Electricity Innovation Lab
ROCKY MOUNTAIN INSTITUTE

RATE DESIGN FOR THE DISTRIBUTION EDGE

ELECTRICITY PRICING FOR A DISTRIBUTED RESOURCE FUTURE

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WHAT IS e-LAB?

The Electricity Innovation Lab (e-Lab) brings together thought leaders and decision makers from across the U.S. electricity sector to address critical institutional, regulatory, business, economic, and technical barriers to the economic deployment of distributed resources. In particular, e-Lab works to answer three key questions:

- How can we understand and effectively communicate the costs and benefits of distributed resources as part of the electricity system and create greater grid flexibility?
- How can we harmonize regulatory frameworks, pricing structures, and business models of utilities and distributed resource developers for greatest benefit to customers and society as a whole?
- How can we accelerate the pace of economic distributed resource adoption?

A multi-year "change lab," e-Lab regularly convenes its members to identify, test, and spread practical solutions to the challenges inherent in these questions. e-Lab has member meetings, coupled with ongoing project work, facilitated and supported by Rocky Mountain Institute.

e-Lab meetings allow members to share learnings, best practices, and analysis results; collaborate around key issues or needs; and conduct deep-dives into research and analysis findings.

For more information about e-Lab, please visit: http://www.rmi.org/eLab.

About this paper:

This e-Lab discussion paper was prepared to support discussion and dialogue about next-generation retail electricity pricing approaches appropriate for a future with increasing quantities of distributed energy resources. It is intended to stimulate and advance discussion about the advantages and disadvantages of alternative pricing approaches. The paper advances a particular point of view, with valuable input from e-Lab members and others. It does not, however, reflect a consensus view of e-Lab members nor does it reflect policy recommendations endorsed by e-Lab members.

e-Lab is a joint collaboration, convened by RMI, with participation from stakeholders across the electricity industry. e-Lab is not a consensus organization, and the views expressed in this document are not intended to represent those of any individual e-Lab member or supporting organization.

EXECUTIVE SUMMARY

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EXECUTIVE SUMMARY

The U.S. electricity system is on the cusp of fundamental change, driven by rapidly improving cost effectiveness of technologies that increase customers' ability to efficiently manage, store, and generate electricity in homes and buildings. With growing adoption of these technologies, the electricity system is shifting toward a future in which the deployment and operation of distributed energy resources (DERs)[1] will have far-reaching implications for grid operation, investment, and security. Yet, there is a looming disconnect between the rapidly evolving new world of distributed energy technologies and the old world of electricity pricing, where relatively little has changed since the early 20th century. By changing electricity pricing to more fully reflect the benefits and costs of electricity services exchanged between customers and the grid, utilities and regulators can unleash new waves of innovation in distributed energy resource investment that will help to reduce costs while maintaining or increasing system resilience and reliability.

The stakes are high in getting this transition right. With or without pricing reform, distributed resources are likely to account for a growing share of total electricity system investments. DER developers and customers will optimize their investments and operations against the price signals provided by the utility, regardless of whether these prices are aligned to create the greatest value for society as a whole. The types of pricing structures most common today for residential and small commercial customers—bundled, volumetric block rates—provide little or no incentive for the deployment and operation of DERs at the times and places where they can create greatest overall benefit. The perpetuation of these pricing structures in the face of ongoing improvement in DER cost and performance and increased adoption of these technologies will result in lost opportunities for cost reduction and inefficient utilization of assets on the part of both customers and utilities.

Creating a clean, efficient, and secure 21st century electricity system will pivot, in part, on successfully integrating DERs into the design and operation of the electricity grid—and pricing provides the incentive structure needed to achieve this integration. More granular pricing, capable of reflecting marginal costs and benefits more accurately than today's rates do, will provide better incentives to direct distributed resource investments, regardless of whether investments in and management of DERs are undertaken by customers, by utilities, or by third-party service providers. Ultimately, prices could be adapted to fully reflect a two-way exchange of value and services between utilities and customers.

[1] For more on DERs, see "What Are Distributed Energy Resources?" and Table 2 on page 11.

Making the transition to new pricing approaches, however, will undoubtedly pose challenges. In particular, it will require making trade-offs against one of the hallmark principles of traditional rate design: simplicity. In addition, introducing new and more sophisticated pricing structures could have disruptive effects on existing business models for DER developers. Developing and implementing new pricing structures will therefore require effective collaboration among utilities, regulators, technology developers, and customers. By creating a shared vision of the future trajectory for prices, however, these parties could create a pathway whereby DER technology and services can co-evolve with increasingly advanced price signals.

This report discusses a pathway for deliberately and incrementally increasing rate sophistication along three continuums for residential and small commercial (i.e., mass-market) customers:

1. ***Attribute unbundling***—shifting from fully bundled pricing to rate structures that break apart energy, capacity, ancillary services, and other components
2. ***Temporal granularity***—shifting from flat or block rates to pricing structures that differentiate the time-based value of electricity generation and consumption (e.g., peak vs. off-peak, hourly pricing)
3. ***Locational granularity***—shifting from pricing that treats all customers equally regardless of their location on the distribution system to pricing that provides geographically differentiated incentives for DERs

A transition to more sophisticated pricing is attainable for large portions of the country, but will require careful planning and customization to local circumstances. The introduction of more pricing options for customers—allowing customers to opt in to new rates that allow them to benefit from actions that reduce system costs—could allow the implementation of new approaches in stages, while providing an opportunity for customers and service providers to experiment with new rates. For example, pricing options could include a default pricing option that gradually changes to become more sophisticated over time, while providing alternative opt-in pricing structures that are more or less sophisticated than the default for customers who want or need such choices.

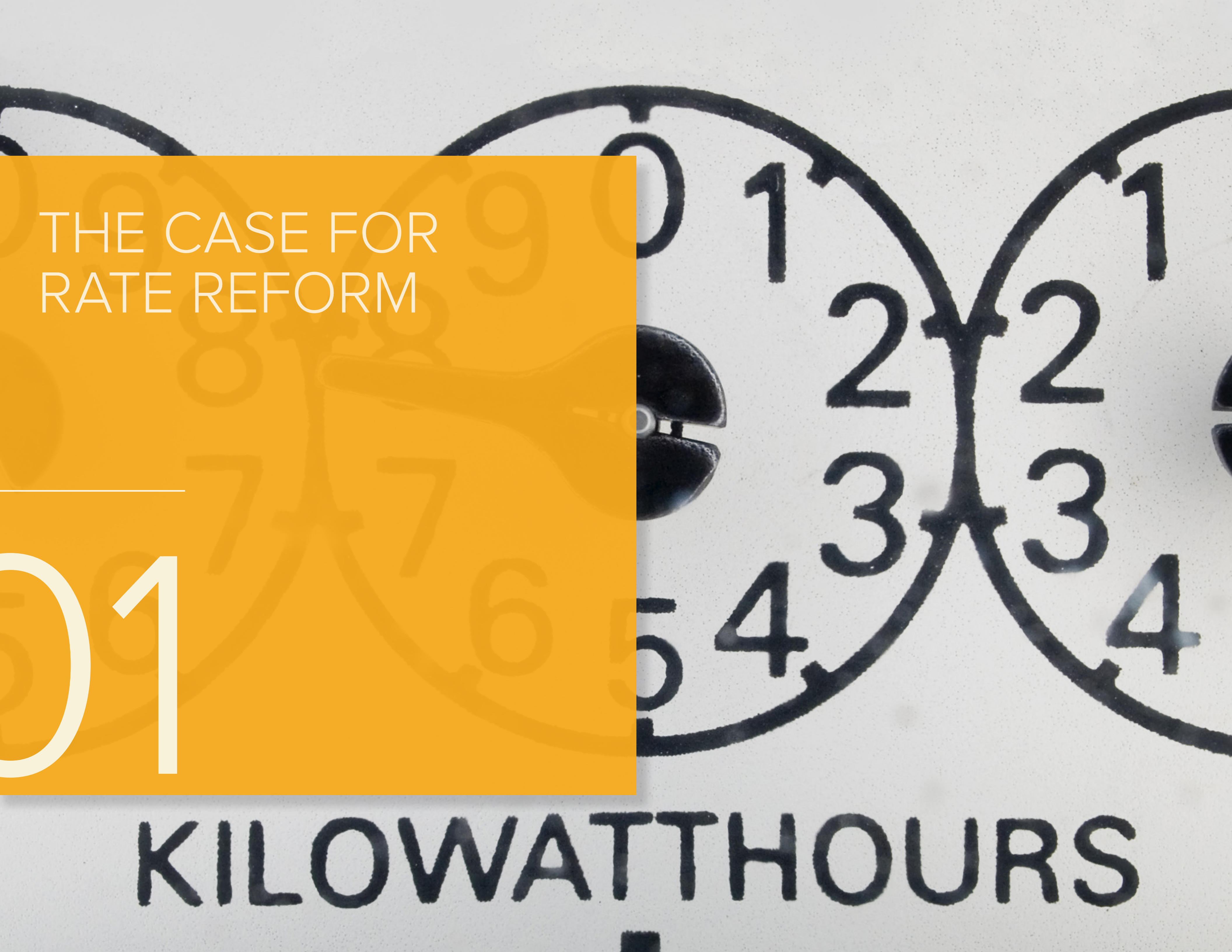
This paper discusses six evolutionary pricing options to consider, individually or in combination (see Table 1).

TABLE 1: **NEAR- AND LONGER-TERM EVOLUTIONARY RATE STRUCTURES**

NEAR-TERM DEFAULT OR OPT-IN POSSIBILITIES	LONGER-TERM, MORE SOPHISTICATED POSSIBILITIES
Time-of-Use Pricing	Real-Time Pricing
Energy + Capacity Pricing (i.e., demand charges)	Attribute-Based Pricing
Distribution “Hot Spot” Credits	Distribution Locational Marginal Pricing

These more sophisticated pricing options need not introduce unnecessary complexity for customers—third-party aggregators, energy management software, smart thermostats, and other technologies can maintain a simple customer experience by optimizing performance behind the scenes even as greater differentiation gets built into the rate structures.

Transitioning to some of the new rate structures explored in this report is possible today or will be realistic in the next few years in some markets, especially where utilities have already transitioned to advanced metering infrastructure. In other cases, implementation of more sophisticated rate structures will take more time—and possibly even legislative and regulatory reform—to achieve. Either way, the conversation about how to adapt electricity pricing to meet the needs of a 21st century electricity system has begun. Bringing this transition to fruition will require participation, dialogue, and collaboration among stakeholders to deliver successful outcomes.



