Caught in a Fix

The Problem with Fixed Charges for Electricity

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CONTENTS

EXECUTIVE SUMMARY 1

1. INTRODUCTION 5

2. TROUBLING TRENDS TOWARD HIGHER FIXED CHARGES 8
   - What's Happening to Electric Rates? 8
   - What is Behind the Trend Toward Higher Fixed Charges? 12

3. HOW FIXED CHARGES HARM CUSTOMERS 14
   - Reduced Customer Control 14
   - Low-Usage Customers Hit Hardest 14
   - Disproportionate Impacts on Low-Income Customers 15
   - Reduced Incentives for Energy Efficiency and Distributed Generation 16
   - Increased Electricity System Costs 18

4. RATE DESIGN FUNDAMENTALS 20
   - Guiding Principles 20
   - Cost-of-Service Studies 20
   - Rate Design Basics 21

5. COMMON ARGUMENTS SUPPORTING HIGHER FIXED CHARGES 22
   - "Most Utility Costs Are Fixed" 22
   - "Fixed Costs Are Unavoidable" 23
   - "The Fixed Charge Should Recover Distribution Costs" 23
   - "Cost-of-Service Studies Should Dictate Rate Design" 25
   - "Low-Usage Customers Are Not Paying Their Fair Share" 26
   - "Fixed Charges Are Necessary to Mitigate Cost-Shifting Caused by Distributed Generation" 26

6. RECENT COMMISSION DECISIONS ON FIXED CHARGES 30
   - Commission Decisions Rejecting Fixed Charges 30
   - Commission Decisions Approving Higher Fixed Charges 32

Settlements 33

7. ALTERNATIVES TO FIXED CHARGES 34

Rate Design Options 34

8. CONCLUSIONS 41

APPENDIX A – BONBRIGHT'S PRINCIPLES OF RATE DESIGN 42

APPENDIX B – RECENT PROCEEDINGS ADDRESSING FIXED CHARGES 43

APPENDIX C – NET METERING IMPACTS ON UTILITY COSTS 48

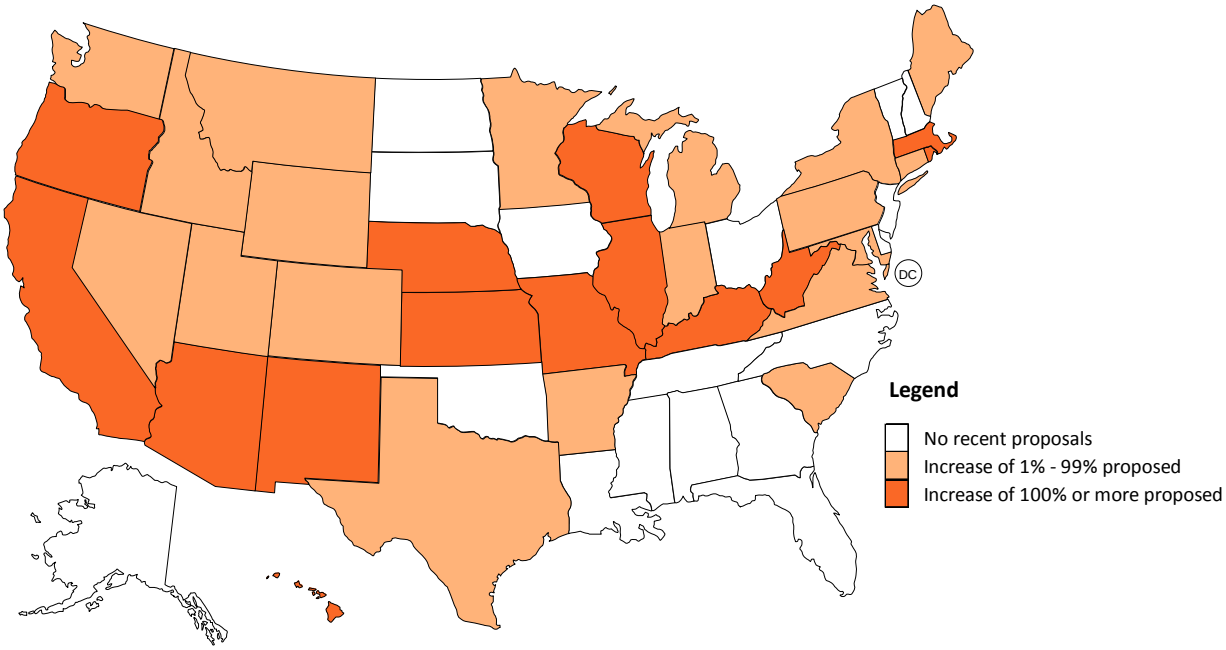
GLOSSARY 52

EXECUTIVE SUMMARY

Recently, there has been a sharp increase in the number of utilities proposing to recover more of their costs through mandatory monthly fixed charges rather than through rates based on usage. Utilities prefer to collect revenue through fixed charges because the fixed charge reduces the utility's risk that lower sales (from energy efficiency, distributed generation, weather, or economic downturns) will reduce its revenues.

However, higher fixed charges are an inequitable and inefficient means to address utility revenue concerns. This report provides an overview of (a) how increased fixed charges can harm customers, (b) the common arguments that are used to support increased fixed charges, (c) recent commission decisions on fixed charges, and (d) alternative approaches, including maintaining the status quo when there is no serious threat to utility revenues.

Figure ES 1. Recent proposals and decisions regarding fixed charges



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Fixed Charges Harm Customers

Reduced Customer Control. Since customers must pay the fixed charge regardless of how much electricity they consume or generate, the fixed charges reduce the ability of customers to lower their bills by consuming less energy.

Low-Usage Customers Hit Hardest. Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised. There are many reasons a

customer might have low energy usage: they may be very conscientious to avoid wasting energy; they may simply be located in apartments or dense housing units that require less energy; they may have small families or live alone; or they may have energy-efficient appliances or solar panels.

Disproportionate Impacts on Low-Income Customers. Data from the Energy Information Administration show that in nearly every state, low-income customers consume less electricity than other residential customers, on average. Because fixed charges tend to increase bills for low-usage customers while decreasing them for high-use customers, fixed charges raise bills most for those who can least afford the increase.

Reduced Incentives for Energy Efficiency and Distributed Generation. By reducing the value of a kilowatt-hour saved or self-generated, a higher fixed charge directly reduces the incentive that customers have to invest in energy efficiency or distributed generation. Customers who have already invested in energy efficiency or distributed generation will be harmed by the reduced value of their investments.

Increased Electricity System Costs. Holding all else equal, if the fixed charge is increased, the energy charge (cents per kilowatt-hour) will be reduced, thereby lowering the value of a kilowatt-hour conserved or generated by a customer. With little incentive to save, customers may actually increase their energy consumption and states will have to spend more to achieve the same levels of energy efficiency savings and distributed generation. Where electricity demand rises, utilities will need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

Common Myths Supporting Fixed Charges

"Most utility costs are fixed." In accounting, fixed costs are those expenses that remain the same for a utility over the short and medium term regardless of the amount of energy its customers consume. Economics generally takes a longer-term perspective, in which very few costs are fixed. This perspective focuses on efficient investment decisions over the long-term planning horizon. Over this timeframe, most costs are variable, and customer decisions regarding their electricity consumption can influence the need to invest in power plants, transmission lines, and other utility infrastructure. This longer-term perspective is what is relevant for economically efficient price signals, and should be used to inform rate setting.

"Fixed costs are unavoidable." Rates are designed so that the utility can recover past expenditures (sunk costs) in the future. Utilities correctly argue that these sunk costs have already been made and are unavoidable. However, utilities should not, and generally do not, make decisions based on sunk costs; rather, they make investment decisions on a forward-looking basis. Similarly, rate structures should be based on forward-going costs to ensure that customers are being sent the right price signals, as customer consumption will drive future utility investments.

"The fixed charge should recover distribution costs." Much of the distribution system is sized to meet customer maximum demand – the maximum power consumed at any one time. For customer classes

without a demand charge (such as residential customers),[1] utilities have argued that these distribution costs should be recovered through the fixed charge. This would allocate the costs of the distribution system equally among residential customers, instead of according to how much energy a customer uses. However, customers do not place equal demands on the system – customers who use more energy also tend to have higher demands. While energy usage (kWh) is not a perfect proxy for demand (kW), collecting demand-related costs through the energy charge is far superior to collecting demand-related costs through the fixed charge.

"Cost-of-service studies should dictate rate design." Cost-of-service studies are used to allocate a utility's costs among the various customer classes. These studies can serve as useful guideposts or benchmarks when setting rates, but the results of these studies should not be directly translated into rates. Embedded cost-of-service studies allocate *historical* costs to different classes of customers. However, to provide efficient price signals, prices should be designed to reflect *future* marginal costs. Rate designs other than fixed charges may yield the same revenue for the utility while also accomplishing other policy objectives, such as sending efficient price signals.

"Low-usage customers are not paying their fair share." This argument is usually untrue. As noted above, distribution costs are largely driven by peak demands, which are highly correlated with energy usage. Further, many low-usage customers live in multi-family housing or in dense neighborhoods, and therefore impose lower distribution costs on the utility system than high-usage customers.

"Fixed charges are necessary to mitigate cost-shifting caused by distributed generation." Concerns about potential cost-shifting from distributed generation resources, such as rooftop solar, are often dramatically overstated. While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power. This power is often provided to the system during periods when demand is highest and energy is most valuable, such as hot summer afternoons when the sun is out in full force. The energy from the distributed generation resource allows the utility to avoid the costs of generating, transmitting, and distributing electricity from its power plants. These avoided costs will put downward pressure on electricity rates, which will significantly reduce or completely offset the upward pressure on rates created by the reduced revenues from the host customer.

Recent Commission Decisions on Fixed Charges

Commissions in many states have recently rejected utility proposals to increase mandatory fixed charges. These proposals have been rejected on several grounds, including that increased fixed charges

[1] There are several reasons that demand charges are rarely assessed for residential customers. These reasons include the fact that demand charges introduce complexity into rates that may be inappropriate for residential customers; residential customers often lack the ability to monitor and respond to demand charges; and that residential customers often do not have more expensive meters capable of measuring customer demand.

will reduce customer control, send inefficient prices signals, reduce customer incentives to invest in energy efficiency, and have inequitable impacts on low-usage and low-income customers.

Several states have allowed utilities to increase fixed charges, but typically to a much smaller degree than has been requested by utilities. In addition, there have been many recent rate case settlements in which the utility proposal to increase fixed charges has been rejected by the settling parties. Nevertheless, utilities continue to propose higher fixed charges, as any increase in the fixed charge helps to protect the utility from lower revenues associated with reduced sales, whether due to energy efficiency, distributed generation, or any other reason.

Alternatives to Fixed Charges

For most utilities, there is no need for increased fixed charges. Regulators who decide there is a need to address utility revenue sufficiency and volatility concerns should consider alternatives to increased fixed charges, such as minimum bills and time-of-use rates.

1. INTRODUCTION

In 2014, Connecticut Light & Power filed a proposal to increase residential electricity customers' fixed monthly charge by 59 percent — from $16.00 to $25.50 per month — leaving customers angry and shocked. The fixed charge is a mandatory fee that customers must pay each month, regardless of how much electricity they use.

The utility's fixed charge proposal met with stiff opposition, particularly from seniors and customers on limited incomes who were trying hard to save money by reducing their electricity usage. Since the fixed charge is unavoidable, raising it would reduce the ability of customers to manage their bills and would result in low-usage customers experiencing the greatest percentage increase in their bills. In a letter imploring the state commission to reject the proposal, a retired couple wrote: "We have done everything we can to lower our usage… We can do no more. My wife and I resorted to sleeping in the living room during the month of January to save on electricity."[2]

Customers were particularly opposed to the loss of control that would accompany such an increase in the mandatory fixed charge, writing: "If there has to be an increase, at least leave the control in the consumers' hands. Charge based on the usage. At least you are not penalizing people who have sacrificed to conserve energy or cut their expenses."[3]

Unfortunately, customers in Connecticut are not alone. Recently, there has been a sharp uptick in the number of utilities that are proposing to recover more of their costs through monthly fixed charges rather than through variable rates (which are based on usage). Some of these proposals represent a slow, gradual move toward higher fixed charges, while other proposals (such as Madison Gas & Electric's) would quickly lead to a dramatic increase in fixed charges of nearly $70 per month.[4]

"If there has to be an increase, at least leave the control in the consumers' hands. Charge based on the usage. At least you are not penalizing people who have sacrificed to conserve energy or cut their expenses."

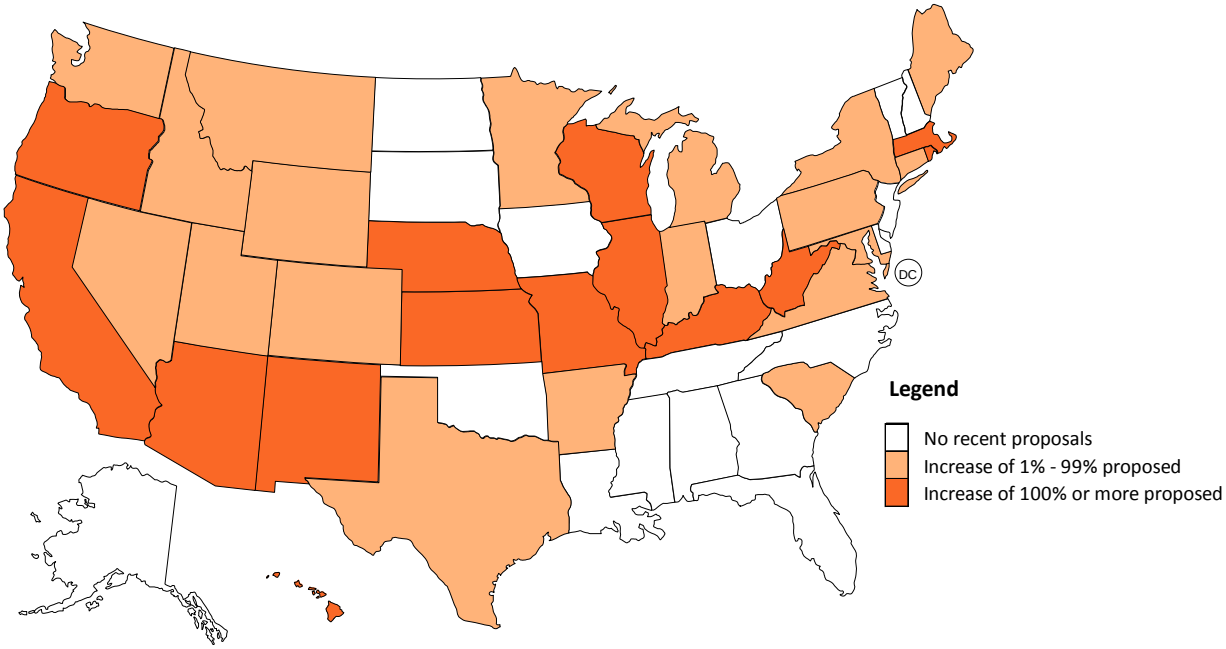
The map below shows the prevalence of recent utility proposals to increase the fixed charge, as well as the relative magnitude of these proposals. Proposals to increase the fixed charge were put forth or decided in 32 states in 2014 and 2015. In 14 of these states, the utility's proposal would increase the fixed charge by more than 100 percent.

[2] Written comment of John Dupell, Docket 14-05-06, filed May 30, 2014

[3] Written comment of Deborah Pocsay, Docket 14-05-06, July 30, 2014.

[4] Madison Gas & Electric's proposal for 2015/2016 offered a preview of its 2017 proposal, which featured a fixed charge of $68.37. Data from Ex.-MGE-James-1 in Docket No. 3270-UR-120.

Figure 1. Recent proposals and decisions regarding fixed charges



Source: See Appendix B

Although a fixed charge may be accompanied by a commensurate reduction in the energy charge, higher fixed charges have a detrimental impact on efficiency and equity. Utilities prefer to collect revenue through fixed charges because the fixed charge reduces the utility's risk that lower sales resulting from energy efficiency, distributed generation, weather, or economic downturns will reduce its revenues. However, higher fixed charges are not an equitable solution to this problem. Fixed charges reduce customers' control over their bills, disproportionately impact low-usage and low-income customers, dilute incentives for energy efficiency and distributed generation, and distort efficient price signals.

