate, where the customer has presumably made no effort to manage its peak demand. Because the PV investment is coupled with a move to a demand charge rate, the decision to invest in PV is also coupled with a decision to engage in peak load management. This is potentially very different than a situation where the customer is already on a demand charge rate and has presumably undertaken some peak load management measures; in that case, the decision to invest in PV is made in isolation, and adoption could conceivably be more significantly curtailed.

For EE, demand-charge rates will generally also constrain growth, as shifting more cost recovery to demand charges will result in lower energy rates (Baatz, 2017). Some measures, particularly those targeting residential cooling loads, which tend to drive customer peak demand, could conceivably produce larger economic benefits under a demand charge than under a higher volumetric energy charge. Unfortunately, the temporal granularity of existing EE load research data is generally quite limited, and little if any public research has been conducted to precisely evaluate the effects of demand charges on EE measure cost-effectiveness.

Demand charges are notoriously problematic for EVs, given the high power draw of EV chargers (particularly DC fast chargers). The impacts on EV adoption are most severe in the case of non-coincident demand charges, but may be lessened with demand charges based on maximum demand during specified (and relatively narrow) coincident peak periods. In fact, such rates could conceivably provide a modest boost to EV adoption, by offering reduced volumetric energy rates and charging costs outside of the designated demand charge window, provided that most customers could easily schedule charging to occur during those times. The same dynamics apply to residential building electrification measures as well: three-part rates with non-coincident demand charges could strongly deter such investments, while rates with peak-period demand charges could modestly boost deployment for measures and regions where the electrified end-uses can be easily scheduled around the designated demand charge window.

In contrast to other types of DERs, demand charges represent an unambiguous benefit to the deployment of storage and DR. Indeed, demand charges have been the primary driver for storage adoption among commercial customers to-date, and the extension of demand charges into the residential sector would likely induce a similar response. In terms of DR adoption, energy service companies are increasingly beginning to offer more advanced technology solutions for residential demand management (often in conjunction with PV), who have been promoting such systems to larger commercial and industrial customers on demand charge rates for years.

**Development of new net-metering alternatives.** Most net metering reforms are driven to some extent by concerns about cost-shifting to non-solar customers; in seeking to mitigate those impacts, the NEM reforms generally dampen the economics of solar adoption and will therefore tend to constrain future deployment. As always, however, the actual implications depend critically on the details of any individual NEM alternative. Many net billing rates, which have thus far been the predominant NEM alternative, have been developed as political compromises or transitional instruments that only marginally reduce the price paid for grid exports relative to full retail rate compensation. Thus, in the very near term, these rate reforms may only minimally impact PV deployment. More significant reductions in grid export prices would, naturally, dampen PV adoption more substantially. An analysis by Barbose et al. (2016), for example, found that replacing NEM with wholesale price-based compensation for grid exports would reduce residential PV adoption by roughly 30% nationally (and much more in some states). As discussed earlier, installation rates dropped by roughly 50% in Hawaii after replacing NEM with net billing (even with grid export rates of roughly 15 cents/kWh).



The effects of net metering reforms on other types of DERs are derivative to their effects on PV. The key to understanding those effects is in recognizing that, under net billing, the customer's marginal electricity price during times when PV is exporting to the grid (i.e., the middle of the day) is the grid export rate. That is, in effect, the cost of incremental consumption (e.g., from EV charging, new electrified loads, storage charging, or shifting load) and the value of incremental EE savings during those hours.<sup>35</sup> The DER deployment impacts of net billing therefore largely mirror those seen under matinee pricing, as both entail a low marginal retail price of electricity during midday hours—the one fundamental difference being that the impacts of net billing are confined to customers with PV (or other applicable forms of onsite generation).

Net billing rates therefore will tend to support greater levels of adoption of storage and DR, which can essentially arbitrage between grid export rates and retail rates. Those arbitrage opportunities could be particularly compelling if the underlying retail rate includes time-based rates or, as is the case in several of Hawaii's new PV tariffs, grid exports are either prohibited or provided zero compensation during midday hours. Impacts on EV adoption are likely to be fairly modest, given that residential charging typically does not occur during midday hours. However, early EV adopters disproportionately tend to also be PV adopters, and net billing rates may amplify those synergies.<sup>36</sup> For example, to the extent that net billing rates encourage greater storage deployment, some additional EV adoption may follow, if customers are motivated specifically to charge their vehicles with solar energy. Other residential electrification measures may also benefit to the extent they can be scheduled to coincide with grid export hours. Conversely, net billing will likely deter EE investments—as such measures will tend to increase the quantity of PV exported to the grid, subjecting such generation to the lower grid-export rate, rather than the more lucrative retail rate that would otherwise be avoided if the PV generation were serving onsite load. Therefore, customers have less incentive to reduce energy usage, particularly when PV is generating.

