COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

INVESTIGATION BY THE DEPARTMENT OF PUBLIC UTILITIES ON ITS OWN MOTION AS TO THE PROPRIETY OF THE RATES AND CHARGES PROPOSED BY MASSACHUSETTS ELECTRIC COMPANY AND NANTUCKET ELECTRIC COMPANY IN THEIR PETITION FOR APPROVAL OF AN INCREASE IN BASE DISTRIBUTION RATES FOR ELECTRIC SERVICE	* * * * * * * * *	Docket D.P.U. 15-155

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DIRECT TESTIMONY

OF

NATHAN PHELPS

ON BEHALF OF
VOTE SOLAR

March 18, 2016

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Nathan Phelps. My business address is 89 South Street, Suite 203, Boston, Massachusetts 02111.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of Vote Solar.

Q. PLEASE DESCRIBE VOTE SOLAR.

A. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has more than 70,000 individual members throughout the United States and 2,150 members in Massachusetts, some of whom reside in the service territory of Massachusetts Electric Company d/b/a National Grid or Nantucket Electric Company d/b/a National Grid (jointly, "National Grid" or "the Company").

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I serve as the Program Manager of Distributed Generation ("DG") Regulatory Policy for Vote Solar. In this capacity, I work on initiatives, development, and implementation of policy related to distributed solar generation ("DSG"). I also review regulatory filings, perform technical analyses, and testify in commission proceedings relating to DSG.

Q. PLEASE DESCRIBE YOUR EXPERIENCE AND QUALIFICATIONS.

A. My primary focus at Vote Solar is utility regulatory issues related to DG. These regulatory issues include: the billing arrangement commonly known as net metering, rate design, rate recovery, and decoupling, primarily within restructured electricity markets in the Northeast. Prior to joining Vote Solar, I was a Senior Economist at the Massachusetts Department of Public Utilities ("DPU" or "the Department") for five years. While at the DPU, I was the primary staff person who worked on issues related to DG and renewable energy, including net metering, interconnection, long-term contracts for renewable energy, and rate-related issues relevant to DG. Prior to joining the DPU, I was a Policy Intern with the Massachusetts Renewable Energy Trust.

I received my undergraduate degree from Willamette University in both Environmental Studies and Politics, and I attended Tufts University for graduate studies in Urban and Environmental Policy and Planning. My resume is attached as Exhibit NP-2.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No, I have not.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN OTHER STATES?

A. Yes. I have testified before the Maryland Public Service Commission. Specifically, I testified in the proceeding concerning the proposed merger between Exelon Corporation and Pepco Holdings (Case No. 9361), and the general rate case of Southern Maryland Electric Cooperative (Case No. 9396). In addition to testimony, I have provided public comments in Iowa, Maryland, New York, Oregon, and Vermont.

II. PURPOSE OF TESTIMONY AND SUMMARY OF RECOMMENDATIONS

Q. HAVE YOU REVIEWED THE TESTIMONY AND OTHER SUPPORTING DOCUMENTS SUBMITTED BY NATIONAL GRID IN THIS CASE?

A. Yes, I have.

Q. DOES YOUR TESTIMONY ADDRESS ALL ASPECTS OF THE COMPANY'S FILING?

A. No, it does not. Pursuant to the *Interlocutory Order on Appeals of Hearing Officer's Ruling on Petitions to Intervene* dated January 14, 2016, my testimony addresses two of the Company's rate design proposals and the potential impact of these proposals on Vote Solar's legitimate interests in the specific outcome of this case.

Q. WHAT COMPANY PROPOSALS DO YOU ADDRESS IN YOUR TESTIMONY?

A. In my testimony, I address the following two rate design proposals: (1) the tiered customer charge proposed for Phase II, and (2) the access fee for stand-alone generators.

With respect to customer charges for R-1, R-2, E (collectively, residential), and G-1 (small commercial and industrial) customers, National Grid proposes two phases of charges. I do not address the Company's Phase I proposal, which would increase the residential customer charge from $4.00 to $5.50 and leave the current small commercial and industrial ("C&I") charge in place. My testimony is limited to the Company's Phase II customer charge proposal, which is a proposal for a tiered customer charge based on kilowatt-hour ("kWh") consumption. Table 1 below summarizes the Company's Phase II proposal.

Table 1: Summary of Phase II Customer Charge Proposal for Residential and Small C&I Customers

Customer Class and Proposed Tier	Proposed Phase II Customer Charge	kWh Consumption
R-1/R-2/E		
Tier 1	$6.00	0 kWh to 250 kWh
Tier 2	$9.00	251 kWh to 600 kWh
Tier 3	$15.00	601 kWh to 1,200 kWh
Tier 4	$20.00	kWh in excess of 1,200
G-1		
Tier 1	$10.00	0 kWh to 75 kWh
Tier 2	$11.00	76 kWh to 500 kWh
Tier 3	$15.00	501 kWh to 2,000 kWh
Tier 4	$30.00	kWh in excess of 2,000

In addition to addressing the tiered customer charge, I also address the Company's proposed access fee for stand-alone generators, which would be a fixed capacity-based charge per month. Table 2 below summarizes the proposal.

Table 2: Summary of Proposed Access Fee for Stand-Alone Generators

Voltage at which the Stand-Alone Generator Is Connected	Proposed Fee
Primary Voltage (≥ 1,000 volts)	$7.00 per kW-month
Secondary Voltage (< 1,000 volts)	$8.50 per kW-month

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I conclude that the Department should reject the Company's proposed tiered customer charge because: (1) increased customer charges do not mitigate, and in fact create, fairness and equity concerns; (2) customer charges do not send an appropriate and actionable price signal to customers; (3) the Company has failed to demonstrate a sufficiently strong relationship between maximum billed usage and maximum hourly load so as to justify using maximum billed usage as a proxy for maximum hourly load; and (4) designing a charge based on a customer's maximum hourly load, or non-coincident peak demand, rather than contribution to system peak, or coincident peak demand, fails to reflect cost causation. I further conclude that a demand charge, for which the Company's tiered customer charge is meant to act as a proxy, is not suitable for residential and small C&I customers. Finally, I conclude that the Department should reject the proposed access fee for stand-alone generators. I conclude that the Company has failed to demonstrate that (1) an access fee is needed; (2) even if needed, the proposed fee is set at the correct level; and (3) a relationship exists between stand-alone generators and class G-2 and G-3 customers.

III. NATIONAL GRID'S PROPOSAL TO IMPOSE A TIERED CUSTOMER CHARGE IS FLAWED AND SHOULD BE REJECTED

A. The Phase II Customer Charge Proposal

Q. PLEASE DESCRIBE THE COMPANY'S TIERED CUSTOMER CHARGE PROPOSAL.

A. As discussed above, the Company proposes a tiered customer charge based on a customer's kWh usage. Specifically, the charge will be based on a customer's highest usage over the previous twelve billing periods, including the most recent billing period.[1]

[1] Nat'l Grid, Ex. NG-PP-1 at 33:4-6, Nov. 6, 2015.

Q. WHY IS THE COMPANY PROPOSING A TIERED CUSTOMER CHARGE?

A. With respect to its distribution rate design proposals generally, National Grid states that "[t]he Company's objective in proposing a new rate design methodology is to move toward rates for distribution service that are fair and equitable across all customers and are designed to reflect the actual relative costs to serve each customer, both those with and without DG."[2] The Company also asserts that "[c]ustomer and demand charges are more reflective of the underlying cost of the distribution system and, therefore, communicate more accurate price signals to customers regarding the costs that the customers impose upon the system."[3]

Q. DID THE COMPANY CONSIDER REACTIONS TO FIXED CHARGE PROPOSALS IN OTHER STATES?

A. Yes, it appears so. According to National Grid, "[t]he Company decided that a proposal to implement a tiered customer charge where the customer charge is determined based upon the size of a customer as determined by that customer's kWh usage would be most appropriate from reactions to proposals to implement fixed charges in other states."[4]

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2 *Id.* at 23:8-11.

3 *Id.* at 33:10-12.

4 *Id.* at 37:3-18.

Q. DOES THE COMPANY RAISE DG AS A CONCERN IN REGARD TO CUSTOMER CHARGES?

A. Yes. In discussing its rate design proposals, the Company explicitly raises the role of the distribution utility in a distributed energy world.[5] Specifically, National Grid asserts that its rate design proposals start to address the following issue concerning the pricing of distribution grid services: that "pricing to recover the costs of the integrated system will need to evolve to recognize the changing nature of the connecting customer."[6]

Q. WHAT IS YOUR GENERAL UNDERSTANDING OF THE COMPANY'S RATIONALE FOR ITS PROPOSAL?

A. Although discerning motivation from a filing can be tricky, National Grid indicates that its tiered customer charge proposal is an attempt mainly to address perceived (i) unfairness and inequities and (ii) inaccurate price signals.[7]

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5 *Id.* at 24-28.

6 *Id.* at 26:2-8, 14-15.

7 The Company also notes that other utilities have proposed to increase their customer charges to improve their revenue recovery. Ex. NG-PP-1 at 37:13-15. To the extent that National Grid is suggesting that revenue collection is a reason for its own proposal, it is worth noting that the Company has not demonstrated any impediments to collecting their revenue with the current rate design, which includes full revenue decoupling.

Additionally, a tiered customer charge—and eventually a demand charge—appears to be part of the Company's vision for the distribution utility in a distributed energy world.

B. The Proposed Customer Charge Would Create—Rather than Cure—Inequities

Q. WHAT DOES THE COMPANY STATE ABOUT CUSTOMER CHARGES AS THEY RELATE TO FAIRNESS AND EQUITY?

A. National Grid states that its "objective in proposing a new rate design methodology is to move toward rates for distribution service that are fair and equitable across all customers and are designed to reflect the actual relative costs to serve each customer, both those with and without DG."[8]

Q. DOES NATIONAL GRID QUANTIFY THE ALLEGED INEQUITIES IT ASSOCIATES WITH DG?

A. Only in part. National Grid calculates the lost base distribution revenue associated with DG (which is collected from all ratepayers), but does not quantify the benefits associated with DG. Without a quantification of the benefits, the Company has not provided a complete picture of the net impacts on ratepayers. Without the complete picture, the Company is providing a distorted representation of how DG impacts ratepayers.

National Grid estimated the lost base distribution revenue associated with on-site consumption to be $1,829,850, and the lost base distribution revenue associated

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[8] Nat'l Grid, Ex. NG-PP-1 at 23:8-11.

with net metering credits to be $270,960.[9] It is important to note that the lost revenue associated with on-site consumption is the same type of lost revenue that the Company experiences as a result of energy efficiency, energy conservation, weather, and economic conditions. In all of these examples, the customer is using less National Grid-provided energy on site. The Department has already addressed this type of lost revenue.

Q. HOW HAS THE DPU ADDRESSED THE ISSUE OF LOST REVENUE ASSOCIATED WITH CHANGES IN CONSUMPTION, WHETHER DUE TO EFFICIENCY, DISTRIBUTED SOLAR, MILD WEATHER, OR SOMETHING ELSE?

A. The Department specifically addressed this issue in D.P.U. 07-50-A in which it approved full revenue decoupling. As the Department stated:

> A full decoupling mechanism separates a distribution company's revenues from all changes in consumption, regardless of the underlying cause of the changes. Full decoupling has two advantages over the targeted and partial mechanisms discussed above. First, unlike a targeted approach, full decoupling does not attempt to distinguish among the types of activities that could lead to an increased deployment of demand resources, thus comprehensively removing the disincentives the distribution companies currently face regarding such deployment. Second, unlike a partial approach, full decoupling does not attempt to distinguish between changes in consumption that are related to the deployment of demand resources and those changes that are unrelated to such deployment, thus reducing the administrative burden associated with implementing a decoupling mechanism, and resulting in a decoupling mechanism that should be transparent and easily understood. Consequently, based on our review of decoupling approaches examined in this proceeding, the Department concludes that a full decoupling mechanism best meets our objectives of (1) aligning the financial interests of the

[9] Nat'l Grid, Resp. to Information Req. EFCA-1-3, Attach. 1, Feb. 12, 2016.

> companies with policy objectives regarding the efficient deployment of demand resources, and (2) ensuring that the companies are not harmed by decreases in sales associated with any increased use of demand resources.[10]

Accordingly, the Company is held financially neutral as a result of demand resources, and the total impacts on ratepayers includes a variety of factors, of which DG is just one.

Q. WHAT DO YOU CONCLUDE ABOUT THE COMPANY'S LOST REVENUE CALCULATIONS?

A. The Company's calculations of lost revenue associated with DG ignore the broader context of the numerous ways in which customers' energy usage can change, and the benefits that DG provides. Moreover, addressing lost revenue associated with reduced customer consumption due to DG—or any demand resources—through a tiered customers charge ignores the existence of full revenue decoupling. Full revenue decoupling was explicitly implemented to address any throughput disincentives that the distribution companies may experience as a result of demand resources.

Without proper context—both in regard to the total impacts of energy usage changes and consideration of the benefits associated with DG—the Company's quantification of the costs of DG should not be used as a basis for setting rates. Simply put, more information on the net impacts of DG is needed to understand any potential cost-shifts.

[10] D.P.U. 07-50-A, Order 31-32, July 16, 2008.

Q. DO INCREASES TO CUSTOMER CHARGES MITIGATE CONCERNS OF EQUITY?

A. No. An increase in a customer charge changes the way in which the distribution company collects revenue from customers, which ultimately results in an increase in revenue collection from low-usage customers. However, the customer charge, as explained below, should only collect revenues that are not usage based—that is, revenues that are purely associated with the number of total customers. A customer charge should not address any issues associated with how the distribution system operates or is maintained. As such, a customer charge increase will not mitigate concerns about any existing inequities, particularly concerns that are based on reductions in energy consumption.

Q. HOW DO INCREASES TO CUSTOMER CHARGES IMPACT CUSTOMER EQUITY?

A. High customer charges actually create inequities, in particular for low-usage customers.[11] As Synapse Energy Economics explains in its recent report, customer charges will disproportionately impact low-use customers because "[c]ustomers who use less energy than average will experience the greatest

[11] I note that low-usage customers often include low-income customers. Thus low-income customers are particularly vulnerable to rate changes that remove their ability to lower their electricity bill.

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."[12]

When discussing customer charge proposals from around the country, National Grid acknowledged that these proposals resulted in "disproportionate bill increases to small customers while larger customers received bill reductions because the customer charge increase was more than offset by the reduction in the per-kWh charge, resulting in more costs being recovered from smaller customers."[13] Although National Grid claims to have mitigated the impact on low-usage customers by seeking to differentiate customers within each rate class through the tiered customer charge, the proposal does not fully address the regressive impact on low-usage customers. After all, Phase II represents an increase in the customer charge for *every* applicable customer, and also results in a decrease in the energy charge for *every* applicable customer (compared to if the customer charge were not increased).

Q. PLEASE ELABORATE ON YOUR POINT THAT CUSTOMER CHARGES DO NOT ELIMINATE INEQUITIES, BUT RATHER CREATE THEM.

A. An increased customer charge can create an inequity and a cross-subsidy between low-usage customers and high-usage customers. Although rates are often set on the basis of an average customer—or the mean usage of all customers in the rate

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[12] Melissa Whited et al., Synapse Energy Economics, Inc., *Caught in a Fix: The Problem with Fixed Charges for Electricity* 14 (2016), attached as Exhibit NP-3.

[13] Nat'l Grid, Ex. NG-PP-1 at 37:9-12.

class—an entire rate class represents many different customers and situations. For example, a studio apartment in a complex will have a very different cost of service than a 10,000-square-foot home with a 4,000-foot service drop. According to the Company, "[e]stablishing the appropriate level of contribution toward these fixed costs [the utility's costs to operate, maintain, and invest in the distribution system] by all customers—those with DG and those without DG—is essential to ensuring that the distribution system can be built, operated, and maintained in a manner that allows for DG interconnection in a safe and reliable manner to achieve the clean energy goals of the Commonwealth."[14] Although the Company may view fixed costs in the totality for a customer class, the fixed costs associated with individual customers can vary substantially.

Q. GIVEN THAT THE FIXED COSTS OF AN INDIVIDUAL CUSTOMER CAN VARY SUBSTANTIALLY, HOW SHOULD A CUSTOMER CHARGE BE APPROPRIATELY DETERMINED?

A. Although the fixed costs associated with individual customers vary, a customer charge that is customer-specific is completely inconsistent with James C. Bonbright's principle of simplicity.[15] For the purposes of simplicity, a customer charge should not vary between customers. A customer charge should, however, never exceed the cost-of-service determination for customer-related costs. Furthermore, a customer charge should also never send an uneconomic price signal to customers.

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[14] *Id.* at 28-29.

[15] James C. Bonbright, *Principles of Public Utility Rates* (1st ed. 1961).

Stated another way, low-usage customers should not have to pay more than their cost of service to ensure that the utility collects their fixed costs from all customers in the rate class. Such an outcome would result in low-usage customers subsidizing high-usage customers through a higher-than-necessary customer charge. Any differences in the cost to serve customers above and beyond the threshold components included in a customer charge (*e.g.*, meter, meter reading, service drop, and billing) should be recovered through the energy charge in order to send an appropriate and actionable price signal to customers to use less electricity, especially during periods of peak demand.

Q. ARE THERE POTENTIAL INEQUITIES AS A RESULT OF RATE DESIGN GENERALLY?

A. Yes. The process of a general rate case (e.g., determining a revenue requirement, classifying and allocating costs, and designing rates) is full of assumptions, estimates, and adjustments made in an effort to spread costs to customer classes based on causation. In addition, and as discussed above, the rate for a class is designed for a mythical customer that is supposed to represent all of the customers in that rate class. However, customers and customer usage are dynamic, so the mythical customer is almost never representative of the rate class over time.

There are very good reasons for why rates are set this way; the process has been over 100 years in the making. We should be careful with how we make changes to the existing processes in an effort to address perceived inequities due to the potential for unintended consequences. Any assumption that the revenue recovered from an individual customer in a given rate class is an accurate reflection of the actual cost of providing electric service to that customer would be, at best, a stretch.

Below is an overview of areas with potential inequities and/or cross-subsidizations:

- Geographic disparities in the cost of service. An example is the cost to serve densely populated urban areas versus low-density rural areas. Even though the rural areas are (usually) more expensive to serve, there is no differentiation in rates or rate structures;
- Low-income programs which are subsidized by other ratepayers;
- The cost to serve low-use customers versus the cost to serve high-use customers;
- The cost of electricity is—for most customers—uniform throughout the day in rates, even though the cost of electricity fluctuates continually; and
- The cost to serve a new customer versus the cost to serve an existing customer.

As such, the Commission should not expect to avoid every potential inequity or cross-subsidy in rates.

Q. ARE YOU SUGGESTING THAT EACH OF THESE "INEQUITIES" BE ADDRESSED BY THE DEPARTMENT?

A. No, I am not. I provide the previous list as an example of how current rates are not precise, and any attempt to increase the customer charge to address any potential cost-shift issues will result in different cost-shift issues.

Q. DOES THIS MEAN THAT VOTE SOLAR IS NOT SUPPORTIVE OF CHANGES IN RATE DESIGN?

A. No, not at all. Vote Solar is very supportive of changes to rate design that better represent cost causation, send appropriate and actionable price signals, balance the traditional ratemaking principles identified by Bonbright, and establish a framework to support the sustainable growth of DSG and related innovation technologies. National Grid has failed to demonstrate that its proposal in this case meets these criteria, and for that reason, I recommend that the Commission reject its proposal.

C. The Proposed Customer Charge Will Not Send Appropriate and Actionable Price Signals

Q. WHAT DOES THE COMPANY ASSERT ABOUT CUSTOMER CHARGES AND PRICE SIGNALS?

A. According to the Company, "[c]ustomer and demand charges are more reflective of the underlying cost of the distribution system and, therefore, communicate more accurate price signals to customers regarding the costs that the customers impose upon the system."[16]

Q. DO INCREASED CUSTOMER CHARGES SEND APPROPRIATE AND ACTIONABLE PRICE SIGNALS?

A. They do not. Increased customer charges punish low-usage customers and otherwise hurt all customers. The price signal that increased customer charges send to customers is that while the price of admission (i.e. the fixed customer

[16] Nat'l Grid, Ex. NG-PP-1 at 33:10-12.

charge) is high, and once you are in, the usage of electricity is cheap. The result is reduced motivation to conserve or use electricity efficiently. This is exactly the opposite price signal that a utility should be sending to customers. The end result of such a price signal is increased electricity system costs as customers, perceiving electricity as cheaper, increase energy consumption.[17] In short, as Steve Kihm, an expert on utility regulation, has explained, "[h]igh fixed charge pricing steers the economy away from efficient resource allocation, not toward it."[18]

Q. WHAT IS THE IMPACT OF THE COMPANY'S PROPOSED PHASE II CUSTOMER CHARGES ON CUSTOMER INCENTIVE TO REDUCE DEMAND?

A. National Grid "has not done any specific analysis around the tiers' impact on customer incentive to reduce demand."[19] But increases to customer charges necessarily result in lower energy charges than otherwise would have been in place had the customer charge remained unchanged, assuming a revenue-neutral proposal.[20] For residential customers and small C&I customers, this means that

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[17] *See* Ex. NP-3 at 18.

[18] Steve Kihm, *Economic Concerns about High Fixed Charge Pricing for Electric Service* (2015), attached as Exhibit NP-4.

[19] Nat'l Grid, Resp. to Information Req. DOER-2-18 at 1, Mar. 8, 2016.

[20] Although not applicable to the immediate discussion, an increase in the customer charge could also reduce the demand charge.

the unit rates per kWh are lower than they otherwise would have been without the increased customer charge.

Q. WHAT IS THE RESULT OF THIS PROPOSAL?

A. The end result is twofold. First, customers will have less control over their electric bills as higher fixed charges reduce customers' ability to lower their bills by reducing their energy consumption through changes in behavior and use of demand-management tools.[21]

Second, customers will have less motivation to use less electricity in general as increased customer charges send inefficient price signals. This means that customers will have less financial motivation to invest in energy efficiency, DG, and distributed energy resources in general because the potential future savings per kWh are reduced. Increases in customer charges thus create a perverse incentive that reduces the motivation for customers to use less electricity. Inevitably, if customers are not encouraged to use less electricity through price signals, then the overall demand on the utility's electric system will increase. This increase in demand will lead to the utility building new infrastructure to meet the increased demand. Ultimately, the new infrastructure will be placed in the rate base, which will increase rates in the future.[22]

[21] *See* Ex. NP-3 at 14.

[22] *See id.* at 16-19.

Q. DO CUSTOMERS ACTUALLY RESPOND TO THE PRICE OF ELECTRICITY?

A. Yes, they do. According to Jim Lazar, a nationally recognized expert on rate design, renewable energy integration, consumer participation in electric utility planning, integrated resource planning, and incentive regulation, "the price elasticity of demand for electricity [is] in the range of -0.1 to -0.7" (Exhibit NP-5 at 3).[23] This means that a 1% decrease in the price of electricity will result in a 0.1-0.7% increase in electricity usage. Thus, National Grid's proposed increase in customer charges will result in an increase in total energy usage, although the exact increase will depend on the elasticity of National Grid customers.

Q. WILL NATIONAL GRID'S TIERED CUSTOMER CHARGE PROPOSAL SEND AN ACTIONABLE PRICE SIGNAL?

A. No, it will not. Fundamentally, National Grid proposes to base the customer charge on the highest kWh usage over the previous twelve billing periods, which is inherently retrospective.

Q. IS THERE A WAY FOR CUSTOMERS TO MONITOR THEIR KWH USAGE TO RESPOND TO THE TIER STRUCTURE?

A. Not easily. In the best-case scenario, customers would monitor their total kWh usage in each month to minimize their exposure to an increased customer charge; but with some rare exceptions, customers do not have a way to monitor their total

[23] Jim Lazar, The Regulatory Assistance Project, *Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs* (2014), attached as Exhibit NP-5.

kWh consumption in real time. The vast majority of National Grid customers do not have advanced metering that will empower customers to monitor consumption in real time.[24] Indeed, National Grid acknowledges that "customers will not know, in real time, how close their actual monthly usage is to a tier boundary."[25] Without real-time information on kWh consumption, customers cannot meaningfully adjust their behavior—a clear sign of poor rate design.

