**BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

In the Matter of the General Investigation to Examine Issues Surrounding Rate Design For Distributed Generation Customers	)))	Docket No. 16-GIME-403-GIE

INITIAL COMMENTS OF MR. BRADLEY D. LUTZ

COMES NOW Kansas City Power & Light Company ("KCP&L" or the "Company"), pursuant to The State Corporation Commission of the State of Kansas' ("Commission") February 16, 2017 *Order Setting Procedural Schedule* ("Order"), and submits the following Initial Comments concerning the issues in this Docket:

I. DOCKET BACKGROUND

1. On March 11, 2016, the Staff of the Commission ("Staff") filed a *Motion to Open Docket* and attached *Report and Recommendation*. Staff's motion was docketed as Docket No. 16-GIME-403-GIE ("16-403 Docket").

2. On July 12, 2016, the Commission issued its Order opening this Docket to examine various issues regarding rate structure for Kansas distributed generation ("DG") customers, as well as ordering parties to file comments on how this Docket should proceed by August 26, 2016.[1]

3. On August 5, 2016, Staff submitted its recommendations regarding procedure and schedule in this Docket.[2]

4. On August 11, 2016, the Citizens' Utility Ratepayer Board ("CURB") submitted its recommendations regarding procedure and schedule in this Docket.[3]

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[1] 16-403 Docket, *Order Opening General Investigation* ("Order"), issued Jul. 12, 2016.
[2] 16-403 Docket, Staff's Comments on How General Investigation Should Proceed, filed Aug. 5, 2016.
[3] 16-403 Docket, CURB's Recommendations Regarding Investigation Procedures, filed Aug. 11, 2016.

5. On August 19, 2016, Westar Energy, Inc. and Kansas Gas and Electric Company submitted comments regarding procedure and schedule in this Docket.[4]

6. On August 26, 2016, KCP&L[5], The Climate and Energy Project[6], the Alliance for Solar Choice[7], Cromwell Environmental, Inc.[8], and Southern Pioneer Electric Company[9] submitted comments regarding procedure and schedule in this Docket.

7. On November 17, 2016 KCP&L filed a Motion for Official Notice of the "Distributed Energy Resources Rate Design and Compensation" manual ("Manual") prepared by the National Association of Regulatory Utility Commissioners ("NARUC") Staff Subcommittee on Rate Design. The Manual was formally adopted at their November 16, 2016 Annual Meeting.

8. On February 16, 2017 the Commission issued its Order Setting Procedural Schedule for the Docket, establishing the due dates for comments, roundtable discussions, and an evidentiary hearing.[10]

II. WITNESS BACKGROUND AND QUALIFICATIONS

9. I am Bradley D. Lutz and I am employed by KCP&L as Manager, Regulatory Affairs. My current responsibilities are focused on regulatory policy, providing support for the Company's regulatory activities in the Missouri and Kansas jurisdictions. Specifically, my duties require me to be current with industry issues with the potential to impact the Company and

[4] 16-403 Docket, Comments of Westar Energy, Inc. and Kansas Gas and Electric Company in Response to Order Opening General Investigation, filed Aug. 19, 2016.
[5] 16-403 Docket, Kansas City Power & Light Company Entry of Appearance, filed Aug. 26, 2016. Note that the filing was mistitled.
[6] 16-403 Docket, The Climate and Energy Project Comments Regarding How General Investigation Should Proceed, filed Aug. 26, 2016.
[7] 16-403 Docket, The Alliance for Solar Choice's Recommendations Regarding Investigation Procedures, filed Aug. 26, 2016.
[8] 16-403 Docket, Comments of Cromwell Environmental, Inc., in Response to Order Opening Generic Investigation, filed Aug. 26, 2016.
[9] 16-403 Docket, Initial Comments of Southern Pioneer Electric Company in Response to Order Opening General Investigation, filed Aug. 26, 2016.
[10] 16-403 Docket, *Order Setting Procedural Schedule,* issued Feb. 16, 2017.

to provide guidance to optimize KCP&L's response to those issues. Previously, I was responsible for the Rate Design function, including class cost of service ("CCOS") support, rate design, tariff management, and filing preparation. Furthermore, I have represented the Company through participation in regulatory rulemakings and compliance reporting. I have also managed certain analytical activities for the department including docket management system administration, rate change implementation, billing determinant calculation, and retail revenue calculation. I hold a Master of Business Administration from Northwest Missouri State University and a Bachelor of Science degree in Engineering Technology from Missouri Western State University.

10. I joined KCP&L in August 2002 as an Auditor in the Audit Services Department. I moved to the Company's Regulatory Affairs group in September 2005 as a Regulatory Analyst where my primary responsibilities included support of our rate design and class cost of service efforts. I was promoted to Manager in November 2010. Prior to joining KCP&L, I was employed by the St. Joseph Frontier Casino for two years as its Information Technology Manager. Prior to St. Joseph Frontier Casino, I was employed by St. Joseph Light and Power Company for nearly 14 years, holding various technical positions including Engineering Technician-Distribution, Automated Mapping/Facilities Management Coordinator, and my final position as Senior Client Support Specialist-Information Technology.

11. I have provided written testimony in Docket Nos. 07-KCPE-905-RTS, 09-KCPE-246-RTS, 12-KCPE-764-RTS, 14-KCPE-272-RTS, and 15-KCPE-116-RTS supporting the Company's CCOS studies or rate design proposals.

III. COMMENTS

12. KCP&L appreciates the opportunity to participate in this general investigation concerning rate design for DG customers. DG can be an important part of the energy grid and can help expand the utilization of renewable energy resources. KCP&L agrees that now is the time to address this issue as DG, while still relatively limited, is beginning to escalate in our service territory. Establishing an appropriate and equitable way to address the rate design issues around DG will help ensure the best experience for all stakeholders and limit any negative consequences of further deployment of this resource.

13. The Company defines DG as any small-scale generator of electric power (often less than one MW in capacity) owned by a customer that is interconnected to the Company's electrical distribution system ("energy grid") generally behind the customer meter. DG systems are located within the energy grid based on customer choice and are not centrally planned or otherwise controlled by the energy grid operator. The Company views DG more broadly, adopting the term Distributed Energy Resource ("DER"), where DER is not just limited to rooftop solar, but may include broader technologies such as: (1) battery storage, including the potential for EV based storage; (2) fuel cells; (3) micro-turbines; and (4) combined heat and power systems. However, rooftop solar, as deployed through the Company's Net Metering tariff, is currently the most common form of DER in KCP&L's service territory[11] and is perceived by the Company to be the primary focus of this Docket. I agree with this focus, but contend that the policies established in this Docket should also be cognizant of other resources considered as DER.

[11] See KCP&L's 2016 Annual Net Metering Report filed March 1, 2017 in Docket No. 12-KCPE-665-CPL for a detailed listing of the DG currently on KCP&L's energy grid.

14. Net metering is a billing mechanism made possible through the Federal Energy Policy Act of 2005[12], the Kansas Net Metering and Easy Connection Act in May 2009 (see K.S.A. 66-1263 through 66-1271), and K.A.R. 82-17-1 through 82-17-5, that allows customers to install renewable energy resources at their location for the purpose of offsetting all or part of their electrical energy requirements. When the renewable energy resource produces energy, this energy is most often consumed on-site. When the renewable energy resource does not produce enough energy to serve the customer's need, the customer draws electricity from the energy grid to supplement the self-produced energy. In the event that the renewable energy resource produces energy in excess of the customer need, the excess energy is transmitted to the energy grid and the customer receives a per kilowatt-hour ("kWh") credit currently equal to the Company's monthly system average cost of energy.

15. KCP&L has significant experience supporting DER technologies. Beginning with net metering, in the State of Kansas, as of March 1, 2017, there are 131 net metered systems installed by KCP&L customers representing 1,200 kilowatts ("kW") of renewable capacity. In the State of Missouri, as of April 15, 2016, counting both KCP&L and KCP&L-Greater Missouri Operations Company ("GMO"), the Company has 2,783 systems installed representing 52,308 kW of renewable capacity. Since the start of net metering in 2008, the Company has worked with customers, and their developers, to deploy net metering systems throughout all customer classes identified by the Company. The following charts examine the growth and utilization of net metering by customers in the KCP&L-Kansas jurisdiction:

[12] This language is referenced in Energy Policy Act of 2005, Pub. L No. 109-58, 119 Stat. 962, §1251(a)(11).