As the frequency of proposals to increase fixed charges rises, so too does awareness of their detrimental impacts. Fortunately, customers in Connecticut may soon obtain some relief: On June 30, 2015, the governor signed into law a bill that directs the utility commission to adjust utilities' residential fixed charges to only recover the costs "directly related to metering, billing, service connections and the

Fixed charges reduce customers' control over their bills, disproportionately impact low-usage and low-income customers, dilute incentives for energy efficiency and distributed generation, and distort efficient price signals.

provision of customer service."[5] However, not all policymakers are yet aware of the impacts of fixed charges or what alternatives might exist. The purpose of this report is to shed light on these issues.

Chapter 2 of this report examines the trends and drivers behind fixed charges, while Chapter 3 provides an assessment of how fixed charges impact customers. In Chapter 4, we explore many of the common technical arguments used to support these charges, and explain the flaws in these approaches. Finally, in Chapter 5, we provide an overview of some of the alternatives to fixed charges and the advantages and disadvantages of these alternatives.

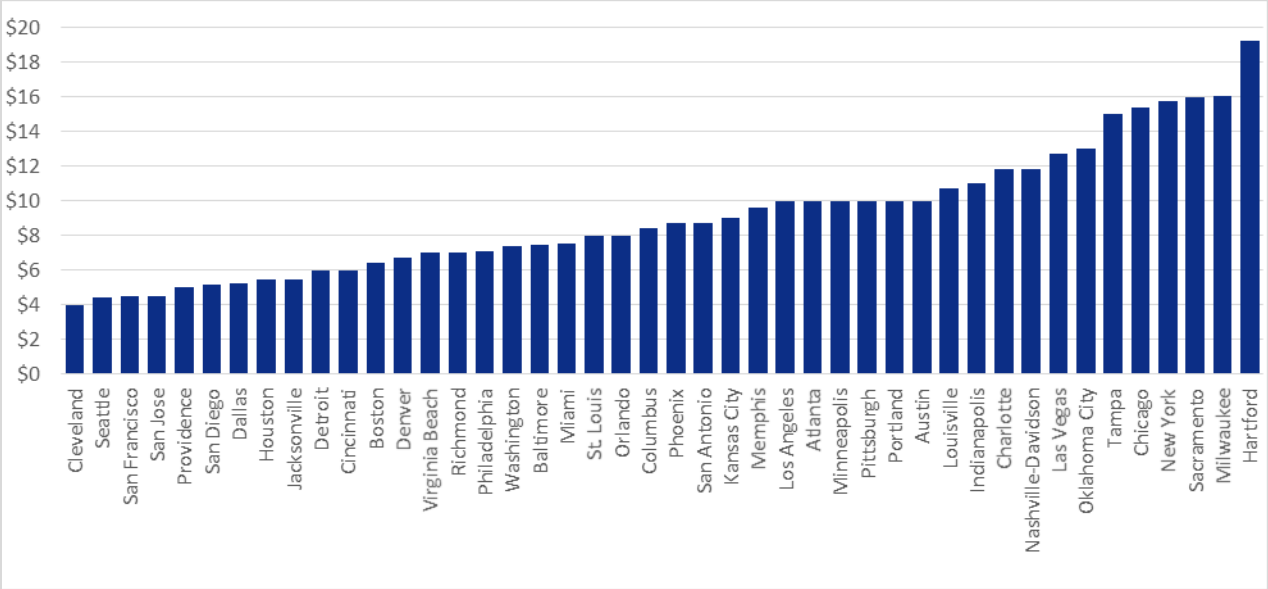
[5] Senate Bill No. 1502, June Special Session, Public Act No. 15-5, "An Act Implementing Provisions of the State Budget for The Biennium Ending June 30, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State."

2. Troubling Trends Toward Higher Fixed Charges

What's Happening to Electric Rates?

Sometimes referred to as a "customer charge" or "service charge," the fixed charge is a flat fee on a customer's monthly bill that is typically designed to recover the portion of costs that do not vary with usage. These costs may include, for examples, costs of meters, service lines, meter reading, and customer billing.[6] In most major U.S. cities, the fixed charge ranges from $5 per month to $10 per month, as shown in the chart below.[7]

Figure 2. Fixed charges in major U.S. cities



Source: Utility tariff sheets for residential service as of August 19, 2015.

Although fixed charges have historically been a small part of customers' bills, more and more utilities across the country—from Hawaii to Maine—are seeking to increase the portion of the bill that is paid through a flat, monthly fixed charge, while decreasing the portion that varies according to usage.

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[6] Frederick Weston, "Charging for Distribution Utility Services: Issues in Rate Design," Prepared for the National Association of Regulatory Utility Commissioners (Montpelier, VT: Regulatory Assistance Project, December 2000).

[7] Based on utility tariff sheets for residential service as of August 2015.

Connecticut Light & Power's proposed increase in the fixed charge to $25.50 per month was significantly higher than average,[8] but hardly unique.

Other recent examples include:

- The Hawaiian Electric Companies' proposal to increase the customer charge from $9.00 to $55.00 per month (an increase of $552 per year) for full-service residential customers, and $71.00 per month for new distributed generation customers (an increase of $744 per year);[9]
- Kansas City Power and Light's proposal to increase residential customer charges 178 percent in Missouri, from $9.00 to $25.00 per month (an increase of $192 per year);[10] and
- Pennsylvania Power and Light's March 2015 proposal to increase the residential customer charge from approximately $14.00 to approximately $20.00 per month (an increase of more than $70 per year).[11]

Figure 3 below displays those fixed charge proposals that are currently pending, while Figure 4 displays the proposals that have been ruled upon in 2014-2015.

[8] Ultimately the commission approved a fixed charge of $19.25, below the utility's request, but among the highest in the country.

[9] Hawaiian Electric Companies' Distributed Generation Interconnection Plan, Docket 2011-0206, submitted August 26, 2014, at http://files.hawaii.gov/puc/3_Dkt 2011-0206 2014-08-26 HECO PSIP Report.pdf.

[10] Kansas City Power and Light, Case No.: ER-2014-0370.

[11] PPL Witness Scott R. Koch, Exhibit SRK 1, Supplement No. 179 to Tariff – Electric Pa. P.U.C. No. 201, Docket No. R-2015-2469275, March 31, 2015, at http://www.puc.state.pa.us/pcdocs/1350814.pdf.

Figure 3. Pending proposals for fixed charge increases

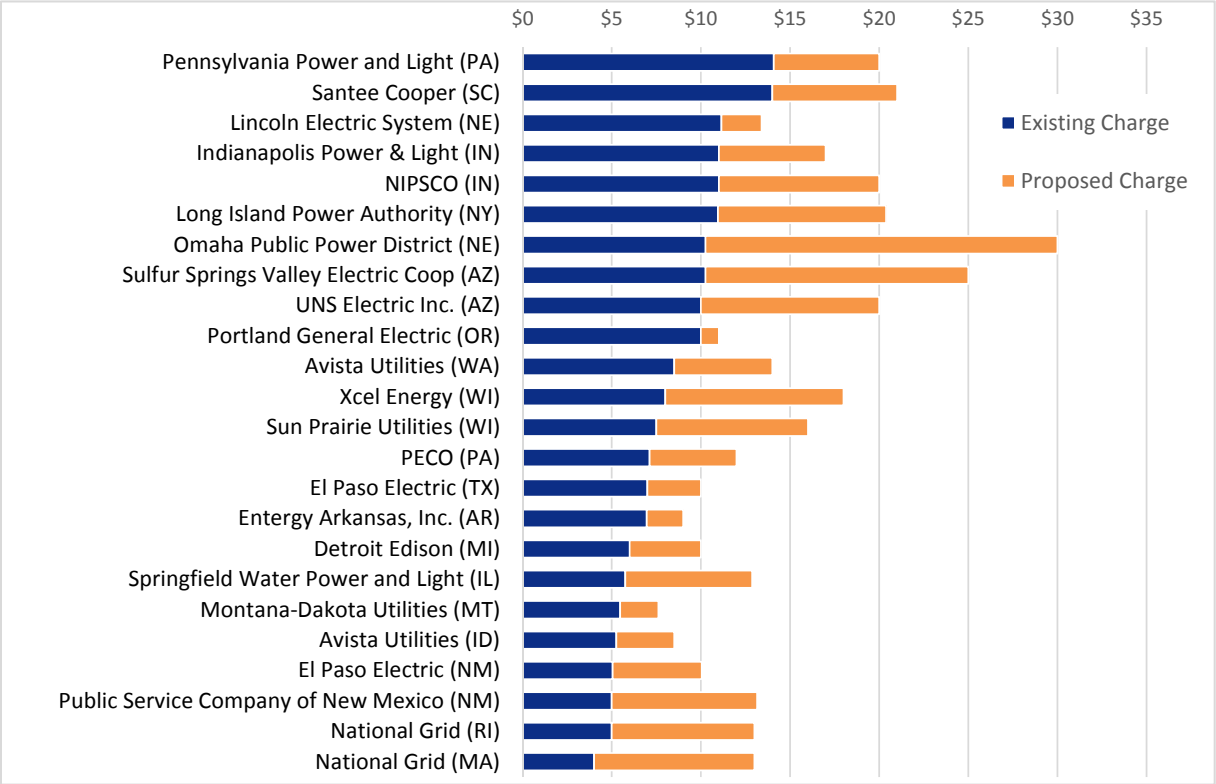

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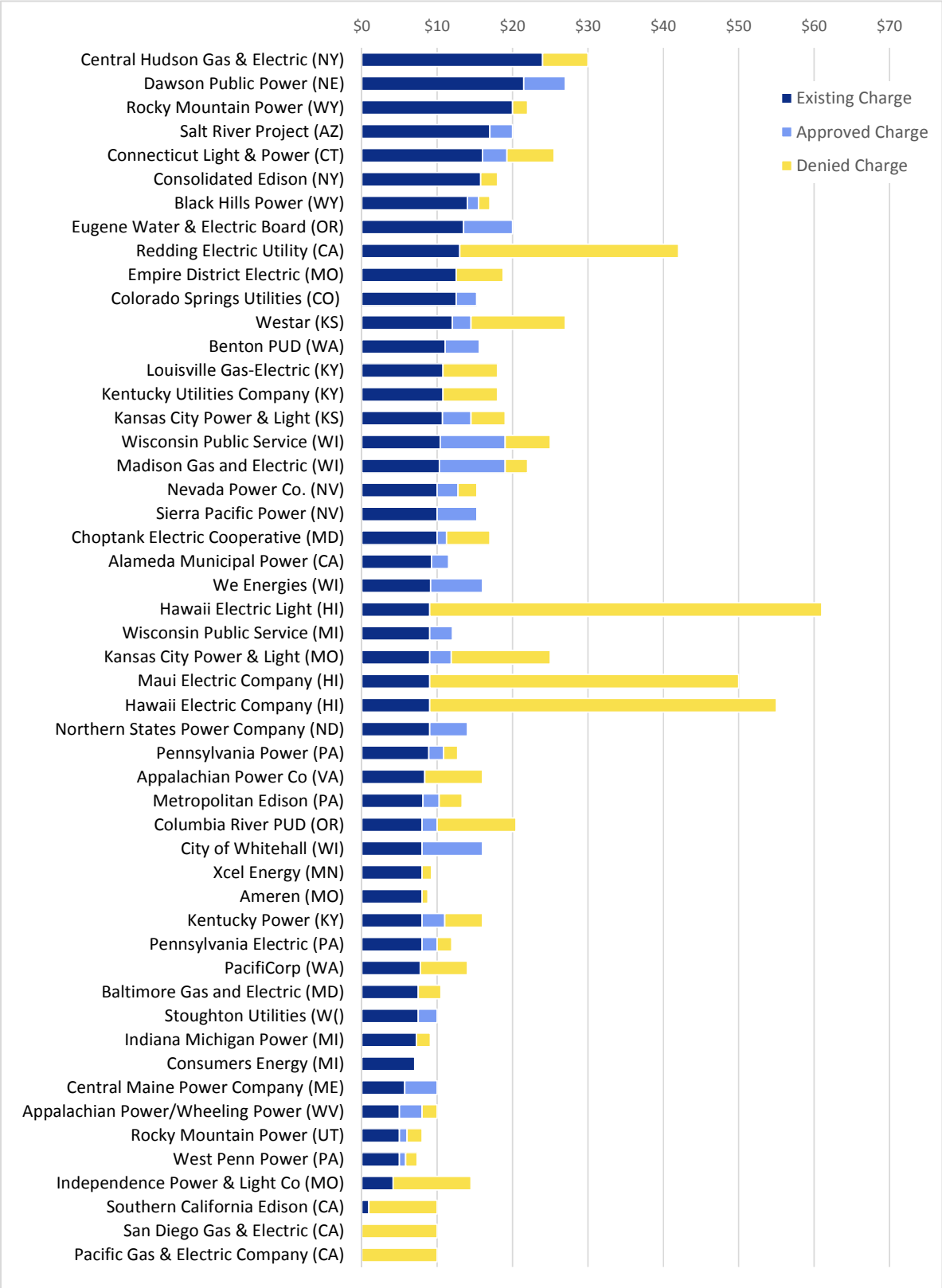
Figure 4. Recent decisions regarding fixed charge proposals



Notes: "Denied" includes settlements that did not increase the fixed charge. Source: See Appendix B

What is Behind the Trend Toward Higher Fixed Charges?

It is important to note that the question of whether to increase the fixed charge is a rate design decision. Rate design is not about how *much* total revenue a utility can collect; rather, rate design decisions determine *how* the utility can collect a set amount of revenue from customers. That is, once the amount of revenues that a utility can collect is determined by a commission, rate design determines the method for collecting that amount. However, if electricity sales deviate from the predicted level, a utility may actually collect more or less revenue than was intended.

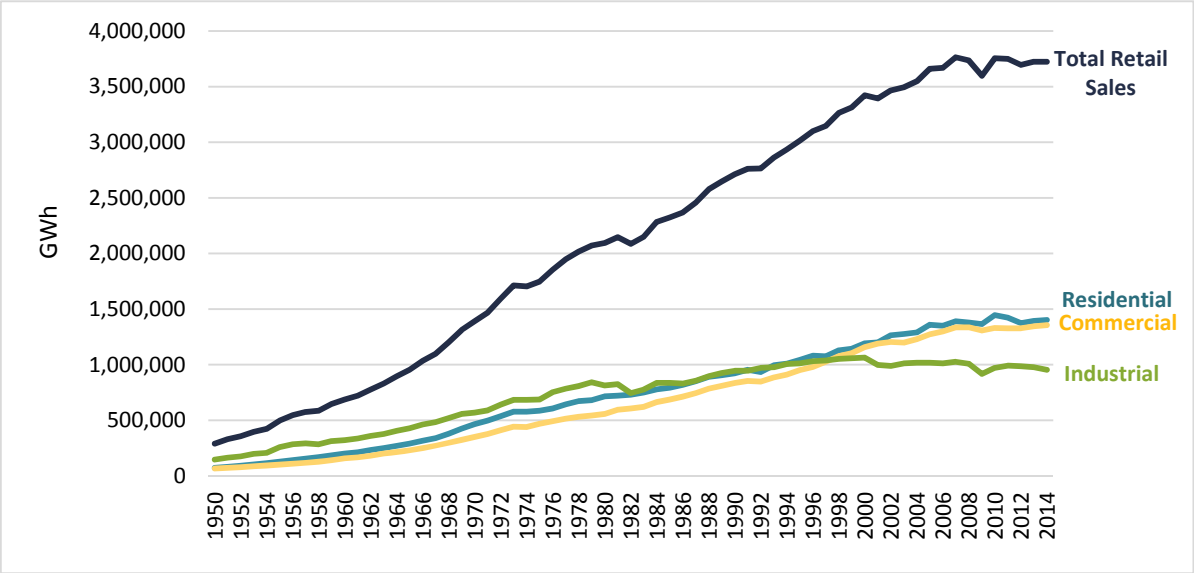
Rates are typically composed of some combination of the following three types of charges:

- Fixed charge: dollars per customer
- Energy charge: cents per kilowatt-hour (kWh) used
- Demand charge: dollars per kilowatt (kW) of maximum power used[12]

Utilities have a clear motivation for proposing higher fixed charges, as the more revenue that a utility can collect through a fixed monthly charge, the lower the risk of revenue under-recovery. Revenue certainty is an increasing concern for utilities across the country as sales stagnate or decline. According to the U.S. Energy Information Administration, electricity sales have essentially remained flat since 2005, as shown in Figure 5 below. This trend is the result of many factors, including greater numbers of customers adopting energy efficiency and distributed generation—such as rooftop solar—as well as larger economic trends. This trend toward flat sales is in striking contrast to the growth in sales that utilities have experienced since 1950, and has significant implications for utility cost recovery and ratemaking.