Q. WILL CUSTOMERS RECEIVE ANY ADVANCE NOTICE BEFORE BEING MOVED INTO A TIER WITH A HIGHER CUSTOMER CHARGE?

A. No. Customers will have no advance notice that they have been moved between tiers and are subject to higher customer charge for the next eleven months. The reason for this lack of notice is that even "[t]he Company will not know until a customer's meter is read and a monthly bill generated that the customer's monthly usage has increased to within the usage range of the next tier, resulting in that customer being billed the higher customer charge associated with that new tier."[26] Simply put, customers cannot realistically monitor their usage or plan to avoid being placed in a higher tier.

The result is the same problem that the Company has with the existing inclining block energy charge. Customers have not adjusted their usage to respond to the

[24] The exceptions are the customers in National Grid's smart grid pilot program.

[25] Nat'l Grid, Resp. to Information Req. LI-2-12 at 1, Feb. 29, 2016.

[26] Nat'l Grid, Resp. to Information Req. VS-2-7, Mar. 2, 2016.

inclining block energy charge,[27] thereby defeating the intent of the current design of the inclining block energy charge. Like the current design of the existing inclining block energy charge, the Company's proposed tiered customer charge fails to send an actionable price signal to customers and do not empower customers to adjust their behavior. For these reasons, the tiered customer charge proposal is inconsistent with the Bonbright principles of simplicity, understandability, and (likely) public acceptability.

Q. HOW DOES THE COMPANY ENVISION THAT CUSTOMERS SHOULD BEHAVE UNDER A TIERED CUSTOMER CHARGE RATE STRUCTURE WHERE NO REAL-TIME USAGE INFORMATION IS AVAILABLE AND NO ADVANCE NOTICE OF MOVEMENT BETWEEN TIERS IS PROVIDED?

A. The Company emphasizes that "it will be important that customers are conscious of their energy consumption *every single day*, particularly during high use months, and work to keep consumption as low as possible to mitigate the chances of moving into a higher tier."[28]

Q. DO YOU THINK THIS "SOLUTION" TO THE ABSENCE OF REAL-TIME INFORMATION AND ADVANCE NOTICE IS FEASIBLE OR REALISTIC?

A. Plainly not. Such an approach places an unreasonable burden on customers to continuously monitor their electricity usage, regardless of how much energy they

[27] Nat'l Grid, Ex. NG-PP-1 at 50:9-12.

[28] Nat'l Grid, Resp. to Information Req. LI-2-12 at 1 (emphasis added).

are using during peak periods (and thus how much they are contributing to peak demand). The type of action that the Company is proposing requires extreme vigilance by customers indefinitely. The likely outcome is that customers will invariably pay less attention over time, will be moved into a higher tier, and will have to pay a higher charge for at least the next eleven months.

D. The Proposed Customer Charge Inappropriately Includes Demand-Related Costs

Q. IN ADDITION TO CUSTOMER-RELATED COSTS, WHAT COSTS DOES THE COMPANY SEEK TO RECOVER FROM CUSTOMERS THROUGH THE TIERED CUSTOMER CHARGE?

A. According to the Company, "[t]he charges for the third and fourth tiers recover the customer-related costs and a portion of the demand-related costs."[29]

Q. SHOULD THE CUSTOMER CHARGE RECOVER DEMAND-RELATED COSTS?

A. Absolutely not. The Company's approach is inconsistent with the point of cost-of-service allocation, which is to determine the cost responsibility of each customer class based on the class load characteristics—specifically: (1) demand-related costs, (2) energy-related costs, (3) customer-related costs, and (4) direct cost assignment for applicable customers. Rates should be designed based on the separation of these costs, and not on a conflation of these costs. By definition the demand-related costs vary with customer usage and it would be inappropriate to recover these costs through customer-related charges. Usage related costs should

[29] Nat'l Grid, Ex. NG-PP-1 at 68:3-4.

only be recovered through usage-based rates, and not through customer-related rates.

Q. IN YOUR EXPERIENCE, WHAT COSTS SHOULD BE INCLUDED IN THE CUSTOMER CHARGE?

A. The customer charge should only include costs that are directly attributable to the customer, regardless of usage. These costs include the meter, meter reading, the service drop, customer service, and billing.

E. National Grid Inappropriately Correlates Energy Usage and Demand in Designing the Phase II Customer Charges

Q. HOW DOES THE COMPANY CORRELATE ENERGY USE AND DEMAND IN ITS PROPOSED CUSTOMER CHARGE?

A. The Company "concluded that maximum kWh use can be reasonably expected to approximate customer size, as measured in kW."[30] Accordingly, the Company is using customer kWh consumption as a proxy for peak customer demand. The Company then differentiates the customer charge for customers based on a kWh range intended to reflect customers' monthly maximum use. National Grid is thereby trying to charge customers with larger peak customer demand more per month through the customer charge.

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[30] *Id.* at 41:19-20.

Q. WHAT IS THE RELATIONSHIP BETWEEN MAXIMUM ENERGY USAGE IN A BILLING PERIOD AND PEAK DEMAND IN A BILLING PERIOD GENERALLY?

A. The strength of the relationship depends on the customer. Specifically, the relationship depends on the load factor of the customer. A perfect load factor (i.e. the same amount of electricity usage for all hours of the billing period) will result in a perfect relationship between maximum energy usage and peak demand. However, such an outcome is extremely unlikely for customers. Most customers do not have a perfect load factor, and therefore the relationship between maximum energy usage and peak demand is less than perfect.

Q. WHAT IS THE RELATIONSHIP BETWEEN MAXIMUM ENERGY USAGE IN A BILLING PERIOD AND PEAK DEMAND IN A BILLING PERIOD FOR NATIONAL GRID CUSTOMERS?

A. An R^2 analysis is used to determine how well a linear model fits a set of observations. A perfect fit (i.e. a value of 1.0) would mean that all observations lie on the linear line and the model explains all of the variability in the data, whereby a value of 0.0 would mean that the model explains none of the variability in the data.

According to the Company, the R^2 for maximum hourly load and maximum billed usage over the course of one year for residential customers is 0.6093.[31] The R^2 for maximum hourly load and maximum billed usage over the course of one year for

[31] Nat'l Grid, Ex. NG-PP-10 at 1, Nov. 6, 2015.

small C&I customers is 0.7512.[32] These R^2 values indicate that neither residential customers nor small C&I customers show a strong relationship between maximum energy usage and peak customer demand.

Q. PLEASE ELABORATE.

A. More granular analyses further reveals the weak relationship between maximum energy usage and peak customer demand for National Grid customers. Table 3 below provides a summary of the R^2 values for both residential customers and small C&I customers, by class and proposed customer charge tier. The R^2 values for the residential tiers in Phase II range from 0.1134 to 0.4587. The R^2 values for the small C&I tiers in Phase II range from 0.0576 to 0.5727. Although the analyses of the tiers include a smaller sample size, the imperfect relationship between maximum energy usage and peak demand is readily apparent. Simply put, maximum billed usage is not indicative of maximum hourly load.

[32] *Id.* at 2.

Table 3: R^2 Values for Maximum Hourly Load and Maximum Billed Usage[33]

Customer Class	R^2 Value
Residential Customers	0.6093
R-1 Customers	0.5985
R-2 Customers	0.6637
R-1/R-2 Tier 1	0.1911
R-1/R-2 Tier 2	0.1352
R-1/R-2 Tier 3	0.1134
R-1/R-2 Tier 4	0.4587
Small C&I Customers	0.7512
G-1 Tier 1	0.2306
G-1 Tier 2	0.0576
G-1 Tier 3	0.3617
G-1 Tier 4	0.5727

Q. WHAT ARE THE IMPLICATIONS OF THE WEAK RELATIONSHIP BETWEEN MAXIMUM HOURLY LOAD AND MAXIMUM BILLED USAGE?

A. Since maximum billed usage is not indicative of maximum hourly load, the entire premise on which the tiered customer charge is built is flawed. The Company is trying to charge customers with high maximum hourly loads more money through the customer charge by relying on maximum billed usage as a proxy for demand. Given that maximum billed usage is a weak indicator of demand, the Company's proposed design does not achieve even its stated purpose.

F. The Proposed Customer Charge Is Improperly Based on Non-Coincident Peak Demand

Q. THE COMPANY'S PROPOSED CUSTOMER CHARGE SEEKS TO CHARGE CUSTOMERS WITH HIGH MAXIMUM HOURLY LOADS

33 *See* Nat'l Grid, Workpaper NG-PP-2, Nov. 6, 2015; *see also* Nat'l Grid, Resp. to Information Req. DPU-9-8, Jan. 13, 2016.

MORE MONEY. IS MAXIMUM HOURLY LOAD THE APPROPRIATE DETERMINATE OF COST CAUSATION?

A. No. Apart from the weak relationship between maximum billed usage and maximum hourly load that renders the proposed customer charge highly problematic, an even more fundamental flaw with the proposed customer charge is that it is based—by proxy—on customers' non-coincident peak demand ("NCP").

The costs that a customer imposes on the Company are related to the customer's demand that coincides with the collective peak demand of customers. The collective peak demand could be for the feeder or the substation that services the individual customer. An individual customer's contribution to the peak demand is commonly referred to as the coincident peak demand ("CP"). By contrast, an individual customer's maximum hourly load is the NCP. The CP is the appropriate measure of cost causation.

Q. ACCORDING TO THE COMPANY, "THE CUSTOMER'S ACTUAL CONTRIBUTION TO COSTS IS BASED UPON THE CUSTOMER'S MAXIMUM DEMAND (KW) USE ON THE SYSTEM (*I.E.* THE CUSTOMER'S MAXIMUM USE AT A POINT IN TIME)."[34] DO YOU AGREE?

A. No, I do not. With the exception of large customers with dedicated feeders, customers share the distribution system. An individual customer does not determine the infrastructure needs for National Grid.

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[34] Ex. NG-PP-1 at 34:1-3.

Q. WHAT ARE THE IMPLICATIONS OF RELYING ON NCP AS THE BASIS FOR RATE DESIGN, AS NATIONAL GRID PROPOSES?

A. National Grid's proposed customer charge based on NCP will create inequities and unfairness. Customers who do not contribute much demand to peak demand will subsidize customers who have high demand during peak demand periods. The customers who have high CPs impose greater costs on the distribution system (and ultimately all ratepayers) because high CPs ultimately lead to infrastructure upgrades or replacements. By contrast, the customers with low CPs impose fewer costs on the distribution system (and ultimately all ratepayers) because they do not significantly contribute to infrastructure upgrades or replacements. The end result is that customers that have high demand during peak periods drive the Company's need to invest resources, and therefore accompanying costs. Without any consideration of CP—which is what the Company proposes—all customers would pay for their maximum hourly usage regardless of how much they are contributing to peak demand.

Q. DO CP OR NCP FACTORS IMPACT COST RECOVERY?

A. No. A rate can be designed based on CP or NCP and still result in the same level of cost recovery. The issue at hand is not the level of revenue collected from customers, but rather the fairness of who is paying for the costs they impose. Accordingly, the use of CP or NCP is strictly a rate design issue.

Q. WHAT ARE THE COINCIDENT PEAKS FOR THE NATIONAL GRID CUSTOMERS WITH HOURLY METERING?

A. Unfortunately, National Grid does not appear to have the information necessary to conduct this analysis. According to National Grid, "the Company's load data does not include an indicator pertaining to location on a feeder or a substation."[35] Although Vote Solar asked for coincident peak information for each of the customers included in Exhibit NG-PP-10, National Grid did not provide the information.

Q. IN THE ABSENCE OF COINCIDENT PEAK INFORMATION, WHAT CAN YOU INFER FROM THE CUSTOMER DATA?

A. Although I'm unable to conduct a coincident peak analysis, I have conducted a frequency analysis of customers' maximum hourly load over the course of a year. Charts 1 through 9 below are frequency analyses for maximum hourly load for G-1, R-1, and R-2 customers by month, day of the week, and hour. The following charts clearly demonstrate a diversity of NCP demand during each of the time periods.

[35] Nat'l Grid, Resp. to Information Req. VS-1-6, Feb. 26, 2016.