Figure 1: Kansas Net Metering Installations
(Source: KCP&L Annual Net Metering Compliance Reports)

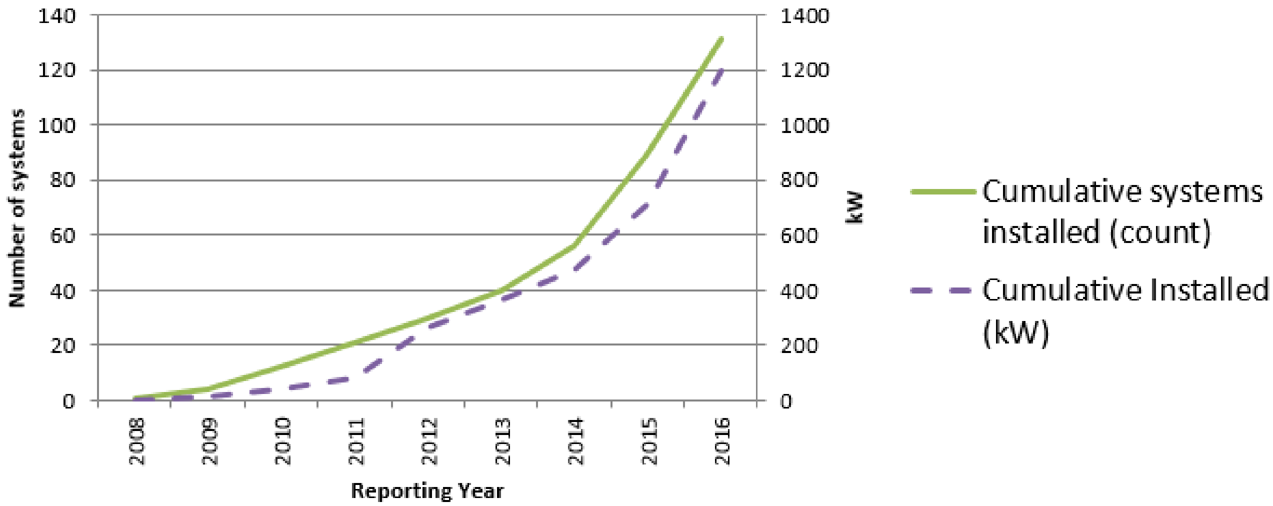


Figure 2: Kansas Net Metering Installations by Customer Class
(Source: KCP&L Customer Data as of March 1, 2017)

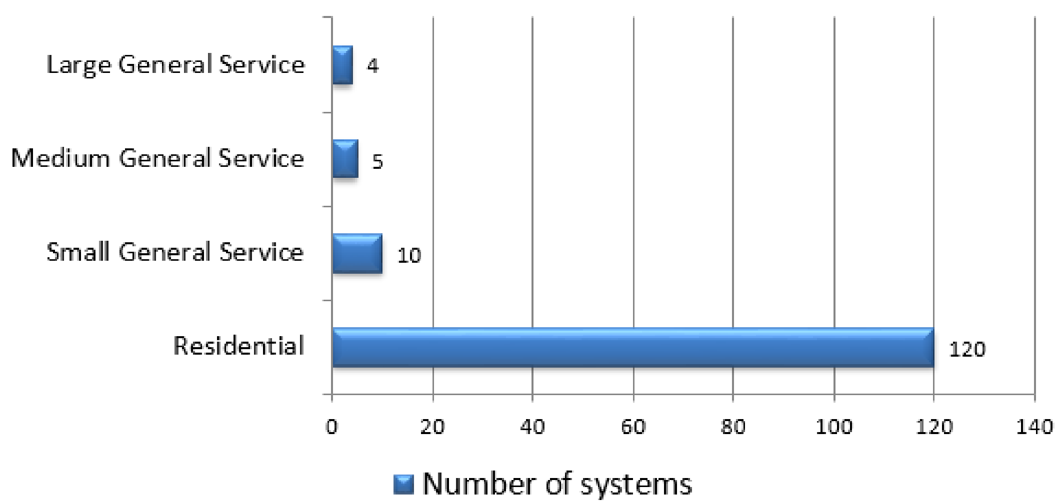


Figure 3: Kansas Net Metering Installations by Renewable Type
(Source: KCP&L Customer Data as of March 1, 2017)

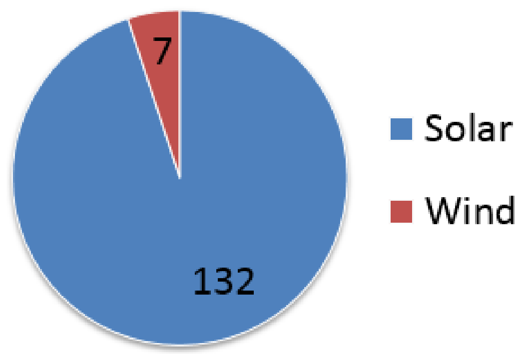
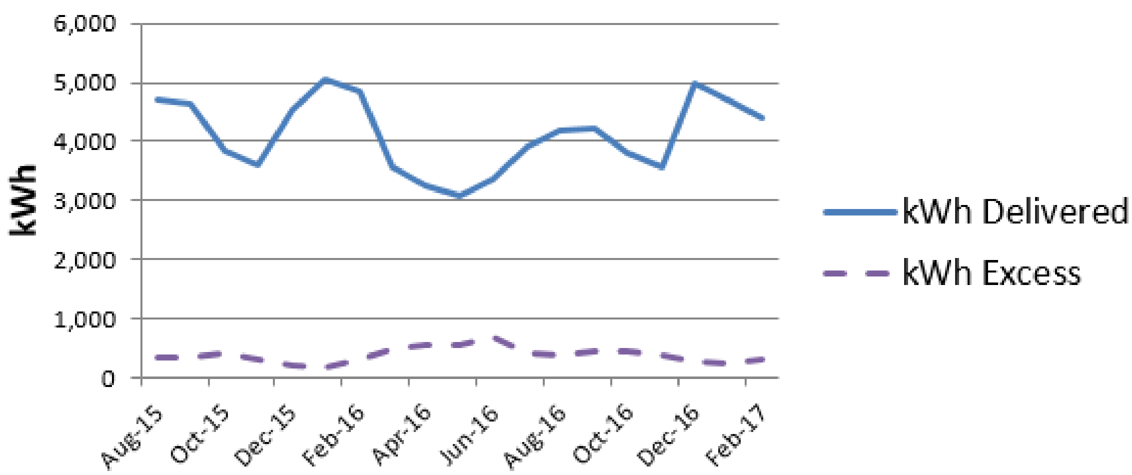


Figure 4: Energy Delivered & Received from Net Metering Systems
(Source: KCP&L Customer Data as of March 1, 2017)



16. As of March 1, 2017, there are 132 solar and 7 wind based net metering systems in KCP&L's Kansas service territory. The 116 Residential solar systems are capable of producing 1,453,874 kWh per year assuming a 16% capacity factor and a typical KCP&L-Kansas residential customer load. These same customers would consume approximately 1,734,396 additional kWh per year from the energy grid.

17. In addition to customer efforts, the Company has deployed DER on its own behalf and installed residential scale systems in the Kansas City area at the Project Living Proof home (3.2 kW) and the Paseo High School (100 kW) plus eight smaller commercial solar systems (5-25 kW each). Furthermore, a one megawatt-hour ("MWh") battery was connected to a distribution circuit as part of the Company's Smart Grid initiative. GMO currently has installed central scale solar at its Greenwood facility (3.6 megawatt ("MW")) and has deployed Landfill Gas generation in St. Joseph, Missouri (1.6 MW). These projects have provided valuable knowledge concerning the installation, operation, and maintenance of DG systems.

18. The decision by the Commission to examine various issues surrounding rate design for DER customers is timely. As you can see from the graphs above, the rate of DER installation is increasing in KCP&L's service territory raising the need to evaluate the effects of DER on KCP&L's energy grid and rate design. There are numerous similar efforts underway or already completed by other state regulatory commissions. Through all of these proceedings, similar themes are being addressed:

- What are the costs and benefits of DER?
- What compensation should DER customers receive for excess energy delivered to the grid?
- How to recover costs, especially energy grid costs, from net metering customers and other partial requirements customers?

These questions have proven difficult to answer. Multiple states have endeavored on multi-year proceedings to develop an answer for their respective jurisdictions. Regional states investigating net metering changes include Iowa, Colorado, and Arkansas. There have also been significant changes to net metering in states such as Arizona, Nevada, and New York.

19. The NARUC recognized the increasing rate of change concerning how energy is delivered to customers and set out to establish a manual to assist member commissions, formally assigning the task to the NARUC Staff Subcommittee on Rate Design.[13] Taking into account comments from stakeholder groups and receiving input through "town hall" meetings, the NARUC Subcommittee on Rate Design developed and adopted the Manual to assist commissions in considering appropriate rate design and compensation policies for DER. On November 17, 2016 KCP&L made a motion in this Docket that the Commission take official notice of the NARUC Manual.