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THE CASE FOR RATE REFORM

01: THE CASE FOR RATE REFORM

The electricity grid is changing. Aging infrastructure requires new waves of investment to upgrade, while technological innovation—especially customer-facing distributed energy resources (DERs)—is transforming the utility-customer relationship. Traditional utility models, in which investments are recovered through revenue that assumed consistent or increasing energy sales, are coming up against rapidly growing DER adoption that reduces utilities' sales. Further, DERs can shift the traditional load profile of both the customer and the system as a whole, but they still depend upon utilization of grid infrastructure to unlock value for customers. In this new environment, block volumetric pricing (the most common rate structure for residential and small commercial customers today) will no longer be able to align stakeholder interests to deliver maximum value to the system over the long term.

More sophisticated rate structures can unleash new investments and innovations in DERs, and direct the deployment of these resources in a manner that maximizes the benefits to the system as a whole. Further, a failure to evolve to more sophisticated rates will become increasingly problematic, because as DERs become ever more accessible and dynamic, consumers will make or forego investments in DERs (often with long-term commitments) in more haphazard ways, without sensitivity to price signals or the impact to the grid as a whole. The transition to this future of more sophisticated rates will need to be undertaken with great care. Attention must be paid to ensure that rates continue to protect affordable access to electricity and encourage the efficient use of resources while minimizing unnecessary cross-subsidization between customers and maintaining a simple customer experience.

MASS-MARKET FOCUS

Rate design varies substantially across customer classes. This paper primarily focuses on rate reform for residential and small commercial customers (also referred to here as mass-market customers). As distributed energy resource adoption grows, elements of rate structures that are prevalent for large customers can be applied to the mass market (and can also help to refine and improve the service options for large customers).

WHAT ARE DISTRIBUTED ENERGY RESOURCES (DERs)?

DERs are demand- and supply-side resources that can be deployed throughout an electric distribution system to meet the energy and reliability needs of the customers served by that system. DERs can be installed on both the customer side and the utility side of the meter, and can be owned by the customer, a third party, or the utility. DERs can be deployed quickly at small or large scale and some can provide rapid response to unplanned changes in load. The value for each DER varies by time and location, changing the cost to serve customers utilizing one or more of these technologies.

Table 2 (at right) characterizes DERs based on whether they produce variable output and are controllable. Here, controllability is defined by the technical capability of a resource, regardless of what entity (e.g., the customer, the grid operator, or a third party) has the ability to control it.

TABLE 2: **DISTRIBUTED ENERGY RESOURCES (DERs)**

	DEFINITION	EXAMPLES	VARIABLE OUTPUT	CONTROLLABLE
Efficiency	Technologies and behavioral changes that reduce the quantity of energy that a customer needs to meet all of their energy-related demands.	LED Light Bulbs High-Efficiency Appliances Building Shell Improvements		
Distributed Generation	Small, self-contained energy sources located near the final point of energy consumption.	Solar PV Combined Heat & Power Small-Scale Wind	✓ (Solar PV) ✓ (Small-Scale Wind)	
Distributed Flexibility & Storage	Technologies that allow the overall system to use energy smarter and more efficiently by storing it when supply exceeds demand, and prioritizing need when demand exceeds supply.	Demand Response Electric Vehicles Thermal Storage Battery Storage		✓ ✓ ✓ ✓
Distributed Intelligence	Technologies that combine sensory, communication, and control functions to support the electricity system and magnify the value of DER system integration (e.g., islandable microgrids, connected thermostats, EV chargers, and water heaters).	Microgrids Home-Area Network & Smart Devices Smart Inverter		✓ ✓ ✓

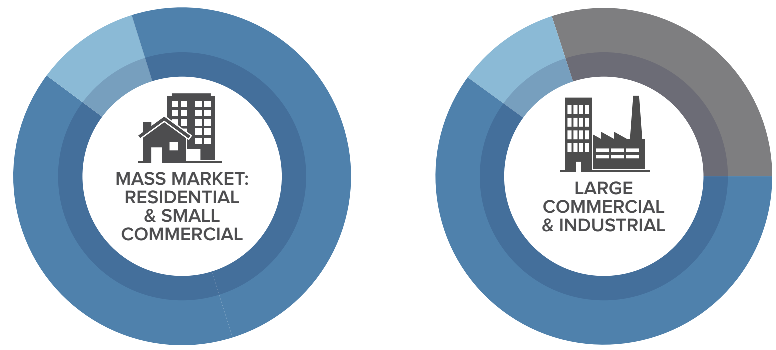
CHALLENGES POSED BY TODAY'S RATE STRUCTURES

Today's Rate Designs Increasingly Reflect Yesterday's Grid

Traditional rate design groups customers into broad classifications (e.g., residential, commercial, industrial), and establishes rates for these customer groups on the basis of peak demand, energy use, and customer counts (see Figure 1). The level of rate design sophistication has varied across these customer classes. For residential and small commercial customers, for instance, the majority of their bill is determined through a per-kWh energy consumption charge (that usually does not differentiate by time of consumption), along with a small fixed charge per month. This contrasts with large commercial and industrial customers, whose bills often are also impacted by their monthly peak demand (through a demand charge), and whose energy charge also is more likely to vary by time of use.

This approach has worked well up to now—utilities could make needed grid investments and recover their costs, and customers benefited from stable, predictable bills while being incentivized to conserve energy, if not capacity. But the reality is that for mass-market customers the behind-the-scenes cost of energy and all the associated attributes (see Figure 2, page 13) do significantly vary by time, location, and along other dimensions not reflected in bundled, volumetric, block pricing. And as DER adoption grows and changes the manner in which customers rely on the grid, it will become increasingly important for utilities to send clear signals and incentives to customers so they know how to—and are economically motivated to—align DER deployment with maximizing grid value (for example, reducing peak demand or shifting use).

FIGURE 1: **TRADITIONAL COST ALLOCATION**



ENERGY CHARGE
kWh-based generation costs (e.g., fuel, wholesale electricity)

CUSTOMER CHARGE
Flat, monthly charge covering fixed costs of servicing customers regardless of use (e.g., billing, customer service)

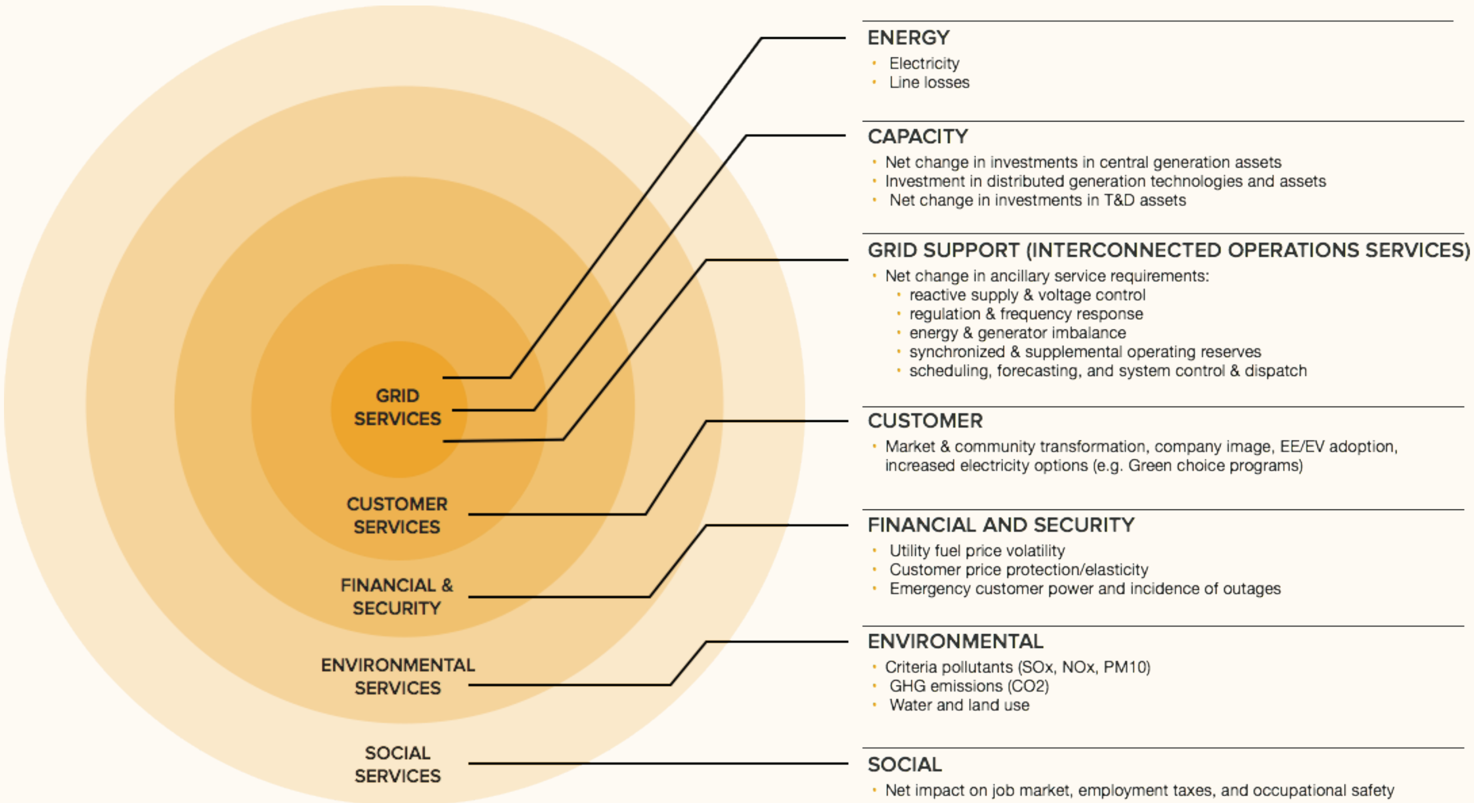
DEMAND CHARGE
Costs of the generation, transmission, and distribution capacity to serve peak demand

MASS-MARKET CUSTOMER BILLS GENERALLY DO NOT REFLECT TIME OF USE, MONTHLY PEAK DEMAND, AND OTHER FACTORS. MEANWHILE, THE BILLS OF LARGE COMMERCIAL AND INDUSTRIAL CUSTOMERS HAVE LONG BEEN MORE SOPHISTICATED.