Chart 1: Frequency Analysis for G-1 Customers of NCP by Month

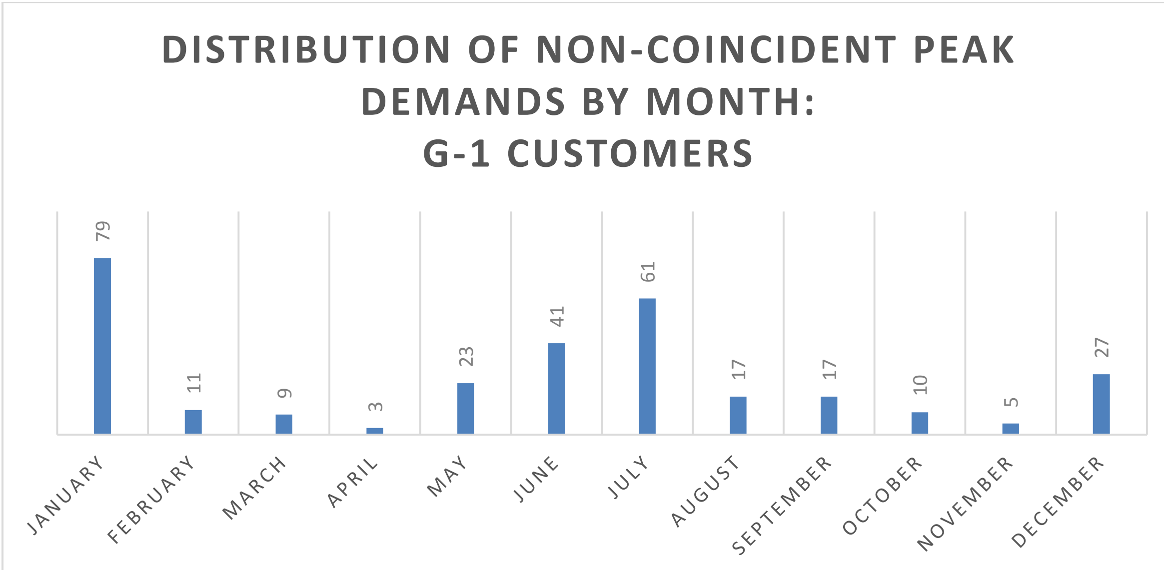


Chart 2: Frequency Analysis for G-1 Customers of NCP by Day of the Week

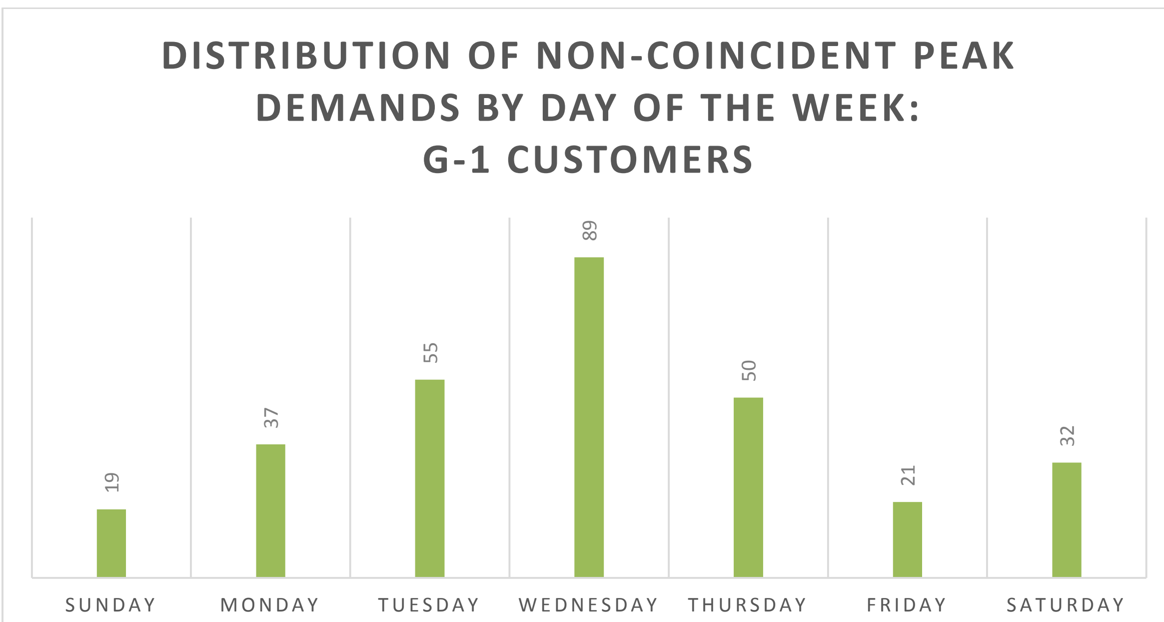


Chart 3: Frequency Analysis for G-1 Customers of NCP by Hour of the Day

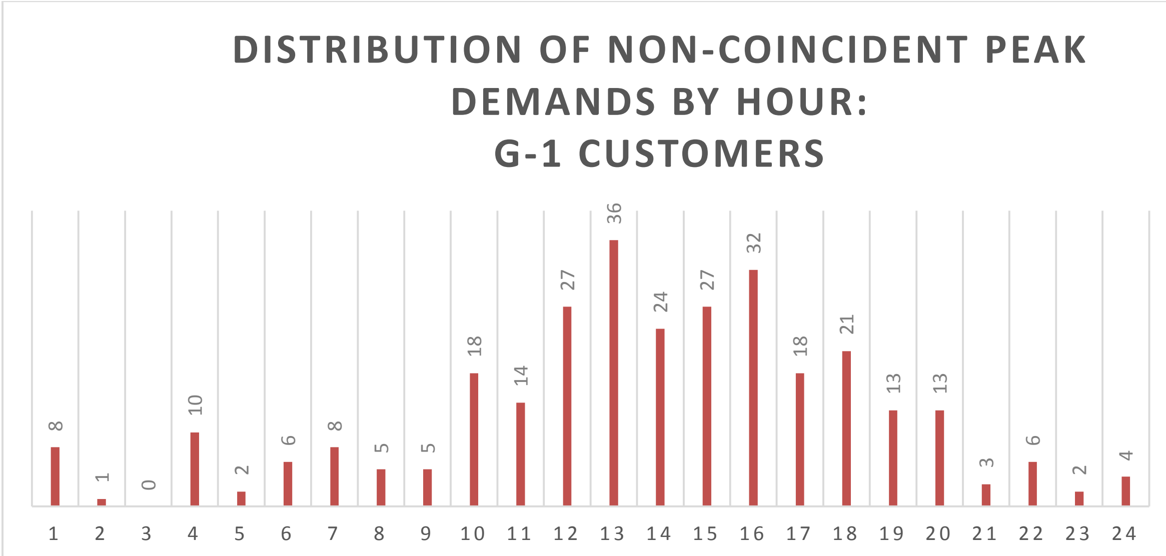


Chart 4: Frequency Analysis for R-1 Customers of NCP by Month

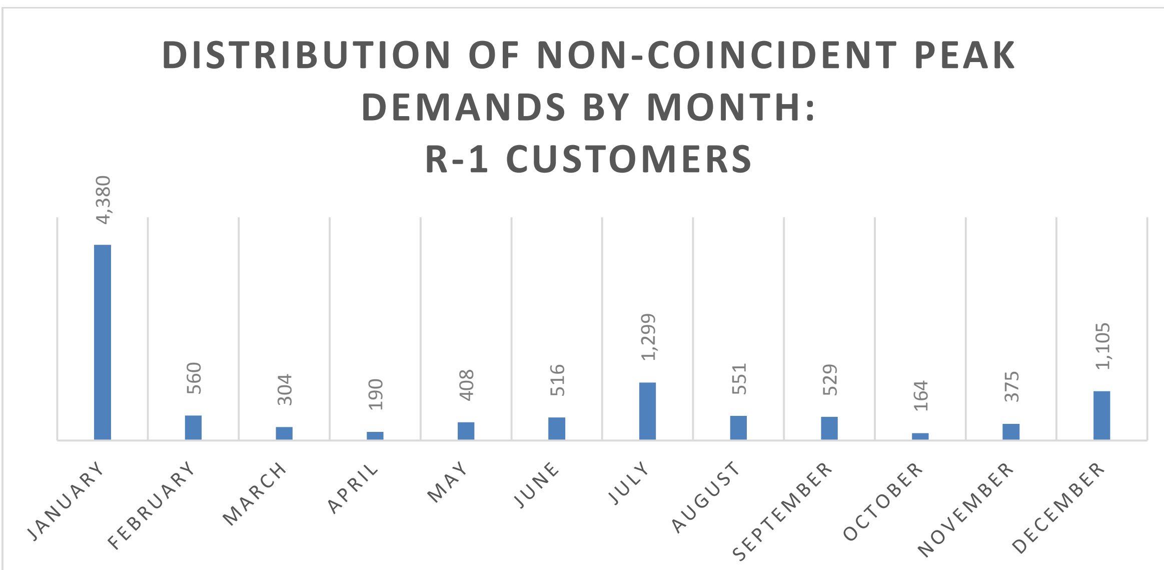


Chart 5: Frequency Analysis for R-1 Customers of NCP by Day of the Week

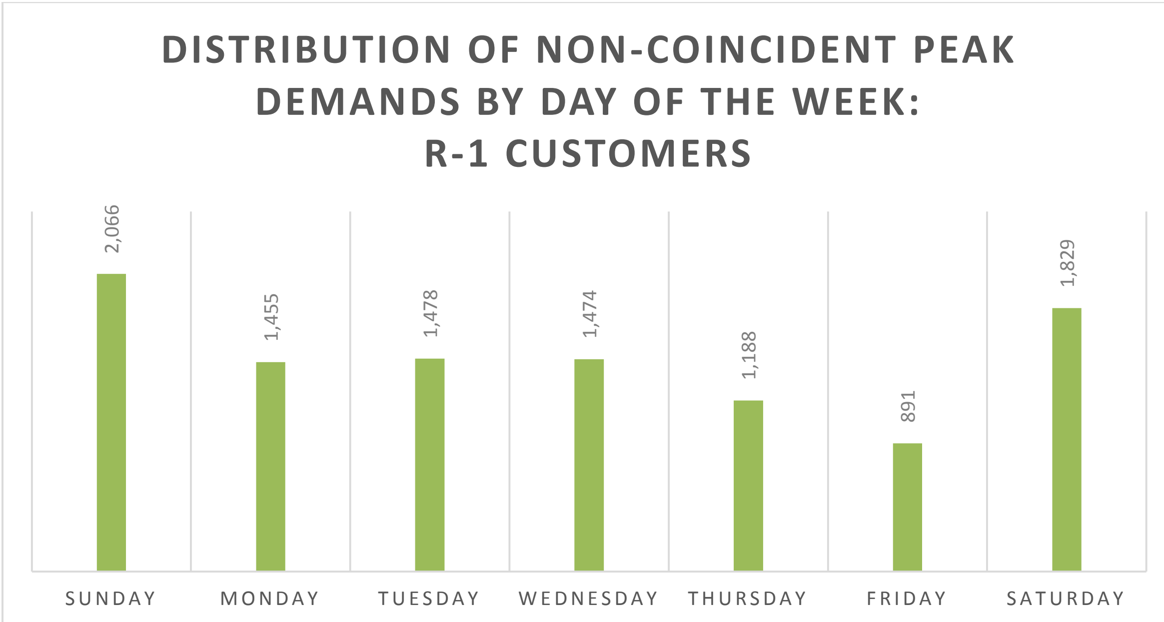


Chart 6: Frequency Analysis for R-1 Customers of NCP by Hour of the Day

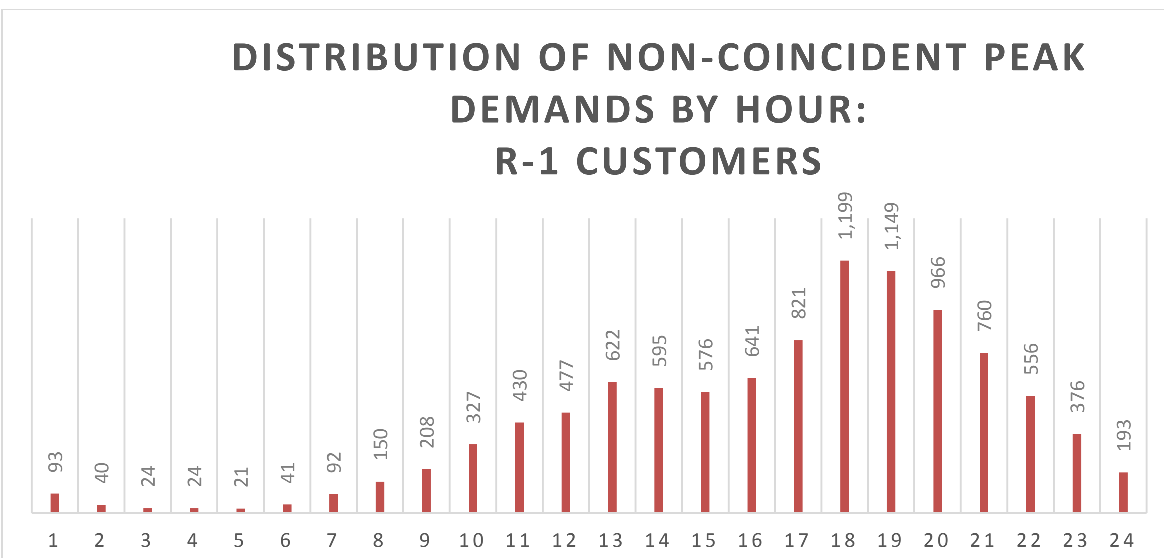


Chart 7: Frequency Analysis for R-2 Customers of NCP by Month

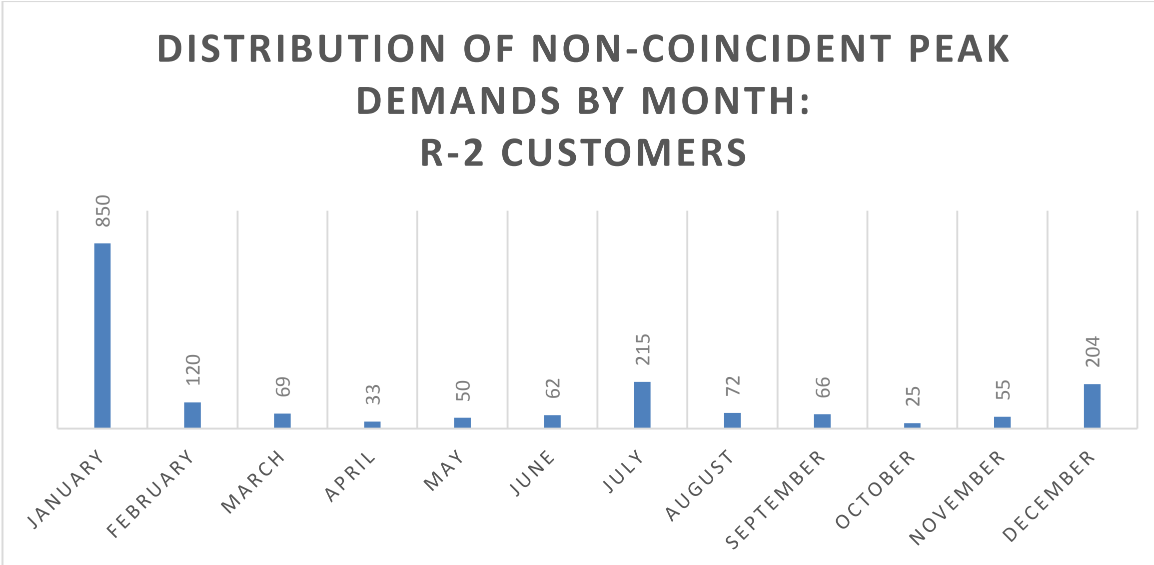


Chart 8: Frequency Analysis for R-2 Customers of NCP by Day of the Week

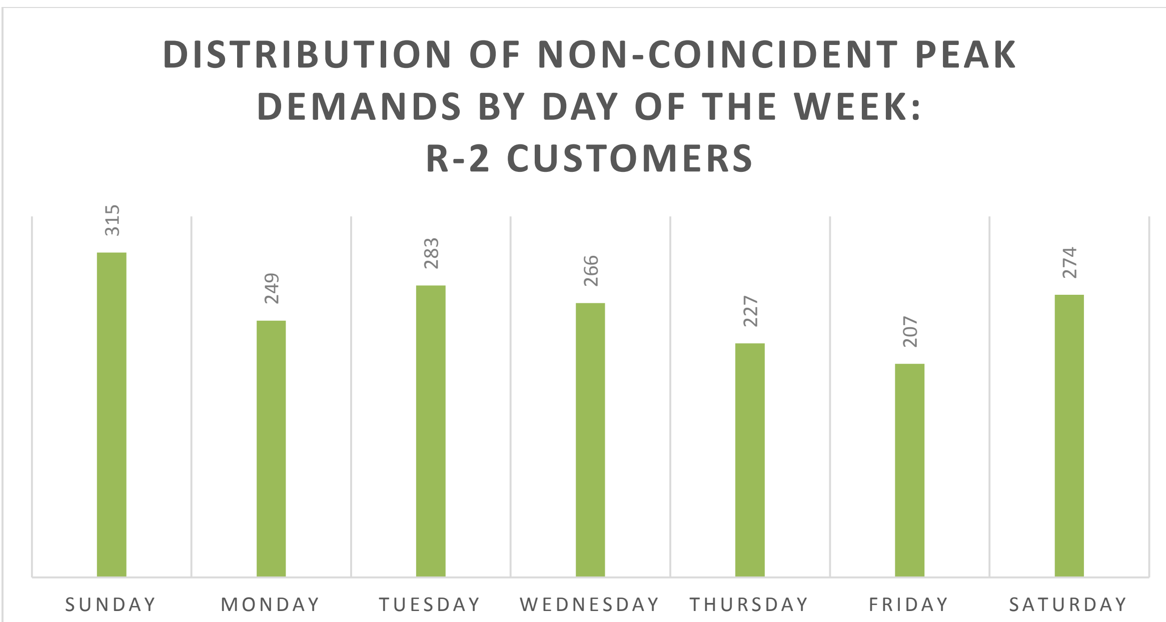
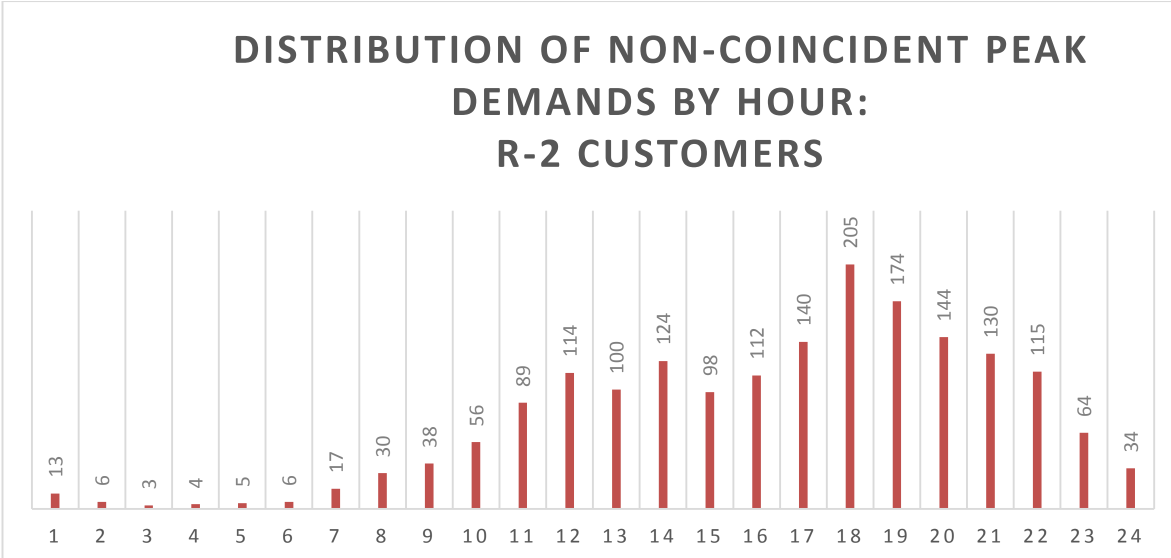


Chart 9: Frequency Analysis for R-2 Customers of NCP by Hour of the Day



Q. WHAT CAN YOU DISCERN FROM THE FREQUENCY ANALYSES?

A. Although information about each customer's CP demand is unavailable, the frequency analyses demonstrate the diversity of customers' NCP demand. Specifically, they show that customers' NCP demand occurs over every month of the year, every day of the week, and every hour of the day. The diversity of demand leads to a sharing of resources by customers. National Grid's design of the proposed customer charge based on customers' NCP completely ignores this reality.

Q. WHAT DO THE FREQUENCY ANALYSES DEMONSTRATE ABOUT THE PROPOSED TIERED CUSTOMER CHARGE?

A. The analyses confirm that NCP is not the appropriate determinant of the costs customers impose on the distribution system. Instead, the Company should use CP to truly reflect the costs that customers impose upon the distribution system. Stated another way, the Company's reliance on NCP to justify its customer charge is misplaced—the NCP basis for the tiered customer charge is flawed because it does not reflect cost causation.

Q. WHAT ARE YOUR CONCLUSIONS ABOUT THE COMPANY'S PHASE II PROPOSAL?

A. First, increased customer charges do not mitigate, but in fact create fairness and equity concerns. Second, customer charges do not send an appropriate and actionable price signal to customers. Third, the Company has failed to demonstrate a sufficiently strong relationship between maximum billed usage and maximum hourly load to justify using maximum bill usage as a proxy for maximum hourly load in designing the tiers of the proposed Phase II customer charges. Finally, a customer's maximum hourly load, or NCP, is an inappropriate basis for cost causation.

Q. WHAT IS THE LIKELY OUTCOME OF THE COMPANY'S TIERED CUSTOMER CHARGE PROPOSAL?

A. Since the Phase II proposal is based on the highest usage for the most recent twelve billing periods (including the current billing period), customers can get locked into a customer charge for behavior that has nothing to do with coincident peak. Furthermore, the behavior could be based on abnormal behavior (e.g., out-of-town guests). The end result is a punitive rate that may have nothing to do with cost causation.

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMPANY'S PHASE II RATE DESIGN PROPOSAL OF A TIERED CUSTOMER CHARGE?

A. For all of the aforementioned reasons, I recommend that the Commission reject the Company's Phase II proposal.

G. Public Service Commissions Around the Country Have Largely Rejected Utility Proposals to Increase Customer Charges.

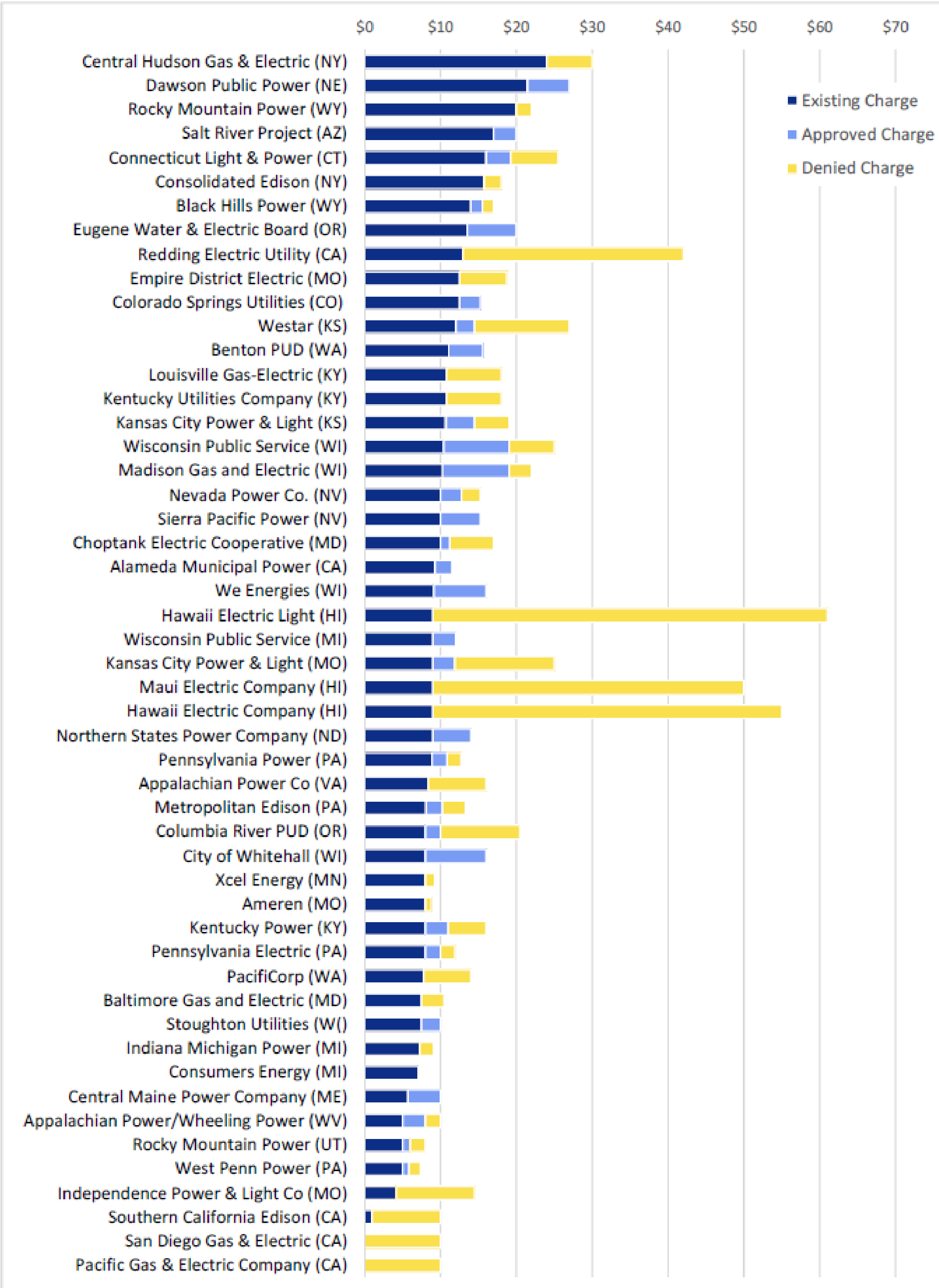
Q. ARE INCREASES IN CUSTOMER CHARGES COMMON ACROSS THE COUNTRY?

A. No. Although proposals to increase customer charges have been common over the past two years, 74.5% of the requests for increases to fixed charges have been either rejected outright, or only granted in part.[36] Although the reasons for rejections vary from jurisdiction to jurisdiction, common reasons have been (1) rate shock to customers, (2) the potential to undermine state policy goals, (3) customer control, (4) energy efficiency, (5) affordability, and (6) other policy goals.[37] In short, requests for increases in customer charges have not been very successful across the country because they are very blunt instruments with the potential to harm customers. Chart 1 below is a brief summary of the results of requests for increases to customer charges.

[36] *See* Ex. NP-3 at App. B.

[37] *Id.* at 30-32.

Chart 10: Recent Decisions Regarding Fixed Charge Proposals[38]



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[38] Ex. NP-3 at 11.

IV. NATIONAL GRID'S LONG-TERM PLAN TO IMPLEMENT DEMAND CHARGES FOR ALL CUSTOMERS WOULD AMOUNT TO A FIXED CHARGE FOR RESIDENTIAL AND SMALL C&I CUSTOMERS AND SHOULD BE REJECTED.

Q. HAS NATIONAL GRID PROPOSED A DEMAND CHARGE FOR G-1, R-1, AND R-2 CUSTOMERS IN THIS DOCKET?

A. No. However, the Company made several statements in regard to demand charges that must be addressed. The Company appears to view a tiered block customer charge as an interim step to demand charges. First, the Company states:

> Using [Bonbright's] principles as a guideline, the ideal rate design for all customer classes would consist of a customer charge designed to collect: (1) customer-related distribution system costs, such as the cost of a meter, billing, and customer service, plus (2) a demand charge that recovers the demand-, or capacity-, related system costs.[39]

Second, the Company states:

> Customer and demand charges are more reflective of the underlying cost of the distribution system and, therefore, communicate more accurate price signals to customers regarding the costs that the customers impose upon the system.[40]

Third, the Company states:

> Under a rate structure where a customer's monthly bill is based upon maximum demand, each customer's monthly charges would consist of a customer charge and a per-kW charge based upon the customer's maximum kW demand. Typically, this demand charge would be the same every month and would not vary with kWh consumption.[41]

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[39] Nat'l Grid, Ex. NG-PP-1 at 29-30.

[40] *Id.* at 33:10-12.

[41] *Id.* at 36:11-14.

These statements indicate that National Grid envisions a future with NCP demand charges for all customers.

Q. ARE DEMAND CHARGES FOR ALL CUSTOMERS CONSISTENT WITH BONBRIGHT'S PRINCIPLES OF SIMPLICITY, UNDERSTANDABILITY, PUBLIC ACCEPTABILITY, AND FEASIBILITY OF APPLICATION AND INTERPRETATION?

A. No, not currently. As the Company correctly notes, Bonbright identified the following rate attributes for consideration and balancing: simplicity, understandability, public acceptability, and feasibility of application and interpretation. For residential and small C&I customers, a demand charge falls well short of meeting these criteria.

Demand charges do not send price signals that enable most customers to respond. In 2013, the Ontario Energy Board commissioned a study that looked, in part, at different utility charges. [42] The Final Report found that:

> The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand [time-of-use rates]. It was not obvious how this would be calculated.
>
> Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast

[42] The Gandalf Group, *Ontario Energy Board Distribution Charge Focus Groups: Final Report* (2013), attached as Exhibit NP-6.

> majority of days during peak demand times and essentially helped to reduce peak consumption.[43]

These results from Ontario are not surprising. As a practical matter, demand charges are highly unlikely to compel any change in behavior among residential customers or small C&I customers. Many of these customers do not understand demand, and even the customers who do understand demand may not have the tools to manage their peak demand.

In short, demand charges are not appropriate for residential and small C&I customers at this point in time. Customers need to better understand their demand and need to be able to change their demand before a demand charge is appropriate. Otherwise, these customers will not be able to respond to the price signals of demand charges, and the end result will be a *de facto* fixed, punitive charge.

Q. DO DEMAND CHARGES SEND AN ACCURATE PRICE SIGNAL TO CUSTOMERS?

A. No. As in the case of the tiered fixed customer charges, demand charges do not send an actionable price signal to which these customers can meaningfully respond.

Q. ARE THERE ALTERNATIVES TO DEMAND CHARGES THAT SEND ACCURATE PRICE SIGNALS?

A. Yes. The point of a price signal is to get customers to adjust their behavior to respond to the price. There are much better rate designs than demand charges to adjust customer behavior. According to National Grid:

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43 *Id.* at 9.

> Encouraging customers to shift load from high use, peak periods into off-peak periods through demand management results in a better utilization of the existing distribution system and other elements of the electric system by reducing the number of hours that the distribution system has to serve peak loads.[44]

If the Company wants to move customer demand from peak demand periods to non-peak demand periods, then the Company should propose rates that send a price signal to customers to which customers can plan to respond. For instance, a time-of-use rate or a critical peak pricing ("CPP") rate would send such a price signal.[45] Implementing this type of time-varying rate would empower customers to change their behavior because they would have advance knowledge about when they should or should not use electricity.[46]

Q. WHAT IS YOUR CONCLUSION ABOUT DEMAND CHARGES FOR RESIDENTIAL AND SMALL C&I CUSTOMERS?

A. Although the Company appears to envision demand charges for all customer classes in the future, I recommend that the Department not accept this future scenario. Specifically, if the Department wants to send actionable price signals to customers, then demand charges are not the best avenue and should be rejected.

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[44] Nat'l Grid, Ex. NG-PP-1 at 30:9-12.

[45] In 2014, the Department chose to not implement time-varying rates for distribution rates. D.P.U. 14-04-B, Anticipated Policy Framework for Time Varying Rates 13-14, June 12, 2014. I nonetheless note that time-varying rates for distribution service are the most effective way to change customer behavior and reduce on-peak demand.

[46] A CPP rate would require the Company to inform customers when the CPP is going to happen *before* it actually occurs.

Furthermore, in addition to the many flaws and inadequacies of the customer charge proposal detailed above, each of which is sufficient reason alone to reject the proposal, the Department should reject the tiered customer charge as a stepping stone to the end goal of demand charges for all customers.

V. NATIONAL GRID'S PROPOSED ACCESS FEE FOR STAND-ALONE GENERATORS IS UNJUSTIFIED, SUFFERS FROM FATAL DESIGN FLAWS, AND SHOULD BE REJECTED.

Q. PLEASE DESCRIBE THE COMPANY'S STAND-ALONE GENERATOR ACCESS FEE PROPOSAL.

A. National Grid proposes an access fee that is applicable to stand-alone generators that apply for interconnection services after the effective date of Phase I rates. As proposed, the access fee is based on the nameplate capacity of the DG facility, adjusted for the facility's capacity availability factor, and is reflected in a fixed charge per month.

Q. WHAT IS THE COMPANY PROPOSING TO CHARGE STAND-ALONE GENERATORS?

A. National Grid's proposed charge is based on the voltage level at which a generator is connected. Specifically, the proposed fee is:

Primary Voltage Level (1,000 volts or greater):	$7.00 per kW-month
Secondary Voltage Level (less than 1,000 volts):	$8.50 per kW-month

Q. WHAT ARE "STAND-ALONE" GENERATORS?

A. The Company defines stand-alone generators as "DG facilities that are directly connected to the distribution system and have no associated on-site load for any

DG facility enrolled in any of the DG programs, such as Qualifying Facilities, net-metered facilities, and facilities resulting from any new programs approved in the future by the Department."[47]

Q. WHAT IS YOUR UNDERSTANDING OF WHY THE COMPANY SEEKS TO IMPLEMENT A NEW FIXED CHARGE FOR NEW STAND-ALONE GENERATORS?

A. The Company proposed this new fee because it believes that the current method of billing net-metered, stand-alone DG facilities does not adequately recover the costs the Company incurs to serve these customers.[48] In terms of what those costs are, the Company focuses on distribution costs associated with energy exports, in addition to ongoing operation, maintenance, and replacement costs of interconnection equipment.[49]

Q. DOES NATIONAL GRID SEEK TO RECOVER ANY OTHER COSTS THROUGH THIS NEW ACCESS FEE?

A. Yes, the Company briefly mentions the costs of interval metering required to meet ISO New England ("ISO-NE") reporting requirements, and costs associated with changes to the Company's dispatching requirements, coordination with the ISO-NE, outage and maintenance scheduling, system planning, and changes to customer service and billing systems and processes.

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[47] Nat'l Grid, Ex. NG-PP-1 at 70:16-20.

[48] *Id.* at 73:12-14.

[49] *Id.* at 74:5-9.

Q. HAS NATIONAL GRID ADEQUATELY DEMONSTRATED A NEED FOR THE ACCESS FEE?

A. No. While, the Company lists several costs associated with stand-alone projects,[50] the Company has not demonstrated that these costs are not already recovered in the interconnection process. Furthermore, the Company has not demonstrated that the costs to serve these customers are significantly different from other customers in the same rate class. Additionally, it is improper to recover the cost of interval metering through a fee that targets stand-alone generators.

Q. WHY DO YOU BELIEVE IT IS IMPROPER FOR NATIONAL GRID TO RECOVER THE COST OF INTERVAL METERING THROUGH ITS PROPOSAL?

A. The Company notes that stand-alone facilities on the G-1 rate class do not compensate the Company for the costs of interval metering required for these DG facilities to settle the corresponding generation asset at ISO-NE.[51] However, the settlement of these facilities at ISO-NE is required by the Department for the benefit of *all* ratepayers, not for the benefit of the individual customer.[52] As such, the stand-alone generators—and all Class II and Class III net metering facilities—should not be responsible for the costs of interval metering. Rather, all ratepayers (the beneficiaries of the interval metering) should be responsible for the costs of the interval metering.

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[50] *Id.* at 74-75.

[51] *Id.* at 74.

[52] *See* D.P.U. 09-03-A, Order Adopting Model Net Metering Tariff, Aug. 20, 2009.