**Development of new electric vehicle-specific rates.** For obvious reasons, new EV-specific tariffs have implications most directly and primarily for EVs. Given that these new tariffs are often being developed with the expressed purpose of facilitating EV deployment (while also incentivizing charging patterns that minimize system impacts), some positive impact on EV adoption would typically be expected. Naturally, the ultimate impact on EV deployment will depend on the particular rate structure and design details. As discussed above, rate designs that incorporate demand charges are likely to adversely impact EV adoption, but introduction of time-of-use rates, especially those that promote load building in off-peak periods like afternoons and overnight hours could provide substantial economic support to EV ownership. Deployment will also likely be affected by whether the new rates target public and workplace charging or home charging. Current tariff offerings, many of which are still either in their

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<sup>35</sup> Increasing load at times when PV is exporting to the grid will reduce the quantity of grid exports; thus, the cost of that increased consumption is the opportunity cost of foregone sales. Similarly, the benefit of reducing load is the value of increased grid exports (not avoided retail purchases, as those purchases are already avoided by onsite generation).

<sup>36</sup> For example, a survey of roughly 20,000 EV owners in California, conducted over the 2013-2015 period, found that 40% either already installed or were planning to install a PV system (CSE 2017).

pilot stages or with relatively low enrollment, will hopefully provide useful information about which approaches are most effective.

In the event EV-specific rates require sub-metering, where the tariff is applied solely to consumption for EV charging, there is likely to be little direct implication for other types of DERs, beyond EVs (as reflected in Table 7). However, EV rates that are based on whole-house/building usage could have significant implications for other types of DERs, depending on the time-varying structure of energy and (if used) demand charges, as discussed already throughout this section.

## 5. Conclusions

Retail electricity pricing is evolving in response to a variety of technical, market, and policy-related drivers. In this report, we highlight and present short case studies of five recent trends: increased pursuit of residential time-based rates, development of rates and programs to promote midday load building, increased application of residential three-part rates, development of new net-metering alternatives, and development of new electric vehicle-specific rates. Early experiences with these rate structures can provide valuable lessons regarding tariff design and implementation, as other states and utilities engage in rate reforms.

Among the many potential implications of these rate reforms are the impacts on DER adoption, in terms of both the quantity and characteristics of DERs deployed. In some cases, these impacts are “by design” (e.g., net metering reforms or new EV-specific rates, which explicitly target specific DERs), while in other cases the impacts may be more implicit or incidental (e.g., residential three-part rates, which may stimulate greater adoption of onsite storage).

In considering how these various rate reform trends may impact DER deployment, three broad themes emerge:

- **DER impacts depend critically on the specifics of the tariff structure.** Though perhaps somewhat obvious, it cannot be over-stated how important are the specifics of any particular rate design in assessing the potential impacts on DER deployment. Among the rate design trends discussed in this report, these details include: the timing and peak-to-off-peak pricing differential under time-based rates, callable vs. regular daily incentives to increase midday load, the use of coincident vs. non-coincident demand charges, the specific price paid for grid exports under net billing rates, and whether or not EV-specific rates are sub-metered vs. applied on a whole-house basis. Details such as these dictate not only the magnitude, but in some cases also the directionality of impact for certain DERs.
- **Flexible DERs generally benefit more under emerging rate design trends.** DERs exist along a continuum of flexibility, ranging from those with largely fixed load shapes (EE and PV), to those with some level of discretion in how they are operated (EVs and certain other forms of electrification), to fully dispatchable resources (storage and certain forms of DR and electrification). As evident by a quick glance at Table 7, most emerging rate reforms tend to support greater deployment of flexible DERs, while often constraining adoption of less-flexible resources. This outcome is driven by the general movement towards rate structures with greater temporal granularity, which naturally tends to encourage price-responsive resources.
- **Emerging rate designs generally encourage load building (during specific times of the day).** Though only one of the five rate design trends discussed in this report is explicitly intended as a tool for load building (“Development of rates and programs to promote midday load building”), most of

the other rate design trends also incentivize load building, whether in the form of EVs, other types of electrification, or energy storage (which increases net electricity consumption due to round-trip losses and ancillary loads). The incentives for load building are often concentrated during particular times of the day, though depending on their design, three-part rates may encourage load building across a fairly broad range of hours. In contrast, the emerging rate designs discussed here generally tend to constrain growth of DERs that reduce consumption of grid-supplied electricity (EE and, especially, PV). This outcome is driven partly by the general movement toward greater levels of attribute unbundling and temporal granularity that better reflects marginal costs. Load building is also a natural response on the part of electric utilities to slowing sales growth and ongoing concerns about revenue erosion from EE and PV, and electrification is a strategy that some state policymakers and regulators have endorsed for addressing their greenhouse gas abatement goals.

Regulators engaged in retail rate reform efforts may wish to consider explicitly how new rate designs may impact deployment trends among different types of DERs, weighing those impacts against the many other considerations and stakeholder perspectives that regulators must balance in establishing utility rate structures.

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