ATTRIBUTE CATEGORIES

Reliable electric service is about more than just electrons. The grid requires a number of specific attributes to function. Each of these attributes can be provided by a combination of central and distributed energy resources. Depending on capabilities, DERs may provide certain attributes to the grid and require others from it. Some attributes are more easily quantified and monetized than others. e-Lab's earlier publication, *A Review of Solar PV Benefit and Cost Studies,*[i] identified these attribute categories (below) and provides a useful framework for considering which attributes are provided by or required to support the broader array of DERs.

FIGURE 2: **ATTRIBUTES OF RELIABLE ELECTRICITY SERVICE PROVIDED BY DERs**



Source: *A Review of Solar PV Benefit and Cost Studies*

DER Adoption is Growing

Currently DERs represent a relatively small but rapidly growing portion of total demand. For example, through 2013, approximately 5.5 GW[2] of distributed solar photovoltaics (DPV) produced around 0.1%[ii] of total electricity in the U.S. While in aggregate at the national level this is still very modest, much of this DPV adoption is concentrated in a handful of markets that offer a "postcard from the future" for the rest of the nation. In places where DPV adoption is high, such as Hawaii, rooftop solar may exceed 100% of minimum load on a circuit on many days. The rapid growth of solar adoption has also been astounding by all accounts. From 2009 to 2012, solar of all types grew 82% per year in the U.S., and is expected to continue growing at 28% annually during 2014–2016.[iii] Other forms of DERs beyond solar may soon grow nearly as rapidly, further raising the importance of getting pricing structures right to better direct these investments.

DERs Are Different

DERs have characteristics that are distinct from those of central generation resources, and consumer- and third-party-owned DERs make future planning and investment more challenging for utilities and grid operators, even as DERs open up new opportunities.

- ***Deployment:*** DERs are small, modular assets that can be installed rapidly, strategically (in high-value locations at many different sizes), and outside of the central resource planning process. Without proper price signals, utilities have little influence as to locations and types of DERs that are installed on the distribution grid.
- ***Operation:*** DERs are installed on the distribution network and generally operate outside of central dispatching mechanisms. Some are variable generation resources that cannot be dispatched on demand—such as rooftop solar without battery—even though their output can be forecasted with increasing accuracy.[iv] Smart meters, smart inverters, and two-way control technologies enable DERs to more seamlessly integrate with central control to help balance load with resources, or to provide ancillary service requirements. More sophisticated price signals from the grid to these DERs can help facilitate the provision of these needed capabilities.
- ***Ownership:*** Because many DER investments are made by customers or third parties outside of normal utility planning processes, it can be difficult for utilities to predict the long-term adoption rates of DERs with accuracy. This, in turn, complicates a utility's efforts to accurately assess the need for alternative or complementary investments in central generation, transmission, or distribution infrastructure. More sophisticated rate structures can provide customers and third parties with price signals that can better direct (in terms of capability, quantity, and location) DER investment by customers and third parties, and reduce complexity in assessing long-term adoption trends.

[2] U.S. Energy Information Administration Form-861S reported 3.6 GW of net-metered rooftop solar installations through 2012 (http://www.eia.gov/electricity/data/eia861/index.html). *Greentech Media* reported 1.9 GW of distributed rooftop solar installed in 2013 (http://www.greentechmedia.com/ articles/read/Slide-Show-How-to-Really-Disrupt-the-Retail-Energy-Market-with-Solar)

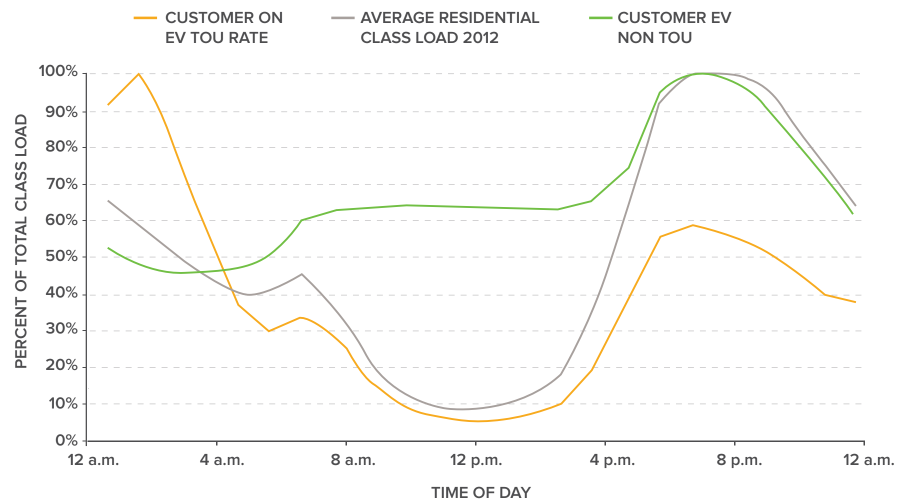
DERs Don't Align with Block, Volumetric Rates

As DER adoption grows, customers are becoming increasingly individualized, depending on whether they have rooftop solar, on-site storage, an electric vehicle, smart thermostats, or other technologies. These technologies can provide to or require from the grid energy, capacity, and ancillary services based on individual capabilities. But these characteristics vary along many dimensions that are not reflected in block, volumetric rates. For example, when a customer is exposed to a high marginal price tier in an inclining block rate structure,[3] rates can both reinforce and skew the message that price signals should send. Rooftop PV can look more competitive with retail rates based on the higher credit received for energy production. Conversely, electric vehicle charging can be discouraged if the energy used for charging shifts a customer to a higher-priced use tier.

A move away from block volumetric pricing will allow utilities to more efficiently direct not just individual DER deployment, but deployment of DERs in various combinations (such as solar paired with storage) to deliver a broader and more valuable set of attributes to the grid.[v,vi] In the absence of more sophisticated rates, customers and businesses are busy deploying thousands of megawatts of rooftop solar PV without smart inverters, storage capabilities, or peak-aligned panel orientation, as well as electric vehicle charging stations that cannot respond to signals from the grid. More dynamic rates offer significant opportunities to capture the capacity and ancillary services that are largely lost today, decreasing grid integration costs and increasing benefits.

[3] In an inclining block rate price structure, the price per kilowatt-hour increases as specified usage levels are reached. For example, the first 500 kilowatt-hours are billed at $0.10 per kilowatt-hour, the second 500 kilowatt-hours are billed at $0.15 per kilowatt-hour, and any additional kilowatt-hours are billed at $0.20 per kilowatt-hour.

FIGURE 3: **AVERAGE RESIDENTIAL VS ELECTRIC VEHICLE CUSTOMER LOADS**



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WHAT DIRECTION SHOULD MY ROOFTOP SOLAR PV SYSTEM FACE?

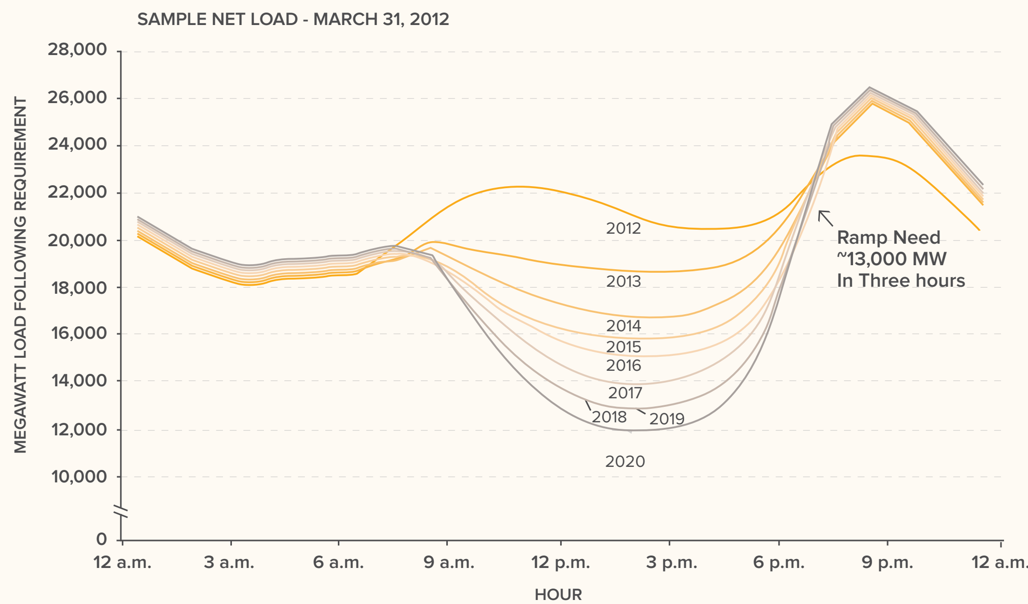
Peak energy demand and highest marginal production cost typically coincide on late summer afternoons. Energy production from rooftop solar, which has close to zero marginal costs, could therefore contribute significant value to the system by orienting the panels towards the west or southwest to best align its affordable peak production with these periods of high demand when the grid usually calls upon more expensive generation resources such as peaking plants. But traditional block volumetric rates do not reflect temporal cost aspects. As a result, it is most advantageous to customers—most of whose solar PV is governed by net metering policies that credit energy consumed from the grid and solar surplus fed into the grid both at the retail rate—to orient a rooftop PV system towards the south or even the east (avoiding cloudy afternoons) to maximize total energy production for the individual customer (instead of to maximize production aligned with greatest system value, which would be coincident with customer and system peak).

THE GROWING NEED FOR RAMPING CAPACITY

We live in an age of the California ISO's famous "duck chart," which shows net demand on the grid's central generation resources in the face of growing levels of solar PV on the distribution edge. With rooftop solar depressing daytime net demand on the grid and overall system peak hitting later in the day after solar production plummets, the duck chart shows a coming and growing very steep ramp. Resources that can either smooth such a curve—decreasing both the slope and amplitude of the ramp—or respond rapidly to meet that curve will thus have immense value.

Today, low-capacity-factor[vii] combustion turbines provide this service. They do so at what some contend is a high cost,[viii] and sub-optimally, considering the emissions and delivery challenges associated with oil or natural gas.[ix] Many contend that customer-sited DERs could be used to achieve the same goals at a lower price.[x] Customers and grid operators can create more value if rates are designed to encourage behavior change (e.g., load shifting from peak hours), DER system design (e.g., panel orientation), and technology combinations (e.g., DPV + storage) that mitigate challenges imposed by, in this case, the ramping down of solar in the late afternoon.