Q. WHAT OTHER CONCERNS DO YOU HAVE WITH THE COMPANY'S RATIONALE FOR THE PROPOSED ACCESS FEE?

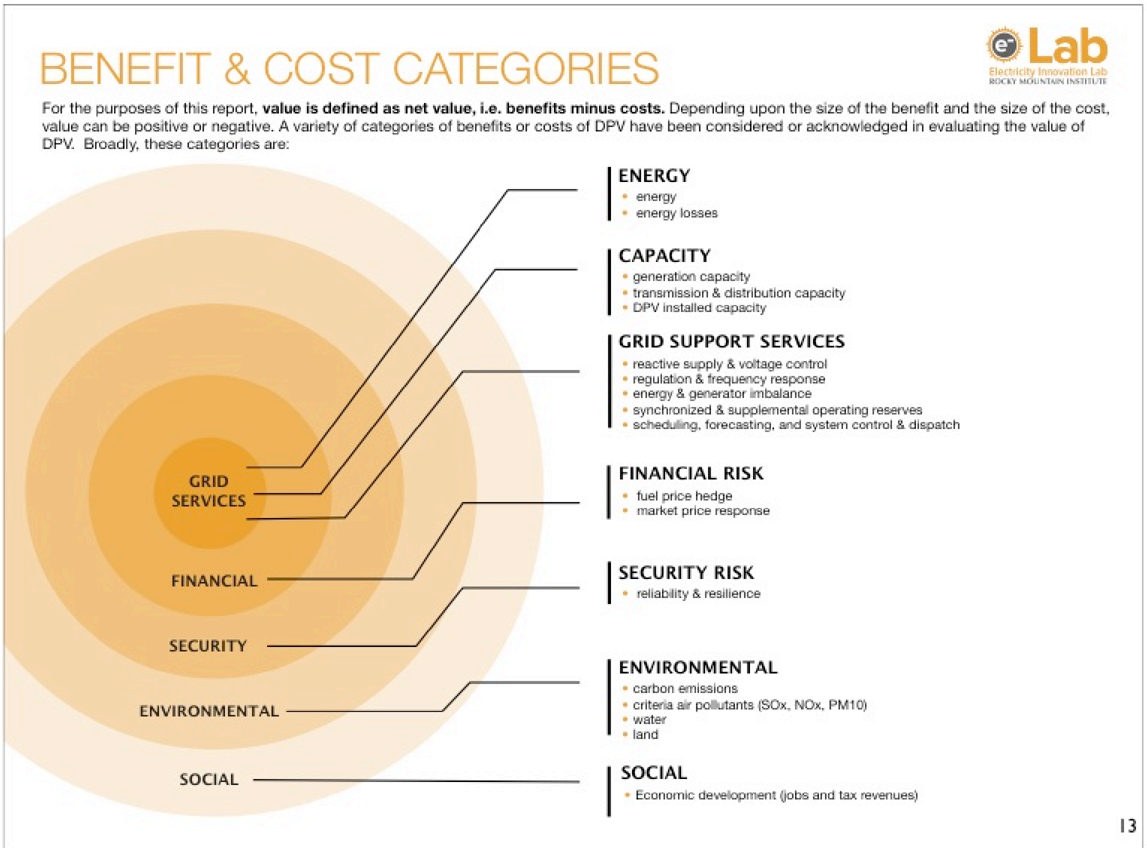
A. A major flaw in the Company's reasoning is that National Grid fails to analyze the associated benefits to all ratepayers as a result of these facilities. From the perspective of ratepayers, the need for an access fee should be based on the net costs (if any) of these facilities; that is, the Company should consider the costs as well as the benefits that stand-alone generators provide. The Company has provided no such analysis.

Q. WHAT TYPES OF BENEFITS ARE ASSOCIATED WITH STAND-ALONE DG FACILITIES AND DG MORE GENERALLY?

A There are many benefits of DG, especially DSG. The Rocky Mountain Institute ("RMI") conducted a meta-analysis of benefit and cost studies related to solar.[53] As part of this analysis, RMI categorized the benefits of solar. Chart 11 below is a summary of the benefits from the RMI meta-analysis.

[53] Lena Hansen & Virginia Lacy, Rocky Mountain Inst., *A Review of Solar PV Benefit and Cost Studies* (2013), *available at* http://www.rmi.org/Knowledge-Center%2FLibrary%2F2013-13_eLabDERCostValue.

Chart 11: Benefit & Cost Categories of DSG



The benefits associated with solar can easily outweigh the costs of solar. Only after a benefit and cost analysis will National Grid be able to say if stand-alone facilities are not paying their fair share of costs.

Q. **DOES EVIDENCE FROM OTHER STATES SUGGEST THAT NET METERING RATES RESULT IN A COST SHIFT FROM NET METERING TO NON-NET METERING CUSTOMERS?**

A. No. Evidence from other states actually suggests that the value of solar may exceed the retail rate. The results of DSG benefit and cost analyses can differ greatly depending on the assumptions and perspective of the entity sponsoring the study. As a result, it is important to look at studies sponsored or performed by an independent party, such as a state agency. A number of studies have been sponsored by independent state entities, and they conclude that the benefits provided by distributed solar generation to the utility exceed the costs. Table 4 below summarizes the results of recent studies performed by or for state governments.

Table 4: Recent Value of Solar Studies

State	Date	Sponsor	Resulting Value
ME	14-Apr-2015 (rev'd)	Legislature	33.7¢/kWh levelized[54]
VT	7-Nov-2014 (rev'd)	Legislature	23.7¢/kWh levelized[55]
MS	19-Sep-2014	PSC	17.0¢/kWh levelized[56]
NV	Jul-2014	PUC	18.5¢/kWh levelized[57]
MN	13-Feb-2014	Dep't of Commerce	14.5¢/kWh levelized[58]

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[54] Me. Pub. Utils. Comm'n, *Maine Distributed Solar Valuation Study* 6 (Apr. 2015), *available at* http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-FullRevisedReport_4_15_15.pdf.

[55] Vt. Pub. Serv. Dep't, *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014* 17 (Nov. 2014), *available at* http://psb.vermont.gov/sites/psb/files/Act%2099%20NM%20Study%20Revised%20v1.pdf.

[56] Elizabeth A. Stanton et al., Synapse Energy Econ., Inc., *Net Metering in Mississippi: Costs, Benefits, and Policy Considerations* 43 (Sept. 2014), *available at* http://www.synapse-energy.com/sites/default/files/Net%20Metering%20in%20Mississippi.pdf.

[57] Energy & Envtl. Econ., *Nevada Net Energy Metering Impacts Evaluation* 93 (July 2014), *available at* http://puc.nv.gov/uploadedFiles/pucnvgov/Content/About/Media_Outreach/Announcements/Announcements/E3%20PUCN%20NEM%20Report%202014.pdf?pdf=Net-Metering-Study.

The experiences in the states included in Table 4 demonstrate that the presumption of a cost shift is premature. Without evidence on the benefits and costs of stand-alone generators, any access fee is unjustified.

Q. IS IT YOUR VIEW THAT STAND-ALONE FACILITIES SHOULD NOT CONTRIBUTE TO THE COSTS OF ELECTRICITY SERVICES?

A. Absolutely not. All facilities should contribute to the costs of electricity services. However, there is no evidence that stand-alone facilities are not currently contributing the right amount given the costs incurred and the benefits that these resources provide. They may or may not be. My point is that the Company has not conducted the analysis necessary to make this determination and thus has not adequately justified its access fee proposal. Moreover, the Company has not sufficiently justified its use of different customer classes as proxies for stand-alone generators.

Q. HOW DID THE COMPANY DERIVE THE PROPOSED ACCESS FEE LEVELS?

A. According to the Company:

> The Company is proposing an access fee of $7.00 per kW-month for stand-alone distributed generation units connected at the primary voltage level (i.e., voltage ≥ 1,000 volts) and $8.50 per kW-month for customers connected at secondary voltage (voltage < 1,000 volts). These proposed charges are identical to the proposed demand charges for Rate G-3 (the basis for the primary voltage fee) and Rate G-2 (the basis for the secondary voltage fee)

[58] Peter Fairley, *Minnesota Finds Net Metering Undervalues Rooftop Solar*, IEEE Spectrum (Mar. 24, 2014), *available at* http://spectrum.ieee.org/energywise/green-tech/solar/minnesota-finds-net-metering-undervalues-rooftop-solar.

> that are developed in the Company's proposed distribution rate design on Exhibit NG-PP-13, pages 4 and 5.[59]

Thus, the Company appears to have used the proposed demand charges for the G-2 and G-3 customer classes as proxies for the proposed access fee, even though stand-alone generators are on the G-1 rate.

Q. DO YOU AGREE WITH THIS APPROACH?

A. No, I do not. The Company has not provided any analysis that the proposed access fee is set to recover the costs—let alone net costs—associated with stand-alone facilities. Despite the Company's discussion of the types of costs it seeks to recover, National Grid has not demonstrated that the proposed access fee is cost based.

Q. HAS THE COMPANY DEMONSTRATED THAT THERE IS A RELATIONSHIP BETWEEN STAND-ALONE GENERATORS AND CLASS G-2 AND G-3 CUSTOMERS?

A. No. While the Company has stated in discovery that most of the stand-alone DG units are similar in size and service needs to Class G-2 and G-3 customers,[60] it has not provided evidence to support this claim. The Company has confirmed that: "[It] has not conducted an analysis on whether the reliance on the [Electric Power System] by a typical 'stand-alone' DG facility is greater than, equal to, or less than electricity customers on Rates G-2 and G-3, and the Company is not certain that it could make such a determination."[61]

[59] Nat'l Grid, Resp. to Information Req. DPU-12-4, Jan. 29, 2016.

[60] Nat'l Grid, Resp. to Information Req. AC-1-3, Feb. 19, 2016.

[61] Nat'l Grid, Resp. to Information Req. AG-27-10, Mar. 10, 2016.

Q. HAS THE COMPANY CONSIDERED THE IMPACTS OF ITS PROPOSED ACCESS FEE PROPOSAL ON DG?

A. No. As National Grid admitted in discovery, "The Company did not analyze whether the proposed Access Fee will impact the development of distributed generation ('DG'), or 'stand-alone' DG."[62]

Q. WHAT DO YOU CONCLUDE ABOUT THE PROPOSED ACCESS FEE?

A. The Company has failed to demonstrate that (1) an access fee is needed, (2) the proposed access fee is set at a correct level, and (3) there is a relationship between stand-alone generators and class G-2 and G-3 customers. For all of the aforementioned reasons, the Department should reject National Grid's proposed access fee.

VI. CONCLUSION AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. After review of National Grid's filing and responses to information requests, I recommend that the Department reject the Company's proposed Phase II customer charge and the proposed access fee for stand-alone generators. I conclude that the Department should reject the Company's proposed inclining block customer charge because: (1) increased customer charges do not address, and in fact create, fairness and equity issues; (2) customer charges do not send an appropriate and actionable price signal to customers; (3) the Company has failed to demonstrate a sufficiently strong relationship between maximum billed usage and maximum hourly load to justify using maximum bill usage as a proxy for

[62] Nat'l Grid, Resp. to Information Req. EFCA-1-8, Feb. 11, 2016.

maximum hourly load in designing the proposed Phase II customer charges; and (4) a customer's maximum hourly load, or NCP, is an inappropriate basis for cost causation. I also conclude that demand charges are not suitable at this point in time for residential and small C&I customers.

Finally, I conclude that the Department should reject the Company's proposed access fee for stand-alone generators because the Company has failed to demonstrate that (1) an access fee is needed; (2) even if it is needed, the proposed access fee is set at a correct level; and (3) there is a relationship between stand-alone generators and class G-2 and G-3 customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Vote Solar Exhibit NP-2

Nathan Raymond Phelps
Vote Solar
Program Manager, DG Regulatory Policy
89 South Street
Suite 203
Boston, MA
02111
(860) 478-2119
Nathan@votesolar.org

Education:

Tufts University
Medford, MA ABD

MA candidate in the Urban and Environmental Policy and Planning Department

Focus: Environmental Policy with a special emphasis on Energy Policy

Willamette University
Salem, OR BA Spring 2005

Majors: Environmental Science; and Politics

Minor: Geography

Manchester Community College
Manchester, CT AS Spring 2003

Major: General Studies

Connecticut School of Broadcasting
Farmington, CT Graduated Spring 1998

Professional Experience:

Vote Solar
Boston, MA October 2013 – Present

Manager of distributed solar generation policy research, development, and implementation for Vote Solar. Engage in related state, regional, and national regulatory processes.

Massachusetts Department of Public Utilities
Boston, MA June 2008 – October 2013

Senior economist for the Electric Power Division of the Massachusetts Department of Public Utilities ("DPU"). Primary focus at the DPU was all issues related to distributed generation, and renewable energy, including net metering, interconnection, and long-term contracts for renewable energy.

Massachusetts Technology Collaborative- Renewable Energy Trust
Westborough, MA January 2007 – December 2007

Policy intern for Fran Cummings. Assisted Mr. Cummings in policy development and implementation for the Massachusetts Renewable Energy Trust.

Tufts Institute of the Environment (TIE)
Medford, MA October 2005 - April 2006

Research Assistant for Professor Ann Rappaport.

Oregon Department of Energy
Salem, OR January 2005 – May 2005

Renewables Intern for Carl DeWitt. The primary focus of the research was to evaluate renewable portfolio standards from around the United States, and develop best practices for possible implementation in Oregon.

Connecticut General Assembly
Hartford, CT January 2001 – May 2001

Intern for Senator Martin Looney.

<u>Testimony</u>

In the Matter of the Application of Southern Maryland Electric Cooperative, Inc. for Authority to Revise Its Rates and Charges for Electricity Service and Certain Rate Design Charges
Maryland Case No.: 9396

In the Matter of the Merger of Exelon Corporation and PEPCO Holdings, Inc.
Maryland Case No.: 9361

Presentations

Distribution Network Policy Matters
Northeast Energy and Commerce Assc. March 2016

Appropriate Valuation Factors for Small DER
MD PSC (PC 40) October 2015

Electricity 101
Northeast Sustainable Energy Assc. March 2015

Evaluating the Benefits and Costs of Solar PV
MADRI Working Group May 2014

Interconnection and Net Metering in Massachusetts
Innovations in Clean Energy September 2012

Net Metering in Massachusetts & Community Solar
ASES Solar 2010 May 2010

Net Metering in Massachusetts
EUEC February 2010

Utility Ownership of Solar Generation in a Deregulated Market
EUEC February 2010

Vote Solar Exhibit NP-3

Caught in a Fix

The Problem with Fixed Charges for Electricity

Prepared for Consumers Union

February 9, 2016

AUTHORS

Melissa Whited
Tim Woolf
Joseph Daniel

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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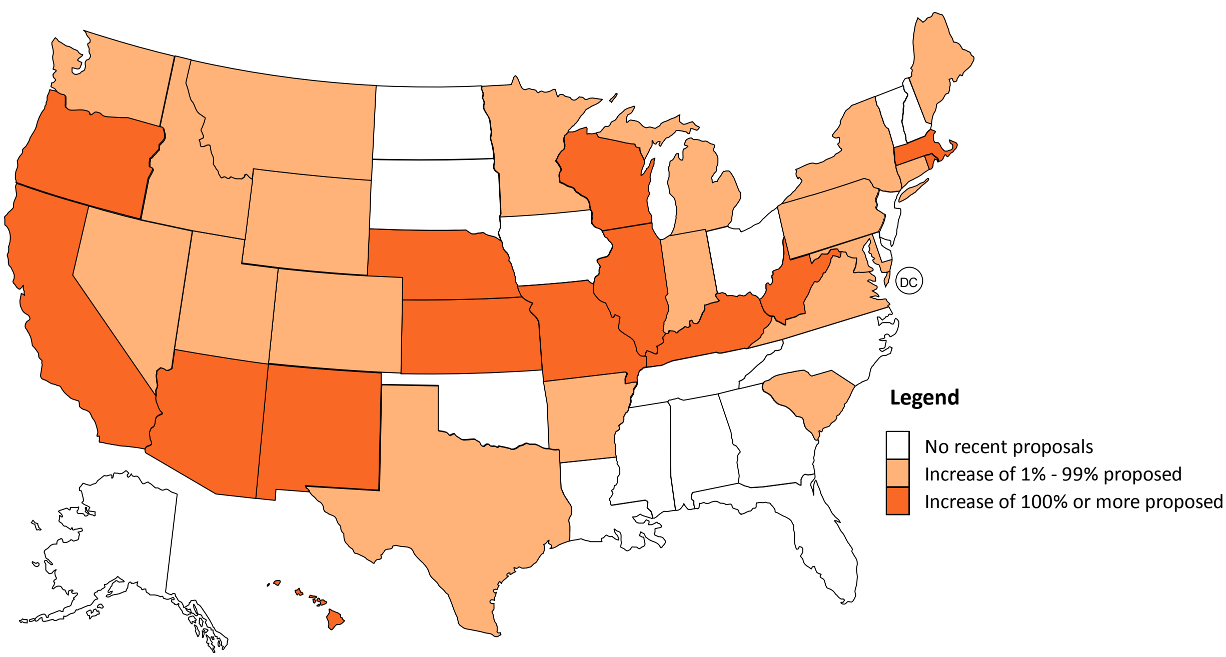
CONTENTS

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



Source: See Appendix B

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.

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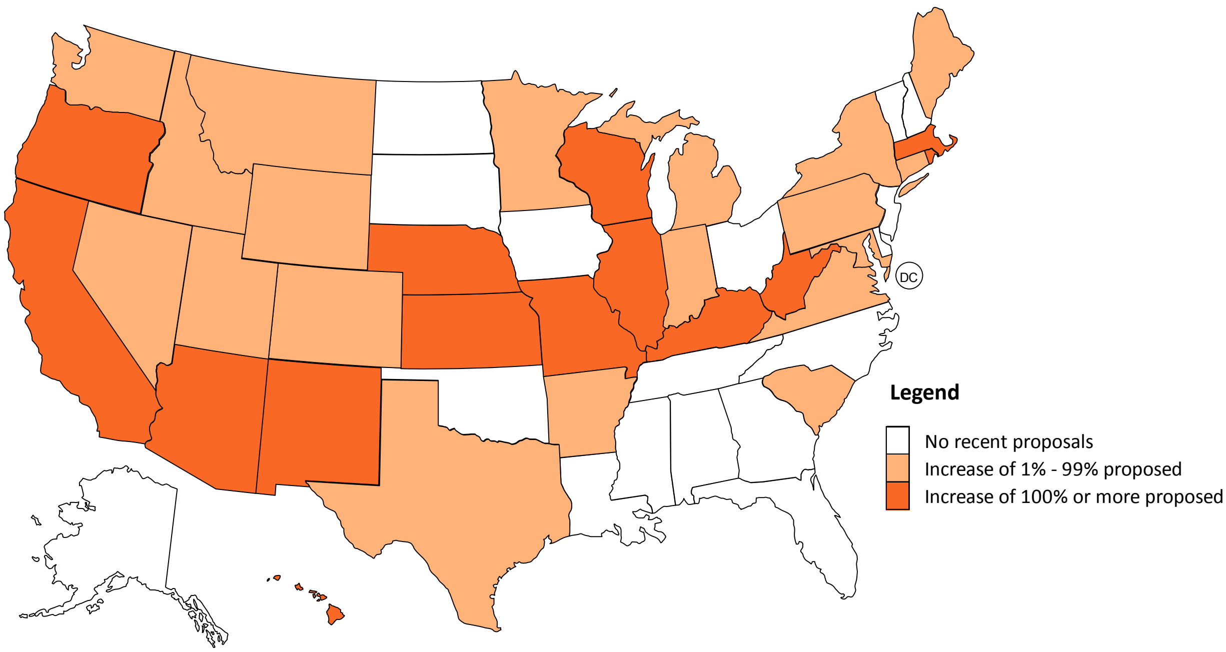
[2] Written comment of John Dupell, Docket 14-05-06, filed May 30, 2014

[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.

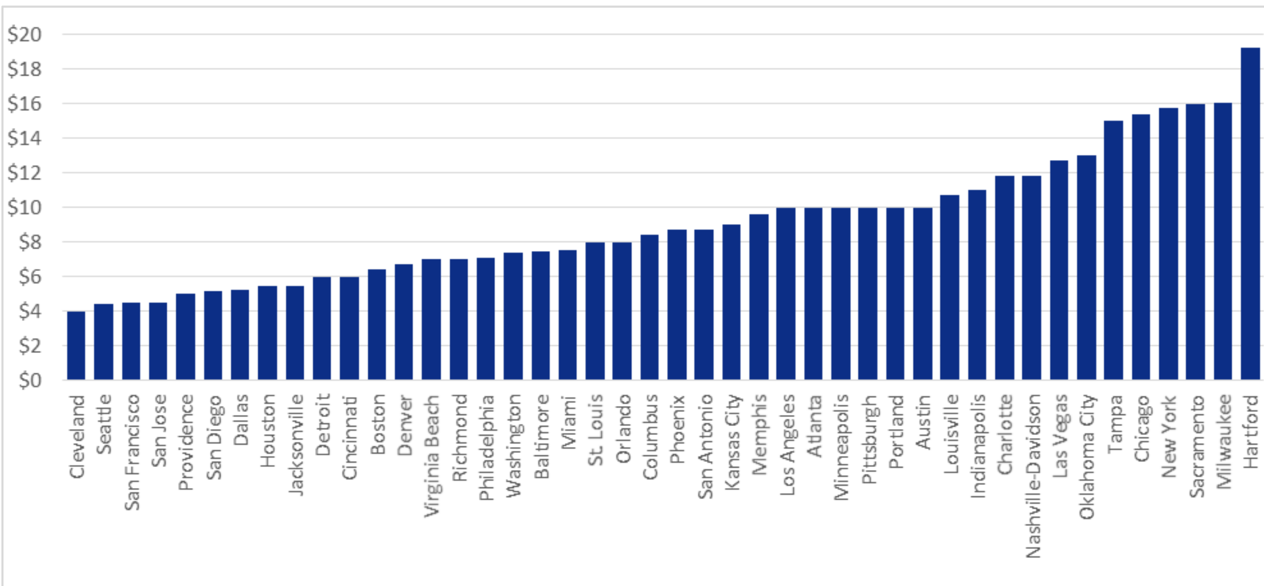
[5] Senate Bill No. 1502, June Special Session, Public Act No. 15-5, "An Act Implementing Provisions of the State Budget for The Biennium Ending June 30, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State."

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.

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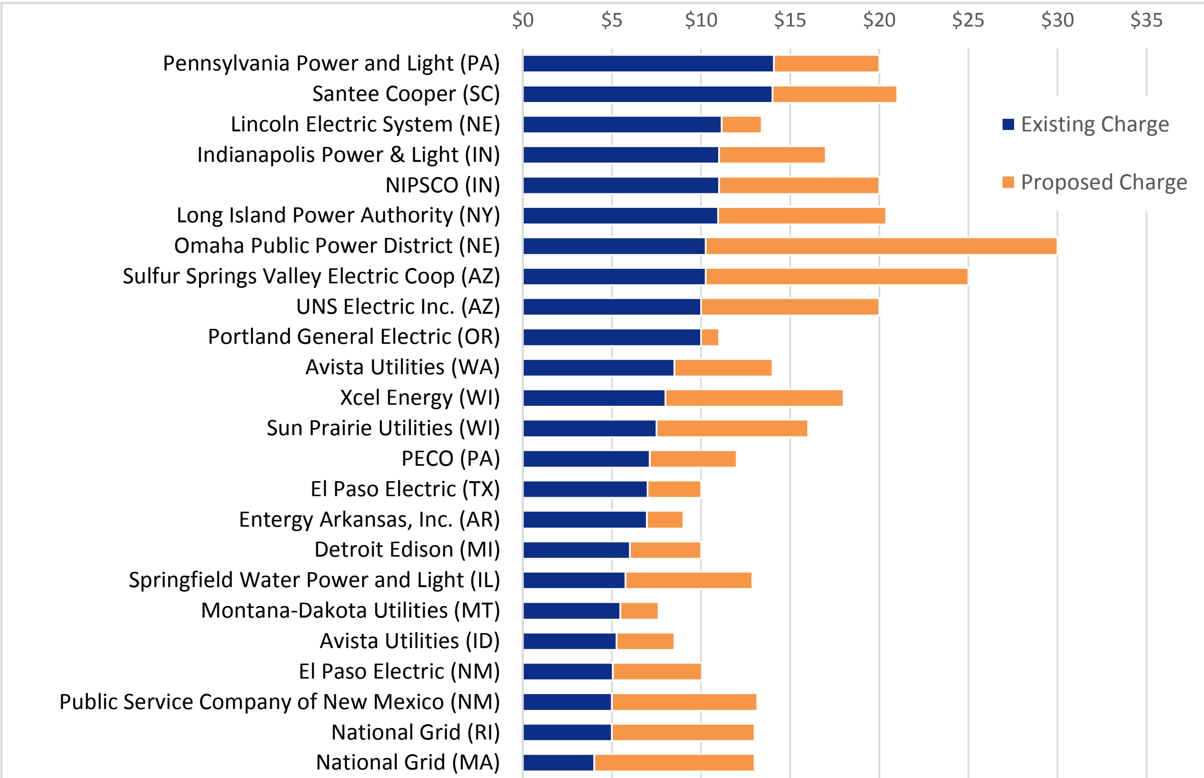
[8] Ultimately the commission approved a fixed charge of $19.25, below the utility's request, but among the highest in the country.