20. To link the Manual to this proceeding, I should be clear that KCP&L identifies DER as inclusive of DG and other distribution level resources to include: (1) Independent Power Resources; (2) Demand-Side Management; (3) Cogeneration; (4) Emergency, Stand-by, or Back-up Generation; and (5) Load Management Resources.

21. In consideration of the Manual, I believe the Commission should place significant emphasis on Chapter Six as it offers insight through three sections pertinent to this Docket: (1) decision framework; (2) the role of technology; and (3) the process for working through questions. Each section makes specific recommendations directed toward the regulator when investigating DER. These sections are:

- **Decision Framework.** This section should hold the greatest level of significance to the Commission for the purposes of this Docket as it offers insight into key questions and potential forms of data sets that may be utilized to facilitate a response to DER-related issues. Specific issues addressed include: (1) how to assess the current DER market

[13] NARUC, "Resolution to Create a NARUC Staff Subcommittee on Rate Design," Nov. 11, 2015, http://pubs.naruc.org/pub/D2DDD7AC-E73C-B386-630C-B8849IDD0608

situation, (2) how to explore the employment of various DER rate design and compensation methodologies, and (3) what data should be used by the regulator so that they may properly conduct their investigation.

- **Role of Technology.** This section places emphasis on how regulators need to remain cognizant of the ever-growing changes in technology, whether it be the energy grid or consumer products, as new opportunities arise and methodologies adapt for how to evaluate the various benefits and costs of DER. In my experience I would offer that technology has the potential to enhance or inhibit rate design efforts. Implementation of a desired rate design might be impacted by the ability to meter the usage or billing systems may be unable to process the design. Conversely, other metering and billing technologies might quickly support a desired rate design. Any policy established concerning DG should be flexible enough to allow for different levels of technical capability.
- **Process for Working through the Questions.** This section provides recommendations to the regulator on how to balance the multiple ideologies and objectives of rate design or compensation methodology along with regulatory policy, technology, and their market's current situation, allowing the regulator to better implement policy that has optimal impacts on utilities, and both DER and non-DER customers.

The use of this Manual to assist with this Docket would bring consistency with the Commission's stated goal from the Order of conducting a "thorough and thoughtful discussion" of issues related to DG.

22. Shifting to rate design, the foundation for current day principles of rate design were developed by two experts in rate design: (1) James C. Bonbright (1969); and (2) Alfred

Kahn (1970). Although I do not support all of the conclusions of the document, a recent Regulatory Assistance Project publication[14] identified four (4) key principles, derived from the Bonbright principles that I believe are valid and should be considered when designing rates for DER customers:

- A customer should be able to connect to the grid for no more than the cost of connecting to the grid;
- Customers should pay for grid services and power supply in proportion to how much (and when) they use these services and how much power they consume;
- Customers who supply power to the grid should be fairly compensated for the full value of the power they supply, no more and no less; and
- Tariffs should fairly balance the interests of all stakeholders: the utility, the non-DER customer, and the DER customer.

23. Regarding the first point on grid interconnection costs, it is KCP&L's responsibility to provide safe, reliable and efficient power for all of our customers. The form, size, and details that define customer-owned generation resources can vary dramatically from case to case. Within that variation, the Company must meet its responsibility for all customers. K.S.A. 66-1,184(c)(3) outlines the DER customer's obligation for providing control and protective apparatus as "shall be designated by the utility as being required as suitable for the operation of the generator in parallel with the utility's system." These interconnection requirements for DER are outlined in the Company's interconnection standard and can vary significantly based on the size and type of DER resource. Requirements range from a simple

[14] Midgen-Ostrander, J. & Shenot, J. (2016). *Designing Tariffs for Distributed Generation Customer.* The Regulatory Assistance Project: Montpelier, Vermont. Available at: http://www.raponline.org/wp-content/uploads/2016/05/rap-madri-designingtariffsfordgcustomers-final.pdf

utility accessible disconnect switch on a net metering residential solar generation installation to sophisticated switching and protective schemes for a complex commercial micro-grid installation. The cost of an interconnection can be significant, particularly if additional infrastructure upgrades are required to accommodate the new DER resource, it is important that these costs be appropriately assigned. The utility should work closely with the DER customer to understand the desired DER system and include only the relevant costs into the interconnection. The desire is to align the cost recovery with the action causing the cost to occur, avoiding subsidy of the cost by other customers.

24. To the second point on payment for energy grid services, DER customers are connected to the utility distribution system and utilize energy grid services around the clock on a continuous, ongoing basis. DER rate designs should reflect that fact. The utility energy grid connection provides DER customers unique and valuable services that they will continue to need to retain the same level of reliable service following installation of a DER resource. Without the energy grid interconnection, DER customers would require significant additional investments for on-site control, storage, and redundant generation capabilities. In fact, for many solar Photovoltaic ("PV") installations, the systems will not operate without the voltage signal provided by the utility energy grid. In addition to grid provided energy (kWh), which has clear recognized customer value, Electric Power Research Institute[15] has identified five primary benefits of energy grid connectivity to consumers with DER that are summarized as follows:

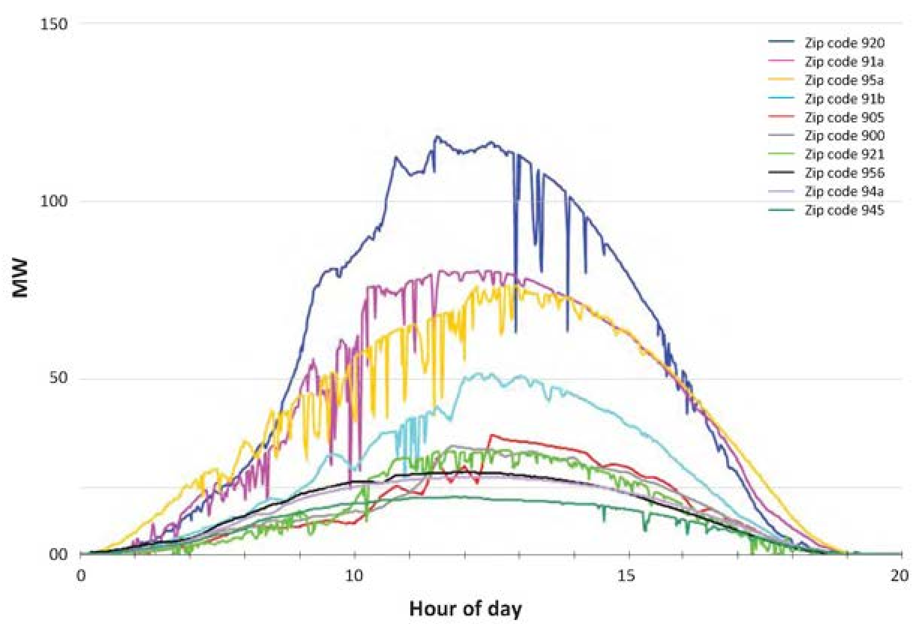
- **<u>Reliability</u>** – The energy grid serves as a reliable source of high-quality power in the event of disruptions to DER and compensates for the variable output of many renewable

[15] *The Integrated Grid – Realizing the Full Value of Central and Distributed Energy Resources.* Electric Power Research Institute: Palo Alto, California. (2014). Available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002002733&Mode=download

generation sources. In the case of solar, the variability is not limited to day and night, but as shown in the following figure, overcast conditions or fast-moving clouds can cause fluctuation of PV-produced electricity. The energy grid serves as a crucial balancing resource available for whatever period, from seconds to hours to days and months, to offset variable and uncertain output from DER resources. This balancing extends beyond real power, as the energy grid also ensures that the amount of reactive power in the system balances load requirements and ensures proper system operation.

