



A Troubling Trend in Rate Design:

Proposed Rate Design Alternatives to
Harmful Fixed Charges



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INTRODUCTION

In recent years, many electric utilities have experienced reduced customer usage driven in part by increased deployment of distributed energy resources (“DERs”). DERs include distributed generation, demand-response programs, and energy efficiency measures. They are frequently installed by the customer at his or her own cost. The rise of DERs has prompted concern by some utilities that flat or declining sales will generate insufficient revenue to cover the fixed costs of maintaining the grid. In response, some utilities have proposed imposing higher fixed charges on their customers. Fixed charges, also known as customer charges or access fees, are fees customers pay for electric service that do not vary with usage. Because they are fixed, the charges cannot be avoided through measures such as energy efficiency or customer-sited renewable resources.

Utilities adopting higher fixed charges may view them as a quick fix—they provide short-term revenue stability and are relatively simple to administer. The reality, though, is that high fixed charges are bad for customers, and ultimately, the utility. High fixed charges harm many customers, especially those with lower incomes who live in smaller homes or apartments, and those with lower electric demands. Further, high fixed charges fail to provide accurate price signals to customers, which are essential for promoting customer investment in DERs and the system-wide benefits they can provide, such as reducing the need for new, high-cost centralized generation capacity. Lastly, high fixed charges are frequently perceived by customers as an effort to punish them for buying less of the utility’s product.

Fundamentally, high fixed charges reflect a failure by utilities to consider a range of smart rate design opportunities that better respond to the changing nature of the grid.

Electricity rate design refers to the pricing structure used by utilities to determine customer bills. It is based on short and long-term utility costs that reflect past, and drive future investment choices. Rate design determines the price signals consumers use to guide their consumption and investment choices. Historically, for residential and small business customers, rates have generally been structured as volumetric energy rates—customers pay a single rate multiplied by the kilowatt-hours (“kWh”) of energy used—with a modest monthly customer charge to cover billing and collection costs. For higher-volume customers, such as large commercial or industrial customers, utilities have divided rates into three parts: 1) a mandatory fee to cover billing and collection costs; 2) a volumetric per-kWh energy price and 3) a demand charge, based on peak kilowatt (“kW”) demand. Under these rate-design structures, utilities’ ability to recover costs are directly tied to customer consumption, with fixed charges only covering the costs that directly vary with each additional customer served.¹

“Smart rate design” refers to an approach to rate design that more accurately aligns utility costs with customer bills, and which better reflects the time- and location-specific costs of delivering electricity. Smart rate design allows utilities sufficient revenue without diluting the customer’s incentive to deploy DERs.

Smart rate design options include time-of-use and other time-varying rates; well-designed minimum bills; and location-based and attribute pricing. Additionally, revenue decoupling—which separates utility revenue recovery from kWh sales—allows utilities to ensure revenue requirements, independent of customer sales volume. Utilities utilizing smart meters will have greater opportunity to adopt smart rate design.

As the electricity market continues to evolve as a result of DERs and smart-grid development, utilities, particularly distribution utilities, are in a unique position to respond to the changing nature of the grid with smart rate design mechanisms to ensure system cost recovery, serve customer interests, and harness new technologies to decrease costs. However, utilities that choose not to utilize smart rate design and instead implement high fixed charges create a barrier to these opportunities for themselves and for their customers.

THE PROBLEM WITH HIGH FIXED CHARGES

Some utilities argue that because many of their electric services costs are fixed, customer fees should also be fixed. They claim that recovering fixed infrastructure and operations costs through volumetric pricing or per-kWh charges raises utility risk, which can in turn lead to increases in their cost of capital, and ultimately, in the rates they charge customers. These utilities believe that fixed charges are the best way to recover their costs and sustain their business model.

However, there are serious short- and long-term downsides to fixed charges. Fixed charges negatively impact certain customer classes and income groups, discourage energy conservation, encourage unnecessary generation and distribution capacity investment, and discourage the development of DERs. These impacts are discussed below.

High Fixed Charges Disproportionately Impact Low-use and Low-income Customers

When utilities impose high fixed charges, they increase the proportion of their revenue requirements recovered through such charges, and decrease the proportion recovered through a volumetric, per-kWh energy rate. Thus, high fixed charges inherently penalize low-use customers, who are often low-income customers, apartment residents, or small businesses, resulting in proportionally higher electric bills for those customers. This is particularly harmful for low-income customers and those on fixed incomes, such as the elderly, who are often already on tight budgets and for whom energy costs consume a disproportionate share of household income.

Table 1 shows a comparison of the usage of low-income consumers to other consumers, for every state.