[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.

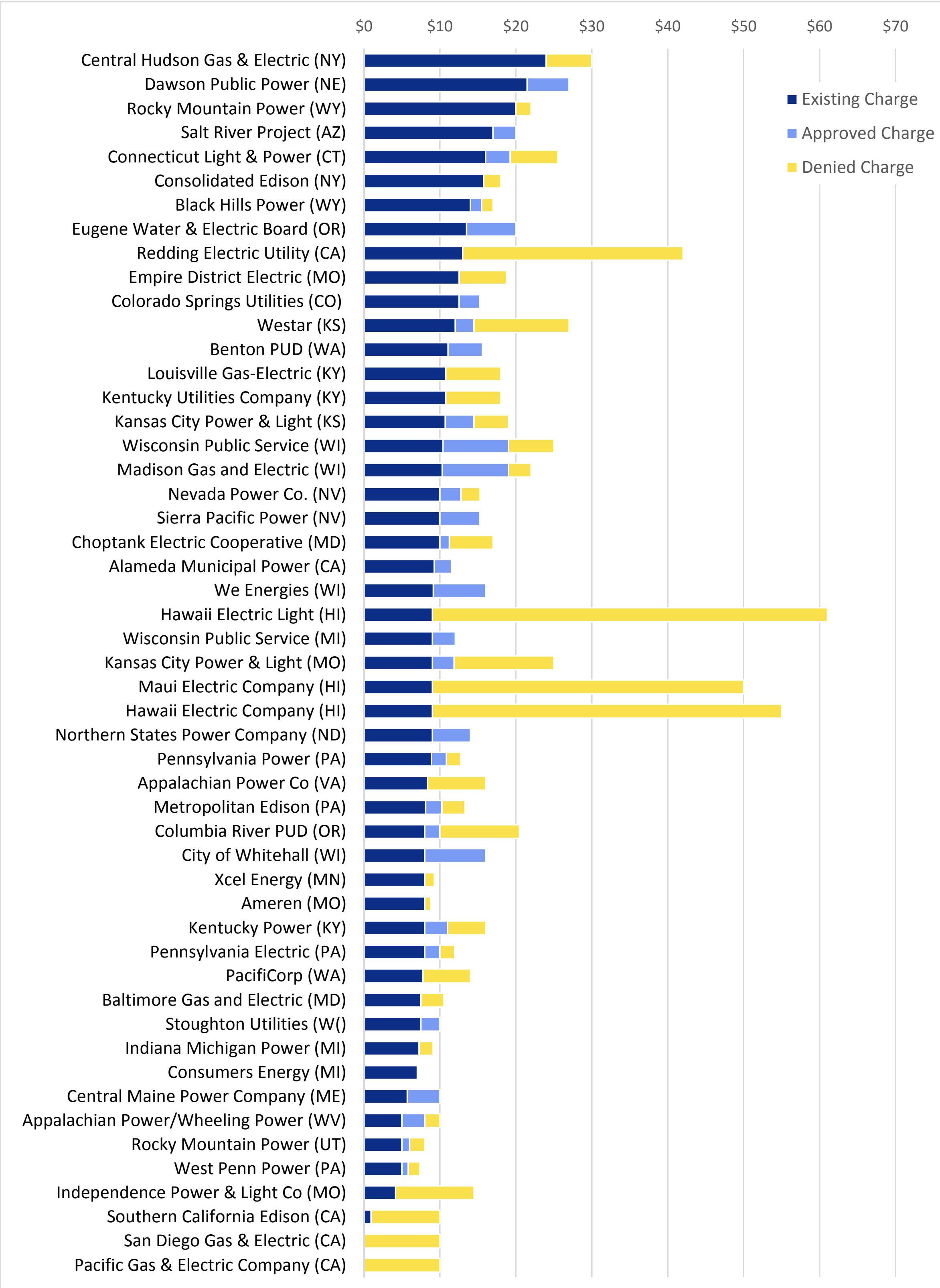
[11] PPL Witness Scott R. Koch, Exhibit SRK 1, Supplement No. 179 to Tariff – Electric Pa. P.U.C. No. 201, Docket No. R-2015-2469275, March 31, 2015, at http://www.puc.state.pa.us/pcdocs/1350814.pdf.

Figure 3. Pending proposals for fixed charge increases



Source: See Appendix B

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.

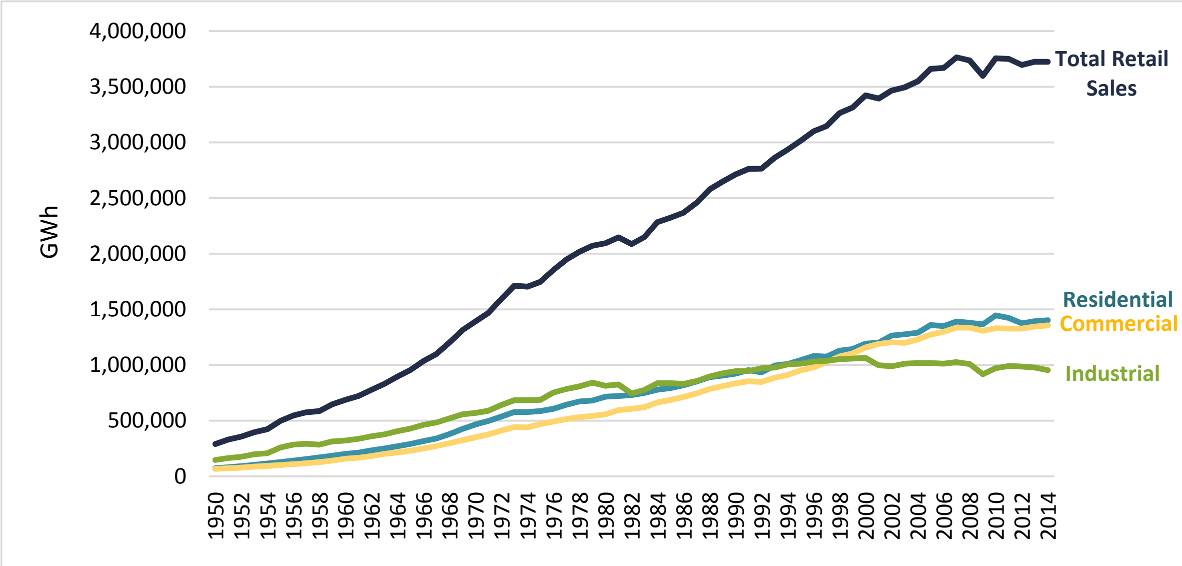
Rates are typically composed of some combination of the following three types of charges:

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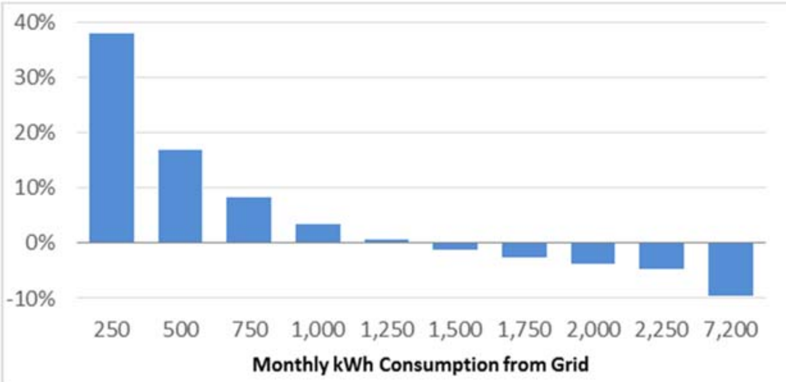
[15] Phil Carson, "Connecticut Light & Power Engages Customers," *Intelligent Utility*, July 1, 2011, http://www.intelligentutility.net/article/11/06/connecticut-light-power-engages-customers?quicktabs_4=2&quicktabs_11=1&quicktabs_6=1.

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

Figure 6. Increase in average monthly bill

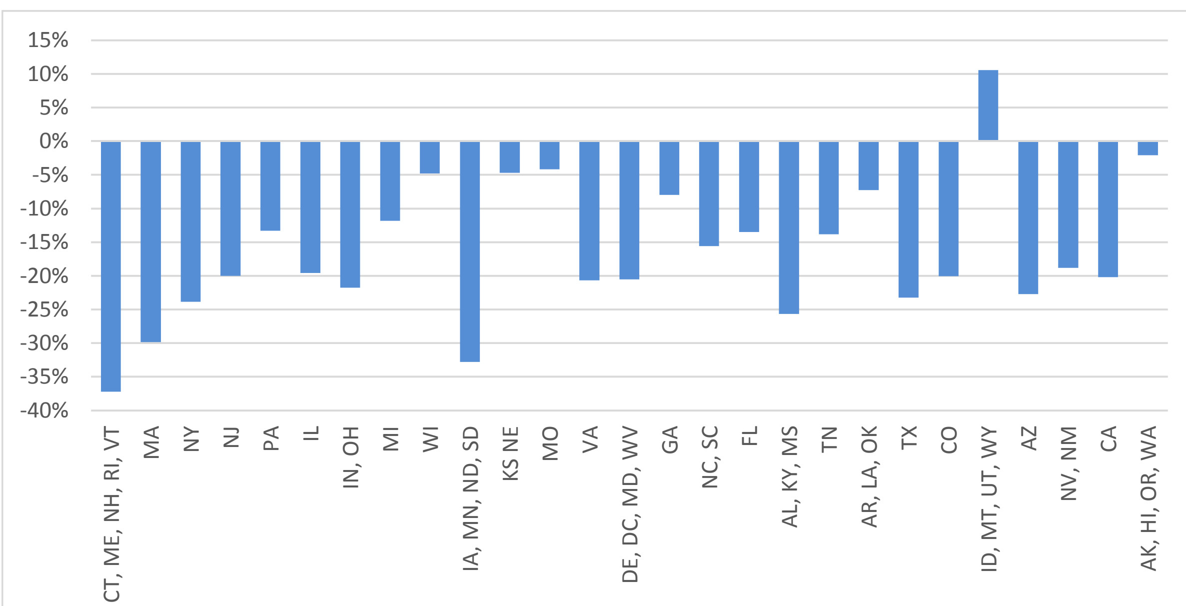


Analysis based on increasing the fixed charge from $9/month to $25/month, with a corresponding decrease in the $/kWh charge.

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.

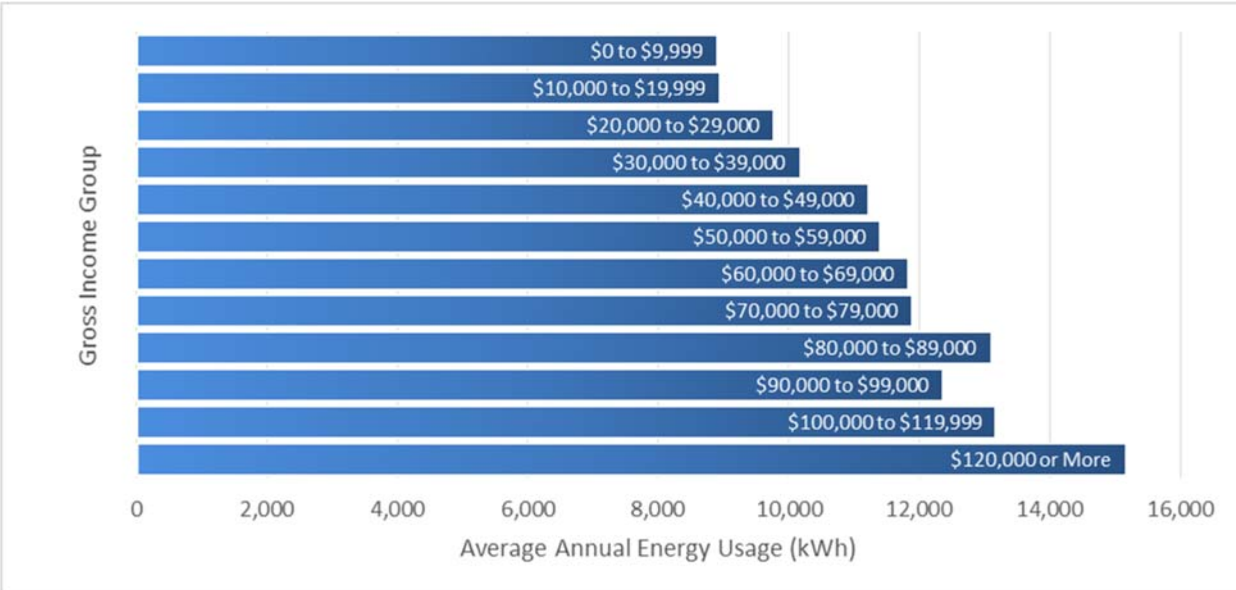
Figure 7. Difference between low-income median residential electricity usage and non-low-income usage



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.

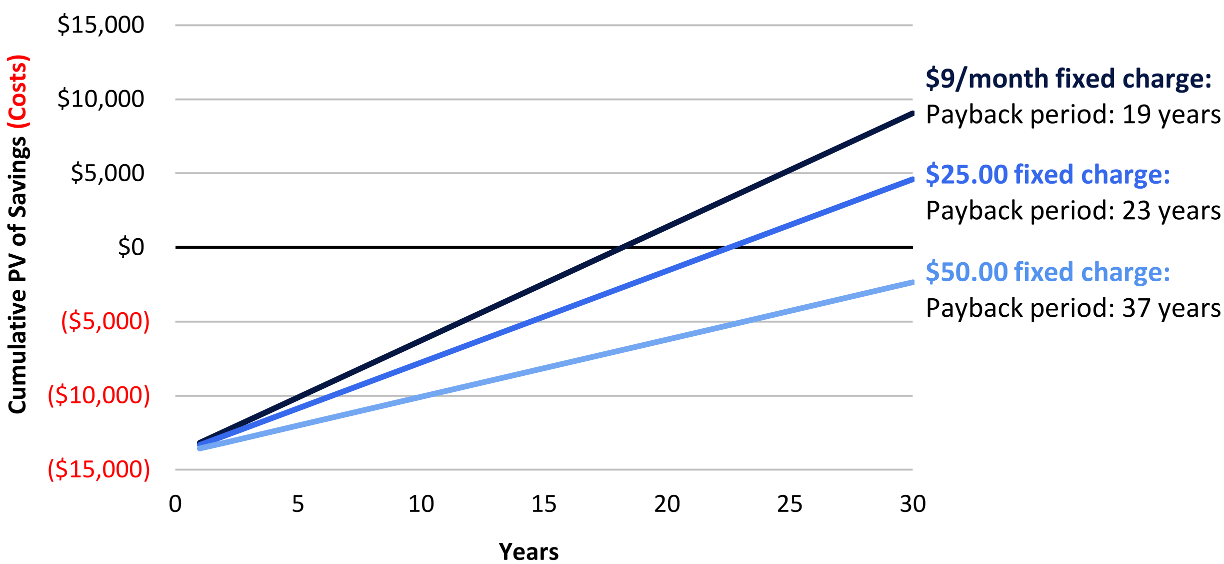
[17] Annie Gilleo et al., "The 2014 State Energy Efficiency Scorecard" (American Council for an Energy Efficient Economy, October 2014).

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]

Increased Electricity System Costs

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

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"

<u>Argument</u>

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

<u>Response</u>

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"

<u>Argument</u>

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.

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 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.

<u>Response</u>

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.

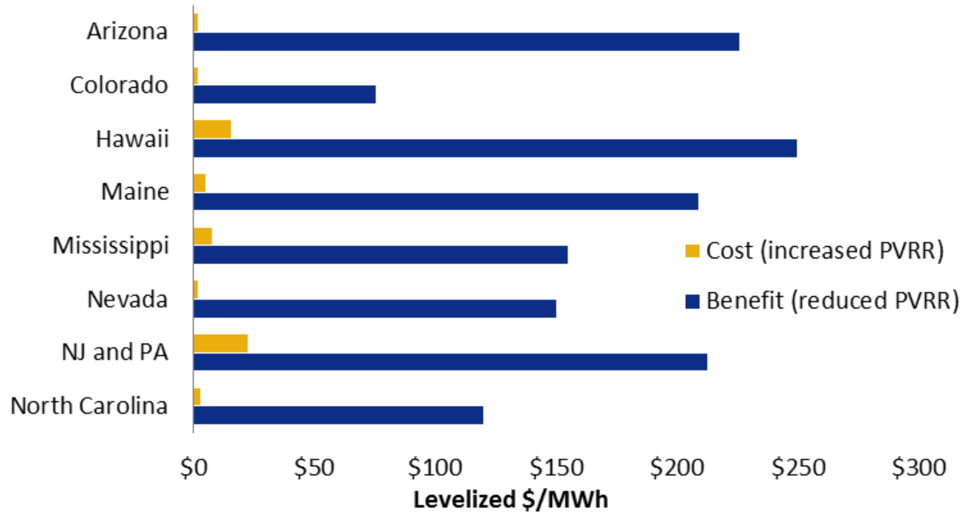
The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may even eliminate, any cost-shifting that might occur.

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

[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.

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[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.

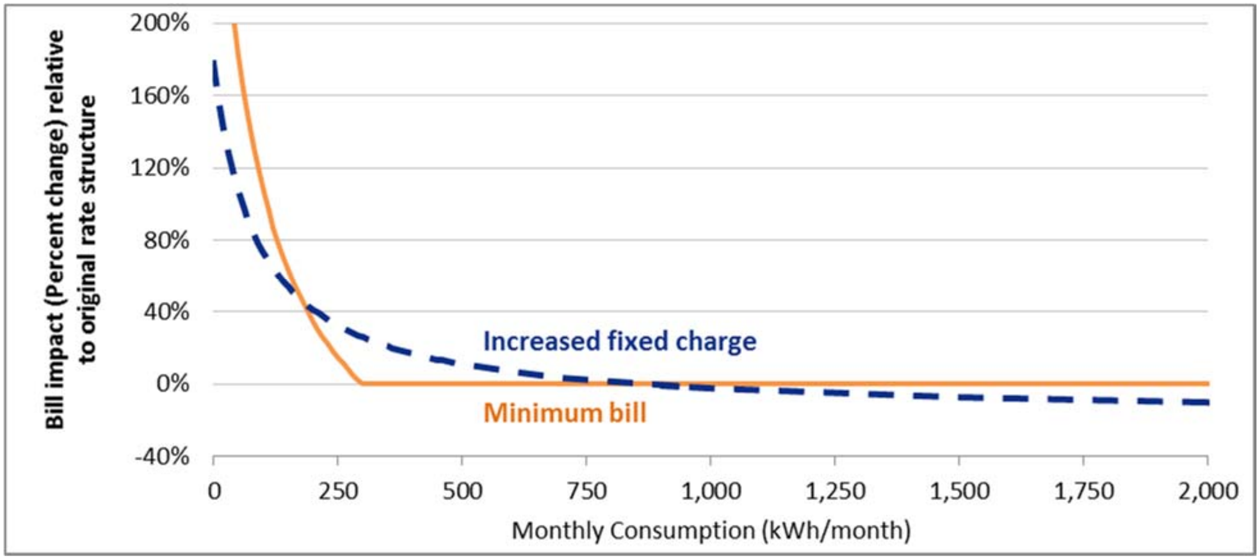
Under the minimum bill option, only customers with usage less than 280 kWh per month (approximately 5 percent of customers at a representative Midwestern utility) would see a change in their bills, and most of these customers would see an increase in their monthly bill of less than $10.

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

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[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.

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[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

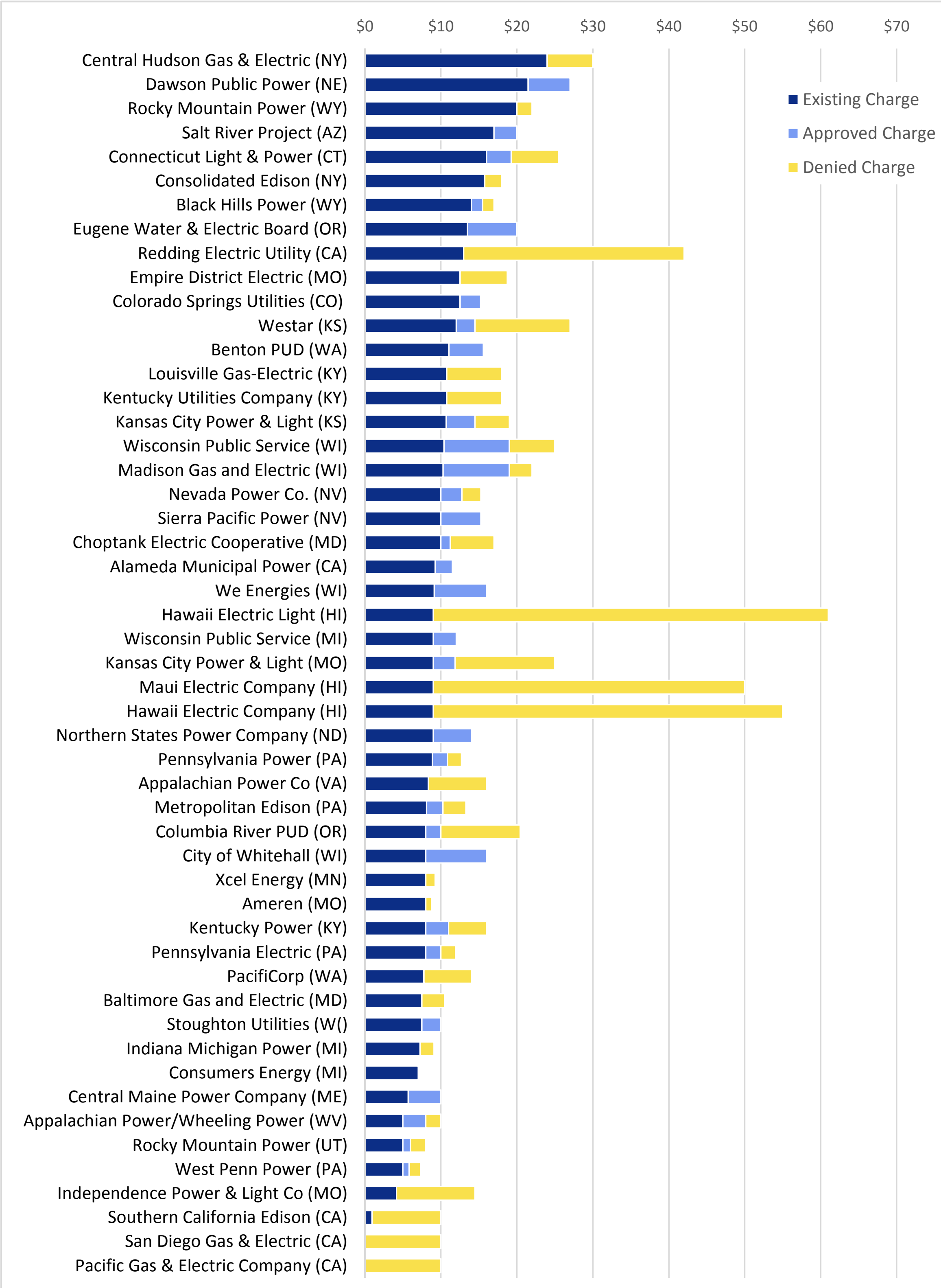
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

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		

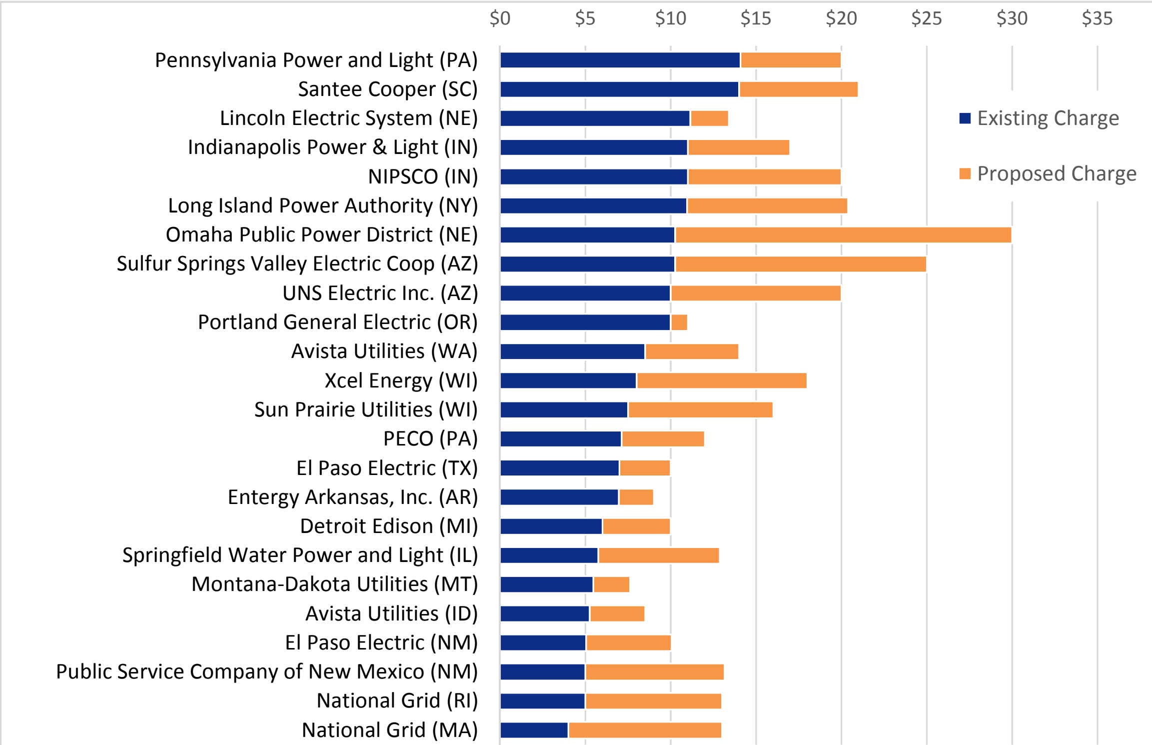
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

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

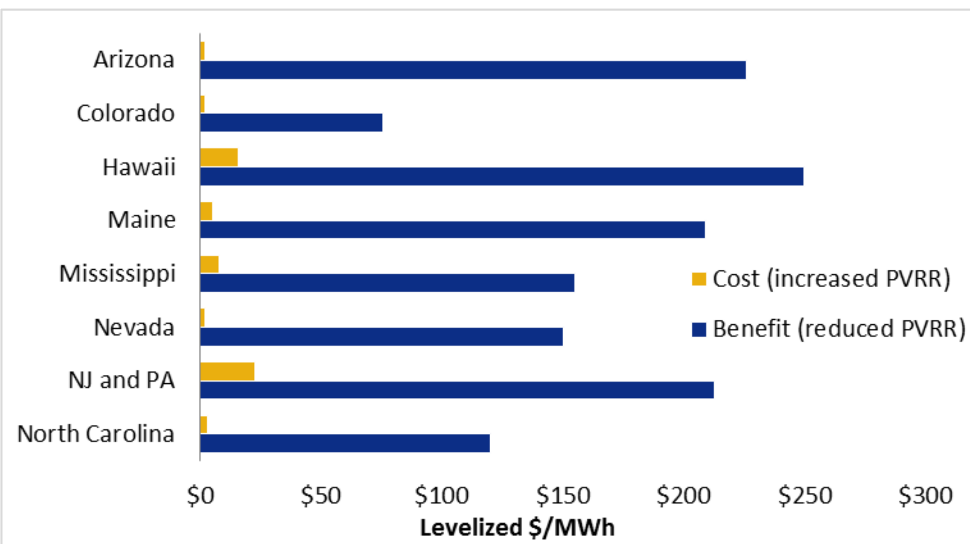


Appendix C – Net Metering Impacts on Utility Costs

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.