Figure 5: Output of PV is Highly Variable and Dependent on Local Weather

(Source: http://www.globalccsinstitute.com/)



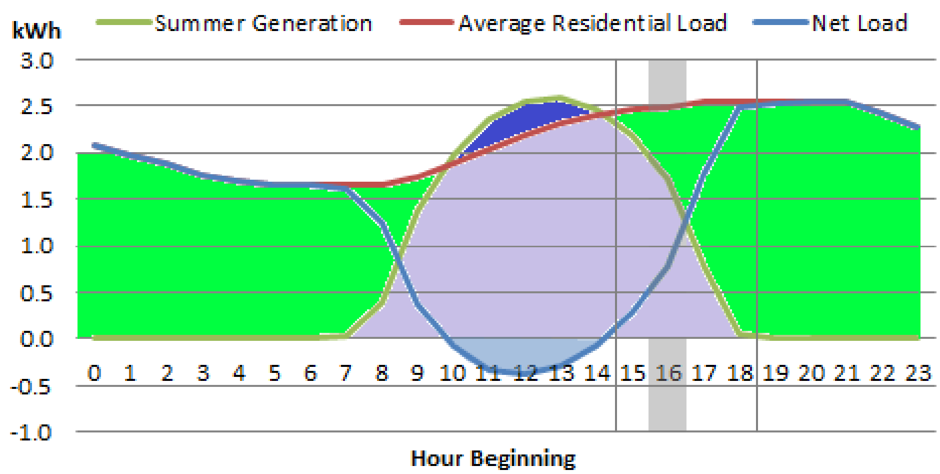
- **<u>Startup Power</u>** – The energy grid provides instantaneous power for appliances and devices such as compressors, air conditioners, transformers, and welders that require a strong flow of current ("in-rush" current) when starting up. This enables them to start reliably without severe voltage fluctuation. Without energy grid connectivity or other supporting technologies, a conventional central air conditioning compressor relying only on a PV system may not start at all unless the PV system is oversized to handle the in-rush current. Oversizing is not allowed under the current Kansas net metering tariffs.

- **Voltage Quality** – The energy grid's high fault current level also results in higher quality voltage by limiting harmonic distortion and regulating frequency in a very tight band, which is required for the operation of sensitive equipment. In contrast, voltage from a distributed system that is not connected to the energy grid will generally have a higher voltage harmonic distortion, which can result in malfunction or damage of sensitive consumer end-use devices
- **Efficiency** – Energy grid connectivity allows DER to operate at optimum efficiency without having to adjust its output based on local load variations. Without energy grid connectivity, the output of a distributed energy resource will have to be designed to match the inherent variation of load demand.
- **Energy Transaction** – Perhaps the most important value that energy grid connectivity provides consumers is the connection itself. A utility connection enables consumers to transact energy with the utility energy grid, getting energy when the customer needs it and sending energy back to the energy grid when the customer is producing more than is needed. This benefit, in effect, shifts risks with respect to the size of the energy resource from the individual user to the utility.

Customer reliance on the energy grid may be demonstrated in another way. Figure 6 below compares a typical customer's load to the energy output from solar generation. The areas on the graph that are shaded in green represent usage taken from the energy grid. The light blue area represents energy consumed from the solar generation. The dark blue area represents excess energy that is delivered back to the energy grid. This size of the blue area will vary through the course of a year. The gray bar identifies the peak hour for the residential class. Ignoring the instantaneous needs of a customer detailed in Figure 5, this graph clearly shows the customer's overall reliance on the energy grid. The value of the grid cannot be ignored in defining an appropriate DER rate design.

Figure 6: Residential Load versus PV System Output

(Source: KCP&L example)



25. To the third point on compensation for power delivered to the energy grid, the Kansas Net Metering and Easy Connection Act (K.S.A. 66-1266) specifies that for all customer generators installed after July 1, 2014, any net excess energy generated during a billing month will be credited to the customer at a rate of 100% of the utility's monthly system average cost of energy per kWh[16].

26. As residential rooftop solar installations proliferate, State and utility solar policies continue to undergo review. In 2016, proceedings considering policy or rate design changes

[16] Alternatively, for customer generators not taking service under net metering, K.S.A. 66-1,184 (b)(2), implemented through the Company's Parallel Generation tariff, provides that any excess energy supplied to the utility shall be compensated at not less than 100% of the utility's monthly system average cost of energy per kWh except that in the case of renewable generators with a capacity of 200 kW or less, such compensation shall be not less than 150% of the utility's monthly system average cost of energy per kWh.

related to DER were underway in many states in the country – specifically 20 solar valuation or net metering studies were initiated in 16 States in 2016.[17] As of yet, no singular policy design has emerged as a leading approach across the country. The solar valuation studies have yielded widely varying results, primarily due to the wide range of perceived benefits included in the analyses. Most of the analyses have included avoided energy, Renewable Portfolio Standard purchases, generation capacity, reserves, ancillary services, Transmission & Distribution capacity, and losses. Other analyses include future estimate items such as: reduced fuel price risk, reduced costs of future carbon regulations, and cost savings associated with reduced wholesale electricity and/or natural gas prices, and other broader societal benefits. Few, if any of the analyses have attempted to estimate the future utility costs associated with increased volt/VAR support and enhanced grid planning, monitoring, operations and control as the penetration of DG increases.

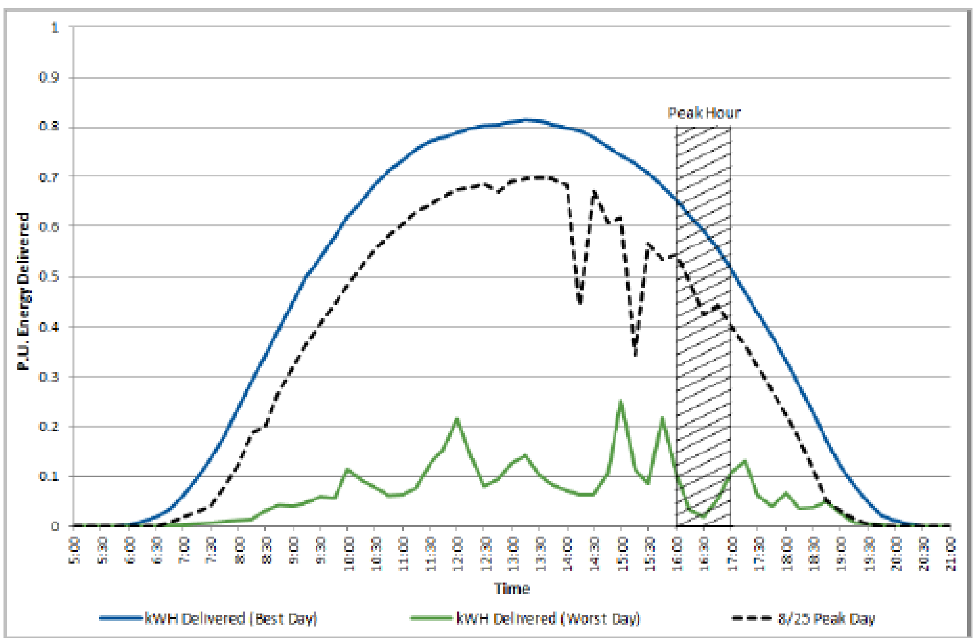
27. Locally, KCP&L and the other regulated utilities in Kansas are regulated under cost of service regulation and, as such, rates are not set based on perceived values, but instead are based on verifiable costs. In addition to the utilities avoided cost of energy, there is an opportunity for DG/DER to contribute to capacity and ancillary services that will be needed to operate the future energy grid. During its Smart Grid Demonstration Project, KCP&L performed several operational tests and conducted preliminary analysis of the potential benefits distributed solar generation and battery storage may have on the energy grid. Key findings are summarized as follows:

- **Supply Capacity** – The extent to which DG reduces system supply capacity requirements depends on the coincidence of the DG output with the system peak load

[17] North Carolina Clean Energy Technology Center, *The 50 States of Solar: Q4 2016 & Annual Review Executive Summary*, January 2017.

conditions. Our Smart Grid analysis, illustrated in Figure 7 below, determined that on a 'good' solar production day the coincidence of solar generation with the KCP&L system peak could range from 40% to 55%, depending on when in July or August the peak condition occurs. If a system peak event occurs in early July, solar coincidence as high as 55% may be expected. But as peak events occur later in the year, the coincidence reduces – to 40% by late August.[18] This figure also illustrates that on a 'poor' solar production day there could be very little solar production coincident with the system peak.