Energy Information Administration, Residential Energy Consumption Survey Reportable Domain	Household Income			Percentage Difference between average KWH low-income and non-low-income households
	Above 150% Poverty Level	At or Below 150% Poverty Level	All Households	
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	7,468	4,709	6,961	-37.0%
Massachusetts	6,056	4,222	5,686	-30.3%
New York	5,969	4,544	5,355	-23.9%
New Jersey	7,497	4,969	7,231	-33.7%
Pennsylvania	9,690	8,402	9,306	-13.3%
Illinois	9,116	7,350	8,432	-19.7%
Indiana, Ohio	9,999	7,831	9,365	-21.7%
Michigan	8,190	7,073	7,764	-13.6%
Wisconsin	7,889	7,449	7,727	-5.6%
Iowa, Minnesota, North Dakota, South Dakota	9,285	6,241	8,940	-32.8%
Kansas, Nebraska	9,402	8,808	9,302	-6.3%
Missouri	12,232	11,705	11,991	-4.3%
Virginia	13,859	10,997	13,231	-20.7%
Delaware, District of Columbia, Maryland, West Virginia	13,063	10,381	12,848	-20.5%
Georgia	13,816	12,727	13,499	-7.9%
North Carolina, South Carolina	14,343	12,105	13,651	-15.6%
Florida	13,760	11,905	13,212	-13.5%
Alabama, Kentucky, Mississippi	15,847	11,802	14,656	-25.5%
Tennessee	14,480	12,537	13,782	-13.4%
Arkansas, Louisiana, Oklahoma	13,646	12,628	13,421	-7.5%
Texas	13,799	10,602	12,878	-23.2%
Colorado	6,516	5,216	6,231	-20.0%
Idaho, Montana, Utah, Wyoming	9,588	10,665	9,804	11.2%
Arizona	13,056	10,088	12,105	-22.7%
Nevada, New Mexico	9,434	7,637	9,164	-19.0%
California	5,939	4,739	5,628	-20.2%
Alaska, Hawaii, Oregon, Washington	10,799	10,597	10,754	-1.9%
Total	10,072	8,432	9,687	-16.3%

Source: 2009 EIA Residential Energy Consumption Survey data by "Reportable Domain," July 2015. Tabulated by National Consumer Law Center, July 2015, John Howat – jhowat@nclc.org.

While the empirical research is currently divided on how low-income customers would respond to specific smart rate designs, it is clear that limiting customers' ability to reduce monthly bills—which is what fixed charges do—would have negative impacts on these vulnerable populations.² Additionally, fixed charges negatively impact both urban and rural residents who use natural gas for space and water heat. Such customers receive proportionately higher electric bills as a result of high fixed charges, because heating costs are not reflected in their electric bill.³ In other words, high fixed charges result in a greater percentage increase in electric bills for those that heat with non-electric fuels.

Higher fixed charges are inequitable for apartment-dwelling urban residents in particular, because they are the lower-cost group of residential customers to serve, simply because the number of customers per transformer and per mile of distribution circuit is higher than for suburban or rural single-family dwellings. If distribution costs are recovered through high fixed charges, higher-cost suburban and rural single-family customers with higher usage see reduced bills—an inequitable result.⁴

High Fixed Charges Undermine Investments in Energy Efficiency

Energy efficiency and conservation reduce customer bills, and they also reduce overall system costs. By reducing peak demands on the utility, energy efficiency and conservation help avoid expensive new capacity upgrades, and by displacing fossil generation, these customer initiatives also reduce carbon emissions. With higher fixed charges, customers have less incentive to reduce their electricity consumption because they are charged a high fixed rate regardless of their energy usage. Often, utilities that implement high fixed charges will simultaneously decrease their per-kWh energy charges with the result that customers' increased usage may not lead to a significant increase in their bill. This encourages wasteful consumption and hinders investment in energy efficiency.



For example, the Regulatory Assistance Project (“RAP”) recently found that, compared to a flat volumetric rate, a high fixed charge rate design advocated by utilities in Ohio, Wisconsin, and Illinois could result in a 7% increase in residential consumer usage. In contrast, an inclining block residential rate with a low customer charge can achieve an 8% reduction in residential consumer usage.⁵

A study by the Kansas Corporation Commission reached similar conclusions. Researchers found that increased fixed charges in Kansas would increase electricity use by 1.1 – 6.8%, varying by utility and season.⁶ To put this in perspective, the projected increase would be greater than all of the energy savings from all energy efficiency programs in the state. **The Commission found that such a change in rate structure and consumption would offset the financial benefits of decades of energy efficiency efforts and penalize customers who have already successfully invested in energy efficiency under previous rate structures.** Weakening the incentive to invest in energy efficiency could also have negative impacts for the local economy and the environment, as investments in energy efficiency are frequently accompanied by local efficiency jobs and pollution reduction.⁷ Rate design that results in increased consumption would also greatly compound the challenges that utilities face in meeting the emission reductions required by the federal Clean Power Plan, which aims to reduce carbon emissions from power plants.

High Fixed Charges Can Encourage Utilities to Overbuild New Capacity Even as Electricity Demand Declines

High fixed charges, paired with per-kWh energy rates that do not account for the timing of use, also discourage peak demand reduction because they fail to provide accurate price signals about the times when electricity is most expensive to produce. High fixed charges signal to customers that increasing peak energy use does not increase costs and capacity requirements for the utility, when in fact the opposite is true. Without proper price signals for customers, consumption may increase in

all periods, including peak periods. High peak demand, in turn, encourages utilities to overbuild new capacity.