[12] Demand charges are typically applied only to medium to large commercial and industrial customers. However, some utilities are seeking to start applying demand charges to residential customers who install distributed generation.

Figure 5. Retail electricity sales by sector



Source: U.S. Energy Information Administration, September 2015 Monthly Energy Review, Table 7.6 Electricity End Use.

Reduced electricity consumption—whether due to customer conservation efforts, rooftop solar, or other factors—strikes at the very heart of the traditional utility business model, since much of a utility's revenue is tied directly to sales. As Kansas City Power and Light recently testified:

> From the Company perspective, reductions in usage, driven by reduced customer growth, energy efficiency, or even customer self-generation, result in under recovery of revenues. Growth would have compensated or completely covered this shortfall in the past. With the accelerating deployment of initiatives that directly impact customer growth, it is becoming increasingly difficult for the Company to accept this risk of immediate under recovery.[13]

At the same time that sales, and thus revenue growth, have slowed, utility costs have increased, as much utility infrastructure nears retirement age and needs replacement. The American Society of Civil Engineers estimates that $57 billion must be invested in electric distribution systems by 2020, and another $37 billion in transmission infrastructure.[14]

[13] Direct Testimony of Tim Rush, Kansas City Power & Light, Docket ER-2014-0370, October 2014, page 63.

[14] American Society of Civil Engineers, "2013 Report Card for America's Infrastructure: Energy," 2013, http://www.infrastructurereportcard.org.

3. How Fixed Charges Harm Customers

Reduced Customer Control

As technology advances, so too have the opportunities for customers to monitor and manage their electricity consumption. Many utilities are investing in smart meters, online information portals, and other programs and technologies in the name of customer empowerment. "We think customer empowerment and engagement are critical to the future of energy at Connecticut Light & Power and across the nation," noted the utility's director of customer relations and strategy.[15]

The fixed charge reduces customer control, as the only way to avoid the charge is to stop being a utility customer.

Despite these proclamations of support for customer empowerment and ratepayer-funded investments in demand-management tools, utilities' proposals for raising the fixed charge actually serve to disempower customers. Since customers must pay the fixed charge regardless of how much electricity they consume or generate, the fixed charge reduces the ability of customers to lower their bills by consuming less energy. Overall, the fixed charge reduces customer control, as the only way to avoid the fixed charge is to stop being a utility customer, an impossibility for most customers

Low-Usage Customers Hit Hardest

Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised, since bills will then be based less on usage and more on a flat-fee structure. There are many reasons why a customer might have low energy usage. Low-usage customers may have invested in energy-efficient appliances or installed solar panels, or they may have lower incomes and live in dense housing.

Figure 6 illustrates the impact of increasing the fixed charge for residential customers from $9.00 per month to $25.00 per month, with a corresponding decrease in the per-kilowatt-hour charge. Customers who consume 1,250 kilowatt-hours per month would see virtually no change in their monthly bill, while low-usage customers who consume only 250 kilowatt-hours per month would see their bill rise by nearly 40 percent. High usage customers (who tend to have higher incomes) would see a bill decrease. The data presented in the figure approximates the impact of Kansas City Power & Light's recently proposed rate design.[16]

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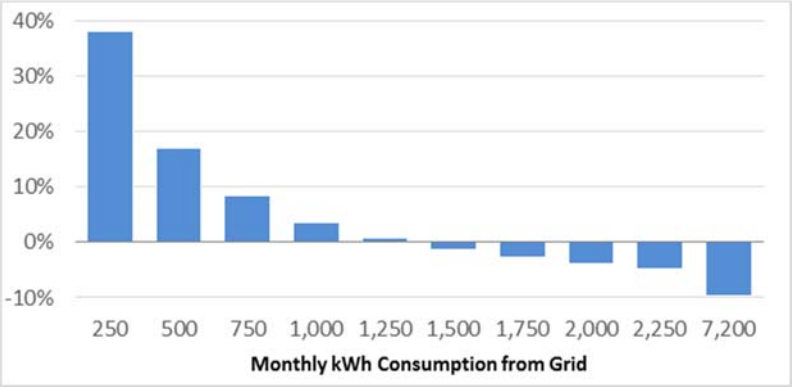
[15] Phil Carson, "Connecticut Light & Power Engages Customers," *Intelligent Utility*, July 1, 2011, http://www.intelligentutility.net/article/11/06/connecticut-light-power-engages-customers?quicktabs_4=2&quicktabs_11=1&quicktabs_6=1.

[16] Missouri Public Service Commission Docket ER-2014-0370.

Figure 6. Increase in average monthly bill

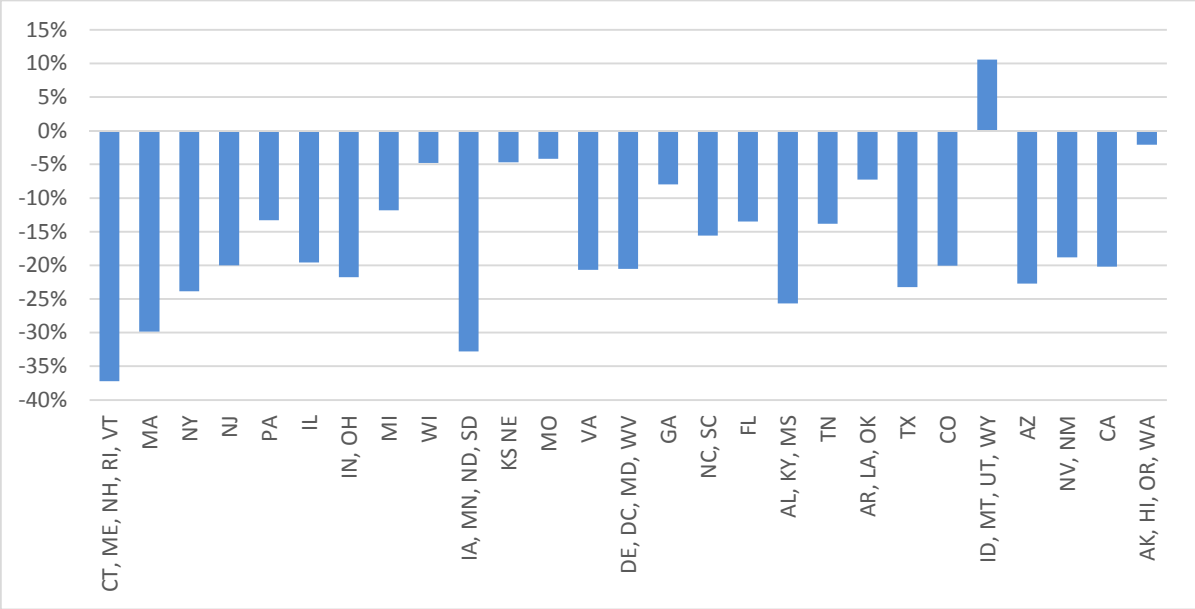


Analysis based on increasing the fixed charge from $9/month to $25/month, with a corresponding decrease in the $/kWh charge.

Disproportionate Impacts on Low-Income Customers

Low-income customers are disproportionately affected by increased fixed charges, as they tend to be low-usage customers. Figure 7 compares median electricity consumption for customers at or below 150 percent of the federal poverty line to electricity consumption for customers above that income level, based on geographic region. Using the median value provides an indication of the number of customers above or below each usage threshold—by definition, 50 percent of customers will have usage below the median value. As the graph shows, in nearly every region, most low-income customers consume less energy than the typical residential customer.

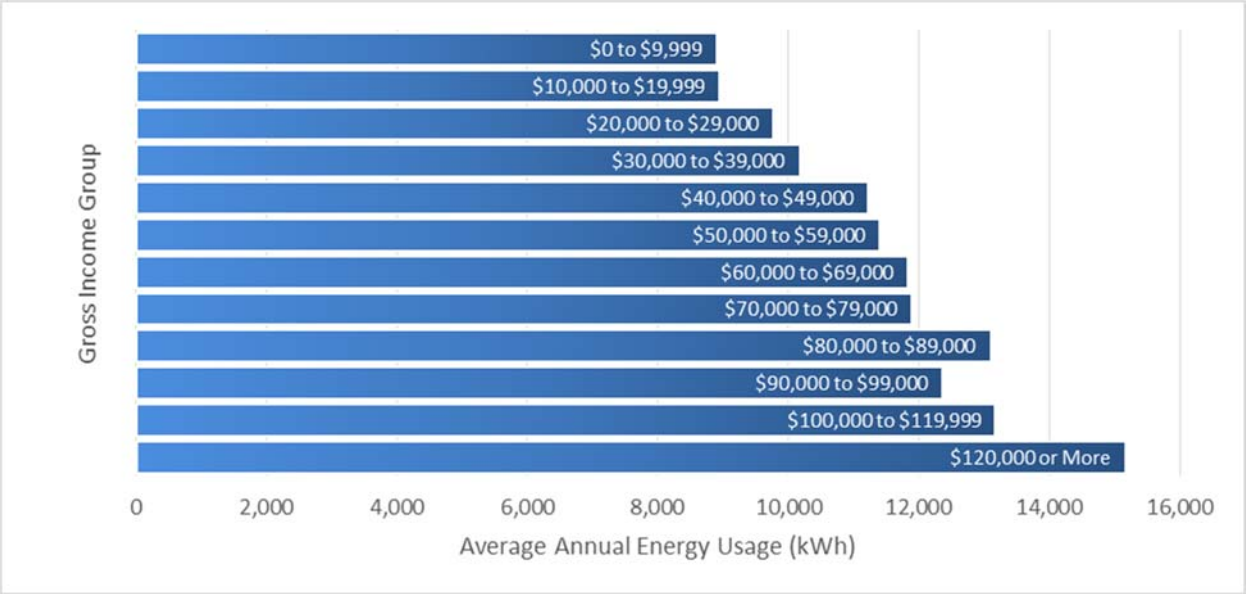
Figure 7. Difference between low-income median residential electricity usage and non-low-income usage



Source: Energy Information Administration Residential Energy Consumption Survey, 2009. http://www.eia.gov/consumption/residential/data/2009. Developed with assistance from John Howat, Senior Policy Analyst, NCLC.

The same relationship generally holds true for average usage. Nationwide, as gross income rises, so does average electricity consumption, generally speaking.

Figure 8. Nationwide average annual energy usage by income group



Source: Energy Information Administration Residential Energy Consumption Survey, 2009 http://www.eia.gov/consumption/residential/data/2009.

Because fixed charges tend to increase bills for low-usage customers while decreasing them for high-use customers, higher fixed charges tend to raise bills most for those who can least afford the increase. This shows that rate design has important equity implications, and must be considered carefully to avoid regressive impacts.

Reduced Incentives for Energy Efficiency and Distributed Generation

Energy efficiency and clean distributed generation are widely viewed as important tools for helping reduce energy costs, decrease greenhouse gas emissions, create jobs, and improve economic competitiveness. Currently, ratepayer-funded energy efficiency programs are operating in all 50 states and the District of Columbia.[17] These efficiency programs exist alongside numerous other government policies, including building codes and appliance standards, federal weatherization assistance, and tax incentives. Distributed generation (such as rooftop solar) is commonly supported through tax incentives and net energy metering programs that compensate customers who generate a portion of their own electricity.

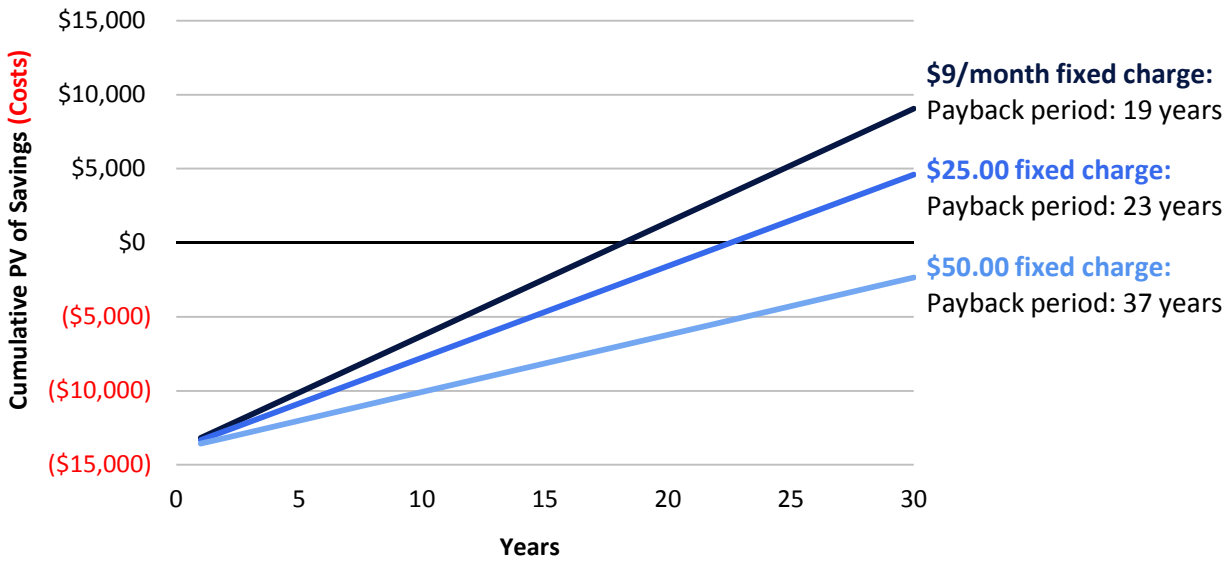
[17] Annie Gilleo et al., "The 2014 State Energy Efficiency Scorecard" (American Council for an Energy Efficient Economy, October 2014).

Increasing fixed charges can significantly reduce incentives for customers to reduce consumption through energy efficiency, distributed generation, or other means. By reducing the value of a kilowatt-hour saved or self-generated, a higher fixed charge directly reduces the incentive that customers have to lower their bills by reducing consumption. Customers who are considering making investments in energy efficiency measures or distributed generation will have longer payback periods over which to recoup their initial investment. In some cases, a customer might never break even financially when the fixed charge is increased. Increasing the fixed charge also penalizes customers who have already taken steps to reduce their energy consumption by implementing energy efficiency measures or installing distributed generation.

"When has it ever been the right of a company under any ethical business practices to penalize their customers for being efficient, conservative and environmentally responsible?"

Figure 9 illustrates how the payback period for rooftop solar can change under a net metering mechanism with different fixed charges. Under net metering arrangements, a customer can offset his or her monthly electricity usage by generating solar electricity—essentially being compensated for each kilowatt-hour produced. However, solar customers typically cannot avoid the fixed charge. For a fairly typical residential customer, raising the fixed charge from $9.00 per month to $25.00 per month could change the payback period for a 5 kW rooftop solar system from 19 years to 23 years – longer than the expected lifetime of the equipment. Increasing the fixed charge to $50.00 per month further exacerbates the situation, causing the project to not break even until 37 years in the future, and virtually guaranteeing that customers with distributed generation will face a significant financial loss.

Figure 9. Rooftop solar payback period under various customer charges



All three scenarios assume monthly consumption of 850 kWh. The $9.00 per month fixed charge assumes a corresponding energy charge of 10.36 cents per kWh, while the $25 fixed charge assumes an energy charge of 8.48 cents per kWh, and the $50 fixed charge assumes an energy charge of 5.54 cents per kWh.