Figure 7: SmartGrid Composite DG Profile - Best, Worst and Summer Peak Day
(Source: KCP&L SmartGrid data)



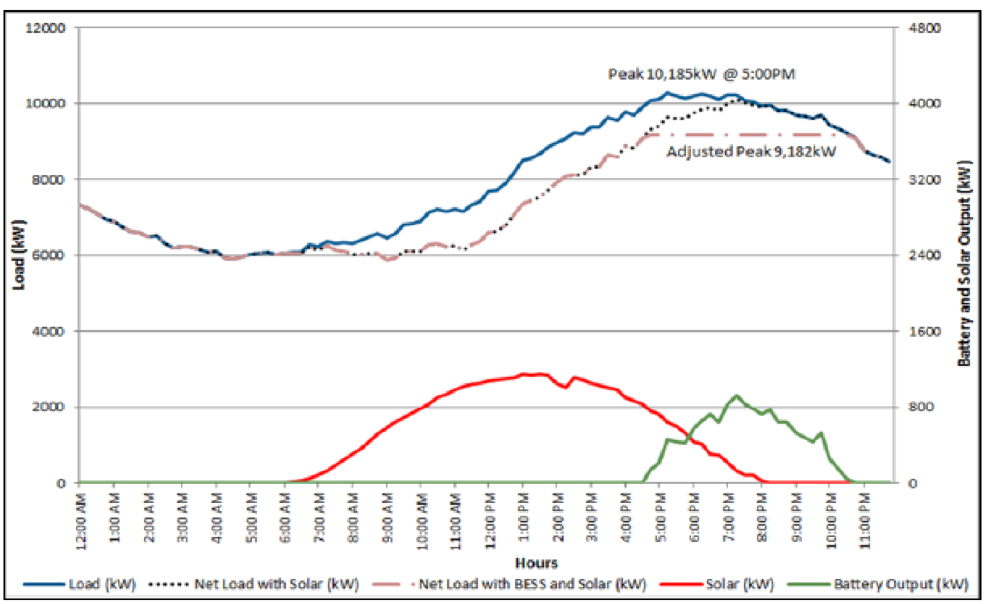
- **<u>Delivery Capacity</u>** – The extent to which DG or DER reduce system delivery capacity depends on the expected output during peak loading of the local distribution feeder, which typically varies from the aggregate system peak. If feeder peak demand occurs in

[18] Kansas City Power & Light Co., *KCP&L Green Impact Zone Smart Grid Demonstration– Final Technical Report, Ver. 2,* May 2015, p. 583.

the late afternoon/evening, as is the case with many residential feeders, local PV output may have minimal ability to reduce feeder capacity requirements. The Smart Grid project performed an analysis to determine if a modest level of distributed solar PV generation would alter the capability of a battery energy storage system ("BESS") to provide distribution peak load reduction. Figure 8 summarizes the results of that analysis for a residential circuit. This analysis shows that a 15% solar penetration (1.5 MW) on the circuit would result in less than a 1% reduction in circuit loading at peak but shifts the peak hour from 5 PM to 7 PM. The analysis also shows that for the solar adjusted residential circuit load profile, an optimally configured 1.0 MW or 4.0 MWh BESS operating in 'load following' mode over seven hours, could achieve a minor, 9% reduction in circuit peak load. Combined, the solar and BESS could potentially achieve a little more, achieving a 9.8% reduction in the circuit peak load.[19]

Figure 8: Solar Adjusted Residential Circuit Peak Day with Storage

(Source: KCP&L SmartGrid data)

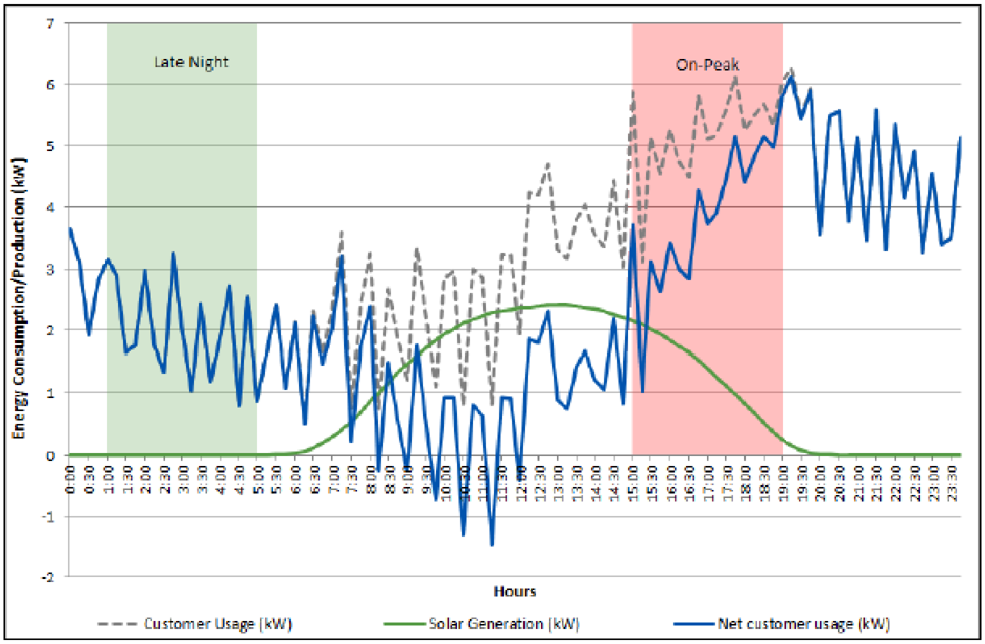


[19] Kansas City Power & Light Co., *KCP&L Green Impact Zone SmartGrid Demonstration – Final Technical Report, Ver. 2*, May 2015, p. 628.

- **<u>Localized Distribution Grid Capacity</u> –** The extent to which DG can reduce loading on local components of the distribution grid depends on the coincidence of the DG output with localized customer loads. If local peak loads occur in the late afternoon/evening, as is the case with many residential customers, local PV output can do little to reduce loading on the local grid. The Smart Grid project performed an analysis to determine the extent to which residential solar PV generation would reduce the residential peak loads. While no two customers have identical usage patterns, a typical pattern can be observed. A typical daily pattern is: minimal usage during the late night, a sharp rise to moderate usage in the early morning hours, then by a mid-morning drop in usage that begins to increase throughout the day, with significant peak usage during the On-Peak period, and then slightly reduced but sustained moderate usage until midnight. The analysis, illustrated in Figure 9, shows that, while some of the late afternoon 'peak' loading periods were reduced with solar PV, the customers overall 'peak' grid capacity requirement was not reduced due to the inability of the solar PV to influence the customers early evening peak loads.[20]

[20] Kansas City Power & Light Co., *KCP&L Green Impact Zone SmartGrid Demonstration – Final Technical Report, Ver. 2,* May 2015, p. 656.

Figure 9: Typical Residential Customer Daily Load Profile with PV
(Source: KCP&L SmartGrid data)



28. The Smart Grid Demonstration Project analysis indicates there are potential capacity reduction or cost avoidance benefits that may flow from DER resources. The primary potential utility benefit derived from solar generation, while only a portion of the rating of the solar system, is from the Supply Capacity which may be further eroded due to the intermittent nature of solar generation. While there may also be capacity or cost avoidance savings possible on portions of the distribution grid, these will largely be circuit/location specific benefits. The potential for distribution grid benefits increases with other forms of DER and storage. The challenge is how to put the proper value on these benefits and to determine the extent to which they exceed the utility costs associated with increased volt/VAR support and enhanced grid planning, monitoring, operations and control as the penetration of DER increases.

29. Smart Inverters are a technology option that is becoming available to facilitate the integration of DER into energy grid operations, minimize the impact of increased levels of DER penetration, and increase the value of DER to the utility. Most DG systems (like solar) and other

DER interface to the energy grid through an inverter. Historically inverters have only converted solar DC energy to AC energy (kWh) and through net metering tariffs, solar systems are incented to maximize kWh production leaving the utility to provide the ancillary services needed by the customer's generator. Smart Inverters can be configured so that the DER customer self-provides some of these ancillary services. Specifically, by providing reactive power and power factor correction and local voltage control through active power management. If the utility's Distribution Management System ("DMS") were allowed to communicate with the Smart Inverter, the output of the customers DER could be operated to improve grid operation and economic performance.

30. Today, there is no incentive for a DER customer to install a Smart Inverter or to operate their system in any mode other than to maximize kWh output. One potential path would be to change the energy grid interconnection standards to require the installation of Smart Inverters and, at a minimum, to operate them in local power factor correction mode. In the future, interconnection standards and DER tariffs should address the potential for a customer's DER system to be integrated with the utility's DMS and how the customer would be compensated for its response to utility request.

31. In light of these details, it is no wonder we see such wide variation in outcomes when states attempt to establish fair compensation for the energy produced by a DER system. This is likely the single most difficult element of this proceeding. In Staff's Motion to open this docket, they identify a number of benefits commonly attributed to DER as part of a benefit analyses. I do not believe it is necessary to perform any studies to establish the value of these benefits. Review of recent efforts show DER benefit valuation, particularly for solar PV, is an imprecise process, providing results that vary significantly dependent upon the basis of the

valuation and drivers external to the valuation effort. Additionally, a comprehensive DER benefit valuation study would be costly, controversial, and likely contribute little additional information to the existing discussion. If the Commission seeks a method to value DER benefits, I would recommend the Commission allow interested parties to cite existing studies accompanied by comments to establish applicability to the Kansas jurisdiction and propose a value. Based on this evidence, the Commission would establish a value or method to be used to calculate the value.