Historically, utilities have built capacity and structured rates based on their ability to ensure peak demand is always met, even during rare high-demand moments. This approach has consistently resulted in utilities overbuilding capacity, and in particular, baseload capacity. For example, while the North American Reliability Council (“NERC”) standard for reserve capacity is around 15%, the U.S. Energy Information Administration’s (“EIA”) Summer 2014 energy forecast put unused generation capacity for the Carolinas at 24%, 26% for Tennessee, 37% for Georgia and Alabama, and 29% for Florida.⁸ The costs of such excess capacity are an extra burden on ratepayers.

In recent years, electricity demand has slowed, and average usage has decreased, while peak usage has increased or remained the same.⁹ The Southeast is no exception. Where previous estimates expected energy demand in the Southeast to grow by 3-4% per year, recent projections by EIA now estimate 1-2% growth. The expansion of DERs is contributing to the slowing of electricity demand growth in both residential and commercial buildings.¹⁰ In some areas of the Southeast, residential demand for delivered electricity is expected to decline.¹¹

This decreased consumption results in increased unused generation and grid infrastructure. As a result, utilities throughout the country and in the Southeast are being pressed to re-examine capacity needs and reforecast expected load growth. For example, TVA recently shifted its forecasted annual load growth from 3 or 4 percent a year to under 1 percent a year. While TVA previously expected to build an additional coal or natural gas unit every year, or a nuclear reactor every two or three years, it is now planning to retire plants and reduce its capacity expansion.¹² With a reduced need to invest in new capacity, TVA has the ability to offer lower long-term rates for its customers.

However, if the distribution utilities that serve customers in TVA’s territory begin to implement high fixed charges which result in increased consumption, this could signal to TVA the need to maintain or build more capacity and increase rates over the long term. For these reasons, high fixed charges have the potential to unfairly penalize all customers by depriving them of price signals that could prevent expensive capital investments and higher customer bills.

High Fixed Charges Discourage Customer Investment in DERs and Prevent the Benefits that Flow to the Grid from that Investment

DERs reduce energy consumption and produce substantial average monthly energy bill savings. Often, utilities claim that because customers with DERs significantly reduce their kWh consumption, they avoid paying their share of the fixed costs of the grid. These utilities argue that high fixed charges for DER customers are justified to prevent an unfair cost shift to non-DER customers. Utilities

most frequently make this argument in regard to solar net metering policies (“NEM”) which compensate customers who send power back to the grid at rates equal to retail rates.

However, contrary to some utility claims, solar is projected to actually decrease system costs for utilities. A new study by Rocky Mountain Institute (“RMI”) projects that DER customers with solar and battery storage provide value to the grid by reducing peak demand, deferring or avoiding system upgrades, relieving congestion, and providing ancillary services.¹³ In addition, other studies by utility regulators have found the value of distributed solar to exceed



retail rates. **For example, Nevada regulators found that the value rooftop solar adds to the grid is 18.5 cents/kWh,¹⁴ Mississippi 17 cents/kWh,¹⁵ Maine 33.7 cents/kWh,¹⁶ Minnesota 14.5 cents/kWh,¹⁷ and Vermont 25.7 cents/kWh.¹⁸** Implementing fixed charges will only result in a missed opportunity for utilities to align the interests of customers using DERs with those of the grid as a whole.

Moreover, data from the residential solar market in Colorado shows that the typical residential customer who installs solar tends to have greater initial usage than an average customer, with an average monthly pre-solar bill of \$126 compared to the average residential bill of \$77 per month. After adding solar, the typical solar customer's bill drops to \$50 per month.¹⁹ In effect, adding solar changes a larger-than-average customer into a smaller-than-average one, but both are well within the range of sizes typical of the residential class.

In 2014, the Utah Public Service Commission reached a similar conclusion in rejecting a proposal from Rocky Mountain Power to impose a net metering facilities charge. In Utah, the typical residential customer uses 500-600 kWh per month, with net metered customers falling at the low end of this range at 518 kWh per month. The Utah commission concluded that “[t]hese facts undermine PacifiCorp’s reasoning that net metered customers shift distribution costs to other residential customers in a fashion that warrants distinct rate treatment.”²⁰