In Connecticut, customers decried the proposed fixed charge as profoundly unfair: "When has it ever been the right of a company under any ethical business practices to penalize their customers for being efficient, conservative and environmentally responsible?" noted one frustrated customer. "Where is the incentive to spend hard-earned money to improve your appliances, or better insulate your home or more efficiently set your thermostats or air conditioning not to be wasteful, trying to conserve energy for the next generation - when you will allow the utility company to just turn around and now charge an additional fee to offset your savings?"[18]

High fixed charges may actually encourage customers to leave the system, leaving fewer and fewer customers to shoulder the costs of the electric system.

Increased Electricity System Costs

Because higher fixed charges reduce customer incentives to reduce consumption, they will undermine regulatory policies and programs that promote energy efficiency and clean distributed generation, leading to higher program costs, diminished results, or both. Rate design influences the effectiveness of these regulatory policies by changing the price signals that customers see. Holding all else equal, if the fixed charge is increased, the energy charge (cents per kilowatt-hour) will be reduced, thereby lowering the value of a kilowatt-hour conserved or generated by a customer.

The flip side of this is that customers may actually increase their energy consumption since they perceive the electricity to be cheaper. Under such a scenario, states will have to spend more funds on incentives to achieve the same level of energy efficiency savings and to encourage the same amount of distributed generation as achieved previously at a lower cost. Where electricity demand is not effectively reduced, utilities will eventually need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

In extreme cases, high fixed charges may actually encourage customers to leave the system. As rooftop solar and storage costs continue to fall, some customers may find it less expensive to generate all of their own electricity without relying on the utility at all. Once a customer departs the system, the total system costs must be redistributed among the remaining customers, raising electricity rates. These higher rates may then lead to more customers defecting, leaving fewer and fewer customers to shoulder the costs.

Where electricity demand is not effectively reduced, utilities will eventually need to invest in new power plants, power lines, and substations, thereby raising electricity costs for all customers.

The end result of having rate design compete with public policy incentives is that customers will pay more—either due to higher energy efficiency and distributed generation program costs, or through more investments needed to meet higher electricity demand. Meanwhile, customers who have already invested in energy efficiency or distributed generation will get burned by the reduced value of their investments and may choose to

[18] Written comment of Deborah Pocsay, Docket 14-05-06, July 30, 2014.

leave the grid, while low-income customers will experience higher bills, and all customers will have fewer options for reducing their electricity bills.

4. Rate Design Fundamentals

To understand utilities' desire to increase the fixed charge—and some of the arguments used to support or oppose these proposals—it is first necessary to review how rates are set.

Guiding Principles

Rates are designed to satisfy numerous objectives, some of which may be in competition with others. In his seminal work, *Principles of Public Utility Rates,* Professor James Bonbright enumerated ten guiding principles for rate design. These principles are reproduced in the appendix, and can be summarized as follows:

1. Sufficiency: Rates should be designed to yield revenues sufficient to recover utility costs.
2. Fairness: Rates should be designed so that costs are fairly apportioned among different customers, and "undue discrimination" in rate relationships is avoided.
3. Efficiency: Rates should provide efficient price signals and discourage wasteful usage.
4. Customer acceptability: Rates should be relatively stable, predictable, simple, and easily understandable.

Different parts of the rate design process address different principles. First, to determine sufficient revenues, the utility's revenue requirement is determined based on a test year (either future or historical). Second, a cost-of-service study divides the revenue requirement among all of the utility's customers according to the relative cost of serving each class of customers based on key factors such as the number of customers, class peak demand, and annual energy consumption. Third, marginal costs may be used to inform efficient pricing levels. Finally, rates are designed to ensure that they send efficient price signals, and are relatively stable, understandable, and simple.

Cost-of-Service Studies

Cost-of-service study results are often used when designing rates to determine how the revenue requirement should be allocated among customer classes. An *embedded* cost-of-service study generally begins with the revenue requirement and allocates these costs among customers. An embedded cost-of-service study is performed in three steps:

- First, costs are functionalized, meaning that they are defined based upon their function (e.g., production, distribution, transmission).
- Second, costs are classified as energy-related (which vary by the amount of energy a customer consumes), demand-related (which vary according to customers' maximum energy demand), or customer-related (which vary by the number of customers).

- Finally, these costs are allocated to the appropriate customer classes. Costs are allocated on the principle of "cost causation," where customers that cause costs to be incurred should be responsible for paying them. Unit costs (dollars per kilowatt-hour, per kilowatt of demand, or per customer-month) from the cost-of-service study can be used as a point of reference for rate design.

A *marginal* cost study differs from an embedded cost study in that it is forward-looking and analyzes how the costs of the electric system would change if demand increased. A marginal cost study is particularly useful for informing rate design, since according to economic theory, prices should be set equal to marginal cost to provide efficient price signals.

One of the challenges of rate design comes from the need to reconcile the differences between embedded and marginal cost-of-service studies. Rates need to meet the two goals of allowing utilities to recover their historical costs (as indicated in embedded cost studies), and providing customers with efficient price signals (as indicated in marginal cost studies).

It is worth noting that there are numerous different approaches to conducting cost-of-service studies, and thus different analysts can reach different results.[19] Some jurisdictions consider the results of multiple methodologies when setting rates.

Rate Design Basics

Most electricity customers are charged for electricity using a two-part or three-part tariff, depending on the customer class. Residential customers typically pay a monthly fixed charge (e.g., $9 per month) plus an energy charge based on usage (e.g., $0.10 per kilowatt-hour).[20] The fixed charge (or "customer charge") is generally designed to recover the costs to serve a customer that are largely independent of usage, such as metering and billing costs, while the energy charge reflects the cost to generate and deliver energy.

Commercial and industrial customers frequently pay for electricity based on a three-part tariff consisting of a fixed charge, an energy charge, and a demand charge, because they are large users and have meters capable of measuring demand as well as energy use. The demand charge is designed to reflect the maximum amount of energy a customer withdraws at any one time, often measured as the maximum demand (in kilowatts) during the billing month. While the fixed charge is still designed to recover customer costs that are largely independent of usage, the cost to deliver energy through the transmission and distribution system is recovered largely through the demand charge, while the energy charge primarily reflects fuel costs for electricity generation.

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[19] Commonly used cost-of-service study methods are described in the *Electric Utility Cost Allocation Manual*, published by the National Association of Regulatory Utility Commissioners.

[20] There are many variations of energy charge; the charge may change as consumption increases ("inclining block rates"), or based on the time of day ("time-of-use rates").

5. Common Arguments Supporting Higher Fixed Charges

"Most Utility Costs Are Fixed"

Argument

Utilities commonly argue that most of their costs are fixed, and that that the fixed charge is appropriate for recovering such "fixed" costs. For example, in its 2015 rate case, National Grid stated, "as the nature of these costs is fixed, the proper price signal for the recovery of these costs should also be fixed to the extent possible."[21]

Response

This argument conflates the accounting definition with the economic definition of fixed and variable costs.

- In accounting, fixed costs are those expenses that remain the same for a utility over the short and medium term regardless of the amount of energy its customers consume. In this sense of the term, fixed costs can include poles, wires, and power plants.[22] This definition contrasts with variable costs, which are the costs that are directly related to the amount of energy the customer uses and that rise or fall as the customer uses more or less energy.
- Economics generally takes a longer-term perspective, in which very few costs are fixed. This perspective focuses on efficient investment decisions over the planning horizon—perhaps a term of 10 or more years for an electric utility. Over this timeframe, most costs are variable.

Because utilities must recover the costs of the investments they have already made in electric infrastructure, they frequently employ the accounting definition of fixed costs and seek to ensure that revenues match costs. This focus is understandable. However, this approach fails to provide efficient price signals to customers. As noted above, it is widely accepted in economics that resource allocation is most efficient when all goods and services are priced at marginal cost. For efficient electricity investments to be made, the marginal cost must be based on the appropriate timeframe. In *Principles of Public Utility Rates*, James Bonbright writes:

> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant

[21] National Grid Pricing Panel testimony, Book 7 of 9, Docket No. D.P.U. 15-155, November 6, 2015, page 36.

[22] Many of these costs are also "sunk" in the sense that the utility cannot easily recover these investments once they have been made.

> marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.[23]

A fixed charge that includes long-run marginal costs provides no price signal relevant to resource allocation, since customers cannot reduce their consumption enough to avoid the charge. In contrast, an energy charge that reflects long-run marginal costs will encourage customers to consume electricity efficiently, thereby avoiding inefficient future utility investments.

"Fixed Costs Are Unavoidable"

Argument

By classifying some utility costs as "fixed," utilities are implying that these costs remain constant over time, regardless of customer energy consumption.

Response

Past utility capital investments are depreciated over time, and revenues collected through rates must be sufficient to eventually pay off these past investments. While these past capital investments are fixed in the sense that they cannot be avoided (that is, they are "sunk costs"), some future capital investments can be avoided if customers reduce their energy consumption and peak demands. Inevitably, the utility will have to make new capital investments; load growth may require new generating equipment to be constructed or distribution lines to be upgraded. Rate design has a role to play in sending appropriate price signals to guide customers' energy consumption and ensure that efficient future investments are made.

In short, utilities should not, and generally do not, make decisions based on sunk costs; rather, they make investment decisions on a forward-looking basis. Similarly, rate structures should be analyzed to some degree on a forward-going basis to ensure that customers are being sent the right price signals, as customer consumption will drive future utility investments.

"The Fixed Charge Should Recover Distribution Costs"

Argument

The electric distribution system is sized to deliver enough energy to meet the maximum demand placed on the system. As such, the costs of the distribution system are largely based on customer peak demands, which are measured in kilowatts. For this reason, large customers typically face a demand charge that is based on the customer's peak demand. Residential customers, however, typically do not have the metering capabilities required for demand charges, nor do they generally have the means to

[23] James Bonbright, Principles of Public Utility Rates (New York: Columbia University Press, 1961). P. 336.

monitor and reduce their peak demands. Residential demand-related costs have thus historically been recovered through the energy charge.

Where demand charges are not used, utilities often argue that these demand-related costs are better recovered through the fixed charge, as opposed to the energy charge. Similar to the arguments above, utilities often claim that the costs of the distribution system—poles, wires, transformers, substations, etc.— are "fixed" costs.[24]

Response

While the energy charge does not perfectly reflect demand-related costs imposed on the system, it is far superior to allocating demand-related costs to all residential customers equally through the fixed charge. Recent research has demonstrated that there exists "a strong and significant correlation between monthly kWh consumption and monthly maximum kW demand," which suggests that "it is correct to collect most of the demand-related capacity costs through the kWh energy charge."[25]

Not all distribution system costs can be neatly classified as "demand-related" or "customer-related," and there is significant gray area when determining how these costs are classified. In general, however, the fixed charge is designed to recover customer-related costs, not any distribution-system cost that does not perfectly fall within the boundaries of "demand-related" costs. Bonbright himself warned against misuse of the fixed charge, stating that a cost analyst is sometimes "under compelling pressure to 'fudge' his cost apportionments by using the category of customer costs as a dumping ground for costs that he cannot plausibly impute to any of his other categories."[26]

Where it is used at all, the customer (fixed) charge should be limited to only recovering costs that vary directly with the number of customers, such as the cost of the meter, service drop, and customer billing, as has traditionally been done.[27]

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[24] For example, in UE-140762, PacifiCorp witness Steward testifies that "Distribution costs (along with retail and miscellaneous) are fixed costs associated with the local facilities necessary to connect and serve individual customers. Accordingly, these costs should be recovered through the monthly basic charges and load size charges (which are based on demand measurements)." JRS-1T, p. 17. Another example is provided in National Grid's 2015 rate case application. The utility's testimony states: "the distribution system is sized and constructed to accommodate the maximum demand that occurs during periods of greatest demand, and, once constructed, distribution system costs are fixed in nature. In other words, reducing energy consumption does not result in a corresponding reduction in distribution costs. Therefore, as the nature of these costs is fixed, the proper price signal for the recovery of these costs should also be fixed to the extent possible." D.P.U. 15-155, Pricing Panel testimony, November 6, 2015, page 36.

[25] Larry Blank and Doug Gegax, "Residential Winners and Losers behind the Energy versus Customer Charge Debate," *Fortnightly* 27, no. 4 (May 2014).

[26] *Principles of Public Utility Rates*, Dr. James Bonbright, Columbia University Press, 1961, p. 349.

[27] Weston, 2000: "there is a broad agreement in the literature that distribution investment is causally related to peak demand" and not the number of customers; and "[t]raditionally, customer costs are those that are seen to vary with the number of customers on the system: service drops (the line from the distribution radial to the home or business), meters, and billing and collection." Pp. 28-29.

"Cost-of-Service Studies Should Dictate Rate Design"

Argument

Utilities sometimes argue that adherence to the principle of "cost-based rates" means that the unit costs identified in the cost-of-service study (i.e., dollars per kilowatt-hour, dollars per kilowatt, and dollars per customer) should be replicated in the rate design.

Response

The cost-of-service study can be used as a guide or benchmark when setting rates, but by itself it does not fully capture all of the considerations that should be taken into account when setting rates. This is particularly true if only an embedded cost-of-service study is conducted, rather than a marginal cost study. As noted above, embedded cost studies reflect only historical costs, rather than marginal costs. Under economic theory, prices should be set equal to marginal cost in order to provide an efficient price signal. Reliance on marginal cost studies does not fully resolve the issue, however, as marginal costs will seldom be sufficient to recover a utility's historical costs.

"I know of no ratemaking or economic principle that finds that cost structure must be replicated in rate design, especially when significant negative policy impacts are attendant to that approach."

Further, cost-of-service studies do not account for benefits that customers may be providing to the grid. In the past, customers primarily imposed costs on the grid by consuming energy. As distributed generation and storage become more common, however, customers are increasingly becoming "prosumers"—providing services to the grid as well as consuming energy. By focusing only on the cost side of the equation, cost-of-service studies generally fail to account for such services.

Cost-of-service study results are most useful when determining *how much* revenue to collect from different types of customers, rather than *how* to collect such revenue. Clearly, rates can be set to exactly mirror the unit costs revealed by the embedded cost-of-service study (dollars per customer, per kilowatt, or per kilowatt-hour), but other rate designs may yield approximately the same revenue while also accomplishing other policy objectives, particularly that of sending efficient price signals. Indeed, most products in the competitive marketplace—whether groceries, gasoline, or restaurant meals—are priced based solely on usage, rather than also charging a customer access fee and another fee based on maximum consumption.

This point was echoed recently by Karl Rabago, a former Texas utility commissioner: "I know of no ratemaking or economic principle that finds that cost structure must be replicated in rate design, especially when significant negative policy impacts are attendant to that approach."[28]

[28] Rabago direct testimony, NY Orange & Rockland Case 14-E-0493, p. 13.

As a final note, utility class cost of service studies are just that. They are performed by the utility and rely on numerous assumptions on how to allocate costs. Depending on the method and cost allocation chosen, results can vary dramatically, and represent one party's view of costs and allocation. Different studies can and do result in widely varying results. Policymakers should view with skepticism a utility claim that residential customers are not paying their fair share of costs based on such studies.

"Low-Usage Customers Are Not Paying Their Fair Share"

Argument

It is often claimed that a low fixed charge results in high-usage customers subsidizing low-usage customers.

Response

The reality is much more complicated. As noted above, distribution costs are largely driven by peak demands, which are highly correlated with energy usage. Thus, many low-usage customers impose lower demands on the system, and should therefore be responsible for a smaller portion of the distribution system costs. Furthermore, many low-usage customers live in multi-family housing or in dense neighborhoods, and therefore impose lower distribution costs on the utility system than high-usage customers.

"Fixed Charges Are Necessary to Mitigate Cost-Shifting Caused by Distributed Generation"

Argument

Several utilities have recently proposed that fixed customer charges should be increased to address the growth in distributed generation resources, particularly customer-sited photovoltaic (PV) resources. Utilities argue that customers who install distributed generation will not pay their "fair share" of costs, because they will provide much less revenue to the utility as a result of their decreased need to consume energy from the grid. This "lost revenue" must eventually be paid by other customers who do not install distributed generation, which will increase their electricity rates, causing costs to be shifted to them.