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Economic concerns about high fixed charge pricing for electric service

The combined impact of a slowly growing economy, increasing adoption of energy efficiency measures and noticeable penetration of customer-sited power generation has kept utility sales in check in recent years. Many utilities suggest that improper pricing of their service is exacerbating this situation.

Pricing to signal the long-run cost of electricity use

When setting residential rates, regulators typically have two tools at their disposal—a variable (volumetric) charge that applies to electricity consumed and a fixed charge that applies to each customer regardless of electric use. A key aspect of utility pricing involves allocating costs to each component. Changes in electricity use have no effect on costs the utility previously expended to build its power plants, transmission lines and substations—those fixed costs are sunk. The efficient volumetric price reflects only those costs that vary with usage. But that notion can be misleading. The relevant economic costs are those that vary over the long run, not the short run.

*The practically achievable benchmark for efficient pricing is more likely to be a type of average **long-run** incremental cost, computed for a large, expected incremental block of sales, instead of a **short-run** marginal cost, estimated for a single additional sale.*[1]

In the long run, all costs are variable.[2] While increased electricity use does not affect the cost of *existing* capacity, it very well may affect the need for *new* capacity. If regulators want to promote efficient resource allocation they will set the volumetric rate above short-run variable costs to reflect full long-run cost causation. This pricing concept is not unique to utilities. Economists observe similar results in unregulated competitive markets where sustainable prices lie noticeably above short-run variable costs.[3]

Which costs belong in the customer charge?

When economist Severin Borenstein looks at the utility system through an economic lens he doesn't see a significant role for a customer charge in recovering utility fixed costs. He asks which costs the utility incurs in the process of merely connecting the customer to the system. In completing the connection, the only costs are those associated with billing administration, the meter and the service drop.[4] Cost studies suggest these distribution costs amount to about $5 per customer per month for the typical electric utility.[5] All other costs depend on usage characteristics. A new 5,000 sq. ft. home requires more system capacity than a new 500 sq. ft. efficiency apartment. Given a choice between the fixed charge and the variable charge, the volumetric charge is the more appropriate home for those capacity costs.[6] If instead they are allocated to the fixed charge, the signal is that all residential customers require the same amount of system capacity, regardless of the size of their residence.

The push for high fixed charge pricing

There is currently much interest in implementing utility pricing based on existing fixed-variable cost relationships. In contrast to the economic pricing approach, these proposed rate designs recover only average short-run variable costs in the volumetric fee, allocating all existing fixed costs to the fixed charge. Under this approach we see fixed charges as high as $70 to $80 per month, with associated variable charges in many cases of only a few pennies per kWh.

What signal does high fixed charge pricing send?

We can illustrate the drawback to such pricing with a simple scenario. With most costs recovered through the fixed charge, customers would receive the signal that increasing the cooling output from an air conditioner on a hot summer day creates no capacity costs for the utility, either in the short-run or the long run. In fact, this pricing implies that the utility never has to add capacity. That is inaccurate and if economic notions of price elasticity[7] have any meaning, moving from traditional pricing to high fixed charge pricing will lead to increased consumption in all periods, including the peak. As peak load grows the utility will then eventually add more capacity and charge the associated costs to their customers, even though the customers never received a price signal to that effect.

Is high fixed charge pricing fair?

American Electric Power finds that high fixed charge rate designs: (1) improperly allocate costs within rate classes, adversely affecting small users; (2) weaken price signals to consumers, reducing the incentive to use energy efficiently; and (3) rest on ill-defined notions of costs.[8] After assessing all the shortcomings of high fixed charge pricing, it concludes:

We believe that there are a host of alternative regulatory strategies that are far more flexible and more closely aligned with traditional regulatory practices.[9]

High fixed charge pricing negatively impacts low users, many of whom are low-income customers. Under this approach the bill for those using less than the average amount of power is higher than the bill they receive under traditional pricing. But since the fixed fee represents the bulk of the monthly bill, and that fee doesn't change with usage, customers can't do much to lower their bill.

Better pricing approaches

Rate design serves multiple purposes and there is room for innovation and compromise on this issue. Some alternatives come to mind. For example, time-differentiated pricing applies a high volumetric rate when the system is near capacity, and a low rate when demand is more limited. A recent preliminary decision at the California Public Utilities Commission finds that time-of-use rates are more cost-based than any flat volumetric rate.[10] Under this approach customers would get the correct signal that ramping up the cooling output from an air conditioner on a hot summer afternoon may increase the need for new capacity over the long run.

The minimum bill approach is another possibility. Under this rate design, the utility might charge $0.10 per kWh for all electricity consumed. There would be no explicit fixed charge, but all customers would pay at least a threshold amount, say $20 per month. A customer using 100 kWh would see a bill of $20 because the volumetric-based charge of $10 would be less than the minimum required level. In contrast, a customer using 500 kWh would simply then pay $50, all of which is usage related, because that amount exceeds the minimum threshold. While the minimum bill may overstate the customer-specific fixed costs to some extent, the Regulatory Assistance Project's Jim Lazar explains the advantage of this approach over high fixed charge pricing. We can see the proper economic pricing foundations in his description:

A minimum bill rate design has an advantage in that the per-kWh price is higher, more closely reflecting long-run marginal costs (all costs are variable in the long run). This rate design encourages prudent usage, better aligned with investment impacts from consumption and investment in energy efficiency. This means customer choices about usage and, importantly, energy-related investments, will be informed by electricity prices that reflect long run grid value.[11]

Summary

As utility markets become more complicated, regulators will be exploring new pricing approaches. High fixed charge pricing steers the economy away from efficient resource allocation, not toward it. Time-differentiated rates and minimum bill approaches offer more promise for regulators interested in sending proper signals about the long-run cost of electricity consumption. ■

[1] Kahn, *The Economics of Regulation,* MIT Press (1988), p. 85.

[2] Varian, *Intermediate Microeconomics,* W.W. Norton & Co. (2014), p. 391.

[3] Hall, "The Relation Between Price and Marginal Cost in U.S. Industry, *Journal of Political Economy* (1988).

[4] Borenstein, "What's So Great About Fixed Charges," Energy Institute at Haas, November 2014.

[5] Lazar, *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed*, Regulatory Assistance Project (April 2013), p. 26.

[6] Another approach is to use a demand charge, which levy a fee based on use at a given point, not on cumulative use over time. To send a proper cost signal, however, those charges must be based on the customer's use at the time of the utility's system peak (coincident demand), and not based simply on the individual customer's peak usage. That approach is not addressed here because designing proper demand charges is a challenging task and great care must be taken when doing so to avoid price distortions and unfair outcomes.

[7] *Price Elasticity of Demand for Electricity: A Primer and Synthesis*, Electric Power Research Institute, January 2008.

[8] American Electric Power Company, *Issues in Electricity: Straight Fixed Variable*, 2014.

[9] American Electric Power Company, *supra*.

[10] *Proposed Decision*, Rulemaking 12-06-013 Before the California Public Utilities Commission, April 21, 2015, p. 117.

[11] Lazar, *Electric Utility Residential Customer Charges and Minimum Bills*, Regulatory Assistance Project, 2015, p. 4.

About the author

This summary of economic pricing principles was prepared by Steve Kihm, an economist with 35 years of experience in the field of utility regulation, including more than 20 years as an analyst at the Wisconsin Public Service Commission. His work has been published in the *Energy Law Journal, The Electricity Journal,* the *Journal of Applied Regulation* and *Public Utilities Fortnightly,* as well as reported in *Forbes* and the *Wall Street Journal.* He is also Senior Fellow at Michigan State University's Institute of Public Utilities.

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Electric Utility Residential Customer Charges and Minimum Bills:

Alternative Approaches for Recovering Basic Distribution Costs

By Jim Lazar[1]

Electric utilities have certain costs that do not vary with the usage of electricity. It is generally accepted that these include the costs of metering, billing, and payment processing. These costs are most often recovered through what is variously called a "customer charge" or a "service charge" or a "basic charge." In the United Kingdom, this is known as a "standing charge."

Regardless of the title, it is a charge (usually less than $10/month for residential service) that is levied each month regardless of electricity usage, with additional charges applying for each kilowatt-hour of electricity consumed. For most utilities in the US, the customer charge covers the cost of billing and collection, and perhaps other customer-specific costs like meter reading, but not the costs of distribution facilities like poles, conductors, or transformers.

Nearly all electric utilities worldwide bundle the cost of distribution service, as well as the power supply cost, into a usage charge, calculated as a price per kilowatt-hour. This is consistent with how competitive firms price their products, whether it is gasoline, groceries, or hotel rooms: the price per unit recovers all of the costs involved in producing, transporting, and retailing of goods and services.

Some rate analysts argue that a portion of the distribution system – poles, wires, and transformers – constitute a fixed cost that does not vary with sales and should be included in the fixed customer charge. Some recent proposals from electric utilities reflect this view. This is controversial.

Many state regulatory authorities rejected this approach when they held hearings and made determinations under the Public Utility Regulatory Policies Act of 1978.[2] The Washington Utilities and Transportation Commission, for example, explicitly rejected the concept that distribution costs were customer-related in nature:

> *In this case, the only directive the Commission will give regarding future cost of service studies is to repeat its rejection of the inclusion of the costs of a minimum-sized distribution system among customer-related costs. As the Commission stated in previous orders, the minimum system method is likely to lead to the double allocation of costs to residential customers and over-allocation of costs to low-use customers. Costs such as meter reading, billing, the cost of meters and service drops, are properly attributable to the marginal cost of serving a single customer. The cost of a minimum sized system is not. The parties should not use the minimum system approach in future studies.*[3]

However, as sales have flattened or declined in recent years, and as more customers install on-site generating resources but remain dependent on grid services for some service, the concept of recovering distribution network costs in fixed charges has experienced resurgence.

Utility sales volumes in some regions have stagnated or declined as appliances, homes, equipment and systems become more efficient. Sales volumes also vary with weather, declining in mild years. Many state net-metering laws allow consumers installing rooftop solar arrays to incur net-bills for zero or very few kilowatt-hours, depending on the geographic location and the design of the net-metering tariff. To improve revenue stability, and to collect distribution system costs from PV customers, some utilities are arguing that "fixed" costs should be recovered in fixed customer charges. Some utilities are seeking customer charges of $20/month or more. In one extreme case, Madison Gas and Electric Company proposed a $69/month customer charge, to recover all costs except for fuel and purchased power expenses.[4] The Wisconsin PUC recently voted 2-1 to approve an increase in the customer charge to

1 Rich Sedano, Janine Migden-Ostrander, Brenda Hausauer and Camille Kadoch provided reviews.

2 Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §§2601-2645 (1978). Available at: http://www.gpo.gov/fdsys/pkg/STATUTE-92/pdf/STATUTE-92-Pg3117.pdf.

3 WUTC v. Puget Sound Power and Light Company, Cause U-89-2688-T, Third Supp. Order, P. 71, 1990.

$19/month for Wisconsin Public Service Company.[5]

An electric utility has a defined revenue requirement, determined by their regulator. A higher customer charge therefore means a lower per-kWh rate will be required. This has important impacts on the utility and its customers. Utility revenue is stabilized by a high customer charge, independent of weather, conservation, or other impacts on sales. However, the impacts on customers of high customer charges can be inconsistent with policy objectives:

- Small-use customers, such as apartment dwellers, low-income households, and second homes will receive much higher electric bills; the vast majority of low-income consumers are also low-use consumers. This is anathema to public policy objectives that normally tend to protect low-income customers and/or reward low usage;
- Urban area residents who use natural gas for space and water heat will receive much higher electric bills;
- Large-use customers, including large single-family homes in suburban and rural areas without access to natural gas most often will receive lower electric bills, depending on the existing utility rate design; and
- The lower per-kWh prices that result when a significant portion of costs are recovered in a fixed monthly customer charge will stimulate consumption. This creates consequences for incremental utility investment and for the environment. It also reduces the economic incentive for careful customer energy management practices and investment in energy efficiency measures by increasing pay-back periods.

There are several ways besides high fixed charges to address utility revenue stability issues:

- **Financial Reserves:** The traditional approach has been to set rates in a manner that recovers distribution and power costs in a per-kWh charge, and expect utilities to have adequate financial reserves to manage the volatility that occurs with weather. This is reflected in the 40% – 50% equity ratios allowed for electric utilities in determining the cost of capital.
- **Frequent rate cases**: If regulators hold rate proceedings every year or two, there is little time for sales volumes to deviate far from the level used to set volumetric rates.
- **Revenue Decoupling:** Many regulators have adopted revenue regulation mechanisms that calculate a true-up at the end of the month or year to align actual revenues with allowed revenues.

All of these methods allow the per-kWh charge to continue to reflect substantially all of the costs of service. By structuring rates this way, regulators preserve the consumer incentive to use electricity wisely.

Rate Designs with Minimum Bill Charges

One alternative to address utility concerns for revenue adequacy in addition to Revenue Regulation and frequent rate cases is a concept known as a "minimum bill." A minimum bill guarantees the utility a minimum annual revenue level from each customer, even if their usage is zero. The vast majority of customers, who consume the overwhelming majority of energy, have usage that exceeds those low thresholds. For these customers, a minimum bill "disappears" when the usage passes that level, and the customer effectively pays a volumetric rate to cover both power supply and distribution costs.

It is important to understand that a very small number of customers will be adversely affected by the minimum bill, because a large majority of all customers have usage in excess of the minimum billed amount. Figure 1 compares the number of customers served at each usage level, and the kilowatt-hours used by those customers at each usage level. Only a few percent of the customers, using less than one percent of the energy, have usage below 150 kWh per month in this illustrative example, and are arguably not making a meaningful contribution to system costs when those costs are built into the per-kWh charge.

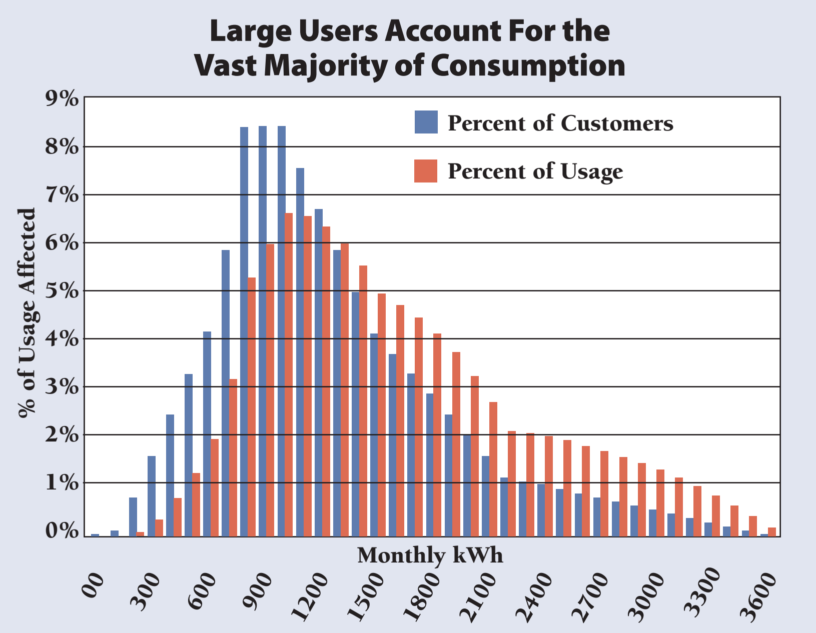
Table 1 compares three example residential rates, all designed to produce the same total level of residential revenue for an illustrative utility with average usage for this example of 1,000 kWh/month/customer.

- **Low Customer Charge:** $5/month, to cover billing and collection
- **High Customer Charge:** $20/month, to cover billing, collection, and a portion of distribution costs
- **Minimum Bill:** $5.00/month to cover billing and collection, with a minimum bill of $20 (which applies if usage falls below 150 kWh/month).

4 Application of Madison Gas and Electric Company for Authority to Change Electric and Natural Gas Rates, Docket 3270-UR-120, April 9, 2014. Available at: http://psc.wi.gov/apps40/dockets/content/detail.aspx?dockt_id=3270-UR-120.

5 Content, T. (2014, November 6). State regulators approve 83% increase in Green Bay utility's fixed charge. *Milwaukee Journal-Sentinel*. Retrieved from: www.jsonline.com.

Figure 1



This shows that for the average customer, the three rate designs produce almost identical bills. With a high customer charge rate design, because the $20 customer charge is collecting $15 more than the $5 low customer charge, the price per kWh is lower by $0.015/kWh. For the minimum bill rate design, however, less than 1% of kWh sales will typically be to those customers using under 150 kWh/month. This group has historically been limited to unoccupied dwellings; more recently, it has come to include customers with solar PV systems that produce as many kilowatt-hours as they consume, but remain dependent on the grid to serve as a "battery" taking excess production during the day, and supplying power when the sun is not shining.

Therefore, there will not be a lot of revenue recovered by the minimum bill charge, leaving most of the revenue requirement recovered by the volumetric charge. The per-kWh rate would only be reduced by about $0.001/kWh (1%) as a result. Under this rate design, very small-use customers, such as PV customers whose panels produce as many kilowatt-hours as the house uses, would pay slightly higher bills. However, as nearly all usage by customers remains priced at a cost-based rate that includes all of the costs of producing and distributing electricity, the low-use PV customer would have negligible usage charges.

Table 1

	kWh	Low Customer Charge	High Customer Charge	$20 Minimum Bill*
Customer Charge		$5.00	$20.00	$5.00
Minimum Bill				$20.00
Per-kWh Charge		$0.10	$0.085	$0.099
	10 kWh	$6.00	$20.85	$20.00
	100 kWh	$15.00	$28.50	$20.00
Customer Bills	200 kWh	$25.00	$37.00	$24.80
	500 kWh	$55.00	$62.50	$54.50
	1,000 kWh	$105.00	$105.00	$104.00
	1,500 kWh	$155.00	$147.50	$153.50
	2,000 kWh	$205.00	$190.00	$203.00

**The minimum bill will only apply when customer's usage is so low that their bill falls below $20.*

Impact on Usage

Electricity usage varies with the price paid. Higher kWh charges create greater incentives for consumers to turn out unneeded lights, manage thermostat settings, and invest in more efficient appliances, windows, and insulation. There is an economic science tool, price elasticity, which measures the expected change in consumption if prices change. Economists variously estimate the price elasticity of demand for electricity in the range of -0.1 to -0.7, with some long-run estimates going higher. An elasticity of -0.2, meaning that a 1% increase in price results in a 0.2% decrease in the quantity demanded, is considered a conservative estimate of long-run price elasticity.

The high customer charge rate design results in a 15% lower price per kilowatt-hour compared to the low customer charge rate design. Assuming an elasticity of -0.2, that would imply that customers would consume about 3% more electricity (-0.2 elasticity x 15% change in rate = 3% change in usage) as a result of the lower per-kWh price.

The minimum bill rate form, on the other hand, only reduces the price per kWh by 1% compared to the low customer charge rate design; assuming the same elasticity factor, the minimum bill design would increase usage by only about 0.2% among customers using more than the minimum billed quantity, when compared with their usage under the low customer charge rate form.

There is, however, a chance that the very small users might increase their usage up to the 150 kWh minimum. With this $20 minimum bill, customers using less than

150 kWh per month would see no change in their bills if they increased usage up to 150 kwh. But, since only a small percentage of customers use that little power, even if they did so, usage would not increase very much.

Evaluating a choice between a $20 fixed customer charge and a $20 minimum bill charge, we would expect about 15 times as much additional usage under the $20 fixed charge as under the $20 minimum bill charge.

Impact on PV Customers

Part of the concern that is raised by utilities is that customers with solar PV systems are "net-metering" to zero kWh, and paying only the customer charge in a monthly bill. These customers remain dependent on the grid for storage and shaping of their daytime energy production. Solar advocates argue that the grid is receiving a more valuable product – daytime renewable energy – than it is providing to the customers at night from conventional generation, and that this is a form of rough equity.

A minimum bill would ensure that a PV customer with net consumption of zero would still contribute to system costs. In the example, these customers would pay $20 per month. But, rather than distort the rate design for all customers, only the low-consumption consumers would be affected, allowing rates that continue to reflect all system costs to be applied to the overwhelming majority of energy sales.

Advantages and Disadvantages

A rate design that uses a customer charge combined with a kWh charge is simple to understand and administer. It provides a clear price signal for each kWh. If the customer charge is lower, the per-kWh charge is higher. However, the public is used to doing business for other purchases with a zero customer charge – grocery stores, gas stations, and virtually all other retailers only charge customers for what they buy, not for the privilege of being a customer (membership warehouse clubs are exceptions, with fees designed to weed out "browsers" from their stores.) There may also be conflict with intended outcomes for low use customers.

A minimum bill rate design has an advantage in that the per-kWh price is higher, more closely reflecting long-run marginal costs (all costs are variable in the long run). This rate design encourages prudent usage, better aligned with investment impacts from consumption and investment in energy efficiency. This means customer choices about usage and, importantly, energy-related investments, will be informed by electricity prices that reflect long run grid value. The disadvantage is that, for the very small number of customers whose usage is below the "minimum," this rate design provides no disincentive at all to using the minimum amount of electricity. It can be perceived to have a disadvantage of encouraging additional usage by those users with usage below the minimum billed amount, but there are very few of these customers, and their prospective additional usage increase is minimal. Users in this group may argue that the minimum bill is unfair to them.