SMART RATE ALTERNATIVE TO FIXED CHARGES

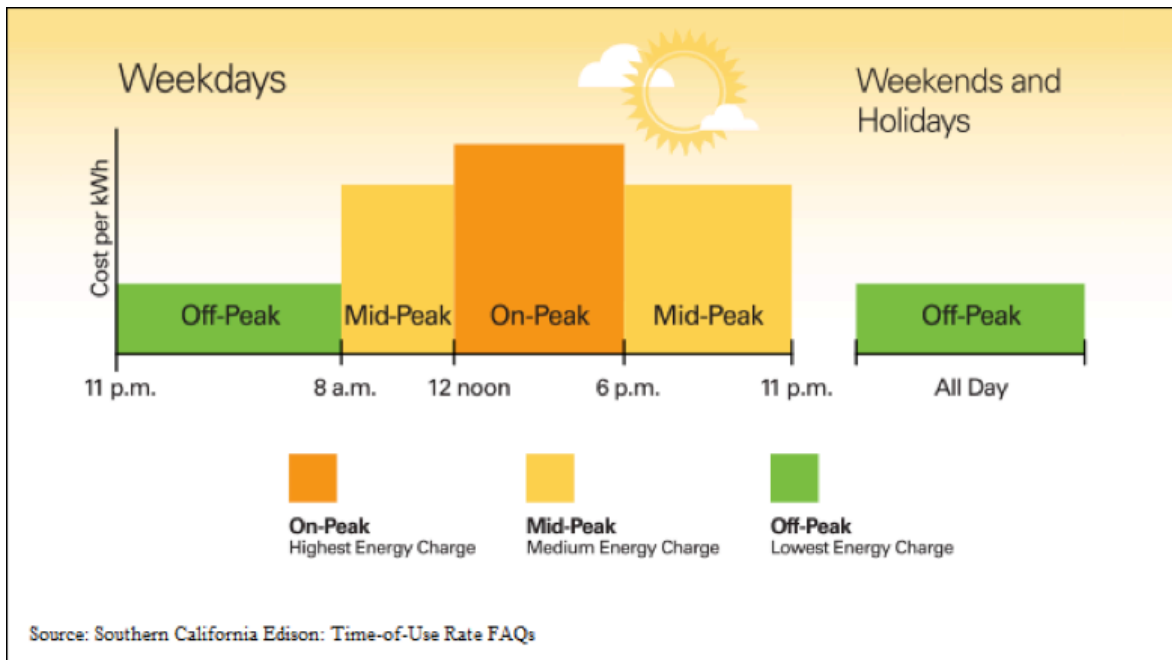
There are a variety of rate design structures that utilities can utilize to ensure fixed cost recovery without causing the negative effects of fixed charges. For years, electric industry experts have recognized the importance of smart rate design founded on mechanisms that send correct price signals to customers. A brief canvas of the literature reveals the following consistent principles of smart rate design.²¹ Based on these principles, customer rates should:

- Be economically efficient, based on total system long-run marginal (not embedded) costs;
- Allow for customers to connect to the grid for no more than the cost of connection;
- Be comprehensible to the customer;
- Assure grid reliability;
- Recover system costs in proportion to how much electricity consumers use, and when they use it;
- Provide customers with the correct price signals about usage and consumption patterns;
- Fairly compensate customers who supply power to the grid at the power’s full value;
- Allow for competition within the market for both generation and ancillary services;
- Assure recovery of utility’s prudently incurred costs;
- Maintain fairness to all customer classes and subclasses;
- Maximize the value of new technologies as they become available; and
- When possible, be temporally and geographically dynamic.

Pursuing smarter rate design can reduce overall system costs while still allowing utilities to receive necessary revenue, create incentives for customers to implement solutions that serve utilities’ interests, promote the integration of DERs, and ensure net benefits to the grid. Some of these rate design techniques include: time-of-use (“TOU”) and other time-varying rates; well-designed minimum billing; and revenue decoupling. Advanced metering infrastructure—including smart meters—also allow utilities to implement even more granular rate designs, such as location-based rates and attribute pricing.

Time-of-Use Pricing

Instead of establishing higher fixed charges, utilities can expand offerings for time-varying rates, such as TOU or dynamic pricing structures. TOU pricing charges customers higher or lower rates based on the timing of energy use and the corresponding demand on the grid. TOU rates are usually set once or twice a year. Dynamic pricing—or Real-Time Pricing (“RTP”)—is a more granular TOU rate that accounts for the hourly change in the cost of generation and more accurately reflects the short-run marginal value of power. While TOU rates are set annually or semi-annually, dynamic pricing may change each hour depending on the real-time cost of generation.²²



TOU pricing is preferable to high fixed charges and flat volumetric rates because it sends more accurate price signals to customers that better reflect the costs to the utility to produce and deliver electricity. While fixed charges fail to capture marginal costs that can vary substantially over time and ignore changing electricity system conditions, TOU and RTP better account for the dynamic cost of energy generation, distribution, and service.²³ The structure of a TOU program can vary significantly, from simple on-peak and off-peak pricing, to seasonal TOU rates, to hourly-based RTP. For example, Nevada Energy’s Residential on-peak TOU rate can reach 50 cents/kWh,²⁴ while Chattanooga EPB’s residential, off-peak TOU rates are as low as 6.5 cents/kWh.²⁵ The efficiency and effectiveness of TOU pricing depend on its ability to reflect real-time changes in electricity conditions.²⁶

At their simplest, TOU rates communicate to customers that the cost to produce and deliver electricity is much higher during peak hours than off-peak hours. For example, TOU customers receive the correct signal that turning up an air conditioner on a hot summer afternoon increases the cost and the need for new capacity over the long run.²⁷ In their more complex forms, such as RTP rates, time-varying rates provide a full picture of the hourly cost to produce and deliver electricity and give greater control to consumers to shift their behavior based on their needs and investment decisions.²⁸