The utilities' proposed solution is to increase fixed charges—at least for the customers who install distributed generation, and often for all customers. The higher fixed charges are proposed to ensure that customers with distributed generation continue to pay sufficient revenues to the utility, despite their reduced need for external generation.

While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power.

OBM and Cholla Energy
Ex. 1034
Page 30 of 58

Response

Concerns about potential cost-shifting from distributed generation resources are often dramatically overstated. While it is true that a host distributed generation customer provides less revenue to the utility than it did prior to installing the distributed generation, it is also true that the host customer provides the utility with a source of very low-cost power. The power from the distributed generation resource allows the utility to avoid the costs of generating, transmitting, and distributing electricity from its power plants. These avoided costs will put downward pressure on electricity rates, which will dramatically reduce or completely offset the upward pressure on rates created by the reduced revenues from the host customer.

This is a critical element of distributed generation resources that often is not recognized or fully addressed in discussions about alternative ratemaking options such as higher fixed charges. Unlike all other electricity resources, distributed generation typically provides the electric utility system with generation that is nearly free of cost to the utility and to other customers. This is because, in most instances, host customers pay for the installation and operation of the distributed generation system, with little or no payment required from the utility or other customers.[29]

One of the most important and meaningful indicators of the cost-effectiveness of an electricity resource is the impact that it will have on utility revenue requirements. The present value of revenue requirements (PVRR) is used in integrated resource planning practices throughout the United States as the primary criterion for determining whether an electricity resource is cost-effective and should be included in future resource plans.

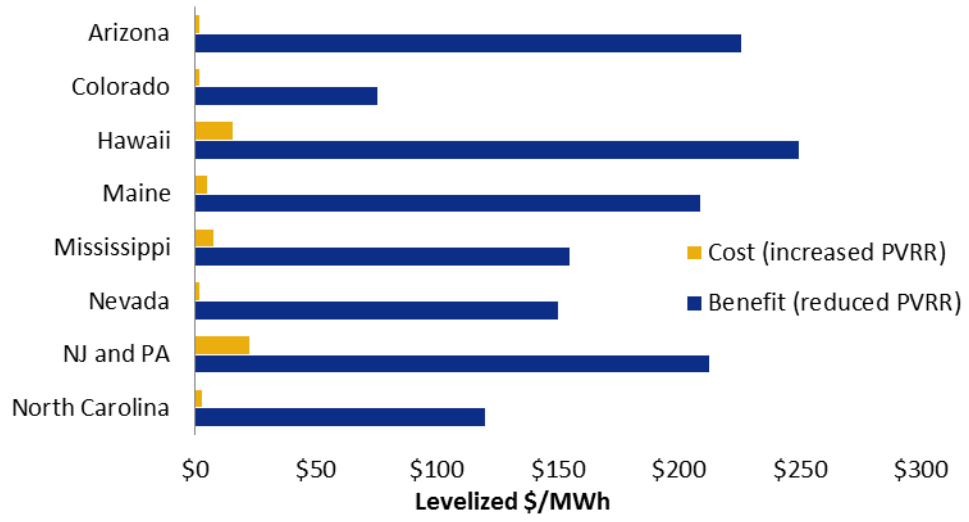
The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may even eliminate, any cost-shifting that might occur.

Several recent studies have shown that distributed generation resources are very cost-effective because they can significantly reduce revenue requirements by avoiding generation, transmission, and distribution costs, and only require a small increase in other utility expenditures. Figure 10 presents the benefits and costs of distributed generation according to six studies, where the benefits include all of the ways that distributed generation might reduce revenue requirements through avoided costs, and the costs include all of the ways that distributed generation might increase revenue requirements.[30] These costs typically include (a) the utility administrative costs of operating net energy metering programs, (b) the utility costs of interconnecting distributed generation technologies to the distribution grid, and (c) the utility costs of integrating intermittent distributed generation into the distribution grid.

[29] If a utility offers some form of an incentive to the host customer, such as a renewable energy credit, then this will represent an incremental cost imposed upon other customers. On the other hand, distributed generation customers provided with net energy metering practices do not require the utility or other customers to incur any new, incremental cost.

[30] Appendix C includes citations for these studies, along with notes on how the numbers in Figure 10 were derived.

Figure 10. Recent studies indicate the extent to which distributed generation benefits exceed costs



As indicated in the figure, all of these studies make the same general point: Distributed generation resources are very cost-effective in terms of reducing utility revenue requirements. In fact, they are generally more cost-effective than almost all other electricity resource options. The results presented in Figure 10 above indicate that distributed generation resources have benefit-cost ratios that range from 9:1 (New Jersey and Pennsylvania) to roughly 40:1 (Colorado, Maine, North Carolina) to as high as 113:1 (Arizona). These benefit-cost ratios are far higher than other electricity resource options, because the host customers typically pay for the cost of installing and operating the distributed generation resource.

Rate designs should be structured to encourage the development of very cost-effective resources, not to discourage them.

This point about distributed generation cost-effectiveness is absolutely essential for regulators and others to understand and acknowledge when making rate design decisions regarding distributed generation, for several reasons:

- The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may possibly even eliminate, any cost-shifting that might occur between distributed generation host customers and other customers.[31]
- When arguments about cost-shifting from distributed generation resources are used to justify increased fixed charges, it is important to assess and consider the likely magnitude of cost-shifting in light of the benefits offered by distributed generation. It is quite possible that any cost-shifting is *de minimis*, or non-existent.
- The net benefits of distributed generation should be considered as an important factor in making rate design decisions. Rate designs should be structured to encourage the

[31] This may not hold at very high levels of penetration, as integration costs increase once distributed generation levels hit a certain threshold. However, the vast majority of utilities in the United States have not yet reached such levels.

development of very cost-effective resources; they should not be designed to discourage them.

Again, policy makers should proceed with caution on claims regarding cost shifting. Where cost shifting is analyzed properly and found to be a legitimate concern, it can be addressed through alternative mechanisms that apply to DG customers, rather than upending the entire residential rate design in ways that can negatively affect all customers.

6. Recent Commission Decisions on Fixed Charges

Commission Decisions Rejecting Fixed Charges

Commissions in many states have largely rejected utility proposals to increase the fixed charge, citing a variety of reasons, including rate shock to customers and the potential to undermine state policy goals. Below are several reasons that commissions have given for rejecting such proposals.

Customer Control

In 2015, the Missouri Public Service Commission rejected Ameren's request to increase the residential customer charge, stating:

> The Commission must also consider the public policy implications of changing the existing customer charges. There are strong public policy considerations in favor of not increasing the customer charges. Residential customers should have as much control over the amount of their bills as possible so that they can reduce their monthly expenses by using less power, either for economic reasons or because of a general desire to conserve energy. Leaving the monthly charge where it is gives the customer more control.[32]

Energy Efficiency, Affordability, and Other Policy Goals

The Minnesota Public Utilities Commission recently ruled against a relatively small increase in the fixed charge (from $8.00 to $9.25), citing affordability and energy conservation goals, as well as revenue regulation (decoupling) as a protection against utility under-recovery of revenues:

> In setting rates, the Commission must consider both ability to pay and the need to encourage energy conservation. The Commission must balance these factors against the requirement that the rates set not be "unreasonably preferential, unreasonably prejudicial, or discriminatory" and the utility's need for revenue sufficient to enable it to provide service.
>
> The Commission concludes that raising the Residential and Small General Service customer charges… would give too much weight to the fixed customer cost calculated in Xcel's class-cost-of-service study and not enough weight to affordability and energy conservation. … The Commission concurs with the OAG that this circumstance highlights the need for caution in making any decision that would further burden low-income, low-usage customers, who are unable to absorb or avoid the increased cost.

[32] Missouri Public Service Commission Report and Order, File No. ER-2014-0258, In the Matter of Union Electric Company, d/b/a Ameren Missouri's Tariff to Increase Revenues for Electric Service, April 29, 2015, pages 76-77.

> The Commission also concludes that a customer-charge increase for these classes would place too little emphasis on the need to set rates to encourage conservation. This is particularly true where the Commission has approved a revenue decoupling mechanism that will largely eliminate the relationship between Xcel's sales and the revenues it earns. As several parties have argued, decoupling removes the need to increase customer charges to ensure revenue stability.[33]

Similarly, in March of 2015, the Washington Utilities and Transportation Commission rejected an increase in the fixed charge based on concerns regarding affordability and conservation signals. The commission also reaffirmed that the fixed charge should only reflect costs directly related to the number of customers:

> We reject the Company's and Staff's proposals to increase significantly the basic charge to residential customers. The Commission is not prepared to move away from the long-accepted principle that basic charges should reflect only "direct customer costs" such as meter reading and billing. Including distribution costs in the basic charge and increasing it 81 percent, as the Company proposes in this case, does not promote, and may be antithetical to, the realization of conservation goals.[34]

In 2012, the Missouri Public Service Commission rejected Ameren Missouri's proposed increase in the customer charge for residential and small general service classes, writing:

> Shifting customer costs from variable volumetric rates, which a customer can reduce through energy efficiency efforts, to fixed customer charges, that cannot be reduced through energy efficiency efforts, will tend to reduce a customer's incentive to save electricity. Admittedly, the effect on payback periods associated with energy efficiency efforts would be small, but increasing customer charges at this time would send exactly [the] wrong message to customers that both the company and the Commission are encouraging to increase efforts to conserve electricity.[35]

In 2013, the Maryland Public Service Commission rejected a small increase in the customer charge, noting that such an increase would reduce customers' control of their bills and would be inconsistent with the state's policy goals.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the

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[33] Minnesota Public Utilities Commission, In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Electric Service in the State of Minnesota; Findings of Fact, Conclusions, and Order; Docket No. E-002/GR-13-868, May 8, 2015, p. 88.

[34] Washington Utilities and Transportation Commission, Final Order Rejecting Tariff Sheets, Resolving Contested Issues, Authorizing And Requiring Compliance Filings; Docket UE-140762, March 25, 2015, p. 91.

[35] Missouri Public Service Commission, Report and Order, In the Matter of Union Electric Company Tariff to Increase Its Annual Revenues for Electric Service, File No. ER-2012-0166, December 12, 2012, pages 110-111.

reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[36]

Commission Decisions Approving Higher Fixed Charges

Higher fixed charges have been rejected in numerous cases, but not all. In many cases, a small increase in the fixed charge has been approved through multi-party settlements, rather than addressed by the commission. Where commissions have specifically approved fixed charge increases, they often cite some of the flawed arguments that are addressed in Chapter 5 above. Below we provide some examples and briefly describe the commission's rationale.

Fixed Charges and Recovery of Distribution System Costs

Over the past few years, Wisconsin has approved some of the highest fixed charges in the country, based on the rationale that doing so will "prevent intra-class subsidies… provide appropriate price signals to ratepayers, and encourage efficient utility scale planning…."[37] This rationale is largely based on two misconceptions: (1) that short-run marginal costs provide an efficient price signal to ratepayers and will encourage efficient electric resource planning, and (2) that recovering certain distribution system costs through the fixed charge is more appropriate than recovering them through the energy charge.[38]

As discussed above, a rate design that fails to reflect long-run marginal costs will result in inefficient price signals to customers and ultimately result in the need to make more electric system investments to support growing demand than would otherwise be the case. Not only will growing demand result in the need for additional generation capacity, it may cause distribution system components to wear out faster, or to be replaced with larger components. Wrapping such costs up in the fixed charge sends the signal to customers that these costs are unavoidable, when in fact future investment decisions are in part determined by the level of system use.

Further, using the fixed charge to recover distribution system costs that cannot be readily classified as "demand-related" or "customer-related" exemplifies the danger that Bonbright warned of regarding using the category of customer costs as a "dumping ground" for costs that do not fit in the other

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[36] In The Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates. Maryland Public Service Commission. Case No. 9299. Order No. 85374, Issued February 22, 2013, p. 99, provided in Schedule TW-4.

[37] Docket 3270-UR-120, Order at 48.

38 For example, Wisconsin Public Service Corporation argued that the fixed charge should include a portion of the secondary distribution lines, line transformers, and the primary feeder system of poles, conduit and conductors, rather than only the customer-related costs.

categories. Use of the fixed charge for recovery of such costs tends to harm low-income customers, as well as distort efficient price signals.

Despite generally approving significantly higher fixed charges in recent years, in a December 2015 order the Wisconsin Public Service Commission approved only a slight increase in the fixed charge and signaled its interest in evaluating the impacts of higher fixed charges to ensure that the Commission's policy goals are being met. Specifically, the Commission directed one of its utilities to work with commission staff to conduct a study to assess the impacts of the higher fixed charges on customer energy use and other behavior.[39] This order indicates that perhaps the policy may be in need of further study.

Demand Costs Not Appropriate for Energy Charge

In approving Sierra Pacific Power's request for a higher fixed charge, the Nevada Public Service Commission wrote:

> If costs that do not vary with energy usage are recovered in the energy rate component, cost recovery is inequitably shifted away from customers whose energy usage is lower than average within their class, to customers whose energy usage is higher than average within that class. This is not just and reasonable.[40]

Despite declaring that demand-related costs are inappropriately recovered in the energy charge, the commission makes no argument for why the fixed charge is a more appropriate mechanism for recovering such costs. Nor does the commission recognize that customer demand (kW) and energy usage (kWh) are likely correlated, or that recovering demand-related costs in the fixed charge may introduce even greater cross-subsidies among customers.

Settlements

Many of the recent proceedings regarding fixed charges have ended in a settlement agreement. Several of these settlements have resulted in the intervening parties, including the utility, agreeing to make no change to the customer charge or fixed charge. For example, Kentucky Utilities and Louisville Gas & Electric requested a 67 percent increase in the fixed charge, from $10.75 to $18.00 per month. The case ultimately settled, with neither utility receiving an increase in the monthly fixed charge.[41] While

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[39] Wisconsin Public Service Commission, Docket 6690-UR-124, *Application of Wisconsin Public Service Corporation for Authority to Adjust Electric and Natural Gas Rates*, Final Decision, December 17, 2015.

[40] Nevada Public Service Commission, Docket 13-06002, *Application of Sierra Pacific Power Company d/b/a NV Energy for Authority to Adjust its Annual Revenue Requirement for General Rates Charged to All Classes of Electric Customers and for Relief Properly Related Thereto*, Modified Final Order, January 29, 2014, Page 176.

[41] Kentucky Public Service Commission Order, Case No. 2014-00372, *In the Matter of Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, page 4; Kentucky Public Service Commission Order, Case No. 2014-00371, *In the Matter of Application of Kentucky Utility Company for an Adjustment of Its Electric and Gas Rates*, page 4.

settlements seldom explicitly state the rationale behind such decisions, it is safe to expect that many of the settling parties echo the concerns stated by the Commissions above.

In conclusion, the push to significantly increase the fixed charge has largely been rejected by regulators across the country as unnecessary and poor public policy. Nevertheless, utilities continue to propose higher fixed charges, as any increase in the fixed charge helps to protect the utility from lower revenues associated with reduced sales, whether due to energy efficiency, distributed generation, or any other reason. In addition, in late 2015, it appeared that some utilities were beginning to propose new demand charges for residential customers instead of increased fixed charges.

7. ALTERNATIVES TO FIXED CHARGES

Utilities are turning to higher fixed charges in an effort to slow the decline of revenues between rate cases, since revenue collected through the fixed charge is not affected by reduced sales. In the past, costs were relatively stable and sales between rate cases typically provided utilities with adequate revenue, but this is not necessarily the case anymore. The current environment of flat or declining sales growth, coupled with the need for additional infrastructure investments, can pose financial challenges for a utility and cause it to apply for rate cases more frequently.

Higher fixed charges are an understandable reaction to these trends, but they are an ill-advised remedy, due to the adverse impacts described above. Alternative rate designs exist that can help to address utility revenue sufficiency and volatility concerns, as discussed below. Furthermore, in many cases, utilities are reacting to perceived or future threats, rather than to a pressing current revenue deficiency. Simply stated, there is no need to increase the fixed charge.