32. Alternatively, I believe the Commission should consider a valuation method that is aligned with the cost of similarly situated utility scale DER. As Kansas utilities are expected to act for the benefit of all customers, including seeking cost-effective energy resources, valuing DER generation at or near the rate at which the utility could obtain and deploy similar renewable generation makes sense. I expect the rate would be greater than the current system average energy cost utilized in the current net metering rate but would not include controversial or speculative elements.

33. The fourth point, stating that tariffs should balance the interest of all stakeholders is similarly complex to implement. Under the current net metering rate designs, I believe there are inequities between customers that should be addressed. Today, based on a 2015 class cost of service study, almost 86% of the costs to serve KCP&L's residential customers are fixed customer[21] and demand-related infrastructure[22] costs; costs that occur whether the customer uses a single kWh of energy or not. Only about 14% of those costs are driven by the cost of energy produced. On the other hand, when a customer pays their bill, only 10% of the bill pays directly

[21] Fixed customer costs include metering, billing, and customer service and are normally allocated on a cost per customer basis.
[22] Demand related infrastructure costs include the generation, transmission and distribution infrastructure capacity installed to meet, in aggregate, the peak demand of all customers.

for service-related fixed cost. The remaining 90% of the residential customer bill is associated with the energy used by the customer. When a customer installs net metering, they have the potential to offset all or part of their load, avoiding these fixed costs all together. In other words, a net metering customer with zero monthly net energy consumed (and those with net energy delivered to the energy grid) does not buy any of our product. Therefore, they do not pay for the grid services, even though they continue to use them. Under the current regulatory constructs, these costs are passed to other customers. More detail concerning this cost shifting is provided on page 67 of the NARUC Manual.

The lack of alignment between costs and rates is problematic under increasing deployment of DER as it causes problems for customers and utilities alike, an issue that has been the subject of an increasing number of regulatory proceedings and industry publications. To be clear, the issue is not one of intentional cost-avoidance, but fundamentally a pricing problem. I believe the utility rate design must evolve to better reflect the distinction between the utility's energy product and grid services, so that customers pay for what they use. Within the context of DER rate design, this evolution could occur in three parts:

- **Specialized DER Rates versus Common Rates** – One question to address is whether the rate structure for all customers of a given class, including DER customers, should be modified to better match cost-causative factors, or whether a special rate should be created that applies only to DER customers. There is a strong argument to be made for changing the rate structure that applies to all customers, as sending all customers the most appropriate price signal should result in the most economically efficient outcomes related to electricity consumption as well as decisions on the installation of DER.[23] While I strongly believe establishing a common rate structure for all customers is a desirable long-term objective, I do support the interim development of a separate rate for DER customers as the best approach to addressing the cost compensation inequities between DER and non-DER customers in the current rate design.

- **Different Customer Classes to Recognize Difference in Service** – Another consideration would be to separate DER customers into their own cost-of-service class or subclass. Such an approach would identify the different ways in which DER and non-DER customers contribute to costs and thereby help monitor for any cost shifting between DER and non-DER customers.[24] I believe that there is a substantial variation in load and usage patterns between customer generators and non-generators to warrant the establishment of a separate cost of service rate subclass. Separating customer generators into their own rate subclass provides transparency and alleviates some of the concern about customer generators covering the cost of grid service they continue to use.
- **Using Rates as Price Signals** – The more a rate structure reflects the costs associated with an activity, the more appropriately customer decisions can be made about how much of a service to use, when to use it, and whether other options for the provision of said service make economic sense. Ideally, rates are price signals for the consumption of electricity.[25]

[23] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, November 2016, p. 75.
[24] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, November 2016, pp. 75-78.
[25] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, November 2016, pp. 78-79.

For DER, the solution would be to design rates that recover from DER customers an appropriate amount to compensate the utility for the investments it has made. Any charges over and above the class-based kWh energy charge should be compensatory, not punitive. Such a charge can be fixed (*e.g.*, interconnection charges) - equivalent to a demand charge - or variable, but should be designed to appropriately compensate the utility for the provision of distribution services.[26] I believe that the most appropriate rate design for residential DER customers would be a three-part rate comprised of a monthly service charge, an energy grid services component or access charge based on the customer's peak demand (kW), and a time of use energy (kWh) charge. A three-part rate constructed in this manner will provide the proper distinction between the utility's energy product and energy grid services, so that DER customers pay for what they use.

34. Volumes of information have been written concerning ratemaking for DER. I would like to highlight a few that complement the positions offered here. Copies are included as an Appendix to these Comments.

- ***Primer of Rate Design for Residential Distributed Generation*, Edison Electric Institute, February 2016** – This document "identifies various options that update net metering policies. These include: (1) demand charges; (2) buy-sell arrangements; (3) fixed monthly charges; (4) time-varying rates; (5) capacity charges; (6) installed capacity fees; (7) DG output fees; (8) interconnection fees; (9) minimum bills; and (10) standby rates. This review of options is followed by a summary of actual case studies, drawn from a review of regulatory practice in 14 states with references to source documents."

[26] National Association of Regulatory Utility Commissioners, *Distributed Energy Resources Rate Design and Compensation*, November 2016, p. 89.

- ***Recovery of Utility Fixed Costs: Utility, Consumer, Environmental, and Economist Perspectives*, Lawrence Berkeley National Laboratory, June 2016** – As part of the Future Electric Utility Regulation series, "authors representing utility (Chapter 1), consumer (Chapter 2), environmentalist (Chapter 3) and economist (Chapter 4) perspectives discuss fixed costs for electric utilities and set out their principles for recovering those costs." The author's relative preferences are summarized for various options for fixed cost recovery, some of which may be used in combination. "A summary of existing literature at the end of the report (Chapter 5) defines each of these options and highlights current practices, potential pros and cons, and the diversity of views held by a wide range of energy experts."
- ***Value of the Grid to DG Customers*, Innovation, Electricity, and Efficiency (IEE) institute of the Edison Foundation, October 2013** – This document "describes how a DG customer (or a microgrid) that is connected to the host utility's distribution system 24/7 utilizes grid services on a continuous, ongoing basis. The point is to recognize the value of these grid services and to develop a methodology for the DG customer to pay for using the services."

I believe these documents help reinforce the view of KCP&L toward DER rate design and I hope they are helpful to the efforts of the Commission in determining an approach suitable for Kansas customers.

IV. CONCLUSION

35. KCP&L appreciates the opportunity to participate in this general investigation concerning rate design for DER customers and share the perspective of KCP&L. The

Commission is timely with this effort to investigate DER ratemaking while deployment levels remain manageable. I believe DER is important as it can be an integral part of the energy grid and help expand the utilization of renewable energy resources. In order for DER to meet its full potential, reasonable rate designs must implement balance and ensure the interests of all parties are considered.

36. In summary, I offer the following recommendations concerning rate design for DG:

- The Commission should consider the NARUC Manual on DER Rate Design and Compensation to help guide the efforts of this Docket.
- The Commission should adopt the four principles concerning DER rate design.
  - A customer should be able to connect to the grid for no more than the cost of connecting to the grid;
  - Customers should pay for grid services and power supply in proportion to how much (and when) they use these services and how much power they consume;
  - Customers who supply power to the grid should be fairly compensated for the full value of the power they supply, no more and no less; and
  - Tariffs should fairly balance the interests of all stakeholders: the utility, the non-DER customer, and the DER customer.
- It is unnecessary to perform any studies to establish the value of these DER benefits. Instead, the Commission should allow interested parties to cite existing studies accompanied by comments to establish applicability to the Kansas jurisdiction and propose a value. Based on this evidence, the Commission would establish a value or

method to be used to calculate the value or alternatively, consider a valuation method that is aligned with the cost of similarly situated utility scale DER.

- The Commission should support an evolution of rate designs to better reflect the distinction between the utility's energy product and grid services, ensuring that customers pay for what they use. Specifically, concerning a DER rate, I support the establishment of a separate cost of service rate subclass for DER customers. I strongly believe establishing a common rate structure for all customers is a desirable, long-term objective but support the interim development of a separate rate for DER customers. I believe that the most appropriate rate design for residential DER customers would be a three-part rate comprised of a monthly service charge, an energy grid services component based on the customer's peak demand (kW), and a time of use energy (kWh) charge.

WHEREFORE, KCP&L requests the Commission consider Kansas City Power & Light's comments regarding the issues in this Docket.