In a recent order, the Massachusetts Department of Public Utilities stated that TOU rates are an essential component of grid modernization.²⁹ Concerned that under the current basic service structure rates do not reflect the time-varying nature of electricity supply costs, the Department is requiring the incorporation of TOU rates for all customers.³⁰ The Department’s recent order will require electric distribution companies to offer two basic service TOU options: 1) A default product with TOU pricing that includes a critical peak pricing (“CPP”) component,³¹ and 2) a flat rate with a peak time rebate (“PTR”) option. Under CPP, utilities designate a number of “critical peak” days each year during which the price of electricity increases significantly. Utilities inform customers ahead of time when critical peak days will occur to allow customers to reduce consumption during CPP periods. Under PTR, utilities apply similar critical peak periods, but instead of charging customers higher rates during those periods, customers who reduce consumption during those periods will receive a rebate for the value of the energy they saved.³²

The Department anticipates that the on-peak rate will be higher, and the off-peak rate lower than a flat-rate design. Thus, customers who respond to price signals by reducing on-peak energy consumption will pay less than they would under a flat rate. TOU pricing can also be a powerful incentive for the smarter integration of DERs, such as solar PV, that tend to produce the most power during sum-

mer months and during peak load hours, thereby reducing peak loads and resulting in both customer and utility savings.

A recent two-year pilot program conducted by the Sacramento Municipal Utility District revealed that customers prefer TOU rates to traditional rate structures. The pilot program tested three TOU options.³³ In one scenario the utility charged an on-peak rate from 4:00 to 7:00 p.m. on weekdays; in another scenario it charged a critical peak rate from 4:00 to 7:00 p.m. on up to 12 days per summer; and in the third scenario it charged both an on-peak rate and critical peak rate. The utility found significant differences in the cost of producing and delivering electricity throughout the day, and also discovered that customers with TOU rates were more satisfied than customers on standard flat rates because customers felt that the TOU rates were fair, provided more opportunity to manage energy costs, and were easier to understand than flat rates.³⁴

In 2013, Duke Energy Progress expanded TOU pricing to residential customers as part of a pilot program in its North Carolina service territory. This rate design includes a seasonal, on-peak demand charge, as well as an on-peak and off-peak energy charge. Rates also include a customer charge and rider charges.³⁵

TOU pricing can also be used to fairly compensate customers who supply power to the grid. Utilities that make TOU pricing available to net metered solar customers can more accurately compensate such customers for the value of the power they supply to the grid based on when they provide it. TOU pricing can be a powerful incentive for the smarter integration of DERs, such as solar PV, to reduce peak loads and to increase loads when there is surplus solar, resulting in both customer and utility savings. The Hawaii PUC recently issued an Order requiring that the mid-day hours be designated as “off-peak” hours.³⁶ And the California ISO has proposed TOU pricing that designates peak solar production times as a low-cost period for customers.³⁷ Under these approaches, the “solar credit” values are tied to on-peak and off-peak demand, and they reduce the potential for lost revenue impacts on the utilities. This TOU approach is an effective alternative to high mandatory fees.³⁸

Additionally, Duke Energy Progress is allowing its residential customers to couple its net metering program with its time variant rate options. These options include net metering under “time-of-use,” “time-of-use demand,” and “time-of-use all-energy” schedules.³⁹ While each option is structured slightly differently, all provide net metered customers with varying levels of compensation based on whether they produce power during peak hours when solar power is more valuable, or during off-peak hours when the value of solar may decrease.⁴⁰

Finally, TOU pricing provides a favorable alternative to **demand charges for residential and small commercial customers**—charges based on a customer’s highest usage every month. Demand charges are unable to account for the diverse usage patterns of residential and small commercial customers, often do not coincide with peak system demand, and can result in significant and inequitable cost-shifting. TOU pricing is a better approach because it more accurately reflects the time-based costs of customer usage and avoids the problems created by such demand charges.

Advanced Metering Infrastructure

Time-of-use rates generally require advanced metering infrastructure (“AMI”) like smart meters. Smart meters allow utilities to receive data, control equipment, and communicate more effectively between the customer and the grid.

For example, in 2013, Chattanooga Electric Power Board (“EPB”), a municipal utility served by TVA, completed the installation of smart meters in all homes and businesses in its 600 square mile service area. The meters allow for one billion data points to be collected annually, providing automated meter reading and billing, outage and voltage anomaly detection, automated connect and disconnect and theft detection. Such data help support the use of expanded TOU pricing in EPB’s service area. EPB offers commercial customers a seasonal TOU rate without the need for high fixed charges.⁴¹ Similarly, Memphis Light, Gas and Water (“MLGW”) has recently begun several projects related to smart grid technologies, including the installation of electric, gas and water smart meters at approx-



imately 60,000 homes. MLGW also offers a seasonal TOU rate for residential customers with smart meters.⁴²