FIGURE 4: **THE DUCK CURVE SHOWS STEEP RAMPING NEEDS**



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NAVIGATING RATE REFORM

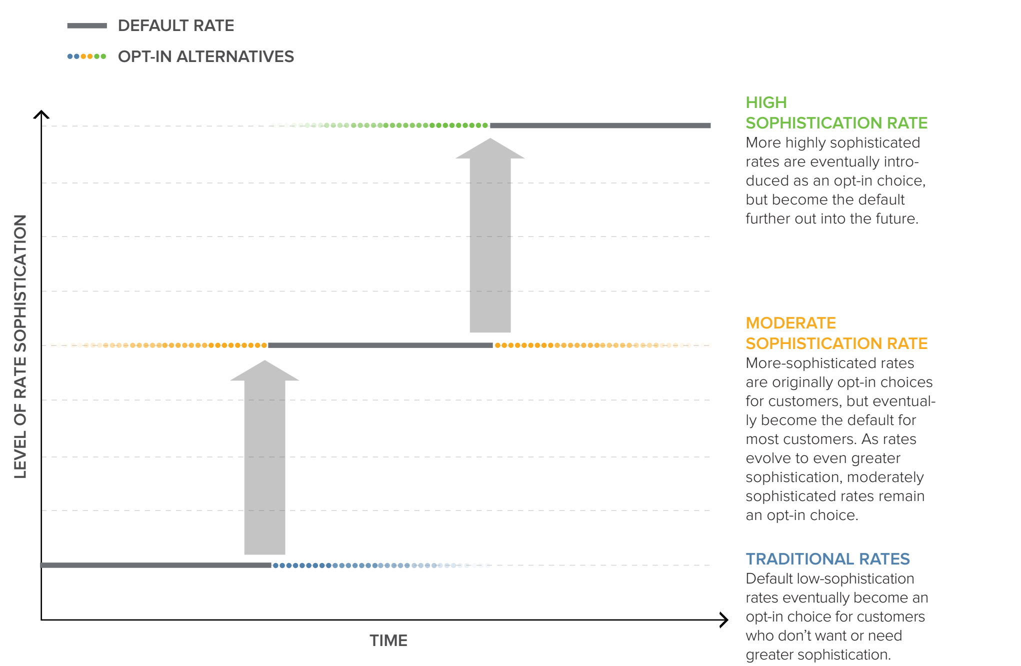
DERs of many types are becoming increasingly widespread and accessible, yet existing rate structures result in DER investment that is largely undirected. There is an increasing need to define the principles to safely integrate and capture the full value of DERs going forward. When James Bonbright developed his principles for public utility ratemaking in 1961, they became the standard that guided the industry for the next half century. They remain as relevant today as ever, even if we revisit their interpretation with new eyes that consider the implications of DERs and a changing grid. Importantly, even though this paper's evolved rate structures might feel a revolutionary world apart from the volumetric block rates that have served the industry until now, they are still closely aligned with an updated interpretation of Bonbright's principles, so they're not nearly as radical as one might think at first glance (for more on an updated application of Bonbright's principles, see Appendix).

REGULATORY COMPACT AND OBLIGATION TO SERVE

Electric utilities are recognized as natural monopolies and are therefore obligated to serve all customers in their territory. It is important to recognize that the non-utility owners or operators of DERs (whether they are individual customers or third-party aggregators) have no such obligation. Rather, individual customers and third parties elect to make DER investment choices on the basis of individual project economics (or other factors). As DER adoption grows, utilities are likely to face increasing challenges and new costs in their efforts to fulfill this important obligation. More sophisticated price signals can better align the DER investment choices that customers and third parties make with the requirement that the utility provide affordable and reliable service to all customers within its footprint.

What Will This Future Look Like?
Behind-the-meter DERs are an important component to building a more resilient and low-carbon electricity system. To accompany this changing resource mix, the sophistication of the default rate option used by most customers can be increased, while still allowing customers the flexibility to opt in to more or less sophisticated options that meet a variety of customer requirements (see Figure 5).

FIGURE 5: **DEFAULTS AND ALTERNATIVES**



This framework can enable stakeholders to adequately prepare for more sophisticated rate offerings, including the introduction of new technology and service offerings that can maintain a simplified customer experience even with more sophisticated rates. Additionally, this structure enables customers to choose alternatives that are most appropriate for them, whether opting out of a new default rate option for something more familiar or opting in to a rate option that is even more advanced.

More granular rates will allow the benefits and costs of each individual attribute associated with reliable electric service to be evaluated and clearly and transparently priced. This will enable regulators to strike an appropriate and intentional balance between incentivizing DERs and ensuring grid infrastructure costs are recovered. Valuation of these attributes can be based on markets or transparent and agreed-upon processes, producing a system for evolving rates that is more dynamic and automatically adjustable compared to the current system of multi-year periods between rate cases.

Customers will respond to these new price signals by shifting their load profile to take advantage of periods of low-cost grid service while making more targeted investments in DERs that can provide greater value to the grid. This combination of price signals beneficially shifting load (such as through home pre-cooling, water heater cycling, and strategic electric vehicle charging) and more optimally directing DER investment can reduce the need for rarely utilized peaking generation units, reduce system congestion, and defer distribution upgrades. To achieve this vision, regulators need to establish processes to lead stakeholders through the transition from today to tomorrow. These processes may need to look fundamentally different than traditional regulatory proceedings, due to the complexity and pace with which DER deployment is happening. Creative, more collaborative approaches may be needed to align stakeholder interests and introduce new rates and accompanying service offerings in ways that customers will embrace.

LONG-TERM ISSUES TO CONSIDER

The issue of rate design does not exist in a vacuum. For one, the rate structures proposed in this paper may require investments in new meters for some utilities.

There are also significant issues around markets, customer education, the utility business model, and the utility resource planning process to be addressed in order to create an environment where more evolved rate designs can be implemented. Specifically, new market mechanisms are needed to value and monetize capacity, ancillary services, and certain environmental attributes in many parts of the country. Customers need to be educated on the benefits of a shift away from a 100-year-old status quo. Laws and regulations must evolve to enable utilities and third parties to compete on a level playing field to provide behind-the-meter products and services to customers. A previous e-Lab discussion paper, *New Business Models for the Distribution Edge*,[xi] explored possible new business model structures better adapted to a high-penetration DER future. These issues fall outside of the specific purview of rate design, but are intimately related to the topic.

NET ENERGY METERING AND VALUE-OF-SOLAR TARIFFS

According to the Solar Energy Industries Association,[xii] by the end of 2013 more than 445,000 residential and commercial rooftop PV[4] customers benefited from net energy metering (NEM) in the United States, where 43 states have adopted the policy. NEM works by "spinning the meter backward," allowing DER customers to consume generation on site, and paying them for any excess generation in credits valued at the retail rate under which the customer is served. When credits from excess generation exceed monthly consumption from the utility, customers are often able to apply these credits to future bills (typically at the full retail rate but sometimes at the utility's avoided cost). As solar costs have declined and customer adoption has increased, NEM has become a contentious topic in the industry.

A value-of-solar (VOS) tariff, meanwhile, is a technology-specific tariff that can be instituted regardless of rate structure that values specific components of a kilowatt-hour that distributed solar PV (DPV) produces, such as energy, capacity, grid support services, and some environmental benefits. This allows utilities to send customers price signals for the value of DPV based on these unbundled attributes rather than compensating customers at the retail rate under which they are served. Multiple viewpoints on the advantages and disadvantages of VOS tariffs exist, including strongly held and varied viewpoints by e-Lab members. VOS is often discussed in the context of a comparison to net energy metering.

This e-Lab paper does not take a side on NEM, either for, against, or advocating reform. Nor does it opine on the relative merits of VOS, either in isolation or in comparison to NEM. Rather, this paper offers another set of solutions—moving away from block volumetric pricing towards more sophisticated structures—that can be implemented regardless of what happens with NEM and VOS.

[4] Not counting other DERs, such as small wind, that qualify for net energy metering.

MOVING TOWARD MORE SOPHISTICATED PRICING

02

02: MOVING TOWARD MORE SOPHISTICATED PRICING

Bundled rates are composed of multiple attributes. The values of some attributes vary by time (across seasons or hours in a day) as well as by location across a utility's distribution system; others remain virtually constant. Depending on the existing characteristics of a utility's generation, transmission, and distribution infrastructure, increasing granularity or sophistication will provide a different level of value along each individual stream.

We advocate increasing rate sophistication along three continuums that can be thought of as the what, when, and where of electricity generation and consumption:

- ***Attribute Continuum***—the unbundling of rates to specifically price energy, capacity, ancillary services, etc.
- ***Temporal Continuum***—moving from volumetric block rates towards highly time-differentiated prices that vary in response to marginal prices or other market signals
- ***Locational Continuum***—delivering price signals that more accurately compensate for unique, site-specific value