Finally, a minimum bill rate form ensures that second-homes, which may have no consumption during the off-season, contribute to utility revenues. This is sometimes presented as an economic justice issue, since second homes are generally held only by upper-income consumers.

Conclusion

The primary purpose of utility regulation is to enforce the pricing discipline on monopolies that competitive markets impose on most firms. Competitive firms nearly always recover all of their costs in the price per unit of their products. Therefore, any fixed monthly charge for electricity service represents a deviation from this underlying principle of utility regulation. The most commonly applied customer charges recover only customer-specific costs, such as billing and collection, in a fixed customer charge, leaving all costs of the shared system to be recovered in usage charges.

A regulator seeking to increase the contribution to utility system costs from those customers with minimal consumption can do so with either a higher customer charge, or establishing a minimum bill. The minimum bill option will ensure that all customers contribute to distribution costs, but without significantly stimulating consumption by higher-use customers or raising the bills of lower-income, low-use customers.

Forthcoming in Second Quarter, 2015: *Electric Rate Design for the Utility of the Future.* Watch for this on our website, www.raponline.org

The Regulatory Assistance Project (RAP)™
Beijing, China • Berlin, Germany • Brussels, Belgium • **Montpelier, Vermont USA** • New Delhi, India
50 State Street, Suite 3 • Montpelier, VT 05602 • *phone:* +1 802-223-8199 • *fax:* +1 802-223-8172
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the gandalf group

Ontario Energy Board

Distribution Charge Focus Groups

Final Report

October 9, 2013

420 Wellington Street West, Toronto, ON, M5V 1E3 | T 416.644.4120
info@gandalfgroup.ca | gandalfgroup.ca

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I. Introduction & Methodology

On behalf of the Ontario Energy Board, the Gandalf Group was pleased to conduct four focus groups with residential electricity consumers about proposed changes to distribution charges.

Groups were 2 hours in duration, with nine to ten participants in each of the four groups. Two groups were held with seniors and representatives of middle and lower income households, and two were held with representatives of middle to upper income households and parents with children in the home. Participants were a mix of Toronto and 905 community residents. All participants were homeowners, condo-owners or renters that pay their own electricity costs. Participants were all customers of Powerstream, Hydro One, Enersource, Veridian, or Toronto Hydro (see Appendix B).

These groups were conducted on September 25th and 26th 2013 in North York.

The moderator's guide for the focus groups (see Appendix A) begins with a warm-up and an introduction to the focus group format. Then basic ideas around electricity use and pricing are discussed including familiarity with time of use pricing and delivery charges. The moderator begins a discussion of distribution costs and pricing. The guide then introduces the new distribution pricing scheme. The current and proposed pricing systems are compared, as well as the introduction of fixed 12-month charges and tiered pricing. Later a rationale document is shared and discussed to see where it is helpful at explaining if not arguing for the changes.

To discuss this report and address any questions or concerns, please contact Alex Swann at 416.644.4125 or swann@gandalfgroup.ca.

II. Executive Summary

Engagement in "time of use" (TOU) pricing among participants is high. Understanding the need to avoid or reduce consumption during peak times is something most were prepared to manage, although with varying degrees of difficulty.

While many understand how TOU and electricity charges are calculated, many do not understand why the electricity system benefits from peak-time pricing. More information about the actual and potential costs of delivery during peak times (and how the system has to be built to handle peak loads) was interesting to participants. It helped build understanding more about the service they get and as rationale for proposed distribution charges that reflect consumption during peak hours.

There was concern among some that bills would likely increase significantly under the proposal. A relationship to TOU specifically will be important – i.e. implying a range of rates rather than a focus on consumption during peak hours. But many people will be anxious to know specifically what will happen to their bills, either in transition or in the long run – will they jump up because of peak time usage or be introduced at a rate similar to what they pay now, given how tiers track consumption?

Consumers want tools not only to understand the calculation but manage their costs by offering evidence of past and present or projected usage with respect to what each mean for bills.

An explanation of how proposed "tiered" charges would track current variable costs was reassuring to some in the sense that they felt the new charges align with what they presently pay. Some could see the opportunity for bill decreases. But in the absence of certainty about their bill others were concerned about the potential increases of several dollars monthly. Citizens of modest means could be very vocal about bill increases amounting to $4 or $5 a month or more.

A more widely shared concern was the proposal to move to 12 months of fixed charges. It helped modestly to explain that system costs are relatively fixed month to month as a justification for fixed charges. That argument was somewhat undermined by the proposal to peg charges at different levels leaving people confused as to whether costs are variable or fixed and whether charges should be too.

Fundamentally there is a concern about cost of living pressures here and an engrained acceptance that a substantial portion of costs or bills should be variable (perhaps more since the introduction of TOU). This specific proposal appears to preclude savings they believe they are working to achieve with steady reductions in use under TOU. Finally, a fixed charge approach over 12 months seems like a higher burden.

III. Detailed Findings

Context: What Consumers Know About Delivery Charges and "Time of Use"
Most in the groups said they had embraced "time of use" (TOU) pricing habits. They were aware of whether peak pricing impacted or benefited them or how they had changed their habits to conserve.

Despite this level of engagement, many do not understand why peak pricing is in place. Some assumed that when energy is in demand it will cost more to generate or import. But others assumed the price is merely raised when it can fetch more on the market. Only a few went so far as to articulate the goal of TOU pricing (to spread out demand) and if they did they would be far more likely to say this was to avoid brownouts than manage investments in system capacity.

Participants believe they get comparatively little information on their bills about delivery charges, compared to the electricity line where both the calculation or rate is evident. As well they are more likely to understand intuitively what they receive for the cost of "electricity." Few could articulate what they get for delivery. The infrastructure behind the system is simply not top of mind. It is not easy to visualize let alone value. This helps to explain why some participants told us they are displeased that the delivery portion could sometimes cost the same or more than the electricity portion of their bill. Some questioned how such a charge could exceed the value of what they believe they are buying.

We provided some detailed information to group participants about the costs entailed in the delivery line of bills. Little of the information about distribution or transmission (poles, high voltage transmission lines etc.) was surprising to them; it served as a reminder of information that is not top of mind. It is somewhat helpful to getting people to visualize the true costs of their electricity consumption.

Showing how the line was calculated seemed more important. The lack of transparency around this charge now was noted in comparison to the detail around how TOU is applied and what drives the electricity charge or line.

A New Approach To Distribution Charges

When a proposal for pricing delivery based on demand during "peak hours" was presented we saw immediate concern from some in the groups. Those consumers appeared to believe they would be charged a higher rate per kwh for all their electricity use in relation to delivery – i.e. a "peak" rate. Others understood that this system would not impact them much if they felt they had reduced or could avoid consumption during peak times already.

A more widely held concern is that their bills give them no tools to manage this going forward. Participants wanted tools or metrics on their bills to better understand how charges are calculated in the new system, and to so see if they what targets they are meeting.

A Rationale for Peak Time Pricing

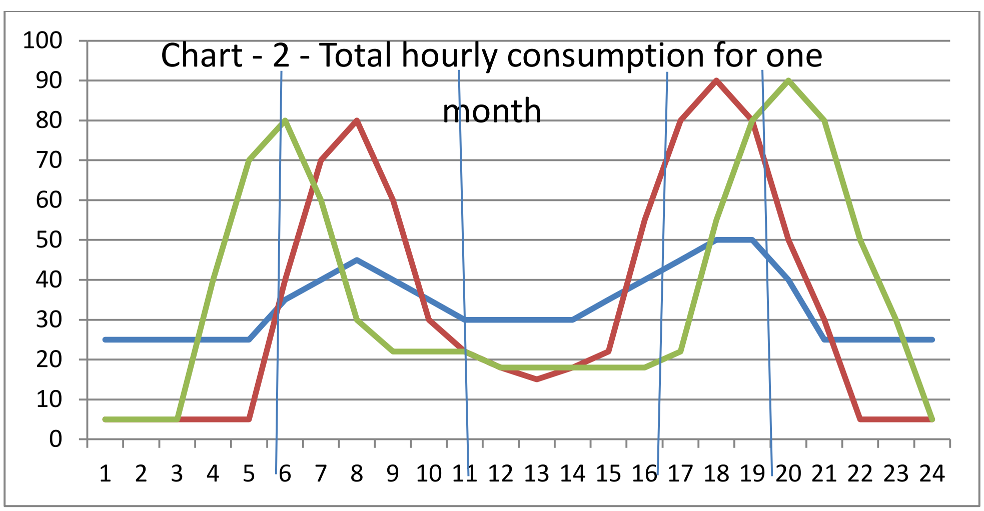
We found that the presentation of a rationale for these changes was somewhat interesting for participants and somewhat helpful to increasing acceptance of the changes. At least it helped break down the cynicism or concern about lack of transparency, which is a separate or additional concern that accompanies electricity charges and rate increases.

A "water pipe" analogy was helpful at building understanding of costs to the system that result from peak demand. This analogy effectively conveyed the idea that we need a bigger system to deliver more power at once.

If we have used language to tell consumers that infrastructure costs are static and don't fluctuate with monthly usage, some will not grasp the water pipe analogy or what costs to the system we could possibly be talking about. Indeed those who questioned whether the system needs to be build out to manage peak capacity assume that poles and wires are cannot be expanded and do not need to be.

It will be important to talk about tangible investments that will have to be made or have been made to handle higher net peak demand. As well we should illustrate the problem in a way that people can grasp – e.g. the hottest days of summer and the concern that utilities must take in planning for the future. This would be a more graphic depiction of the costs and the risks and the need for pricing signals to forestall this.

There was a tension between an argument for less fluctuation month to month in terms of what the customer pays on the one hand and the need to talk about future costs or expanding the system to handle peak consumption. It is difficult to try convey that costs do not fluctuate as much as charges do (as the communications materials we tested did) and then speak to reduce peak consumption. It seems that a discussion of fixed costs should not be discussed outside of the larger argument or context. In our communications, the sooner we explain the big picture, and get at the total costs to the system of peak days (the "water pipe" analogy and planning for peak days) the better our argument. Our argument would emphasize that the system has to have a maximum capacity, one that might vary over time (i.e. some variability) but in essence only grow with increases in maximum demand, and not contract if average demand decreases.



A presentation of how peak time users' consumption could vary substantially from a consumer who either shifts or reduces peak consumption helped to illustrate to group participants the range of demand that homes have and what this can entail for the system during peak hours (shown in red in chart 2 above).

The idea that different utilities calculate the charge differently now (with some offering a very low flat rate) raised an issue of fairness that people agreed should be fixed. It might be considered as a talking point in communications; but if different utilities continue to have different costs (or if rural customers continue to pay more) it would negate the overall credibility of this argument. (Yes, there would likely be more fairness between consumers with similar consumption patterns with some of the various utilities but not overall.)

Tiered Pricing

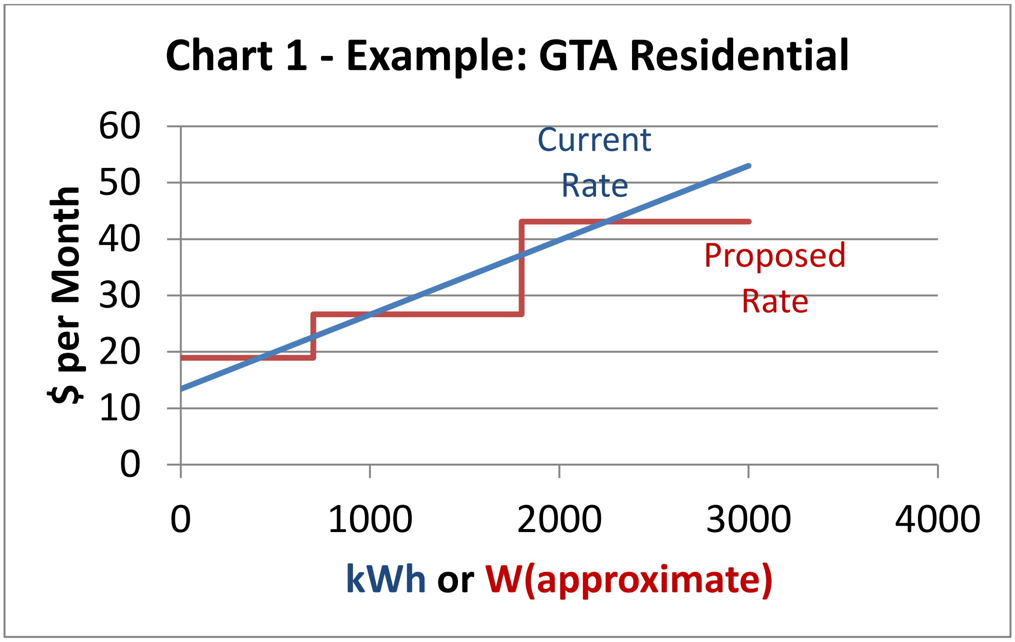
Moving to tiered pricing drew mixed reactions.

Some in the groups were not concerned about new charge system because they believed they had shifted or could move their power consumption away from peak times. Some believed they would benefit with a lower charge. How many will be able to do so in transition, and over time, will impact the long-term communications around this issue.

Others felt that since they are likely to adopt some energy efficiency measures, but are limited from adopting substantial conservation efforts, this system prevents them from seeing small reductions in costs and therefore any reductions which they would see otherwise.

A few questioned any suggestion that this was revenue neutral – either to consumers overall or to them in particular. This fact will not be assumed. Some will assume the tiers have been selected in a way that means a net revenue increase.

The key concern here is the possibility that some would see increases. In the short run, many will be concerned about this possibility. And in the long run, a few may determine their charges increased even if they haven't switched tiers that they are in the lower-end of the scale within a tier (see chart 1: differential can be deduced from the pricing graph with tiers and current charges or rates, e.g. at about 900 kwh or 1900kwh where the red tiered line exceeds the blue straight line of current rates).



An approximate increase of close to $5 monthly will be an irritant for those who believe their bills have increased of late with no change in consumption. They will be a serious concern for those of modest means. Based on what we heard, citizens of modest means who already feel stretched could be very concerned and very vocal about bill increases amounting to $4 or $5 a month or more. We heard suggestions about increasing the number of tiers to make such cost differentials lower.

Maximum Usage Pricing

The concept of maximum use during peak times is difficult for people to understand and raised concern among a few. There is no template for measuring maximum use that people are used to in the way they understand TOU. It was not obvious how this would be calculated.

Without precise details of this there was concern expressed by some that small lapses in their conservation efforts will mean they will have to pay a high price for that (even if they conserve diligently on the vast majority of days during peak times). So there will be questions of fairness if they have conserved on the vast majority of days during peak demand times and essentially helped to reduce peak consumption.

Fixed Monthly Charges

Moving to a fixed monthly charge every month for 12 month periods was problematic for participants in our groups. Concerns included:

- The fact that many assume they will seek efficiencies in the course of each year and that this will forestall the benefit or reduce the payback of those.
- Others believed that if we were encouraging reductions in peak consumption, along the lines of TOU pricing that they should be incentivized either to the full extent or in the way they are accustomed to.
- Some worried that in order for them to qualify for lower charges due to decreased consumption, that decrease in consumption would have to be sustained for 12 months and with less forgiveness than exists now for lapses. It seems like a higher burden, with a chance of no reward if they fall short.
- Two groups' participants were particularly cynical and felt that utilities might simply change the rules or conditions at the end of each year, and that the promise of lower rates based on a reassessment of usage would essentially disappear with a rate increase.
- This helps explain why several respondents immediately asked if they would see credits retroactively if use was lower than assumed in the rate they were charged.

The responses we heard suggest people believe their bills and distribution charges vary substantially month to month.

Variability is a deeply engrained principle – from home to home and month to month. While most cannot explain how the charge is calculated now they apply the perspective that charges should not be the same for each household and should be affordable for those who are both of modest means and consuming less. Individually, for themselves, consumers expect to be able to decrease each bill amounts as their consumption comes down.

We found a few individuals supported the idea of fixed charges in that costs to them do not fluctuate month to month given the constant costs of delivery infrastructure. But, if they accepted that, they might then have trouble understanding why delivery charges could be pegged higher or lower based on peak demand. This issue is complex and confusing until we introduce the need for the system to be built to handle peak demand (using a "water pipe" analogy, which we discuss below).

IV. Considerations for Communications & Implementation

The following are a number of considerations and suggestions for any eventual implementation of the proposed new delivery pricing scheme drawing on what we learned from the groups.

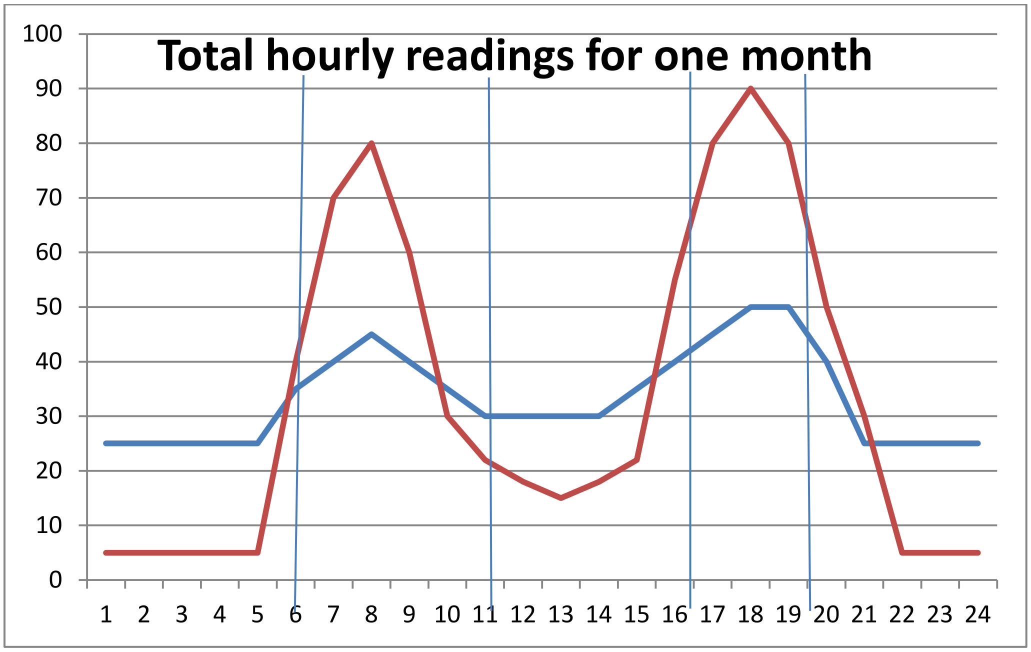
1) The first key area for communications inevitably deals with the cost to consumers.
   - Many will want to know what their new costs will be after transition. If there is likely to be little to no change it will be important to communicate it. It will not be assumed – many simply assumed they would be paying very different amounts for delivery charges. Sample bills and a chart showing the relationship between pricing tiers and current rates will be helpful to explaining the costs after transition. (Chart 1)
   - Caution must be taken to carefully explain that pricing based on usage during peak-hours does not mean automatically mean higher charges across the board. It would be more appropriate to explain we are introducing different charges that reflect whether consumers shift usage away from "peak" hours, rather than say we are introducing charges based on "peak" consumption. We should come as close as possible to aligning this to TOU principles, rather than "peak" rates per se to explain more clearly that there will be lower rates and a high rate.
   - But consumers also want the ability to manage and understand implications of usage on these charges. Such tools could help to forestall "sticker shock" and offer fairer warning. Obviously if we could offer the potential of savings in writing or offer a clearer signal of the benefit of reducing peak consumption it will be helpful as well. Announcing the new delivery pricing scheme before it will go into effect, but begin including usage tracking and projected delivery costs on bills in advance would help with the transition. The initial announcement should include a brief fact sheet (bill insert) and direction to an OEB website with an FAQ document and detailed materials, including different electricity consumption profiles to demonstrate the overall effect of the scheme.
   - What the groups could not assess was the likelihood that some would in effect jump up a tier or two if they were substantial peak time consumption users, but low net users overall. Many assumed from the tiered pricing we presented to them that their new charges would roughly track current charges (or that they could or had reduced peak time consumption already). Ultimately, where people

land will depend on a calculation of their bills, something we couldn't do or present in these groups. Managing communications around those larger increased (if they occur after transition) will require some planning based on an understanding of the likelihood and frequency of those cases.

2) In addition to outlining how this charge will be calculated, offering some rationale would be helpful.
   - Participants mostly accepted and understood the rationale and "water pipe" analogy for explaining why the new scheme is necessary. Many said we had presented a good argument for changing the charge or at least why "peak" time consumption is an important issue that needed to be dealt with. But more work could be done to consider how to build this analogy and make it real – both in practical descriptive ways if not also in ways that are graphic or capture attention around the seriousness of the risks or costs if a system is not built to handle maximum capacity.
   - Understanding this was also the only way to convey this scheme had a fairness element – i.e. those who put strain on the system in peak hours should pay for the costs associated with that. In the absence of that, these charges will appear arbitrary and fairness will not be understood or assumed in any way.
   - Peak-time pricing seemed in people's minds more linked to the cost of generation and electricity in peak hours than the delivery costs of an LDC. The relation between peak-time pricing and the delivery line may not be as readily accepted as it has been with respect to the electricity line. So the "water pipe" analogy, if built out a bit more with tangible examples will overcome the doubt that would otherwise exist about how peak rates for electricity would really impact static or day-to-day costs at LDCs.

Messaging (or the rationale) should cover off whether this scheme is revenue neutral or not (i.e. whether it is designed to raise more resources for LDC's investments). If it is revenue neutral but meant to send price signals we should say that. If the intent is to raise funds for identified future distribution costs, we should say that too but also stress to the extent possible that this offers a price signal with the capacity to help contain escalation of those system costs.

A chart comparing different approaches to total consumption or to shifting consumption out of peak time, proved to be helpful to the arguments we were making and the behaviour we were seeking to effect. It illustrated at once the degree of stress that peak-time usage can put on the system overall (the rationale for costs that handle larger peak consumption or in this case a higher maximum) and the divergence between customers (the potential variance in cost per consumer).



There were many technical adjustments that group participants told us they wanted (or matters requiring clarification). To be sure many consumers will want less risk of increases. But below are some suggestions we received. Most of these are geared towards avoiding unintended consequences.

- Some consumers wanted us to consider more than 3 price tiers. The price differentials could be reduced as could the number of people who see increases because of where they sit relative to the curve. These people may be small in number as a percentage of the population but they may be more vocal than those who see savings.
- Participants asked about scenarios where someone moved into a new apartment or buys a home wherein the previous user had high peak-hours consumption. They found the idea that they would be punished for someone else's behaviour to be unfair. Perhaps new residents of apartments and new owners of homes and condos should begin with the median delivery rate. After 3 months, the

consumer would be assigned a tier based on their consumption thus far, thereby beginning a new one year period of delivery.

- Moving to 12 months of fixed charges was a difficult concept for participants to accept. As mentioned above, the idea that charges would be assessed only annually was seen as either too high a bar to set for conservation or too great a lag between behaviour change and reward. A 3 or 6 month cycle might be somewhat more acceptable, but could at least could be considered in a transition phase: e.g. with a reassessment at 3 or 6 months, as part of a transition period before moving to 12 months of fixed charges. If someone ends up in a higher tier based on previous year's usage, they will be able to opt out sooner if they have the capability to shift consumption. As well a true price signal with some measure of forgiveness and of limited impact might be one of the best forms of communication to effect change.
- It may be worth demonstrating how much or how little changes from month to month under current pricing with some utilities. Many don't track this now, but they presume it's not a small amount. Some presumed that on a net basis they would miss out on savings resulting from months when they have substantially lower peak-time consumption. A transition phase and some element of more on-bill transparency about how charges have varied month to month might illustrate how little the variation and savings have been in some months and vice versa how that fixed charge could also be below what they have paid in a given month.

In the long-run, communications about and the impact of this file will depend on the degree of increases that are likely. For the majority we seem to be talking about small changes with minimal financial impact. And that will need to be part of the thrust of communications. Under normal circumstances that would merit only modest efforts of communications or passing notice. But a small minority could be a vocal one and the number of people who see substantial increases needs to be understood and anticipated and managed accordingly.

Some consumers are irritated about the costs they pay for distribution and electricity as it is. So our adjustments do not come in a vacuum. They will be perceived along with the complexity entailed in other recent changes to bills.

Second, this is a complex brief. We are proposing or discussing three technical changes at once to calculating one charge on the bill. It will be important to put an emphasis in communications on two ideas, not several technical changes. The details of the changes should be made available to all but not the thrust of communications messages.