Respectfully submitted,

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COUNSEL FOR
KANSAS CITY POWER & LIGHT COMPANY

CERTIFICATE OF SERVICE

I, the undersigned, do hereby certify that on this 17th day of March, 2017, a true and correct copy of the above and foregoing document of Kansas City Power & Light Company was electronically served, hand-delivered or mailed, postage prepaid, to all parties of record.

|s| Robert J. Hack

Robert J. Hack

BEFORE THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS

In the Matter of the General Investigation to Examine Issues Surrounding Rate Design For Distributed Generation Customers	)))	Docket No. 16-GIME-403-GIE

AFFIDAVIT OF BRADLEY D. LUTZ

STATE OF MISSOURI)
) ss
COUNTY OF JACKSON)

Bradley D. Lutz, being first duly sworn on his oath, states:

1. My name is Bradley D. Lutz. I work in Kansas City, Missouri, and I am employed by Kansas City Power & Light Company as Manager, Regulatory Affairs.

2. Attached hereto and made a part hereof for all purposes are the Initial Comments on behalf of Kansas City Power & Light Company, having been prepared in written form for introduction into evidence in the above-captioned docket.

3. I have knowledge of the matters set forth therein. I hereby swear and affirm that the information contained in the foregoing document is true and accurate to the best of my knowledge, information and belief.

Bradley D. Lutz

Bradley D. Lutz

The foregoing was subscribed and sworn to before me this 17th day of March, 2017.

Jill Cunningham

Notary Public

My Commission Expires:

1-5-20

JILL M. CUNNINGHAM
My Commission Expires
January 5, 2020
Clay County
Commission #00409289

NOTARY PUBLIC
NOTARY SEAL
STATE OF MISSOURI

Edison Electric INSTITUTE

1.0 Primer on Rate Design For Residential Distributed Generation

February 2016

1.0 A Primer on Rate Design for Residential Distributed Generation

Executive Summary

Customer interest in the use of distributed generation (DG) systems, such as customer-owned rooftop solar systems, continues to grow. DG offers an attractive option for some customers, and utilities are actively examining the ways in which DG systems can be better integrated into the grid to enhance reliability, improve resiliency, reduce costs to consumers and to the grid and to improve the environment. Given the significant decline in the cost of solar photovoltaics (PV), coupled with the rapid growth in residential rooftop solar and other DG systems, policymakers across the country continue to examine how to update current net metering programs to address the cost shifting that occurs among customers and to ensure that everyone who uses the grid continues to share equitably in the costs of paying for the grid. The utility industry is investing more than $20 billion annually in the grid to better integrate distributed generation and to enhance reliability and resiliency.

This paper identifies various options that update net metering policies. These include: demand charges; buy-sell arrangements; fixed monthly charges; time-varying rates; capacity charges; installed capacity fees; DG output fees; interconnection fees; minimum bills and standby rates.

This review of options is followed by a summary of actual case studies, drawn from a review of regulatory practice in 14 states with references to source documents. We have not evaluated the specific methods or commission decisions. The reader can draw his or her own conclusions.

I. Introduction

A. Background

In order to provide electricity to customers, a utility has to bear – directly or indirectly – costs related to generation, transmission, distribution, metering and customer service (such as billing and customer inquiry). Generation costs consist of capacity costs and energy costs. The former vary primarily with peak demand while the latter vary with electricity consumption. Distribution and transmission costs vary largely with demand. The costs of metering and customer services vary with the number and type of customers and are considered a fixed cost for each customer. Some of these costs also vary across time. Generation energy costs will vary from hour to hour depending on the marginal generation source. Distribution and some transmission networks, while used year round, are sized to meet peak demand at the locational level while the transmission system and generation capacity costs are sized to meet system peak demand.

According to the principle of cost causation, rates should be designed to reflect costs, to promote efficiency in the use of electricity and equity across customers. Rates for medium and large commercial and industrial customers historically have done a better job of reflecting costs than residential rates, due primarily to the more advanced metering technology with which the larger customers are equipped. Residential rates are typically designed to cover most of the costs of residential service on the basis of energy consumption; with most of the fixed costs and capacity related costs rolled into this volumetric charge using some assumptions about class load factor.

Figure 1: The Mismatch between Energy Costs and Energy Pricing: An Illustrative Example from a Representative Investor Owned Utility

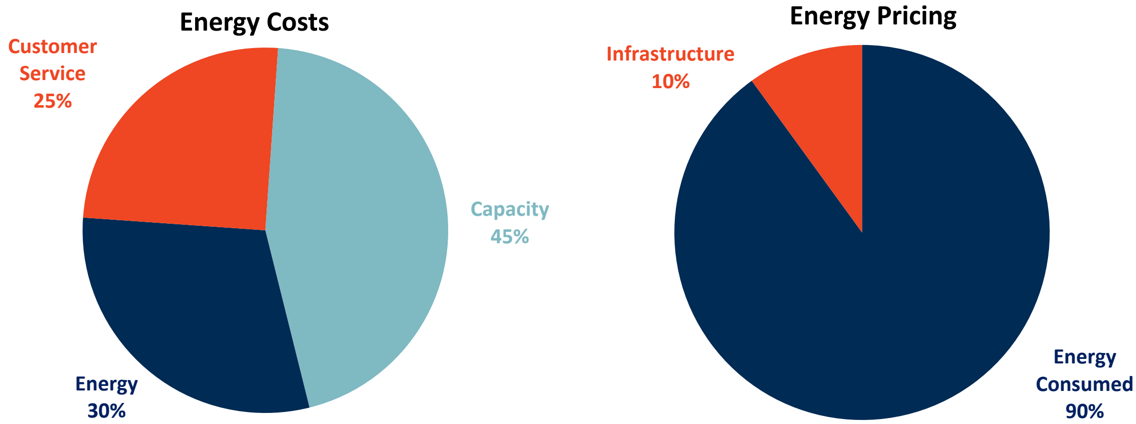


Figure 1: The Mismatch between Energy Costs and Energy Pricing: An Illustrative Example from a Representative Investor Owned Utility shows an example from a representative Investor Owned Utility of the difference between the calculated costs of serving a residential customer compared to the way that these costs are recovered by the utility. It is clear that even though only a fraction of the calculated costs vary with energy consumption, almost the entire amount of revenue is collected based on variable energy consumption charges ($/kWh). With the recent increases in the amount of residential DG installed in most jurisdictions across the U.S., this volumetric rate structure, which is not cost-reflective, is increasingly failing to meet the objectives of good rate design.[1] This failure is exacerbated by the utilization of Net Energy Metering (NEM).

NEM pays the DG customer the retail rate for any generation that is fed into the grid. Customer-generators receive the same kWh credit regardless of the market price of the energy they are supplying into the grid.[2]

This arrangement introduces two problems:

1) **Customer-generators are not paying for grid and customer costs.** Customer-generators are being credited not just for the value of the energy they are producing, but also for the grid services that they are consuming, such as use of the transmission and distribution networks to receive and sell electricity. For example, a customer-generator can size a solar array to become a "net-zero" consumer, meaning over the course of the year they are producing as

[1] Good rate design seeks to balance the competing goals of economic efficiency, removal of cross subsidies (equity) and utility revenue stability, among other objectives.

[2] Most NEM policies have a "banking" mechanism where generation credits earned in one period can be used to offset consumption in another. Often these banking policies have a finite reconciliation period (typically one calendar year), after which any net excess generation credits earned over the entire period are paid out at some price. This is often not the full retail rate.

much energy as they consume. These customers will pay very little for their utility bills. Of course on a day to day basis, they are not net-zero consumer of energy. During the daytime they use the grid to export excess electricity and during the nighttime they use the grid to import electricity into their homes.[3] Moreover, they rely on the grid to smooth out peaks and valleys in their generation profile due to the intermittency of distributed generation. In this way the grid acts as a free battery for DG customers.[4] These customers need to be metered to track their net usage and billed each month to acknowledge their energy credits, which creates an additional cost. If there is a failure with their DG system, they can rely on the grid to meet their full power needs and call the utility's customer service line for support. As a result, the cost of maintaining the grid and customer support services for these customers is borne by other customers who do not have self-generation.

2) **Customer-generators are trading a low-priced good for a high-priced good.** Electricity prices can be quite volatile over the course of a day and also vary seasonally. Rather than reflecting those prices, NEM simply treats all energy the same, regardless of the time at which it is produced.[5] In most jurisdictions the time at which solar production peaks is not the same time when the system peaks. Electricity generation is more costly in peak periods than off-peak periods. Typically customer-generators will produce solar and in the middle of the day when the value is lower and consume electricity in the evening when the value is higher, without having to pay the pricing differential on the electricity produced and consumed. This price differential will need to be paid by other customers who do not have self-generation. Another consequence of this pricing regime is that customers are incentivized to site DG to maximize kilowatt hours of production, not to maximize the market value of those kilowatt hours.