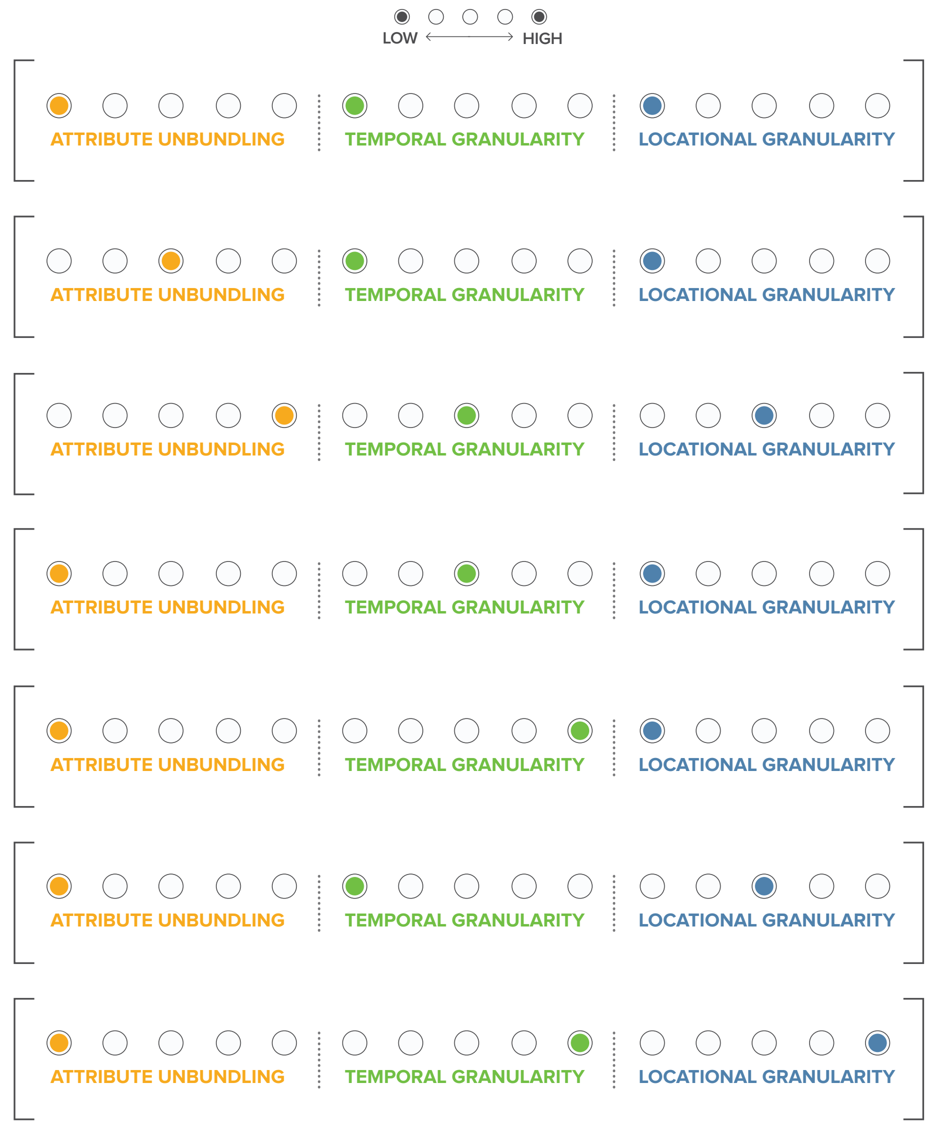
Breaking down rates into these distinct value streams (see Figure 6, page 22) is an important tool to direct investment decisions that optimize value to all customers as well as to the grid as a whole. In a highly evolved scenario, we would see increased rate sophistication along all three axes. For example, customers could receive real-time price signals across all hours of the day, with a demand charge that also varies by time, with additional compensation available to customers who install DERs with the capability to address distribution hot spots.

Multiple rate options can offer customers choices that meet their lifestyle, technology requirements, and budget. Within a handful of years, significant progress could be made to introduce new, more sophisticated default rate options along all three of these continuums in many areas of the country, guided by the particular local circumstances. For instance, the default rate option could introduce more sophistication along both the attribute and temporal spectrum, such as two- or three-period TOU rates for energy coupled with a demand charge. The demand charge could also vary temporally.

Some customers (perhaps those with no DERs) could elect to opt out to a less sophisticated fully bundled rate, while other customers may elect even more sophisticated options that harness the capabilities of a broader array of DERs. In this case, a customer who participates in a demand response program (including automation of multiple appliances) may find the greatest value in a rate that unbundles time periods to include peak, off-peak, and critical peak periods with a demand charge. Meanwhile, a rooftop solar customer with an electric vehicle may find the most value from a real-time pricing rate that encourages shifting usage to off-peak periods while compensating excess generation at a market-based rate.

The transition need not be, and likely would not be, linear across these continuums, or uniform from one utility service territory to the next. Each option can provide benefits to customers, utilities, grid operators, and third parties, but also requires careful monitoring to ensure that benefits and costs are properly accounted for and appropriately assigned.

FIGURE 6: **INCREASING SOPHISTICATION THROUGH RATE STRUCTURE EVOLUTION**



TODAY'S BUNDLED, VOLUMETRIC, BLOCK PRICING
In the simplest system, prevalent today, there is no unbundling (i.e., fully bundled pricing) with no time- or location-based differentiation.

ENERGY + CAPACITY PRICING
Breaking apart energy and capacity values begins to unbundle prices, but leaves many still bundled. Time- and location-based differentiation is still minimal.

ATTRIBUTE-BASED PRICING
Attributed-based pricing more fully unbundles electricty prices, while doing so could also add time- and location-based sophistication.

TIME-OF-USE PRICING
Relatively basic time-of-use pricing (e.g., off-peak, peak, critical peak) begins to add time-based differentiation, but could still allow attributes to remain fully bundled with no location-based differentiation.

REAL-TIME PRICING
Real-time pricing, with prices dynamically varying by one-hour or sub-hour increments, adds much time-based sophistication, but could still allow attributes to remain fully bundled with no location-based differentiation.

DISTRIBUTION SYSTEM HOT SPOT PRICING
Identifying distribution system "hot spots" begins to add location-based differentation, but could still allow fully bundled attributes and little or no time-based differentiation.

DISTRIBUTION LOCATIONAL MARGINAL PRICING
Distribution LMP adds location-based sophisitication, and in turn a high degree of temporal sophistication.

THE ATTRIBUTE CONTINUUM

The attribute continuum describes parsing an energy resource into its specific value components through partial or total unbundling of electricity rates. The goal is to match services that a given resource can provide with the needs of the grid to unlock greater value to the customer and to the grid. The addition of a capacity (demand) charge is the most common tool available to begin to unbundle rates along the attribute continuum. As customers, utilities, and regulators collect and analyze the growing amount of data available from advanced metering infrastructure and other sources, rates can move toward fully unbundled, attribute-based pricing.

Energy + Capacity

An early step in unbundling attributes for mass-market customers is to separate energy (kWh) and capacity (kW). This approach is already common for large commercial and industrial customers. In addition to a fixed customer charge and a per-kWh energy charge, a demand charge delivers a price signal about a customer's instantaneous use. Demand charges can measure demand in five- or fifteen-minute increments and bill a fixed dollar per kilowatt rate for the peak monthly use.

Separating energy and capacity charges offers several benefits. In a world where DERs increasingly threaten the traditional utility model of investment recovery through volumetric sales, demand charges can provide utilities with better assurance of investment recovery while simultaneously providing customers with signals that motivate them to place less stress and cost on the system. More specifically, a demand charge more closely allocates cost of service based on a customer's load profile. Under this structure, energy charges are reduced (i.e., closer to wholesale energy costs) while the fixed costs associated with maintaining adequate capacity are separately recovered. A demand charge creates an incentive to add combinations of DERs that more evenly spread use throughout the day, thereby lowering the impact and cost on the system. When a customer with a demand charge is also a net metered customer, the demand charge is not avoided by excess generation credits, resulting in better cost recovery for the capacity required to support some DERs.[xiii] A demand charge also begins to reduce intra-class cross-subsidies created between customers with different load factors.

Demand charges offer several challenges as well. First, some customers may be unable to spread their use more evenly throughout the day and could thus be subject to negative bill impacts from a high demand charge (depending on the price for the demand charge relative to the unit price of energy). More advanced meters are also required to measure and bill demand, and education is also necessary to ensure customers understand how demand is billed as well as ways to mitigate exposure to high charges. Despite these obstacles, it is conceivable that many parts of the country could establish a timeline of just a few years to introduce demand charges as a default rate option for mass-market customers, provided appropriate service offerings and alternative rates were also made available.

Attribute-Based Pricing

Further along the attribute continuum are subsequent opportunities to break out and provide price signals for providing or receiving more and more attributes of electric service. Attribute-based pricing is technology neutral and could conceivably incorporate the value of all attributes and services of energy resources. Instead of "all-in" pricing, the specific components that comprise a retail electric price per kWh are separated and priced independent of one another. Under this structure, credits or charges are assessed for the array of attributes required for safe, reliable electric service (see Figure 2, page 13). Unbundling and pricing attributes of electric service will become increasingly important as DER adoption grows, because DERs may provide or consume individual grid attributes, which is a new phenomenon compared to historical use where consumers simply received all components of reliable grid service from the utility, and paid for them almost entirely on a per-kWh basis.

Attributes may vary daily, seasonally, and geographically, as well as by utility service territory and transmission grid operator requirements. Stakeholders may also determine that some attributes, such as job creation, ultimately fall outside of the purview of rate design and should be compensated via other mechanisms.

In an attribute-based pricing format, rates can be designed to compensate customers for the specific resources needed and delivered: energy, capacity, flexibility, reliability, resilience, and environmental attributes, among others. Asset owners who can provide these monetized attributes can be compensated for providing them to the grid on an as needed basis. For example, a hospital operating a combined heat and power system may be able to provide excess peak generation to the grid while continuing to self-supply and use waste heat on site.[xiv] Or an electric vehicle driver can enable the battery to be used as a demand response resource while charging during the work day.[xv]

The benefit of attribute pricing is that proper implementation enables all resources to compete on a level playing field. Centralized and distributed resources can be compensated for services provided, and incentivized to install complementary technologies, such as smart inverters and storage, to enable the supply of needed grid services. This offers the possibility to increase penetration of DERs with characteristics that provide specific services, such as peak management or voltage control in high-value locations or that can contribute to grid stability at high-value times of day or season.

Attribute-based pricing also presents challenges to both customers and to utilities. It is more complicated than traditional, bundled volumetric pricing (including the possibility that attributes contributed to the grid may be priced differently than attributes consumed from the grid). As a result, some customers may be unwilling to utilize the DERs necessary to capture the full value of a highly granular rate (and therefore remain on less-granular rate options). Additionally, markets and methods for valuation will need to be developed before attribute-based pricing can be fully deployed. For the foreseeable future, attribute pricing should be thought of as an option that could be made available to customers, but not as a default or mandatory rate structure.

THE TEMPORAL CONTINUUM

The second value stream comes from services needed by the grid (and the attributes that an energy resource can provide) on a temporal basis. The cost of generating electricity varies over the course of a day's load profile, as utilities call upon more expensive generation resources to meet peak demand. Thus DERs that can shave that peak and smooth the day's load curve, including distributed generation coincident with peak that can provide an economical alternative to expensive peaking plants, can provide value—if provided the right price signals.

Time-of-Use Pricing and Critical Peak Pricing, explained in subsequent sections, both send price signals to shift use to off-peak periods of day. Real-Time Pricing represents the highest level of granularity on the temporal spectrum.