The rationale is likely to be helpful, but communicating it to millions of Ontario consumers is understandably a large challenge. Despite the amounts they pay, it's noteworthy how little most know about the costs of the system. Many have not investigated the issues at stake up until now.

Moving to fixed charges will be a difficult issue to explain or justify, unless the net impact remains small. A transition period will help so people feel they have a chance to lower bills. The more tools we provide about past and future variability and how to manage costs and see rewards the less concern people will have that they are locked in for one year. If we can truly point a way to lower bills for some, at least some will feel advantaged by the system. Finally, it's noteworthy how many use the tools that come with their bills. As complex as it may be, a reengineering of the delivery line will lead many into some understanding of our change.

V. Appendix A – Moderator's Guide

i. Warm-up/Introduction

- *Thank participants for attending*
- *Lay out key ground rules, goals of the discussion*
- *Note one way mirror and video/audiotape, assure complete confidentiality*
- *Electricity - brief intro to topic – ask participants to introduce themselves tell us if they receive bills from a local utility and which. Ask if they signed a contract with a reseller/marketer. Ask how long they have purchased from that utility/marketer and how long they have lived where they live.*

ii. Background – 10 minutes

1. I'm going to ask you about various charges on your electricity bill. First off, how many of you know what time of use pricing is? Are you familiar with that? (show of hands, have a brief discussion to establish facts)

2. And peak pricing? (show of hands, have a brief discussion to establish facts)

3. How many of you have tried to reduce your peak consumption since time of use pricing was introduced? (show of hands)

4. Why does the electricity system charge more during peak hours?
(Probe to understand how many see this as related to charging for demand versus managing demand supply, conservation)

5. What would happen if prices for electricity were the same at all hours?

6. Does the cost of running the electricity system go up during those hours – if and when a lot of consumers are at their maximum demand all at once? (Probe to see if this scenario is thought to be not about costs and infrastructure but about risks and brownouts or both or other.)

7. How many of you have noticed the delivery charge on your bills? What does that charge comprise or pay for? What are some examples?

8. Where does that charge go? Who receives it?
(At this point ask each to review a sample of a bill. Each has been encouraged to bring copies of their bills. We will have a sample on hand – "HANDOUT 1")

9. It actually represents two different payments: one to pay for distribution to you from the utility and second to the transmission company that brings the power from the generator to the cities at high voltages. Is that new information? Does that seem different than you expected?

10. *(The moderator will then explain)* The delivery charge represents the cost of such things as the transmission towers, wires, transformer stations, the poles outside your home and all of the operational costs to maintain and enhance that system. Is that a different explanation than you might have expected?

11. Are there other costs to delivery that that list did not include that you would think would be included?

12. Does the delivery charge vary between households?

13. Does the delivery charge vary from month to month? Can you bring this cost down or just your electricity charges? Or both?

14. Can you tell me how the delivery charge is calculated?

15. Do you look to see if that charge changes month to month? Is it something you watch closely?
(Probe to understand how they view this now and what variables they feel exist)

16. How many of you have heard of the Ontario Energy Board? Do you know what it does? (After gauging sense and awareness, moderator will read out a basic summary of the mandate of the board.)

- Mission: to promote a viable, sustainable and efficient energy sector that serves the public interest and assists consumers to obtain reliable energy services at reasonable cost.

- The Board regulates the electricity and natural gas sectors in a manner that focuses on outcomes that are valued by consumers

iii. Technical Change Testing – 25 minutes

(Each participant will receive and be asked to read a handout. Ask respondents to read these paragraphs - all excerpts from the primer document that deal with a proposed technical change – this is "Handout 2". Using pens or pencils circle ideas or phrases they like, cross out what they don't like. Put a question mark where they have questions or are confused by anything.)

17. Please review this document about the delivery line. This outlines a proposed change to the delivery line. Using pens or pencils circle ideas or phrases that you think are positive, cross out what you don't like. Put a question mark where you have questions or are confused by anything. I will collect these at the end of the groups. Please don't put your names on them. When you're done we'll talk about your reactions, so please just read this through till the end before discussing.

HANDOUT 2

a) *The biggest part of the Delivery line on your bill goes to your local distribution company, like Toronto Hydro, Enersource, Powerstream, Veridian etc. Those utilities (there are 77 of them) apply to the Ontario Energy Board for permission to collect enough money to cover their costs of serving their customers.*
b) *Utilities charge households a small monthly fixed fee along with a rate based on how much you consume.*
c) *A new way to calculate and charge distribution rates would be to link those rates to how much a customer uses during busy, peak demand time of the day.*
d) *We can do that using the data from a home's smart meter and pegging a person's distribution charge based on how he or she used electricity during the previous year. It would be a fixed, monthly charge pegged at a level related to your usage during the peak time of day.*
e) *Over the course of the year, your monthly charge would not change from month to month. The charge would be based on your consumption from the previous year. If you reduce or increase consumption significantly you could pay a lower or higher amount.*

f) Customers with a charge in the middle or upper range could shift their consumption away from those times of day when electricity is most expensive and when demand is high and be able to reduce that fixed charge for the following year.

18. Was there any language here that you found needed clarification? Is there anything that you didn't understand? (probe first to understand if any of this was not clear).

19. What is your reaction to this?

(Moderator will need to ensure at this point that everyone has understood the facts – that this is a change to the distribution charge within the distribution line only. Take the time at this point to discuss the basic changes introduced here, ensure each is understood and get any further reaction.)

20. The new way to calculate and charge distribution rates would be to link those rates to how much a customer uses during busy, peak demand time of the day.
    a. Did you have any questions about that or does that seem clear?
    b. Do you have concerns about that?

21. You would pay the same amount each month so there would not be the fluctuation from month to month. At the end of the year, a re-calculation could occur if you have increased or decreased consumption during peak periods.
    a. What did you think of that?
    b. Did you have any questions about that or does that seem clear?
    c. Do you have concerns about that?

22. Does this concern you at all, possibly or not at all?

23. What concerns would you have?

24. Why would this be a good thing?

25. Why do you think this is being done? (probe for as many reasons as possible)

iv. Pricing Calculation Change

(Moderator will share "Handout 3" the pricing chart that outlines GTA Residential Pricing Example – the chart would show pricing now for KWH and compare that to the pricing those customers would now pay OR show charts with current pricing based on consumption and based on peak consumption)

1. This chart shows you the fixed charges that different residents could pay for distribution charge that is included in the delivery line of your bill. What this outlines is that there are three different charges that households would pay based on their consumption – more or less or an amount in the middle. And it shows you where those households are today when it comes to the distribution charge they pay.

2. How would you describe what is different with the new charge?

3. So the proposed system is different than a charge based on consumption calculated by a rate. This is not a sliding scale. Here we have pricing tiers. Have a look at this chart and then I will ask for your reactions to this. So while pricing for distribution will be pegged to amount consumed, it will not vary slightly, it will vary between levels of consumption, if you reduce consumption your charge will not come down until or unless you move out of the tier you're in. What is your reaction to this?

4. What is your reaction to the impact that this will have on bills? (Probe to see here if people feel this is fair and whether they think this will entail significant rises or decreases.)

5. Why might this be a good thing for consumers?

6. Are there other reasons why this might be a good thing for consumers or for the system?

7. (At this point the moderator will hand out the sample bills "HANDOUT 4". to put into real terms what the bottom line impacts are going to be and determine whether reaction or understanding increases or lessens with the chart and/or in turn what reaction or understanding the sample bills help to bring about.)

Here are sample bills for residential households. If you look at the delivery line in the current bills and the delivery line in the new proposed approach you can see the impact in context. So the distribution portion of the delivery line is being calculated differently now and you can see the impact. What is your reaction to this?

8. Is this about what you expected based on the chart? Does this seem different than what we had discussed in the first handout?

9. Do you have any questions at this point?

v. Maximum pricing

1. I want to ask you one more question. And that is about determining what to charge based on how much you consume during peak hours. Imagine that this would be calculated based on the maximum during the peak hours as defined for Time of Use. This could be the one-time maximum reached at any point in the year or average of the 5 highest days. What's your reaction to that?

vi. Rationale – 25 minutes

1. (The moderator will now present "Handout 4" which presents context and rationale.) Please review this document about the delivery line. Using pens or pencils circle ideas or phrases that you think are positive, cross out what you don't like. Put a question mark where you have questions or are confused by anything. I'd like to ask you at the end after everyone has read this if you felt any of this was surprising, important to you or a good argument for this change. This is specifically about the proposal you just read.

HANDOUT 5

a) *Right now, utilities charge households a small monthly fixed fee along with a rate based on how much you consume. That fixed charge varies from utility to utility to cover things like administrative and billing costs. Some distributors use a higher fixed charge and lower rate based on how much you consume; other distributors are the opposite. The result is that two identical households* *with different distribution companies could be charged different amounts on their delivery line depending on how their utility charges its customers.*

b) *There are other challenges with collecting rates that way. First, the province requires these local distributors to encourage customers to use less electricity. But if customers use less, the distributor makes less money, even though they still need to buy just as many poles and just as much wire as before. In fact, most of that local distributor's costs have very little connection with overall consumption because you still need all the wires and poles and such to get the electricity to each home and business in the community, regardless of how much each home and business is using.*

c) *What the Ontario Energy Board has been looking at is whether there is a better way to do distribution rates. We know that utilities need money to maintain and modernize their systems. We also know that customers value stable, predictable rates. Is there a way for utilities to collect that money that is more in line with their costs? Is there a way to make distribution rates that send the right message to consumers about how their consumption affects the utility's costs?*

d) *The Board thinks there is. Rather than charge a rate based on how much a customer uses through the month it's a more relevant measure to charge based on how much a customer consumes during the busiest demand period of the day. Much like time-of-use prices on the larger Electricity line of a bill.*

e) *Consider how the utility invests its money. Distributors build their systems so that they have the capacity to carry enough electricity into homes and businesses during the busiest time of day. It's not unlike figuring out how big of a pipe you need to deliver water to a neighbourhood. If everyone in the community used their water at a slow and steady rate through the day, you may only need a two-inch pipe to make sure everyone had sufficient water pressure. But because people generally use their water in bunches (like everyone having their morning shower at the same time), then you need a wider, more expensive pipe to make sure everyone can shower whenever they want. Back to electricity, that means a lot of money is spent to make sure we don't run short of power for that short period each day when everyone is coming home from work, turning on lights and starting supper, or cranking up their air conditioners on a hot summer afternoon. In other words, the activity that is driving up delivery costs is that high-demand time of the day. It is not so much about your total consumption through the month.*

f) *Consider someone who consumes a lot of electricity during other times of the day. She or he actually adds very little to how much their utility needs to spend to make sure the system is big enough to handle the busier, high-demand periods. And yet, right now, that person pays a higher distribution charge than someone who is using more electricity during the busy periods, but less overall during the month.*

g) *A more sensible way to charge distribution rates would be to link it to how much they use during that busy, peak demand time of the day. That's because those are the times that require the utility to spend money on things like bigger lines and bigger transformer stations. We already do that for time-of-use prices on the Electricity line on your bill. Prices are related to the cost of generating the electricity during the time of the day you are using the electricity. By pegging a person's distribution rate to how much they use during the busiest time of the day, customer bills would more accurately reflect their costs on the system. It would mean that person who uses more electricity through the month, but less during busy times of day, isn't subsidizing other customers who focus their electricity use on the busiest, and most expensive, times of day.*

h) *Another benefit to this is that it offers a bigger reward to customers already working to shift their consumption away from those times of day when electricity is most expensive. Avoiding that expensive time when demand is high would enable a customer to reduce that fixed charge for the following year.*

2. What was your reaction to this document overall? On balance do you agree with the arguments? Disagree? Or was this unclear? (Probe to see whether they agreed with this, disagreed on balance, and what they disagreed with, and what they agreed with.)

3. What parts were unclear?

4. (Moderator will go through each paragraph and discuss each to the extent that they have not been discussed already) So let's review each paragraph. For the first/next paragraph:
   a. Did you agree or disagree with this?
   b. Is this a good explanation for why we would change the way the delivery line should be calculated?

(Repeat for each paragraph)

5. This document said that peak times are the times that require the utility to spend money on things like bigger lines and bigger transformer stations. Did that surprise you or is that different than you thought was the result of many people reaching their maximum consumption during the day (or evenings in winter)?

6. Does that change your mind about why the electricity system has been charging more for electricity during peak times? (Probe for and recall reasons they thought prices were higher during peak times)

7. If infrastructure has to increase or be large enough to handle peak consumption times when more people want more electricity at once, what would you figure or guess would be the ways in which the system's capacity would have to expand? We talked about a water pipe for instance that had to widen when more people want a lot at once, rather than the same amount over a smaller period. What are the parts of the electricity system that you see around you that have to widen?

8. What did you think of that water pipe analogy? Was that a fair comparison? Is there a better comparison?

vii. Wrap up

1. So now that you've read about this proposal in detail let me ask you, if I said to you this is a smarter way to make rates for the charges your electric utility charges would you agree with that or disagree with that?

2. What's your reaction to that statement? "This is a smarter way to make rates."

3. Why might it be a good thing?

4. Having read all the material now, does this concern you a great deal or not at all or a little?

5. What concerns would you have?

6. What do you think the Ontario Energy Board should consider before going ahead with this?

7. What was the most important piece of information or explanation to helping you understand the impact on your bill?

8. What was the most helpful piece of information we discussed that answered questions you had that clarified what this was for?

9. What was the best argument for doing this?

10. I'd like to ask you to tell me the objectives are of this? What is the main objective? (probe to see if there is consensus on this?) How would you sum it up in your words?

11. What are the secondary objectives?

12. How is this good for the electricity system? (Probe to see whether simpler regulation, consistency in regulations, stability of revenue for utility, stability of rates for customer, and conservation/peak use mgt and cost control to keep costs down have come up? If any have not come up ask if they agree that this is a reason behind this and whether it's a good reason)

13. How would you sum up the impact on consumers? Who will see the results on their bill?
(Probe to see if this is good, neutral or bad for the consumer. Is it good/bad for most, for some, for all?

14. How many of you use natural gas at home? Could this system apply to delivery of natural gas? Does the same concept apply? Would you agree or disagree that this applies as much to how we charge for natural gas as for electricity. Or is this more applicable to natural gas? Or less applicable?

15. Probe: is this revenue neutral?

16. Reminder: an open consultation will occur before this happens/would be implemented.

17. What should a bill insert say? What three things to advise you?

VI. Appendix B – Recruitment Screener

Project Energy Communications

Group 1: September 25 – 6 pm - skew middle to lower income, and seniors
Group 2: September 25 – 8 pm - skew middle to upper income, and parents with kids at home
Group 3: September 26 – 6 pm - skew middle to lower income, and seniors
Group 4: September 26 – 8 pm - skew middle to upper income, and parents with kids at home

Location: Head Quarters (Uptown) – 5075 Yonge Street, Suite 601 (North of Sheppard Ave)
Map: http://www.head.ca/toronto_map_hq.html

Target

Recruit 10 respondents per group

Recruit respondents who live in Toronto, Aurora, Richmond Hill, Vaughan, Markham, Brampton, Uxbridge or Mississauga any other 905 communities. Ensure a similar mix in each group in terms of proportion from 416 vs 905 e.g. a max of Toronto Hydro customers.

All respondents will be homeowners, condo owners or renters that pay their own electricity costs and receive their electricity bills at their home - No respondent will have a landlord pay it or have the cost of electricity rolled into a condo fee.

All respondents must purchase electricity and receive a bill from a utility company. All respondents must purchase electricity directly from one of the following utility companies: PowerStream, Hydro One, Enersource or Veridian or Toronto Hydro. At a minimum we'd want four of those 5 companies' customers represented.

All respondents will be asked to bring a copy of one of their electricity bills. This is not compulsory.

INTRODUCTION:

Hello, my name is ________ and I'm calling today from _______ to invite you to a focus group discussion scheduled for **September 25 and 26 in the Yonge & Sheppard area**. It will be a moderated discussion running a maximum of 2 hours with about 9 other people to give your input and thoughts regarding a specific topic regarding electricity pricing.

Your participation in the research is completely voluntary and your decision will not affect any future opportunities with us. All information collected, used and/or disclosed will be used for research purposes only and administered as per the requirements of the Privacy Act. We will not share your last name, phone number, or mailing address.

You will also be asked to sign a waiver to acknowledge confidentiality and that the session discussion will be recorded. You will receive an $85 cash honorarium as a thank you for participating in this focus group. May we have your permission to ask you some further questions to see if you fit in our study?

Yes 1
No...2 – THANK AND TERMINATE

INDICATE: Male......................................1 } GOOD MIX PER GROUP
Female..................................2

1. Are you or is any member of your household employed in, or ever been employed in:

	Current		Ever	
	No	Yes	No	Yes
Market Research	( )	( )	( )	( )
An Electric Company or electricity marketing company	( )	( )	( )	( )
A Natural Gas company				
Marketing	( )	( )	( )	( )
Public Relations	( )	( )	( )	( )
Any media (Print, Radio or TV)	( )	( )	( )	( )

IF YES TO ANY OF THE ABOVE – THANK AND TERMINATE

2. In what city do you live? ________________________________ -
SPECIFY

ENSURE A GOOD MIX OF CITIES PER GROUP

3. May I have your age, please? ________________________________ -
SPECIFY

17 and under..........................1 – THANK AND TERMINATE
18 – 24 years 2
25 – 40 years.........................3
41 – 49 years ....4 GOOD MIX PER GROUP
50 – 64 years.........................5
65 - 70 years 6
71+ years...............................7

4. Are you a home owner, condo owner or a renter?

Home owner..........................1 – SKIP TO Q6
Condo Owner ....2 – ASK Q5
Renter..................................3 – ASK Q5

5. (ASK ONLY IF RESPONDENT IS A CONDO OWNER OR A RENTER AT Q4, OTHERWWISE SKIP TO Q6) Is the cost of your residential electricity blended into your condo fees/rent, meaning you do not see or receive a regular electricity bill from the utility company?

Yes...1 – THANK AND TERMINATE
No ....2 – ASK Q6

ALL RESPONDENTS MUST PAY THEIR OWN ELECTRICITY COSTS – NO RESPONDENT WILL HAVE A LANDLORD PAY IT OR HAVE THE COST OF ELECTRICITY ROLLED INTO A CONDO FEE

6. (ASK ALL RESPONDENTS) Do you receive a bill for your home electricity use at home?

Yes...1
No ....2 – THANK AND TERMINATE

7. Who in your household is responsible for paying the electricity bill for your home?

Yourself only...................................... 1
Yourself and someone else 2
Someone else .... 3 – THANK AND TERMINATE

8. How often, if at all, do you look at your electricity bill? Would that be…

All of the time 1
Occasionally....................................... 2
Some of the time................................ 3
Or never .... 4 – THANK AND TERMINATE

9. Which utility company do you receive your electricity bill from?

PowerStream.................1 – MINIMUM 1 PER GROUP North GTA
Toronto Hydro ....2 – MINIMUM 2/MAXIMUM 5 PER GROUP
Hydro One.....................3 – MINIMUM 1 PER GROUP North GTA
Veridian ....4 – MINIMUM 1 PER GROUP East GTA
Enersource ....5 – MINIMUM 1 PER GROUP Mississauga
Other (SPECIFY) ....6 (Only some will be considered – please place on standby)

IDEALLY A MINIMUM OF 1 RESPONDENT IN EACH GROUP MUST PURCHASE ELECTRICITY FROM ONE OF THE UTILITY COMPANIES LISTED ABOVE AT Q9. BUT IF NECESSARY ENSURE 4 of 5 OF THOSE COMPANIES ARE REPRESENTED AND THAT respondents are invited from around the GTA. A MINIMUM OF 2/MAXIMUM OF 5 RESPONDENTS PER GROUP WILL PURCHASE FROM TORONTO HYDRO

10. Do you buy natural gas for home energy use?

Yes... 1
No 2

11. Participants in this group will be asked to read and review and then comment on written material that will be presented in the groups. Are you able to do that or have any concerns in that regard?

Yes, comfortable 1
No, is concerned .... 2 – THANK AND TERMINATE
Unsure .... 3 – THANK AND TERMINATE

NOTE: IF RESPONDENT OFFERS ANY REASON SUCH AS SIGHT OR HEARING PROBLEM, A WRITTEN OR VERBAL LANGUAGE PROBLEM, A CONCERN WITH NOT BEING ABLE TO COMMUNICATE EFFECTIVELY – THANK AND TERMINATE

12. Would you be willing to bring a copy of a recent electricity bill to consult during the groups? You will not be required to share information about your bill, just to consult it during discussion. This focus group is for research only and not a sales pitch.

(record that this has been read aloud)

13. As we need to speak with people from all walks of life, could you please tell me into which category I may place your total annual household income? Would that be:

Under $35,000 1
$35,000 - $50,000 2
$50,000-$80,000 3
$80,000 -$100,000 4
$100,000 and up...............5

6 pm groups to be made up of 1, 2 or 3
8 pm groups to be made up of 3, 4 or 5

14. (ASK ALL RESPONDENTS) Do you have any children, under the age of 18 years of age, living at home with you?

Yes ....1 – Parents to be in 8 pm groups
No...2 – 6 pm groups

15. What is your marital status?

Married/Common Law 1
Single/Div./Wid./Sep 2

16. What is your current employment status? (ENSURE A GOOD MIX)

Full Time Employed	( )	
Part Time Employed	( )	
Homemaker	( )	
Student	( )	– MAXIMUM 1 RESP. PER GROUP
Retired	( )	6 pm groups
Unemployed	( )	– MAXIMUM 1 RESP. PER GROUP

17. (ASK ONLY IF RESPONDENT IS EMPLOYED FULL OR PART TIME OR RETIRED, OTHERWISE SKIP TO Q21) What is your current (former if retired) occupation?

Occupation	Type of Company

18. (ASK ONLY IF RESPONDENT IS MARRIED/COMMON LAW, OTHERWISE SKIP TO Q15) What is your spouse's current occupation and employer?

Occupation	Type of Company or Industry

19. Could you please tell me, what is the last level of education that you have completed?

Some High School	1	– THANK AND TERMINATE
High School	2	ENSURE A GOOD MIX
Some College/University	3	
Completed College/University	4	

20. Participants in a focus group discussion are asked to voice their opinions and thoughts, how comfortable are you, in sharing your opinions and respectfully disagreeing with others and presenting new perspectives in a discussion? Are you....

Very Comfortable	1	
Comfortable	2	
Fairly or Somewhat Comfortable	3	
Not Very Comfortable	4	– THANK AND TERMINATE
Very Uncomfortable	5	– THANK AND TERMINATE

21. Have you attended a focus group or one to one discussion for which you have received a sum of money, here or elsewhere, in the last year?

    Yes...............................1 – MAXIMUM 3 RESP. PER GROUP, ASK Q22
    No ....2 – MINIMUM 5 RESP. PER GROUP

22. (ASK ONLY IF RESPONDENT SAID "YES" AT Q21) Could you please tell me the topics discussed in previous focus groups or one to one discussion in which you have attended?

    ____

    ____

    ____

THANK AND TERMINATE IF RESPONDENT HAS PARTICIPATED IN A PREVIOUS FOCUS GROUP OR ONE TO ONE DISCUSSION ON A SIMILAR TOPIC

IMPORTANT:

We offer each participant an $85.00 cash gift as a token of our appreciation. I should also tell you that the groups will be MONITORED BY A MODERATOR AND MEMBERS OF THE RESEARCH TEAM. Everything you say will be kept confidential

[ ] CHECK TO INDICATE YOU HAVE READ THE STATEMENT TO THE RESPONDENT.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid pursuant to General Laws Ch. 164, § 94 and 220 C.M.R. §§ 5.00 et seq. for a general increase in distribution rates	))))))	D.P.U. 15-155

AFFIDAVIT OF NATHAN PHELPS

Nathan Phelps, does hereby depose and say as follows:

I, Nathan Phelps, on behalf of Vote Solar, certify that testimony, including information responses, which bear my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

I declare, under penalty of perjury, that the foregoing information is true, accurate, and correct. Executed this 17th day of March, 2016.

Nathan Phelps

THE COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

D.P.U. NO. 15-155

CERTIFICATE OF SERVICE

I hereby certify that I have this day served true copies of the foregoing upon all parties of record in this proceeding in accordance with the requirements of 220 CMR 1.05(1) (Department's Rules of Practice and Procedure).

DATED: March 18, 2016

Hannah Chang
Earthjustice
48 Wall Street
19th Floor
New York, NY 10005
hchang@earthjustice.org
(212) 845-7382