As the utility industry continues to evolve toward a smarter grid, smart meters will be an essential component of that evolution. Utilities without AMI will likely be unable to keep up with the innovations and opportunities that the changing grid creates. For example, **locational marginal pricing (“LMP”)** allows utilities to reflect the value of providing service at different locations, accounting for the patterns of load, generation, and the physical limits of the transmission system. There are multiple forms of LMP, with a range of granularity in pricing methods. LMP requires extensive knowledge of the distribution system, customer demand profiles, and the monetization of different energy services in both space and time. LMP is usually applied in wholesale markets, but recently LMP has been proposed with respect to distribution values.⁴³

In addition, **attribute pricing** allows utilities to individually account for valuable attributes that may be delivered by customers implementing DERs, or by the utility, such as energy, capacity, reliability, flexibility, resilience, ancillary services and other related value streams. Attribute pricing allows utilities to more accurately compensate or charge customers for the specific value of these services, and it is particularly useful when integrating customer-owned DERs. Attribute pricing is typically paired with TOU pricing which improves its delivery, helping customers make better decisions and giving them appropriate compensation for the services they provide.⁴⁴

AMI allows utilities to collect valuable data and apply that information towards smarter rate design that benefits the utility and its customers. However, even utilities without AMI can choose smarter alternatives to high fixed charges, such as well-designed minimum bills.

Minimum Bills

An increasingly-popular alternative to fixed charges is the adoption of a minimum bill. A well-designed minimum bill guarantees the utility a minimum annual revenue level from each customer, even if their usage is zero, but does not significantly alter the volumetric, per-kWh rate.⁴⁵ Unlike a fixed charge, a minimum bill does not come into effect unless the customer uses less than a certain amount of power each month, essentially ensuring utilities that even if no power is consumed, the connection is paid for and that every customer contributes at least a minimum amount toward the maintenance of the grid.

The structure of a minimum bill is crucial to its effectiveness, because a poorly-structured minimum bill can result in similar negative effects as a high fixed charge. The key to minimum bills is to set the minimum at a level that ensures the utility a consistent level of appropriate revenue, while not penalizing the vast majority of customers, or inhibiting efficiency. Minimum bills are determined by calculating the marginal cost to deliver the average daily minimum metered charges per customer. If structured correctly, a minimum bill preserves the incentive to conserve energy by not drastically decreasing the per-kWh energy charge or by shifting the bulk of a bill to a fixed charge, while still providing adequate revenue for the utility.⁴⁶ RAP recommends that utilities base minimum bills on the future, marginal cost to deliver energy to each customer, and charge minimum bills annually rather than monthly.⁴⁷

Many utilities throughout the country are exploring the use of minimum bills in lieu of fixed charges. A study by the Texas Ratepayers’ Organization to Save Energy documented that the number of Texas retail electricity providers assessing minimum usage fees grew from 36% to 81% between 2011 and 2013.⁴⁸ Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric have established residential minimum bill policies. In addition, the Sacramento Municipal Utility District and the Texas Public Utility Commission allow minimum or low usage charges to be assessed on customers with low consumption. The Los Angeles Department of Water and Power imposes a zero fixed charge, a three-block inclining rate design, and a \$10 minimum bill.

A recent study on the impacts of minimum bills has shown that given a choice between a \$20 fixed customer charge with a lower per-kWh rate, and a \$20 minimum bill charge with a slightly higher per-kWh rate, customers would consume 15 times as much additional energy under the former as un-