SMART HOME RATE

A Smart Home Rate is a hypothetical version of an attribute-based pricing structure for customers who adopt a combination of technologies that can respond to sophisticated pricing signals and provide value both to the customer and to the grid as a whole. Locational and temporal price volatility more closely reflects the cost of service; customers pay for consumption and receive compensation based on real-time or day-ahead price signals. For example, Smart Home Rate customers with storage technology (stationary or electric vehicle-to-home export capability) have the ability to fully self-serve from the storage system (or greatly reduce usage) for short periods of time in response to critical peak pricing events during the most expensive 100–200 hours per year. This reduces system demand and protects customers from critical peak prices. These customers can also respond to low (or negative) wholesale prices by programming electric vehicles to start or stop charging, pre-heat or cool the home, and perform other energy-intensive tasks when prices fall below a pre-defined point. The Smart Home Rate described in Table 3 (at right) is an example of how customers could be billed when they employ multiple DERs to meet their electricity needs.

TABLE 3: **SMART HOME RATE**

LINE ITEM	BILLING UNIT	COMPONENTS
Monthly Service Fee	$/month	Customer Service Billing Metering
Monthly Peak Demand Charge	$/kW	Capacity
Day-Ahead Hourly Price	$/kWh	Energy Ancillary Services
Real-Time Price	$/kWh	Real-Time Signal for Price-Responsive Loads When Prices Are Low
Export Credit for Services Supplied by Customer	$/kWh	Symmetric to Day-Ahead Hourly $/kWh

A Smart Home Rate that clearly delivers the price for values sought from different resources can encourage investment in resources that provide value to both the customer and the grid. Consumption and supply prices are assumed to be symmetrical but could vary by attribute.

Time-of-Use Pricing (with Critical Peak)

ATTRIBUTE UNBUNDLING | TEMPORAL GRANULARITY | LOCATIONAL GRANULARITY

Time-of-use (TOU) pricing represents a move towards more granular pricing on the temporal spectrum. It is becoming increasingly common today, and is used to communicate information to customers on how the value of energy services provided by—and to—the grid vary by time. Under this rate design, customers are billed different rates across peak, shoulder peak, and off-peak periods. To capture additional value, the addition of a critical peak period (CPP), which occurs only during grid emergencies or during the most expensive hours of the year, sends a temporally-specific price signal to customers about the high cost of energy in an effort to shift and/or reduce use.

The benefit is that customer interaction with the grid is priced to more closely match the cost to generate, transmit, and distribute energy. Customers will know when the most and least expensive times of day are to use energy, how to align DER installations to meet peak demand, or where it is economically advantageous to add storage (which may be in locations that not only provide value to the customer but also to the grid as a whole) based upon the availability and accessibility of enabling technologies and the implementation of robust education and marketing efforts. When enough customers reduce their peak demand, or install DERs to provide peak energy to the grid, the utility's peak demand can either decrease or shift. This is significant because peak demand on a system level is one of the main factors that drive the need to build central generation assets, especially "surplus" generators built to meet peak spikes but which otherwise sit idle much of the time when demand doesn't call for them. Further, as DER penetration increases, load requirements can also shift. The California "duck curve" scenario (see Figure 4, page 16) creates a need for flexibility resources, whether from load shifting, DERs, or central energy resources.

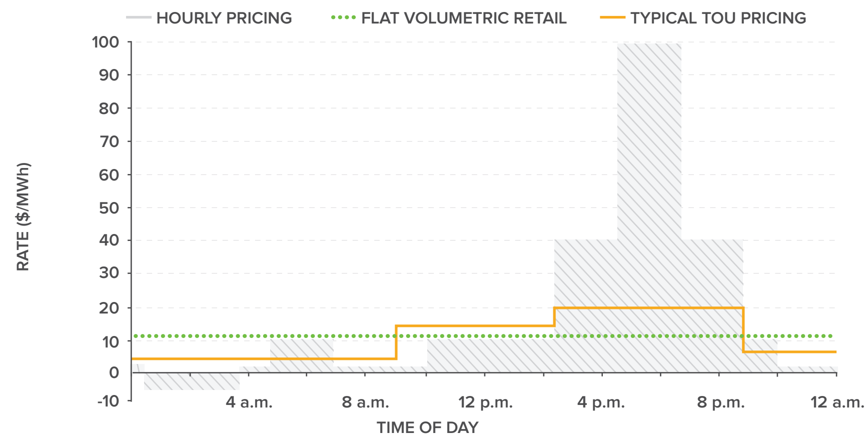
On the flip side, the primary challenges facing TOU rates relate to customer acceptance and program design. While TOU is common in many parts of the country, it is primarily offered as an optional rate and often with only one choice of time periods. Broadly defined time periods may make it too difficult for customers to shift use (e.g., on-peak pricing periods may commonly be seven hours in duration). Likewise, if the incentive to reduce use is not large enough, then it may not be worth the effort to change behavior. Despite these challenges, successful TOU programs to date[xvi,xvii] suggest that it is plausible that many areas of the country could move to TOU pricing as a default rate option within a matter of a few years, provided appropriate service offerings, customer education, and alternative rates were also made available.

Real-Time Pricing

Real-time pricing is the most granular structure on the temporal continuum. It uses hourly day-ahead or sub-hourly (e.g., five-minute interval) spot market prices to bill and compensate customers for services required and provided.

A key benefit of this degree of sophistication along the temporal continuum is that it can unleash innovation in DERs and direct investment in new technologies that can provide great benefits to the system more cost effectively and with less potential for cross-subsidization than less-sophisticated rate options. For instance, under hourly pricing, a customer (and in turn the system as a whole) may benefit from installing a combination of solar PV and battery technology that might not be economical under a less-granular rate structure such as traditional TOU rates. The battery system in this case could be sized to power the home for short periods, like the one or two hours of the day when energy prices are expected to be highest. These granular time periods offer the added benefit of shortening the window during which the battery system is needed (thus enabling a smaller and more affordable battery). By comparison, the rate differentials between on- and off-peak periods under a two-period TOU rate are not as great as they would often be under hourly prices, and the time periods for the on-peak period may be too long to be economically attractive for customers to consider.

FIGURE 7: **TEMPORAL PRICING STRUCTURE**



Although a TOU rate more equitably charges customers for usage at different times of the day, it does not capture short-term price spikes that can significantly raise prices during an otherwise low-price time period. In the chart above, a TOU customer is exposed to peak, shoulder peak and off-peak prices each day. The peak and shoulder peak prices are in effect for almost twelve hours each day, even though the actual peak market price is different each day (and occurs over a much shorter time period). This creates a scenario in which customer behavior must be responsive over a long period of time when an hourly price signal could encourage investment in DERs that could help to reduce the price spikes, benefitting all customers.

Despite its merits, not all utilities or grid operators are yet capable of deploying widespread real-time or hourly pricing. Additionally, many customers may not be willing to adopt rate structures this sophisticated for the foreseeable future. That said, there are significant opportunities to make real-time pricing easy for customers by pairing it with technologies that can automatically adjust use in response to granular price signals. In the near term, it is plausible that many areas of the country could make hourly or real-time pricing available as an option for customers, enabling solution providers to combine technologies and services to deliver value to customers and to the system as a whole.

THE LOCATIONAL CONTINUUM

The third value continuum involves more granular pricing on a locational basis. In order to capture this value, utilities and grid operators can offer credits or price signals over a short- or long-term horizon, based on specific system needs. Distribution System Hot Spot rates or incentives can begin to move rate design in a more location-based responsive direction, while Distribution Locational Marginal Pricing (Distribution LMP) represents the highest level of granularity in this stream.

Distribution System Hot Spot Pricing

“Hot spots” are locations on the distribution system that suffer from congestion due to overloading of infrastructure. When new load is added, particularly during peak periods, it can be more cost effective to signal customers to install DERs—ranging from demand response to storage to distributed generation that can shift or reduce load—to alleviate stress. Customers that install DERs in high-value locations or with high-value temporal attributes could be compensated for their contribution to the system through incentives such as credits. One method to calculate the value is to compare the savings produced by the DER relative to the cost of deferred or avoided distribution system upgrades (similar to non-transmission alternatives[xviii]). This is a step that offers an alternative to significant distribution investments, such as new substations. Substation upgrades are not only expensive but can require decades for full cost recovery (subject to threats from continued evolution of DER technology).

Another benefit is the ability to specifically target locations with short-term availability of incentives for DER installation. By doing so, utilities can control the costs of incentive programs while maximizing return on investment. For example, the Con Edison Brooklyn/Queens Demand Management[xix] plan seeks DERs—ranging from on-site generation to storage to load management technologies—that collectively can defer the need for a $1 billion substation upgrade. The program is only available to customers within the area served by the existing substation. If successful, it could be expanded to other areas as needs are identified.

Unfortunately, hot spot credit or pricing can be challenging since the ability of DERs to defer or obviate distribution investments is a point of debate, and also because distribution system upgrade plans are not commonly available to all stakeholders until the decision to invest by the utility has already been made. Regulators can add significant value by enabling and/or requiring utilities to share data on system operations (while addressing data privacy concerns) that can provide a broader group of stakeholders with the ability to offer non-distribution alternatives to the system planning process.