Rate Design Options

Numerous rate design alternatives to higher fixed charges are available under traditional cost-of-service ratemaking. Below we discuss several of these options, and describe some of the key advantages and disadvantages of each. No prioritization of the options is implied, as rate design decisions should be made to address the unique circumstances of a particular jurisdiction. For example, the rate design adopted in Hawaii, where approximately 15 percent of residential customers on Oahu have rooftop solar,[42] may not be appropriate for a utility in Michigan.

[42] As of the third quarter of 2015, nearly 40,000 customers on Oahu were enrolled in the Hawaiian Electric Company's net metering program, as reported by HECO on its website: http://www.hawaiianelectric.com/heco/_hidden_Hidden/Community/Renewable-Energy?cpsextcurrchannel=1#05

Status Quo

One option is to simply maintain the current level of fixed charges and allow utilities to file frequent rate cases, if needed. This option is likely to be most appropriate where a utility is not yet facing any significant earnings shortfall, but is instead seeking to preempt what it views as a future threat to its earnings.

By maintaining the current rate structure rather than changing it prematurely, this option allows the extent of the problem to be more accurately assessed, and the remedy appropriately tailored to address the problem. Maintaining the current rate structure clearly also avoids the negative impacts on ratepayers and clean energy goals that higher fixed charges would have, as discussed in detail above.

However, maintaining the status quo may have detrimental impacts on both ratepayers and the utility if the utility is truly at risk of significant revenue under-recovery.[43] Where a utility cannot collect sufficient revenues, it may forego necessary investments in maintaining the electric grid or providing customer service, with potential long-term negative consequences.

In addition, the utility may file frequent rate cases in order to reset rates, which can be costly. Rate cases generally require numerous specialized consultants and lawyers to review the utility's expenditures and investments in great detail, and can drag on for months, resulting in millions of dollars in costs that could eventually be passed on to customers. Because of this cost, a utility is unlikely to file a rate case unless it believes that significantly higher revenues are likely to be approved.

Finally, chronic revenue under-recovery can worry investors, who might require a higher interest rate in order to lend funds to the utility. Since utilities must raise significant financial capital to fund their investments, a higher interest rate could ultimately lead to higher costs for customers. However, such chronic under-recovery is unlikely for most utilities, and this risk should be assessed alongside the risks of overcharging ratepayers and discouraging efficiency.

Minimum Bills

Minimum bills are similar to fixed charges, but with one important distinction: minimum bills only apply when a customer's usage is so low that his or her total monthly bill would otherwise be less than this minimum amount. For example, if the minimum bill were set at $40, and the only other charge was the energy charge of $0.10 per kWh, then the minimum bill would only apply to customers using less than 400 kWh, who would otherwise experience a bill less than $40. Given that the national average residential electricity usage is approximately 900 kWh per month, the minimum bill would have no effect on most residential customers.

[43] Of course, the claim that the utility is at risk of substantially under-recovering its revenue requirement should be thoroughly investigated before any action is taken.

A key advantage claimed by proponents to the minimum bill is that it guarantees that the utility will recover a certain amount of revenue from each customer, without significantly distorting price signals for the majority of customers. The threshold that triggers the minimum bill is typically set well below the average electricity usage level, and thus most customers will not be assessed a minimum bill but will instead only see the energy charge (cents per kilowatt-hour). Minimum bills also have the advantage of being relatively simple and easy to understand.

Minimum bills may be useful where there are many customers that have low usage, but actually impose substantial costs on the system. For example, this could include large vacation homes that have high usage during the peak summer hours that drive most demand-related costs, but sit vacant the remainder of the year. Unfortunately, minimum bills do not distinguish these types of customers from those who have reduced their peak demand (for example through investing in energy efficiency or distributed generation), and who thereby impose lower costs on the system.[44] Further, minimum bills may also have negative financial impacts on low-income customers whose usage falls below the threshold. For these reasons, minimum bills are superior to fixed charges, but they still operate as a relatively blunt instrument for balancing ratepayer and utility interests. Further, utilities will have an incentive to push for higher and higher minimum bill levels.

To illustrate the impacts of minimum bills, consider three rate options: (1) an "original" residential rate structure with a fixed charge of $9 per month; (2) a minimum bill option, which keeps the $9 fixed charge but adds a minimum bill of $40; and (3) an increase in the fixed charge to $25 per month. In all cases, the energy charge is adjusted to ensure that the three rate structures produce the same amount of total revenues. The figure below illustrates how moving from the "original" rate structure to either a minimum bill or increased fixed charge option would impact different customers.

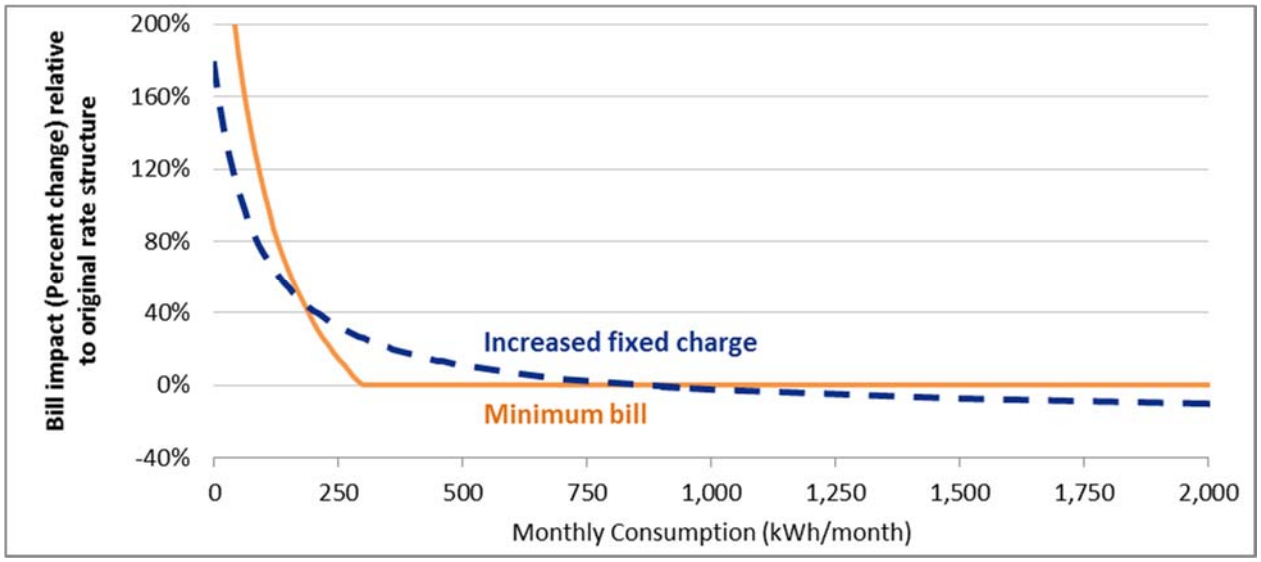
Under the minimum bill option, only customers with usage less than 280 kWh per month (approximately 5 percent of customers at a representative Midwestern utility) would see a change in their bills, and most of these customers would see an increase in their monthly bill of less than $10.

In contrast, under the $25 fixed charge, all customers using less than approximately 875 kWh per month (about half of residential customers) would see an increase in their electric bills, while customers using more than 875 kWh per month would see a *decrease* in their electric bills.

[44] In the short run, there is likely to be little difference in the infrastructure investments required to serve customers with high peak demands and those with low peak demands. However, in the long run, customers with higher peak demands will drive additional investments in generation, transmission, and distribution, thereby imposing greater costs on the system. A theoretically efficient price signal would reflect these different marginal costs in some manner in order to encourage customers to reduce the long-run costs they impose on the system.

Figure 11. Impact of minimum bill relative to an increased fixed charge

Rate Structure	Energy Charge	Fixed charge	Minimum bill
Typical rate structure	10.36 cents / kWh	$9 / Month	$0 / Month
Minimum bill	10.34 cents / kWh	$9 / Month	$40 / Month
Increased fixed charge	8.48 cents / kWh	$25 / Month	$0 / Month



Source: Author's calculations based on data from a representative Midwestern utility.

Time-of-Use Rates

Electricity costs can vary significantly over the course of the day as demand rises and falls, and more expensive power plants must come online to meet load.[45] Time-of-use (TOU) rates are a form of time-varying rate, under which electricity prices vary during the day according to a set schedule, which is designed to roughly represent the costs of providing electricity during different hours. A simple TOU rate would have separate rates for peak and off-peak periods, but intermediate periods may also have their own rates.

Time-varying rate structures can benefit ratepayers and society in general by improving economic efficiency and equity. Properly designed TOU rates can improve economic efficiency by:

1. Encouraging ratepayers to reduce their bills by shifting usage from peak periods to off-peak periods, thereby better aligning the consumption of electricity with the value a customer places on it;

2. Avoiding capacity investments and reducing generation from the most expensive peaking plants; and

[45] Electricity costs also vary by season and weekday/weekend.

3. Providing appropriate price signals for customer investment in distributed energy resources that best match system needs.

Time-varying rates are also capable of improving equity by better allocating the costs of electricity production during peak periods to those causing the costs.

Despite their advantages, TOU rates are not a silver bullet and may be inappropriate in the residential rate class. They may not always be easily understood or accepted by residential customers. TOU rates also require specialized metering equipment, which not all customers have. In particular, the adoption of advanced metering infrastructure (AMI) may impose significant costs on the system.[46] Residential consumers often do not have the time, interest or knowledge to manage variable energy rates efficiently, so TOU blocks must be few and well-defined and still may not elicit desired results. Designing TOU rates correctly can be difficult, and could penalize vulnerable customers requiring electricity during extreme temperatures. Some consumer groups (such as AARP) urge any such rates be voluntary. Finally, even well-designed TOU rates may not fully resolve a utility's revenue sufficiency concerns.

Value of Solar Tariffs

Value of solar tariffs pay distributed solar generation based on the value that the solar generation provides to the utility system (based on avoided costs). Value of solar tariffs have been approved as an alternative to net metering in Minnesota and in Austin, Texas. In both places, a third-party consultant conducted an avoided cost study (value of solar study) to determine the value of the avoided costs of energy, capacity, line losses, transmission and distribution.

Value of solar tariffs are useful in that they more accurately reflect cost causation, thereby improving fairness among customers. They also maintain efficient price signals that discourage wasteful use of energy, and improve revenue recovery and stability.

However, value of solar tariffs are not easily designed, as there is a lack of consensus on the elements that should be incorporated, how to measure difficult-to-quantify values, and even how to structure the tariff. Value of solar rates are also not necessarily stable, since value-of-solar tariff rates are typically adjusted periodically. However, there is no reason that the tariff couldn't be affixed for a set time period, like many long-term power purchase agreements.

Alternatively, if the value of solar is determined to be less than the retail price of energy, a rider or other charge could be implemented to ensure that solar customers pay their fair share of costs. Regardless of the type of charge or compensation mechanism chosen, a full independent, third-party analysis of the costs and benefits of distributed generation should be conducted prior to making any changes to rates.

[46] AMI also allows remote disconnections and prepaid service options, both of which can disadvantage low-income customers. See, for example, Howat, J. *Rethinking Prepaid Utility Service: Customers at Risk.* National Consumer Law Center, June 2012.

Demand Charges

Generation, transmission, and distribution facilities are generally sized according to peak demands—either the local peak or the system peak. The peak demands are driven by the consumption levels of all electricity customers combined. Demand charges are designed to recover demand-related costs by charging electricity customers on the basis of maximum power demand (in terms of dollars per kilowatt), instead of energy (in terms of dollars per kilowatt-hour).

Designing rates to collect demand-related costs through demand charges may improve a utility's revenue recovery and stability. Proponents claim that such rates may also help send price signals that encourage customers to take steps to reduce their peak load. These charges have been in use for many years for commercial and industrial customers, but have rarely been implemented for residential customers.

Demand charges have several important shortcomings that limit how appropriate they might be for residential customers. First, demand charges remain relatively untested on the residential class. There is little evidence thus far that demand charges are well-understood by residential customers; instead, they would likely lead to customer confusion. This is particularly true for residential customers, who may be unaware of when their peak usage occurs and therefore have little ability or incentive to reduce their peak demand.

Second, depending on how they are set, demand charges may not accurately reflect cost causation. A large proportion of system costs are driven by system-wide peak demand, but the demand charge is often based on the customer's maximum demand (not the utility's). Thus demand charges do not provide an incentive for customers to reduce demand during the utility system peak in the way that time of use rates do. Theoretically, demand charges based on a customer's maximum demand could help reduce local peak demand, and therefore reduce some local distribution system costs. However, at the residential level, it is common for multiple customers to share a single piece of distribution system equipment, such as a transformer. Since a customer's maximum demand is typically triggered by a short period of time in which that customer is using numerous household appliances, it is unlikely that this specific time period coincides exactly when other customers sharing the same transformer are experiencing their maximum demands. This averaging out over multiple customers means that a single residential customer's maximum demand is not likely to drive the sizing of a particular piece of distribution-system equipment. For this reason, demand charges for the residential class are not likely to accurately reflect either system or local distribution costs.

Third, few options currently exist for residential customers to automatically monitor and manage their maximum demands. Since customer maximum monthly demand is often measured over a short interval of time (e.g., 15 minutes), a single busy morning where the toaster, microwave, hairdryer, and clothes dryer all happen to be operating at the same time for a brief period could send a customer's bill skyrocketing. This puts customers at risk for significant bill volatility. Unless technologies are implemented to help customers manage their maximum demands, demand charges should not be used.

Fourth, demand charges are not appropriate for some types of distributed generation resources. Some utilities have proposed that demand charges be applied to customers who install PV systems under net energy metering policies. This proposal is based on the grounds that demand charges will provide PV customers with more accurate price signals regarding their peak demands, which might be significantly different with customer-sited PV. However, a demand charge is not appropriate in this circumstance, because PV resources do not provide the host customer with any more ability to control or moderate peak demands than any other customer. A PV resource might shift a customer's maximum demand to a different hour, but it might do little to reduce the maximum demand if it occurs at a time when the PV resource is not operating much (because the maximum demand occurs either outside of daylight hours, or on a cloudy day when PV output is low).

Fifth, demand charges may require that utilities invest in expensive metering infrastructure and in-home devices that communicate information to customers regarding their maximum demands. The benefits of implementing a customer demand charge may not outweigh the costs of such investments.

In sum, most residential customers are very unlikely to respond to demand charges in a way that actually reduces peak demand, either because they do not have sufficient information, they do not have the correct price signal, they do not have the technologies available to moderate demand, or the technologies that they do have (such as PV) are not controllable by the customer in a way that allows them to manage their demand. In those instances where customers cannot or do not respond to demand charges, these charges suffer from all of the same problems of fixed charges: they reduce incentives to install energy efficiency or distributed generation; they pose an unfair burden on low-usage customers; they provide an inefficient price signal regarding long-term electricity costs; and they can eventually result in higher costs for all customers. For these reasons, demand charges are rarely implemented for residential customers, and where they have been implemented, it has only been on a voluntary basis.

8. CONCLUSIONS

In this era of rapid advancement in energy technologies and broad-based efforts to empower customers, mandatory fixed charges represent a step backward. Whether a utility is proposing to increase the fixed charge due to a significant decline in electricity sales or as a preemptive measure, higher fixed charges are an inequitable and economically inefficient means of addressing utility revenue concerns. In some cases, regulators and other stakeholders have been persuaded by common myths that inaccurately portray an increased fixed charge as the necessary solution to current challenges facing the utility industry. While they may be desirable for utilities, higher fixed charges are far from optimal for society as a whole.

Fortunately, there are many rate design alternatives that address utility concerns about declining revenues from lower sales without causing the regressive results and inefficient price signals associated with fixed charges. Recent utility commission decisions rejecting proposals for increased fixed charges suggest that there is a growing understanding of the many problems associated with fixed charges, and that alternatives do exist. As this awareness spreads, it will help the electricity system continue its progression toward greater efficiency and equity.