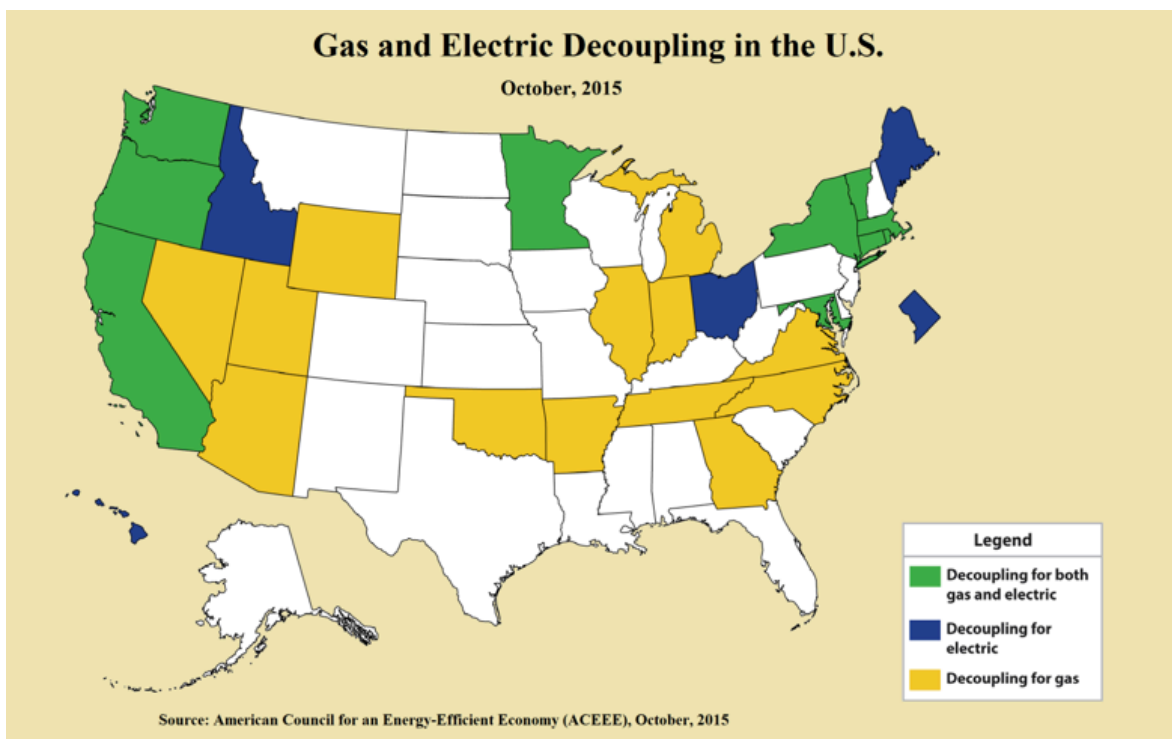
der the latter.⁴⁹ Additionally, Greentech Media recently examined the impact of minimum bills on solar customers in comparison to fixed charges and found that a minimum bill would be more economic for solar customers than a fixed charge, assuming the minimum bill is set at the same level as the fixed charge.⁵⁰ Greentech Media’s study compared the monthly and annual bills of a solar customer with a 6.3 kW rooftop solar system who was charged a \$10 monthly minimum bill versus a \$10 monthly fixed charge. Under the \$10 monthly minimum bill, the solar customer paid less than the customer with the \$10 fixed charge.

Revenue Decoupling

One reason utilities are seeking higher mandatory fees is to stabilize their revenue in the face of stagnant or declining sales levels. Another approach to revenue stabilization is known as revenue regulation, or “decoupling.” Decoupling is an adjustable rate mechanism that breaks the link between the amount of energy sold and the revenue collected by the utility.⁵¹ Under decoupling, a utility’s rates are adjusted every month or every year to account for variations from the sales prediction made when rates were set. If sales decline, rates increase to recover the utility’s required revenue. If sales increase, rates decline.

Through decoupling, utilities can achieve revenue stability without changing the rate design in a manner that increases costs to low-income consumers, renters, and other low-use customers. Rates can retain the traditional per-kW recovery of system costs that allocates these costs in proportion to system usage. Customers do not lose the incentive to invest in energy efficiency measures, and the utility becomes indifferent to sales volumes. The utility can concentrate on controlling the cost of service and providing excellent service to consumers.

Decoupling has been used in most U.S. states for electric, gas, and water utilities in one form or another. The map below shows the states in which one or more utilities have implemented some form of revenue regulation mechanism.



Decoupling is usually utilized by investor-owned utilities regulated by a state utilities commission. However, distribution utilities that set their own rates, such as electric cooperatives and municipal utilities, may also implement decoupling as part of their rate design. The Los Angeles Department of Water and Power implemented a decoupling mechanism in 2013. They did so in order to retain a pro-

gressive rate design with a zero customer charge and an inclining block rate design, while protecting the revenue stability that ensures the utility's strong bond rating. Since then, decoupling adjustments have been no more than 2% per year.⁵²

Decoupling can take several different forms, but all of the methods have a few common elements:

- Initially rates are set in a traditional rate proceeding;
- Rates are adjusted periodically to produce the target revenue, taking into account any increase or decrease in sales volumes compared with the level assumed in the rate proceeding;
- The mechanism is defined in advance as to whether it will cover only distribution costs, or all costs; different methods are appropriate for each approach;
- Some annual cap on how much rates can rise is usually imposed; if sales deviations exceed these thresholds, increases are spread across more than one year;
- A true-up mechanism ensures that the utility recovers the allowed revenue; no more and no less.

CONCLUSION

The electric industry is changing in ways that empower customers but that also may threaten utilities' ability to earn required revenue. Utility customers increasingly have at their disposal a variety of means for reducing their dependence on the grid. As they do this, utilities may be tempted to respond with regressive rate mechanisms, such as high fixed charges. But fixed charges, and other departures from volumetric pricing, are not a good solution. These measures fail to provide a core component of smart rate design, which is to provide accurate pricing signals to customers. Fixed charges hurt low-income customers and encourage economically inefficient outcomes.

Instead of instituting unfair and short-sighted pricing mechanisms, utilities should instead pursue more dynamic, reflective pricing strategies such as time-of-use pricing, well-structured minimum bills, and locational and attribute pricing. Additionally, utilities should consider revenue decoupling to further ensure that necessary revenues are recovered while not deterring efficiency. These pricing strategies respect the customer's right to deploy DERs, while more accurately capturing the benefits and costs to the grid of all resources. This is a better pathway for ensuring utility cost recovery as the grid continues to evolve to meet customer needs and preferences.