Distribution Locational Marginal Pricing

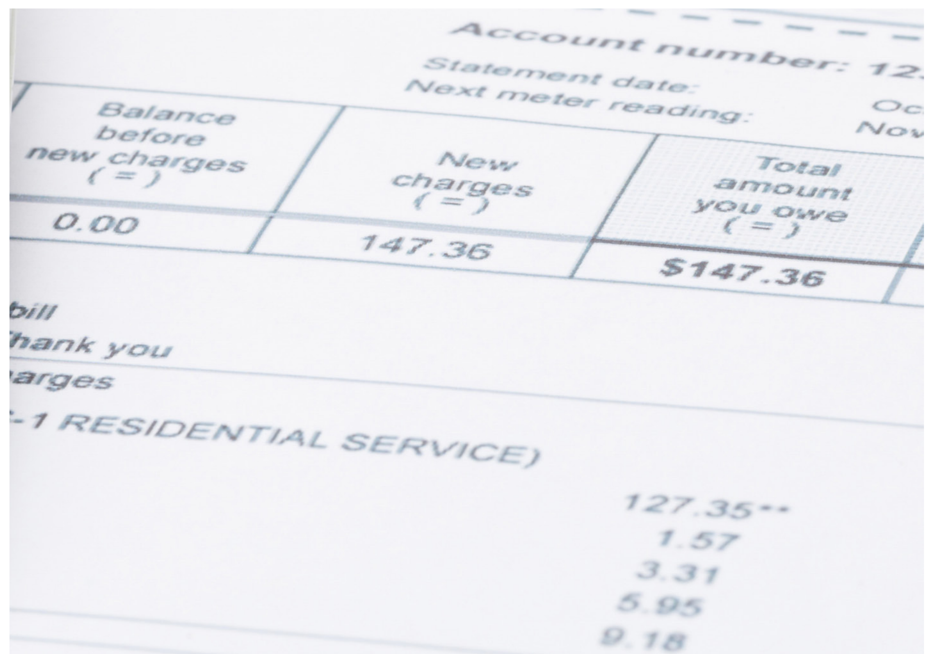
ATTRIBUTE UNBUNDLING | TEMPORAL GRANULARITY | LOCATIONAL GRANULARITY

The Distribution Locational Marginal Pricing (Distribution LMP) concept is a distribution system version of the transmission system locational marginal price common today in many wholesale markets. Instead of sending short-term price signals in the form of a credit under a "hot spot" design, a distribution LMP simply provides hourly or sub-hourly price signals at nodes on the distribution system. In one iteration, customers could be billed, and compensated, based on the services required and provided at each node. Customers would receive more accurate price signals on which to base their DER investment decisions and grid operations would be less likely to be disrupted by DERs in low-value locations. Another variation would be to calculate the value of line losses and cost of potential line failures at various load levels and bill customers for services required or provided.[xx]

A distribution LMP is more advanced than the "hot spot" credit program in its focus on real-time system conditions. Rather than focus on long-term system planning by providing credits only in key locations, a distribution LMP charges and compensates customers for value consumed and provided at any point on the distribution system with prices that reflect daily or hourly system events.

There are several challenges that may limit the possibilities of distribution LMP. One very important challenge is that it could simply be untenable from a public perception standpoint to charge customers materially different rates based on where they live. This may be considered counter to long-standing notions of providing universal access to affordable electric service. Another challenge is that many utilities and grid operators lack the ability to provide pricing on such a granular level on the distribution system. Significant metering and communications infrastructure may be required to capture and convey accurate price signals. Additionally, customers in areas with high distribution LMPs may not be able to respond to sophisticated price signals.

In short, this level of locational sophistication is not likely to be practical, at least for the foreseeable future. In the meantime, the value of establishing structures to address the most high-value "hot spots" on the system could be further explored and pursued in many areas of the country within the coming years.



03 RECOMMENDATIONS FOR REGULATORS

03: RECOMMENDATIONS FOR REGULATORS

Increasing DER adoption presents a need for rates to evolve along the locational, temporal, and attribute spectrums. However, customers, utilities, grid operators, and solution providers may not yet be ready to jump to highly granular attribute pricing today. A multi-stage transition with defaults and alternatives can gradually increase rate sophistication while still allowing customers to opt in to more or less sophisticated rates.

Regulators can enable utilities and third-party service providers to provide new technologies and solutions to keep the customer experience simple while introducing more sophisticated price signals. And as rates become more sophisticated, regulators can focus on increasing the accuracy and transparency of the rate design process to maximize the value available to the system.

IDENTIFY DEFAULTS, ALTERNATIVES, AND TIMELINES

Today, the default rate is relatively simple, and is generally the simplest option available to customers. Regulators can establish processes to identify new, more sophisticated rate options (such as TOU rates with demand charges) that could become the default within a period of a few years. In advance of this option becoming the default, customers could be given the opportunity to opt in to it or other even more sophisticated options. After it becomes the default, customers could have the option to opt out of the default to either a simpler rate (perhaps similar to what they've had before) or into even more sophisticated options. Over time, the default option could increase in sophistication yet again, following the same pattern.

Multiple, highly granular rate options can co-exist as choices—hourly pricing, TOU block pricing, critical peak pricing, inclining block rates, and others—as long as customers, or the service providers serving them, can easily identify the value associated with each relative to their lifestyle and technology choices.

As an alternative to the traditional model of pilots that are common today, utilities can offer customers and solution providers a staged approach to implementing more granular rates (see Figure 5, page 17). This will allow utilities, customers, and solution providers time to analyze customer response, to identify any required supporting technologies, and to address concerns from other stakeholders so that the transition is as smooth as possible.

DEFAULT TIME-OF-USE RATES IN CALIFORNIA

The California Public Utility Commission, at the direction of Assembly Bill 327,[xxi] is undergoing a process of rate reform. AB 327 lifts many of the restrictions on residential rate design. The state's investor-owned utilities (IOUs) can now propose residential rates more reflective of cost, in keeping with the Commission's principle that rates should be based on cost-causation and other rate design principles.[xxii] AB 327 also contains limits designed to protect certain classes of vulnerable customers and permits default TOU pricing for residential customers starting in 2018.

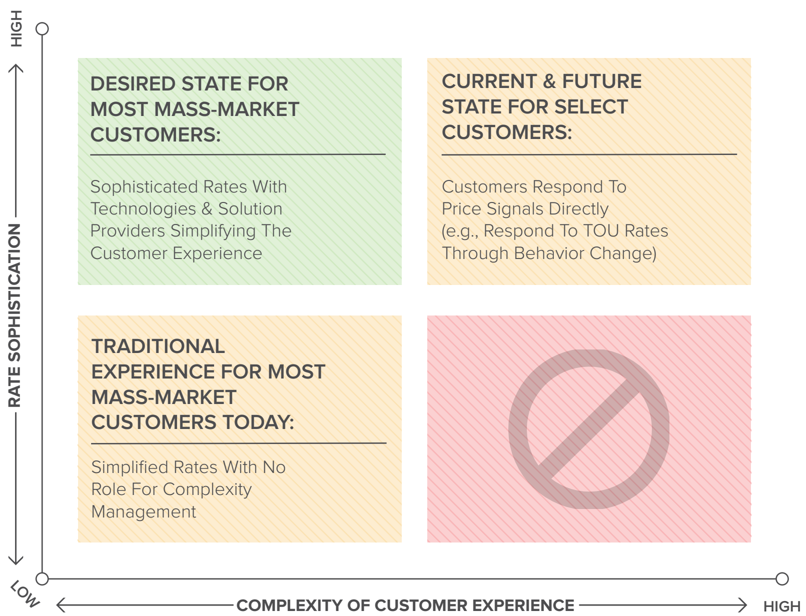
Thus far, SDG&E is the only one of the three California IOUs to propose transitioning all residential customers to default TOU rates starting in 2018, although all three have proposed collapsing the current four-tier inclining block rate structure to a two-tier structure. If default TOU is adopted in 2018, a customer must have the ability to opt out to a non-TOU rate with at least two tiers. Customers will have access to a rate calculator to compare options and also have one year of bill protection to ensure the annual bill on the new TOU rate does not exceed the amount the customer would have paid on the non-TOU rate.

This multi-year, multi-step transition gives customers and solution providers ample time to understand the requirements and test new service options. Most importantly, evidence suggests the majority of customers will remain on the default option, even if the default option contains time-differentiated pricing, if the default is designed and implemented well.[xxiii]

MANAGE THE COMPLEXITY OF THE CUSTOMER EXPERIENCE

To accompany the default and alternatives framework outlined, utilities or third-party service providers need to find ways to manage the complexity of the customer experience (see Figure 8). The typical residential customer wants to save money without sacrificing time or convenience (or at the very least, not more than the value of the savings).

FIGURE 8: **MANAGING RATE COMPLEXITY FOR THE CUSTOMER**



Bridging rate sophistication for customers – Utilities and third-party solution providers can serve as intermediaries to evaluate more sophisticated rate designs for customers, offering products and services to capture bill savings while maintaining a simple customer experience.

Highly simplified rate structures leave value on the table by offering few opportunities to take action that can achieve significant savings. More granular rates that more fully differentiate the value to serve a customer will drive utilities and third-party solution providers to develop technologies and services that increase savings and decrease complexity. The service providers can earn revenue through the service they offer, the customer can gain value through a lower monthly bill, and the utility and grid can lower costs through a more efficiently operated system. It is important to consider that regulatory reform outside of rate design (such as data sharing and privacy standards and the ability of utilities to sell and own behind-the-meter products and services) may be required to promote competition that can help maintain a simple customer experience.

SOPHISTICATED RATE STRUCTURES CAN UNLEASH INNOVATIVE TECHNOLOGIES AND SERVICES THAT CAN PROVIDE SIGNIFICANT SAVINGS TO CONSUMERS AND UTILITIES WHILE MAINTAINING A SIMPLE CUSTOMER EXPERIENCE.

IMPROVE THE RATE DESIGN PROCESS

To support more sophisticated rates, regulators need to enable improvements to the rate design process itself. Specifically, regulators should:

- Increase the quantity and quality of electricity system data available to all stakeholders while addressing data privacy concerns
- Enhance transparency of valuation methodologies
- Determine how non-monetized attributes should be included in (or excluded from) rate design

Increase the Quantity and Quality of Electricity System Data Available to all Stakeholders While Addressing Data Privacy Concerns

The effectiveness of resource deployment decisions will improve if regulators can increase both data transparency and availability for all stakeholders. The reach of data collection infrastructure such as advanced metering infrastructure (AMI) on the utility side of the meter and cloud-connected solar inverters, electric vehicle charging stations, and home automation systems on the customer side of the meter is currently limited. Regulators are in the challenging position of trying to evaluate the benefits of new technology in the absence of many years of operational data. But new analysis and modeling capabilities can combine what does exist from smart meters, rooftop installations, and charging stations to predict system requirements. More importantly, solution providers and customers can participate. By employing newly available data[xxiv] from these sources, they can leverage more granular prices to interact with connected devices throughout the home.

Through this process, care should be taken to ensure that data privacy concerns are well addressed. Options to alleviate concerns include enabling streamlined customer consent or adequately masking or aggregating specific data.