APPENDIX A – BONBRIGHT'S PRINCIPLES OF RATE DESIGN

In his seminal work, *Principles of Public Utility Rates*, Professor James Bonbright discusses eight key criteria for a sound rate structure. These criteria are:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the appointment of total costs of service among the different customers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).[47]

[47] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

APPENDIX B – RECENT PROCEEDINGS ADDRESSING FIXED CHARGES

The tables below present data on recent utility proposals or finalized proceedings regarding fixed charges based on research conducted by Synapse Energy Economics. These cases were generally opened or decided between September 2014 and November 2015.

Table 1. List of finalized utility proceedings to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Alameda Municipal Power (CA)	AMP Board vote June 2015	$9.25	$11.50	$11.50	
Ameren (MO)	File No. ER - 2012-0166 Tariff No. YE-2014-0258	$8.00	$8.77	$8.00	Company initially proposed $12.00. Settling parties agreed to $8.77. Commission order rejected any increase, citing customer control
Appalachian Power Co (VA)	PUE-2014-00026	$8.35	$16.00	$8.35	
Appalachian Power/Wheeling Power (WV)	14-1152-E-42T	$5.00	$10.00	$8.00	
Baltimore Gas and Electric (MD)	9355, Order No. 86757	$7.50	$10.50	$7.50	Settlement based on Utility Law Judge
Benton PUD (WA)	Board approved in June 2015	$11.05	$15.60	$15.60	
Black Hills Power (WY)	20002-91-ER-14 (Record No. 13788)	$14.00	$17.00	$15.50	
Central Hudson Gas & Electric (NY)	14-E-0318	$24.00	$29.00	$24.00	
Central Maine Power Company (ME)	2013-00168	$5.71	$10.00	$10.00	Decoupling implemented as well
City of Whitehall (WI)	6490-ER-106	$8.00	$16.00	$16.00	
Columbia River PUD (OR)	CRPUD Board vote September 2015	$8.00	$20.45	$10.00	
Colorado Springs Utilities (CO)	City Council Volume No. 5	$12.52	$15.24	$15.24	
Connecticut Light & Power (CT)	14-05-06	$16.00	$25.50	$19.25	Active docket
Consolidated Edison (NY)	15-00270/15-E-0050	$15.76	$18.00	$15.76	Settlement
Consumers Energy (MI)	U-17735	$7.00	$7.50	$7.00	PSC Order
Choptank Electric Cooperative (MD)	9368, Order No. 86994,	$10.00	$17.00	$11.25	PSC approved smaller increase
Dawson Public Power (NE)	Announced June 2015	$21.50	$27.00	$27.00	Based on news articles
Empire District Electric (MO)	ER-2014-0351	$12.52	$18.75	$12.52	Settlement
Eugene Water & Electric Board (OR)	Board vote December 2014	$13.50	$20.00	$20.00	
Hawaii Electric Light (HI)	2014-0183	$9.00	$61.00	$9.00	Part of "DG 2.0"
Maui Electric Company (HI)	2014-0183	$9.00	$50.00	$9.00	Part of "DG 2.0"
Hawaii Electric Company (HI)	2014-0183	$9.00	$55.00	$9.00	Part of "DG 2.0"
Independence Power & Light Co (MO)	City Council vote September 2015	$4.14	$14.50	$4.14	Postponed indefinitely
Indiana Michigan Power (MI)	U-17698	$7.25	$9.10	$7.25	Settlement
Kansas City Power & Light (KS)	15-KCPE-116-RTS	$10.71	$19.00	$14.50	Settlement
Kansas City Power & Light (MO)	File No. ER-2014-0370	$9.00	$25.00	$11.88	
Kentucky Power (KY)	2014-00396	$8.00	$16.00	$11.00	Settlement was $14/month; PSC reduced to $11
Kentucky Utilities Company (KY)	2014-00371	$10.75	$18.00	$10.75	Settlement for KU LGE
Louisville Gas-Electric (KY)	2014-00372	$10.75	$18.00	$10.75	Settlement for KU LGE

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Madison Gas and Electric (WI)	3270-UR-120	$10.29	$22.00	$19.00	
Metropolitan Edison (PA)	R-2014-2428745	$8.11	$13.29	$10.25	Settlement
Nevada Power Co. (NV)	14-05004	$10.00	$15.25	12.75	Settlement
Northern States Power Company (ND)	PU-12-813	$9.00	$14.00	$14.00	Under previous rates, customers with underground lines paid $11/month
Pacific Gas & Electric Company (CA)	R.12-06-013, Rulemaking 12-06-013	$0.00	$10.00	$0.00	$10 minimum bill adopted instead
PacifiCorp (WA)	UE-140762	$7.75	$14.00	$7.75	Commission order emphasized customer control
Pennsylvania Electric (PA)	R-2014-2428743	$7.98	$11.92	$9.99	Settlement
Pennsylvania Power (PA)	R-2014-2428744	$8.86	$12.71	$10.85	Settlement
Redding Electric Utility (CA)	City Council Meeting June 2015	$13.00	$42.00	$13.00	Postponed consideration until 2/2017
Rocky Mountain Power (UT)	13-035-184	$5.00	$8.00	$6.00	Settlement
Rocky Mountain Power (WY)	20000-446-ER-14 (Record No. 13816)	$20.00	$22.00	$20.00	
Salt River Project (AZ)	SRP Board vote February 2015	$17.00	$20.00	$20.00	Elected board of SRP voted Feb. 26 2015
San Diego Gas & Electric (CA)	A.14-11-003 & R.12-06-013, Rulemaking 12-06-013	$0.00	$10.00	$0.00	$10 minimum bill adopted instead
Sierra Pacific Power (NV)	13-06002, 13-06003, 13-06004	$9.25	$15.25	$15.25	
Southern California Edison (CA)	A.13-11-003 & R.12-06-013, Rulemaking 12-06-013	$0.94	$10.00	$0.94	$10 minimum bill adopted instead
Stoughton Utilities (W()	5740-ER-108	$7.50	$10.00	$10.00	
We Energies (WI)	5-UR-107	$9.13	$16.00	$16.00	
West Penn Power (PA)	R-2014-2428742	$5.00	$7.35	$5.81	Settlement
Westar (KS)	15-WSEE-115-RTS	$12.00	$27.00	$14.50	Settlement
Wisconsin Public Service (MI)	U-17669	$9.00	$12.00	$12.00	Settlement
Wisconsin Public Service (WI)	6690-UR-123	$10.40	$25.00	$19.00	
Xcel Energy (MN)	E002 / GR-13-868	$8.00	$9.25	$8.00	Commission order emphasized customer control

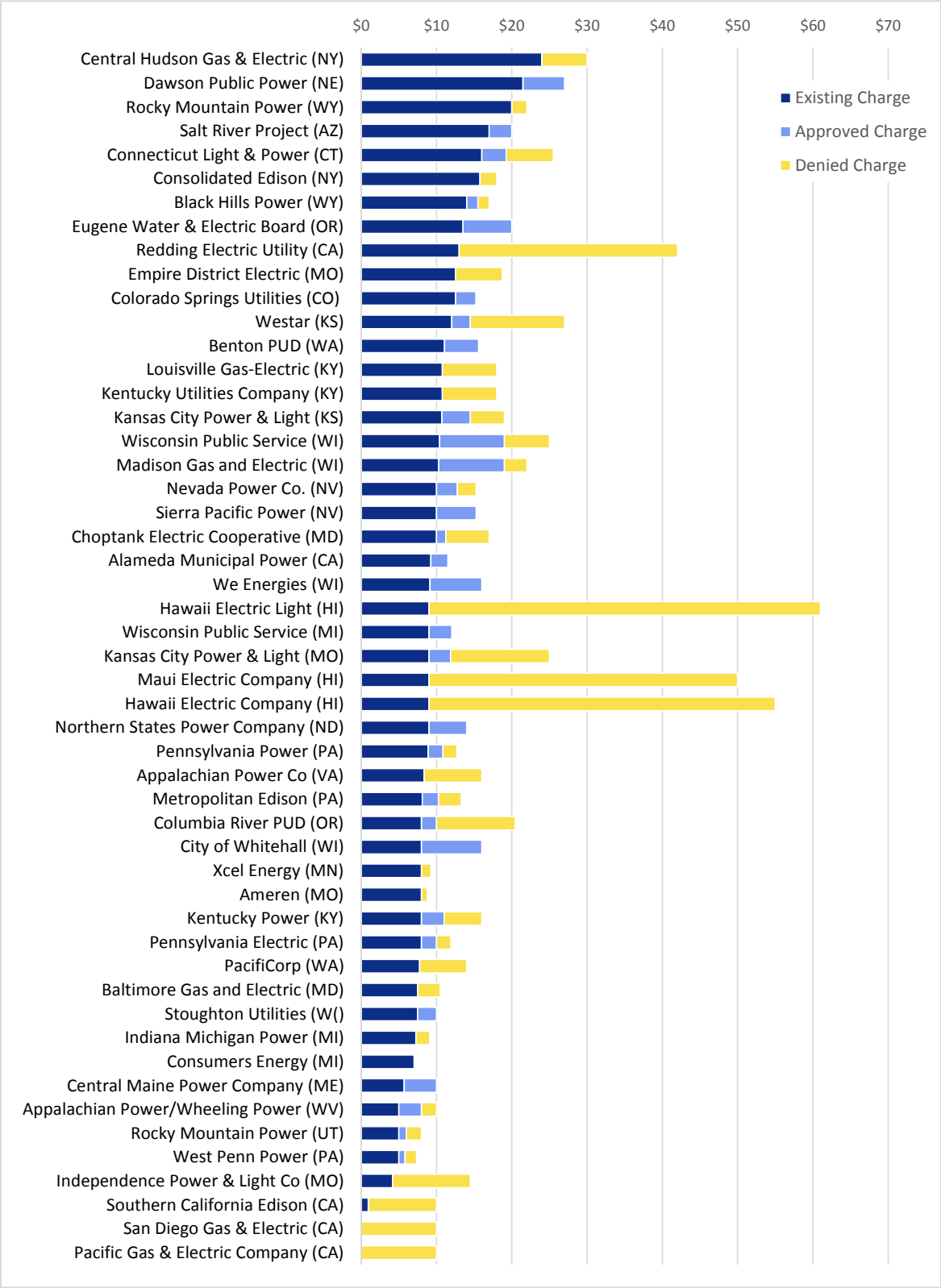
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Table 2. Pending dockets and proposals to increase fixed charges

Utility	Docket/Case No.	Existing	Proposed	Approved	Notes
Avista Utilities (ID)	AVU-E-15-05	$5.25	$8.50		Active docket
Avista Utilities (WA)	UE-150204	$8.50	$14.00		
Detroit Edison (MI)	U-17767	$6.00	$10.00		Proposed order has rejected residential increase
El Paso Electric (TX)	44941	$7.00	$10.00		Public hearings ongoing
El Paso Electric (NM)	15-00127-UT	$5.04	$10.04		Public hearings ongoing
Entergy Arkansas, Inc. (AR)	15-015-U	$6.96	$9.00		Active docket
Indianapolis Power & Light (IN)	44576/44602	$11.00	$17.00		Active docket, values reflect proposal for customers that use more than 325 kWh
Lincoln Electric System (NE)	City council proceeding	$11.15	$13.40		City council decision is pending
Long Island Power Authority (NY)	15-00262	$10.95	$20.38		Rejected by PSC, LIPA Board has ultimate decision
Montana-Dakota Utilities (MT)	D2015.6.51	$5.48	$7.60		BSC based on per day not per month, values converted to monthly
National Grid (MA)	D.P.U. 15-120	$4.00	$13.00		Proposed as part of Grid Mod plan, presented as "Tier 3" customer, for use between 601 to 1,200 kWh per month
National Grid (RI)	RIPUC DOCKET NO. 4568	$5.00	$13.00		Presented as "Tier 3" customer, for use between 751 to 1,200 kWh per month
NIPSCO (IN)	44688	$11.00	$20.00		Active Docket
Omaha Public Power District (NE)	Public power	$10.25	$30.00		Based on news coverage of stakeholder meetings. No specific number submitted, $20, $30, $35 where floated past stakeholders
PECO (PA)	R-2015-2468981	$7.12	$12.00	$8.45	Settlement not yet ratified
Public Service Company of New Mexico (NM)	15-00261-UT	$5.00	$13.14		Public hearings ongoing
Portland General Electric (OR)	UE 294	$10.00	$11.00		Proposed
Pennsylvania Power and Light (PA)	R-2015-2469275	$14.09	$20.00	$14.09	Settlement not yet ratified
Santee Cooper (SC)	State utility	$14.00	$21.00		Pending, expected decision in December 2015
Springfield Water Power and Light (IL)	Municipal board	$5.76	$12.87		Pending as of Oct 1 2015
Sulfur Springs Valley Electric Coop (AZ)	E-01575A-15-0312	$10.25	$25.00		Active docket
Sun Prairie Utilities (WI)	5810-ER-106	$7.00	$16.00		
UNS Electric Inc. (AZ)	E-04204A-15-0142	$10.00	$20.00		Active docket, hearings in March 2016
Xcel Energy (WI)	4220-UR-121	$8.00	$18.00		

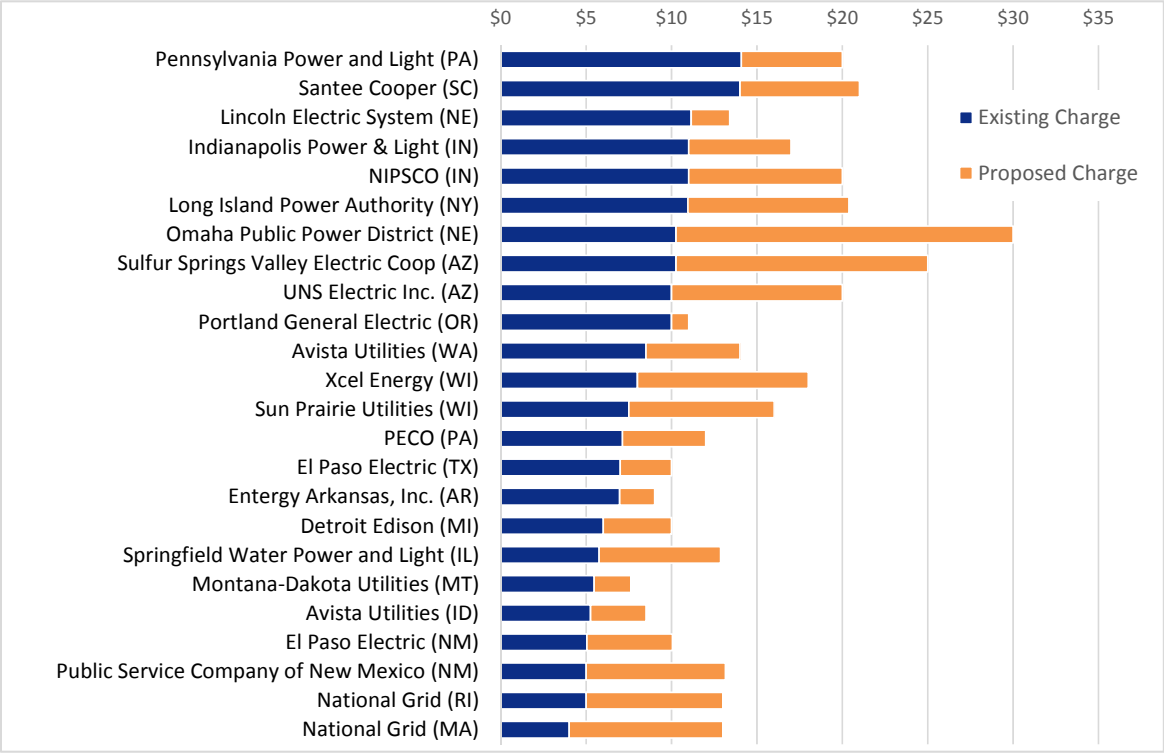
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Figure 12. Finalized decisions of utility proceedings to increase fixed charges



Notes: Denied includes settlements that did not increase the fixed charge.