There is no one-size-fits-all solution. Each utility and each state is different. In the Southeast, markets are predominantly served by large, vertically integrated utilities. The Southeast also lacks a single regional transmission organization ("RTO") or independent system operator ("ISO") that, in other areas of the country, establishes the methods and economics of real-time transmission costs and contracts for ancillary services. Thus the responsibility falls to the IOUs, electric cooperatives and municipal utilities, and to regulators to create the framework for smarter rate design, to make economically efficient decisions based on the cost of service, and to pursue the innovation necessary to adapt to the changing electricity sector landscape. The pathway may look different in each state, but the goal should be the same: smarter economics and stronger policy that treats customer choice as a resource for the benefit of all ratepayers.

ENDNOTES

- ¹ Revenue requirements refer to the annual revenues required by the utility to cover both its expenses and have the opportunity to earn a fair rate of return. They also refer to the annual costs to provide safe and reliable service to the company's customers that the company is allowed to recover through rates.
- ² Faruqui, A., Sergici, S. and Palmer, J., *The Impact of Dynamic Pricing on Low Income Customers*, Edison Institute, (2010), http://www.edison-foundation.net/IEE/Documents/IEE_LowIncomeDynamicPricing_0910.pdf; Nancy Brockway, Rick Hornby, *The Impact of Dynamic Pricing on Low-Income Customers: An Analysis of the IEE Whitepaper*, Synapse Energy, (2010), <http://www.synapse-energy.com/sites/default/files/SynapseReport.2010-11.MD-OPC.IEE-Low-Income-Customer-Report.10-042.pdf>; Trevor R. Roycroft, *Impact of Dynamic Pricing on Low Income Consumers: Evaluation of the IEE Low Income Whitepaper* (2010), available at http://www.roycroftconsulting.org/Roycroft_Dynamic_Pricing_Low_Income_11-29-10.pdf.
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- ³¹ Under this TOU pricing structure, the retail electricity price will be higher during certain hours of the week when customers typically use more electricity and wholesale energy prices rise (e.g., the "on-peak" hours of noon to 8:00 p.m. each weekday) than during the remaining hours of the week when electricity usage and wholesale prices are typically lower (i.e., the "off-peak" hours).

- ³² Under PTR, customers will have an incentive to lower their electricity usage when it is most critical to do so, but even those who ignore the incentive will be insulated against higher peak prices because they will pay one price for all electricity consumption.
- ³³ The Sacramento Municipal Utility District, which serves approximately 540,000 customers in and around Sacramento, California, implemented a two-year SmartPricing Options pilot program. See Jennifer M. Potter, et. al, Sacramento Municipal Utility District, SmartPricing Options Final Evaluation (Sept. 5, 2014), https://www.smartgrid.gov/files/SMUD-CBS_Final_Evaluation_Submitted_DOE_9_9_2014.pdf.
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- ³⁶ Haw. Pub. Util. Comm'n, Docket No. 2014-0192, Decision and Order No. 33258 (Oct. 12, 2015).
- ³⁷ California ISO, Matching Time-of-Use Rate Periods with Grid Conditions Maximized Use of Renewable Resources (2015), <https://www.caiso.com/Documents/MatchingTimeOfUsePeriodsWithGridConditions-FastFacts.pdf>.
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- ³⁹ Net metering customers under TOU and TOU-E pay a significantly higher price for electricity generated during on-peak hours, but the TOU schedule charges a higher rate for on-peak energy than the TOU-E schedule. The TOU schedule also offers a shoulder rate (between on-peak and off-peak), which provides more opportunity for a customer to avoid on-peak energy consumption, but provides fewer hours for a customer to get paid the maximum on-peak rate for energy generated by their PV system. An advantage of both the TOU and TOU-E rate schedules over the time-of-use demand (TOU-D) schedule is that there is no demand charge. Therefore, a homeowner gets the time-of-use advantage of a higher rate for on-peak PV generation without the burden of a demand charge. The SunSense option pays a lower rate for electricity sold to the grid during both on- and off-peak hours. The greatest advantages of the SunSense program are the reduced upfront cost and the five-year monthly payment based on system size.
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- ⁴² Memphis Light Gas & Water, Time-of-Use Residential Rate, http://www.mlgw.com/images/content/files/pdf_rates/RSTOUOct14.PDF.
- ⁴³ Recently, the New York Department of Public Service proposed adopting multiple changes in rate design for their delivery rates, including the adoption of LMP with the added marginal value of distribution. This is different from, DLMP, which is sometimes used to refer to a granular calculation of time- and location-specific costs on the distribution system. LMP+D is a broader measure capturing the full value of DER, including energy (LMP) and the full range of values provided by distribution level resources (D). See New York State Energy Research and Development Authority, *Large-Scale Renewable Energy Development in New York: Options and Assessments* (2015), filed in N.Y. Pub. Serv. Comm'n. Docket No. 15-E-0302 (June 1, 2015).
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- ⁴⁵ Jim Lazar, Regulatory Assistance Project, Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs (2013)(hereinafter "Lazar, Minimum Bills"), <http://www.raonline.org/document/download/id/7361>.
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