Enhance Transparency of Valuation Methodologies

Nationwide consensus on specific attribute valuation methodologies is unlikely (and perhaps undesirable, given differences across utilities and geographies). What regulators should strive for is agreement on principles of valuation. e-Lab's earlier report *A Review of Solar PV Benefit and Cost Studies*[xxv] revealed a collection of best practices that together can produce a rigorous methodology to value DERs. These include:

- A transparent and open process for identifying and evaluating attributes
- An agreed-upon procedure to continually update the methodology
- Proper oversight to ensure equity for all stakeholders
- Simplicity to enable participation by all interested stakeholders, regardless of size or funding

In Minnesota, the process to establish a value-of-solar (VOS) methodology included an open review of potential attributes, followed by adoption of a transparent valuation methodology to set thefinal rate. Stakeholders had the ability to contribute at every stage of the process. Although not all interveners agreed on the final value, the approach allowed for important stakeholder interactions and rigorous debate that will inform future refinement.

Determine How Non-Monetized Attributes Should Be Included In (or Excluded From) Rate Design

Services that are relatively straightforward to measure and represent costs directly incurred by the utility, such as energy, are commonly included in rates. Others, such as ancillary services and environmental benefits that are harder to measure, or security and economic development which are not yet generally monetized, are not broken out in rates.

However, just because an attribute may be difficult to quantify, its value is not automatically zero.[xxvi] The same applies to attributes that are not presently monetized in rates and regulators may ultimately conclude that some attributes are best addressed outside of rates, but this is difficult to determine prior to a comprehensive analysis.

Regulators have multiple options when an attribute has a benefit or cost associated with it (such as carbon emissions), but it is not clear how to accurately calculate that value. In Minnesota the VOS calculation used the Environmental Protection Agency-developed "Social Cost of Carbon"[xxvii] as a proxy to assign value for the reduction in carbon emissions from solar generation. Similarly, the Bureau of Land Management offers a model for calculating the environmental mitigation expense for federal lands based on acquisition, restoration, and preservation costs.[xxviii] The National Renewable Energy Laboratory's Jobs and Economic Development Impact models estimate the economic impacts of constructing and operating power plants, fuel production facilities, and other projects[xxix] and many utilities calculate the benefits of attracting and retaining new sources of load to offer economic development rate reductions.

CONCLUSION

04

04: CONCLUSION

Historically, simplified rate structures for residential and small commercial electricity customers—embodied in bundled, volumetric, block rates—were both appropriate and necessary. For one, customers could reasonably be lumped into a relatively small number of large, averaged rate classes with similar load profiles and relationships with the grid. For another, the system lacked the tools on both sides of the meter—especially advanced metering, data, and communications infrastructure—to enable more sophisticated approaches.

But deployment of new grid technologies and proliferation of myriad distributed energy resources—including rooftop solar, smart thermostats, electric vehicles, demand response, battery storage, and much more—are fundamentally changing the grid. That changing grid requires new rate structures for the distribution edge, better aligned with the evolving 21st century electric grid. In addition, DERs will continue to garner growing levels of investment, which will only further the expanding disconnect between 20th century rate structures and a 21st century grid.

More sophisticated rate structures can provide better price signals that will enable central and distributed energy resources—and utilities, customers, and third-party solution providers—to compete on a fair and level playing field and to share in value that can more optimally direct investment in support of an affordable, reliable, low-carbon grid.

This paper advocates deliberately and incrementally increasing rate sophistication along three continuums: attribute, temporal, and locational. It describes six hypothetical rate structures that could so move the needle—separately, in parallel, or in combination—by partially or wholly unbundling the attributes implicit in block electricity prices; honoring the way the cost of electricity generation and consumption varies over the course of hours, days, and seasons; and recognizing the differential cost to serve customers at different locations throughout the distribution network.

A transition to more sophisticated and highly differentiated pricing should happen as an evolution that allows all stakeholders to become comfortable with increasing sophistication. That evolution includes an incrementally more sophisticated default option implemented over time, while allowing additional rate options with greater and lesser sophistication for customers that want or need it. The evolution should also include—via third-party solutions providers, energy management software, "intelligent" systems, and other such customer "interfaces"—that preserve behind-the-scenes granularity while allowing for a simpler, more user-friendly customer experience.

Several of the rate structures we propose are possible now or within the next few years in many utility service territories, especially those where advanced metering infrastructure is already in place. Others might require longer time frames and legislative and regulatory reform to become realistic options. Thus we conclude with recommendations for regulators on how to support an evolution toward more sophisticated rate structures.

In an era when the distribution edge is the front line of the electric grid's evolution, we need rate structures that reflect its new landscape. Hopefully, this discussion paper helps take the industry a step in that direction.

APPENDIX

AP

APPENDIX

PRINCIPLES TO GUIDE RATE DESIGN IN A HIGH-DER FUTURE

In 1961, James Bonbright laid out a set of principles to guide the design of public utility rates.[xxx] These principles, which promoted rate simplicity, stability of the customer experience, utility revenue recovery, fair distribution of cost among customers, and efficiency of energy use became the foundation of public utility ratemaking in the U.S. for the next half century.

Today, however, rates must address dynamic customer behavior, increasingly cost-effective energy efficiency options, and competitive on-site generation, storage, and automation technologies that reduce overall system peaks and can shift distribution feeder peaks to earlier or later in the day. Bonbright's principles remain relevant and appropriate in large measure even today, although modern-day challenges and opportunities require certain facets of these classic principles to be reinterpreted. In Table 4 (at right) are the original Bonbright principles along with a suggestion of how they should be interpreted given the future we are facing and capabilities that were previously not available.

WHAT TO PRESERVE FROM TRADITIONAL RATE DESIGN

The benefits offered by more granular rate design should not overshadow the components of rate design today that offer value to individual customers and the grid as a whole. Social equity, resource efficiency, a simple customer experience, and the minimization of unintended cross-subsidies are important features that can be preserved—and improved upon—as rates evolve to meet the needs of customers and DERs.

TABLE 4: A 21ST CENTURY INTERPRETATION OF THE BONBRIGHT PRINCIPLES OF PUBLIC UTILITY RATEMAKING

BONBRIGHT PRINCIPLES	21ST CENTURY INTERPRETATION
Rates should be practical: simple, understandable, acceptable to the public, feasible to apply... and free from controversy in their interpretation.	*The customer experience* should be practical, simple, and understandable. New technologies and service offerings that were not available previously can enable a simple customer experience even if underlying rate structures become significantly more sophisticated.
Rates should keep the utility viable, effectively yielding the total revenue requirement and resulting in relatively stable cash flow and revenues from year to year.	*Rates* should keep the utility viable by encouraging economically efficient investment in both centralized and distributed energy resources.
Rates should be relatively stable such that customers experience only minimal unexpected changes that are seriously adverse.	*Customer bills* should be relatively stable even if the underlying rates include dynamic and sophisticated price signals. New technologies and service offerings can manage the risk of high customer bills by enabling loads to respond dynamically to price signals.
Rates should fairly apportion the utility's cost of service among consumers and should not unduly discriminate against any customer or group of customers	*Rate design* should be informed by a more complete understanding of the impacts (both positive and negative) of DERs on the cost of service. This will allow rates to become more sophisticated while avoiding undue discrimination.
Rates should promote economic efficiency in the use of energy as well as competing products and services while ensuring the level of reliability desired by customers.	*Price signals* should be differentiated enough to encourage investment in assets that optimize economic efficiency, improve grid resilience and flexibility and reduce environmental impacts in a technology neutral manner.

Continued Focus on Social Equity

Consideration of any new rate design must be undertaken with assurances that customers will have access to adequate, affordable electric service. Some customers will be unwilling or unable to take advantage of more dynamic rate options. This may result in adverse rate impacts and an inability to pay the monthly bill if proper protections are not in place. One solution is to offer multiple rate options, which will allow less flexible customers to choose the rate that serves them best. Another solution is to offer across the board percentage discounts for low income customers, which would allow these customers to still receive the same price signals as other customers, but simply pay a lower bill.

Continued Focus on Resource Efficiency

Care should be taken to preserve appropriate emphasis on resource efficiency and conservation as rate design evolves. For instance, if increasing portions of customer bills are collected in the form of fixed monthly charges—and less in the form of volumetric charges or other types of charges that the customer has the ability to influence—the incentive to conserve could be diminished. New rate designs can maintain the focus on resource efficiency by limiting the portion of a customer bill collected through fixed charges, or layering in tiered-volumetric rates with time-differentiated rates to simultaneously promote resource efficiency and peak-time load shifting.

BONBRIGHT'S PRINCIPLES REMAIN RELEVANT AND APPROPRIATE TODAY, ALTHOUGH GROWING ADOPTION OF DISTRIBUTED ENERGY RESOURCES REQUIRES A FRESH INTERPRETATION.

Simple Customer Experience

A shift to more granular and dynamic rates will need to be undertaken in tandem with efforts to introduce new products and services that can automate customer responses to price signals to maintain a simple customer experience. Smart grid technologies are being rapidly deployed and there are increasing opportunities for solution providers (including third-party aggregators, utilities, and others) to manage complexity on behalf of the customer, so that the customer experience is at least as simple or more so than it is today. For example, home energy management systems can respond to price signals from the utility and alert customers to critical peak pricing periods.

Minimal Unintentional Cross-Subsidization

Cross-subsidies[5] have always been present in rates. The important thing is to ensure that any subsidies within and across customer classes achieve the policy goals they were designed to achieve without creating undue burden on individuals or groups of customers. It is also essential that legislators, regulators and other stakeholders fully understand how cross-subsidies in rates change as the penetration of DERs increases.

Cross-subsidies that are exacerbated as DER penetration grows can be managed through more granular rate design. Electric vehicle customers, for example, can be both subsidized by or subsidize other customers under traditional rate design. Inclining block rates penalize customers as use increases, even if the increased use is the result of EV charging during off-peak hours. Conversely, electric vehicle charging during peak periods can be subsidized under a bundled, volumetric pricing structure. The proposed Vehicle Grid Integration Pilot Program at San Diego Gas & Electric[xxxi] is designed in part to alleviate these subsidies. Price signals encourage charging at times most valuable to both the customer and the grid. Proposed rates are based on hourly day-ahead pricing and include price reductions for customers who can charge during surplus energy events, when spot market prices are negative.

[5] Cross-subsidies in electric rates occur when the cost to serve a customer or class of customers is not fully recovered in the rates charged to the customer, with the difference made up through increased rates on other customers or customer classes. This can be the result of intentional policy implementation (e.g., discounts for low income customers) or can occur naturally over time (e.g., when a group of customers reduces consumption to the point that loss of kilowatt-hour sales causes rates to be increased to account for the loss in revenue.

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