Figure 13. Existing and proposed fixed charges of utilities with pending proceedings to increase fixed charges

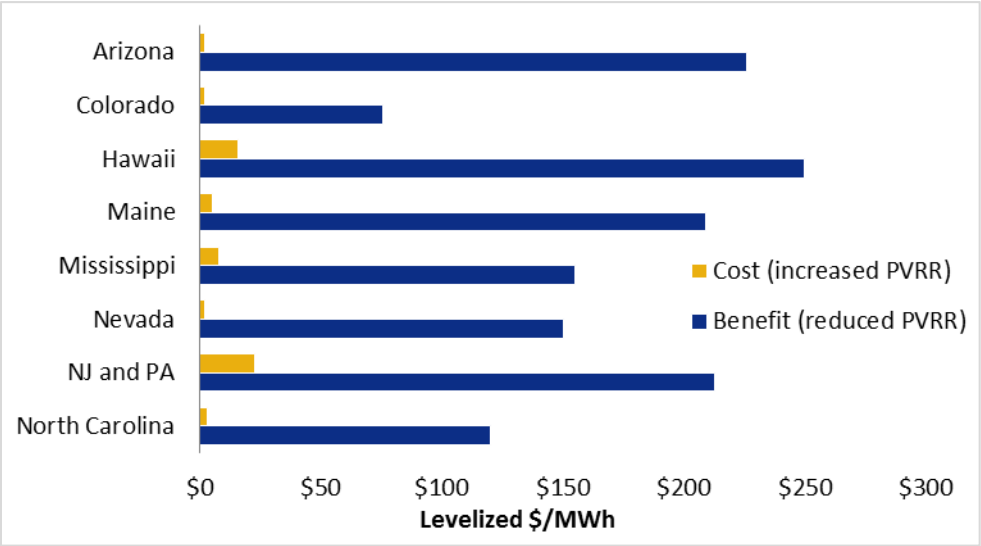


APPENDIX C – NET METERING IMPACTS ON UTILITY COSTS

A utility's revenue requirement represents the amount of revenue that it must recover from customers to cover the costs of serving customers (plus a return on its investments). Customers who invest in distributed PV may increase certain costs while reducing others. Costs associated with integration, administration, and interconnection of net energy metered (NEM) systems will increase revenue requirements, and thus are considered a cost. At the same time, a NEM system will avoid other costs for the utility, such as energy, capacity, line losses, etc. These avoided costs will reduce revenue requirements, and thus are a benefit. These costs and benefits over the PV's lifetime can be converted into present value to determine the impact on the utility's present value of revenue requirements (PVRR).

Over the past few years, at least eight net metering studies have quantified the impact of NEM on a utility's revenue requirement. Key results from these studies are summarized in the table and figure below. Note that only those costs and benefits that affect revenue requirements are included as costs or benefits. If a study included benefits that do not affect revenue requirements (such as environmental externality costs, reduced risk, fuel hedging value, economic development, and job impacts), then they were subtracted from the study results. Similarly, the costs presented below include only NEM system integration, interconnection, and administration costs.[48] Other costs that are sometimes included in the studies but do not affect revenue requirements, such as lost revenues, are not included.

Figure 14. Recent studies indicate extent to which NEM benefits exceed costs



[48] Historically, some utilities have offered incentives to customers that install solar panels (or other NEM installations). While these incentive payments do put upward pressure on revenue requirements, the incentives themselves are removed from Figure 14 and Table 3 to help compare costs and benefits when utility-specific incentives are taken out of the equation.

Table 3. Net metering studies that report PVRR benefits and costs

Year	State	Funded / Commissioned by	Prepared by	Benefit ($/MWh)	Cost ($/MWh)	Benefit-Cost Ratio
2013	Arizona	---------	Crossborder Energy	226*	2	113
2013	Colorado	Xcel Energy	Xcel Energy	75.6	1.8	42
2014	Hawaii	HI PUC	E3	250*	16	16
2015	Maine	Maine Public Utilities Commission	Clean Power Research, et. al.	209	5	42
2014	Mississippi	Mississippi Public Service Commission	Synapse Energy Economics	155	8	19
2014	Nevada	State of Nevada Public Utilities Commission	E3	150	2	75
2012	NJ and PA	Mid-Atlantic Solar Energy Industries Association & Pennsylvania Solar Energy Industries Association	Clean Power Research	213*	23*	9
2013	North Carolina	NC Sustainable Energy Association	Crossborder Energy	120*	3	40

**Indicates that the value displayed in the table is the midpoint of the high and low values reported in the study.*

Source: Synapse Energy Economics, 2015.

Arizona

The Arizona study, performed by Crossborder Energy, presents 20-year levelized values in 2014 dollars.[49] Benefits include avoided energy, generation capacity, ancillary services, transmission, distribution, environmental compliance, and costs of complying with renewable portfolio standards. The avoided environmental benefits account for non-CO_2 market costs of NO_X, SO_X, and water treatment costs, and thus are included as revenue requirement benefits. The benefits range from $215 per MWh to $237 per MWh. Figure 14 and Table 3 present the midpoint value of this range: $226 per MWh. The report estimates integration costs to be $2 per MWh.

Colorado

The Colorado study, performed by the utility Xcel Energy, presents 20-year levelized net avoided costs under three cases in the report's Table 1.[50] The benefits include avoided energy, emissions, capacity, distribution, transmission and line losses. The benefits also include an avoided hedge value, which does not affect revenue requirements. Removing the hedge value from the benefits yields a revenue

[49] Crossborder Energy. 2013. The Benefits and Costs of Solar Distributed Generation for Arizona Public Service. Page 2. Table 1.

[50] Xcel Energy. 2013. Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System. Executive Summary, page V.

requirement benefit of $75.6 per MWh. The study estimates solar integration costs to be $1.80 per MWh.

Hawaii

The Hawaii study, performed by E3, presents the 20-year levelized costs and benefits of NEM on the various Hawaii utilities (HECO, MECO, HELCO, and KIUC). The base case NEM benefits are $213 per MWh for KIUC,[51] $234 per MWh for MECO,[52] $242 per MWh for HELCO,[53] and $287 for HECO.[54] Figure 14 and Table 3 present the midpoint of these values: $250 per MWh. The NEM revenue requirement costs are estimated to be $16 per MWh, which includes integration costs ($6 per MWh) and transmission and distribution interconnection costs ($10 per MWh).[55]

Maine

The Maine study, prepared by several co-authors, presents the 25-year levelized market and societal benefits for Central Maine Power Company.[56] The revenue requirement benefits, including avoided costs and market price response benefits, are $209 per MWh. The study estimates the NEM revenue requirement costs to be $5 per MWh, reflecting NEM system integration costs.

Mississippi

The Mississippi study, prepared by Synapse Energy Economics, presents base case 25-year levelized benefits associated with avoided energy, capacity, transmission and distribution, system losses, environmental compliance costs, and risk.[57] The total revenue requirements benefit is $155 per MWh, which excludes the $15 per MWh risk benefit. The NEM administrative costs are estimated to be $8 per MWh.

Nevada

The Nevada study, conducted by E3, presents costs and benefits on a 25-year levelized basis in 2014 dollars. The study estimates the costs and benefits for several "vintages" of rooftop solar. Figure 14 and Table 3 present the vintage referred to as "2016 installations," because this is most representative of

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[51] E3, Evaluation of Hawaii's Renewable Energy Policy and Procurement, January 2014, page 53, Figure 26.

[52] Ibid. Page 50, Figure 23.

[53] Ibid. Page 47, Figure 20.

[54] Ibid. Page 43, Figure 17.

[55] Ibid. Pages 55 and 56.

[56] Clean Power Research, Sustainable Energy Advantage, & Pace Law School Energy and Climate Center for Maine PUC. 2015. *Maine Distributed Solar Valuation Study*. Page 50. Figure 7.

[57] Synapse Energy Economics for Mississippi PSC. 2014. *Net Metering in Mississippi*. Pages 33 and 38.

costs and benefits in the future. The revenue requirement benefits, including avoided costs and renewable portfolio standard value, are estimated to be $150 per MWh. The E3 study also reports the "incentive, program, and integration costs" to be $6 per MWh.[58] This value includes the integration costs, which were assumed by E3 to be $2 per MWh.[59] Customer incentive costs are not included in any of the results presented in Figure 14 and Table 3, so the revenue requirement costs for Nevada include only the integration costs of $2 per MWh.

New Jersey and Pennsylvania

The New Jersey and Pennsylvania study, prepared by several co-authors, presents the 30-year levelized value of solar for seven locations.[60] The benefits include energy benefits (that would contribute to reduced revenue requirements), strategic benefits (that may not contribute to reduced revenue requirements), and other benefits (some of which would contribute to reduced revenue requirements). To determine the revenue requirement benefits, the benefits associated with "security enhancement value," "long term societal value," and "economic development value" are excluded. The highest reported benefit value was in Scranton ($243 per MWh) and the lowest value was reported in Atlantic City ($183 per MWh). Figure 14 and Table 3 present the midpoint of these two values: $213 per MWh. Similarly, they present the midpoint of the solar integration costs ($23 per MWh).

North Carolina

The North Carolina study, prepared by Crossborder Energy, presents 15-year levelized values in 2013 dollars per kWh. The benefits are presented for three utilities separately. A high/low range of benefits were presented for each benefit category (energy, line losses, generation capacity, transmission capacity, avoided emissions, and avoided renewables). The low avoided emissions estimate reflects the costs of compliance with environmental regulations, which will affect revenue requirements, but the high avoided emissions estimate reflects the social cost of carbon, which will not affect revenue requirements. Therefore, the low avoided emissions value ($4 per MWh) is included, but the incremental social cost of carbon value ($18 per MWh) is excluded. The lowest revenue requirement benefit presented in the study is $93 per MWh for DEP, and the highest one is $147 per MWh for DNCP (after removing the incremental social cost of carbon). Figure 14 and Table 3 present the midpoint between the high and low values, $120 per MWh, as the revenue requirement benefit. The study also identifies $3 per MWh in revenue requirement costs.

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[58] E3 for Nevada PUC. 2014. *Nevada Net Energy Metering Impacts Evaluation*. Page 96.

[59] Ibid. Page 61.

[60] Clean Power Research for Mid-Atlantic & Pennsylvania Solar Energy Industries Associations. 2012. *The Value of Distributed Solar Electric Generation to NJ and PA*. Page 18.

GLOSSARY

Advanced Metering Infrastructure (AMI): Meters and data systems that enable two-way communication between customer meters and the utility control center.

Average Cost: The revenue requirement divided by the quantity of utility service, expressed as a cost per kilowatt-hour or cost per therm.

Average Cost Pricing: A pricing mechanism basing the total cost of providing electricity on the accounting costs of existing resources. (See Marginal Cost Pricing, Value-Based Rates.)

Capacity: The maximum amount of power a generating unit or power line can provide safely.

Classification: The separation of costs into demand-related, energy-related, and customer-related categories.

Coincident Peak Demand: The maximum demand that a load places on a system at the time the system itself experiences its maximum demand.

Cost-Based Rates: Electric or gas rates based on the actual costs of the utility (see Value-Based Rates).

Cost-of-Service Regulation: Traditional electric utility regulation, under which a utility is allowed to set rates based on the cost of providing service to customers and the right to earn a limited profit.

Cost-of-Service Study: A study that allocates the costs of a utility between the different customer classes, such as residential, commercial, and industrial. There are many different methods used, and no method is "correct."

Critical Period Pricing or Critical Peak Pricing (CPP): Rates that dramatically increase on short notice when costs spike, usually due to weather or to failures of generating plants or transmission lines.

Customer Charge: A fixed charge to consumers each billing period, typically to cover metering, meter reading, and billing costs that do not vary with size or usage. Sometimes called a Basic Charge or Service Charge.

Customer Class: A group of customers with similar usage characteristics, such as residential, commercial, or industrial customers.

Decoupling: A regulatory design that breaks the link between utility revenues and energy sales, typically by a small periodic adjustment to the rate previously established in a rate case. The goal is to match actual revenues with allowed revenue, regardless of sales volumes.

Demand: The rate at which electrical energy or natural gas is used, usually expressed in kilowatts or megawatts, for electricity, or therms for natural gas.

Demand Charge: A charge based on a customer's highest usage in a one-hour or shorter interval during a certain period. The charge may be designed in many ways. For example, it may be based on a customer's maximum demand during a monthly billing cycle, during a seasonal period, or during an annual cycle. In addition, some demand charges only apply to a customer's maximum demand that coincides with the system peak, or certain peak hours. Typically assessed in cents per kilowatt.

Distribution: The delivery of electricity to end users via low-voltage electric power lines (usually 34 kV and below).

Embedded Costs: The costs associated with ownership and operation of a utility's existing facilities and operations. (See Marginal Cost.)

Energy Charge: The part of the charge for electric service based upon the electric energy consumed or billed (i.e., cents per kilowatt-hour).

Fixed Cost: Costs that the utility cannot change or control in the short-run, and that are independent of usage or revenues. Examples include interest expense and depreciation expense. In the long run, there are no fixed costs, because eventually all utility facilities can be retired and replaced with alternatives.

Flat Rate: A rate design with a uniform price per kilowatt-hour for all levels of consumption.

Fully Allocated Costs or Fully Distributed Costs: A costing procedure that spreads the utility's joint and common costs across various services and customer classes.

Incentive Regulation: A regulatory framework in which a utility may augment its allowed rate of return by achieving cost savings or other goals in excess of a target set by the regulator.

Incremental Cost: The additional cost of adding to the existing utility system.

Inverted Rates/Inclining Block Rates: Rates that increase at higher levels of electricity consumption, typically reflecting higher costs of newer resources, or higher costs of serving lower load factor loads such as air conditioning. Baseline and lifeline rates are forms of inverted rates.

Investor-Owned Utility (IOU): A privately owned electric utility owned by and responsible to its shareholders. About 75% of U.S. consumers are served by IOUs.

Joint and Common Costs: Costs incurred by a utility in producing multiple services that cannot be directly assigned to any individual service or customer class; these costs must be assigned according to some rule or formula. Examples are distribution lines, substations, and administrative facilities.

Kilowatt-Hour (kWh): Energy equal to one thousand watts for one hour.

Load Factor: The ratio of average load to peak load during a specific period of time, expressed as a percent.

Load Shape: The distribution of usage across the day and year, reflecting the amount of power used in low-cost periods versus high-cost periods.

Long-Run Marginal Costs: The long-run costs of the next unit of electricity produced, including the cost of a new power plant, additional transmission and distribution, reserves, marginal losses, and administrative and environmental costs. Also called long-run incremental costs.

Marginal Cost Pricing: A system in which rates are designed to reflect the prospective or replacement costs of providing power, as opposed to the historical or accounting costs. (See Embedded Cost.)

Minimum Charge: A rate-schedule provision stating that a customer's bill cannot fall below a specified level. These are common for rates that have no separate customer charge.

Operating Expenses: The expenses of maintaining day-to-day utility functions. These include labor, fuel, and taxes, but not interest or dividends.

Public Utility Commission (PUC): The state regulatory body that determines rates for regulated utilities. Sometimes called a Public Service Commission or other names.

Rate Case: A proceeding, usually before a regulatory commission, involving the rates and policies of a utility.

Rate Design: The design and organization of billing charges to distribute costs allocated to different customer classes.

Short Run Marginal Cost: Only those variable costs that change in the short run with a change in output, including fuel; operations and maintenance costs; losses; and environmental costs.

Straight Fixed Variable (SFV) Rate Design: A rate design method that recovers all short-run fixed costs in a fixed charge, and only short-run variable costs in a per-unit charge.

Time-of-Use Rates: A form of time-varying rate. Typically the hours of the day are segmented to "off-peak" and "peak" periods. The peak period rate is higher than the off-peak period rate.

Time-Varying Rates: Rates that vary by time of day in order to more accurately reflect the fluctuation of costs. A common, and simple form of time-varying rate is time-of-use rates.

Variable Cost: Costs that vary with usage and revenue, plus costs over which the utility has some control in the short-run, including fuel, labor, maintenance, insurance, return on equity, and taxes. (See Short Run Marginal Cost.)

Volumetric Rate: A rate or charge for a commodity or service calculated on the basis of the amount or volume actually received by the customer (e.g., cents/kWh, or cents/kW). May also be referred to as the "variable rate." If referring to cents per kilowatt-hour, it is often referred to as the "energy charge."

Adapted from Lazar (2011) "Electricity Regulation in the US: A Guide." Regulatory Assistance Project.