Proponents of NEM and similar policies argue that this explanation does not account for the benefits of solar for society as a whole. Some of these benefits (which are discussed in Section D) fit into the traditional cost of service framework, which focuses on costs directly borne by utility customers, such as avoided distribution capacity investments. Other benefits such as environmental amenities are not traditionally included in a cost of service. While often valuable for public policy investment decisions (i.e. "Is it in the public interest to engage in this action?"), including these (difficult to quantify) benefits will distort ratemaking decisions, since similar benefits are not fully accounted for in other societally beneficial programs such as grid-scale generation, Demand Response (DR) or Energy Efficiency (EE).

Conversely, many are concerned that some of the benefits of solar to the grid may be offset or eclipsed by increased distribution costs, such as the need to update distribution and communication networks to accommodate two-way power flows (These are discussed below in Section D).

B. Purpose

[3] There are also seasonal imbalances.

[4] Although no physical storage occurs.

[5] Ashley Brown and Jillian Bunyan, "Valuation of Distributed Solar: A Qualitative View", *The Electricity Journal,* December 2014, Vol. 27, Issue 10, p.33

The purpose of this memorandum is two-fold. Firstly, we evaluate a number of different rate design options that are either in place today or have been proposed to help eliminate the cross-subsidization caused by current DG rate designs and NEM policies in particular. In states with significant residential DG penetration, these issues need to be tackled before they escalate further. In states without significant residential DG penetration, addressing these issues early will help avoid future conflict and also create a stable environment where customers can assess their DG investment decisions with greater information and certainty. Secondly we survey the state of DG rate design proceedings across the nation where decisions have either been reached or have been proposed and are undergoing review.

C. The Bonbright Principles of Rate Design

Professor Bonbright developed 10 Principles of Rate Design that are widely used as a foundation in designing rates.[6] We have distilled these 10 principles, for which there is considerable overlap, into 5 Core Principles of Rate Design.

1. **Economic efficiency:** The price of electricity should convey to the customer the cost of producing it, ensuring that resources consumed in the production and, delivery of electricity, are not wasted. If the price is set equal to the cost of providing a kWh, customers who value the kWh more than the cost of producing it will use the kWh and customers who value the kWh less will not. This will encourage the development and adoption of energy technologies that are capable of providing the most valuable services to the power grid and the customers it serves.

2. **Equity**: There should be no unintentional subsidies between customer types. A classic example of the violation of this principle occurs under flat energy rate pricing structures (i.e., cents/kWh). Since customers have different load profiles, “peaky” customers, who use more electricity when it is most expensive, are subsidized by less “peaky” customers who overpay for cheaper off-peak electricity. Note that equity is not the same as social justice, which is related to inequities in socioeconomic status rather than cost. The pursuit of one is not necessarily the pursuit of the other, and vice versa.

3. **Revenue adequacy and stability**: Rates should recover the authorized revenue requirements of the utility and should promote revenue stability. Theoretically, all rate designs can be implemented to be revenue neutral within a class, but this would require perfect foresight of the future. Changing technologies and customer behaviors make load forecasting more difficult and increase the risk of the utility either under-recovering or over-recovering costs when rates are not cost reflective.

4. **Bill stability**: Customer bills should be stable and predictable while striking a balance with the other ratemaking principles. Rates that are not cost reflective will tend to be less stable over time, since both costs and loads are changing over time. For example, if fixed infrastructure costs are spread over a certain number of kWh’s in Year 1, and the number of

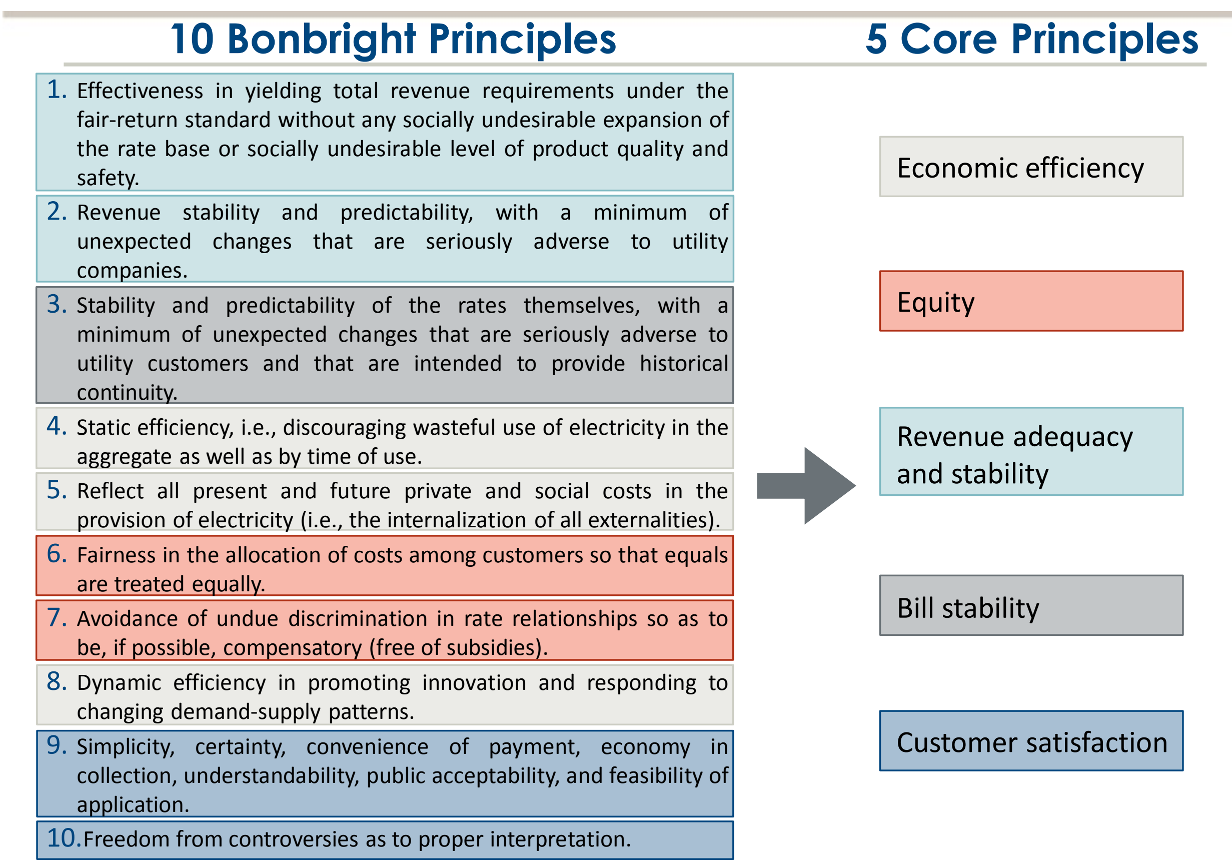
[6] See James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, “Principles of Public Utility Rates, 2nd Edition”, Public Utilities Reports (March , 1988)

kWh's halves in Year 2, then the price per kWh in Year 2 will double even though there is no change in the underlying infrastructure cost of the utility.

5. **Customer satisfaction**: Rates should enhance customer satisfaction. Because most residential customers devote relatively little time focusing on reading their electric bills, rates need to be relatively simple so that customers can understand them and perhaps respond to the rates by modifying their energy use patterns. Giving customers meaningful cost-reflective rate choices helps enhance customer satisfaction.

Figure 2 shows the mapping between Bonbright's original 10 principles and the 5 Core Principles defined above.

Figure 2: Deriving the 5 Core Principles of Rate Design



D. Value of Distributed Generation / Value of the Grid

The grid is a valuable resource that continues to be used extensively by customer-generators. Although they may be able to offset some of their own energy needs, customer-generators rely on the transmission and distribution systems to distribute excess electricity that they generate and supply electricity to them when production is less than consumption. This happens on an hourly basis since solar photovoltaic panels only generate energy when the sun shines and wind only generates energy when the wind blows. In addition, customer-generators rely on the grid to supply them their complete load needs in the event that their self-generation fails. Throughout this process, customer-generators rely on the utility's customer support to track net energy usage using a metering system that needs to be read and maintained, supply bills and the customer support necessary to answer bill inquiries or any customer issues such as outages.

Customer-generators may also increase the cost of using the grid for themselves and other customers on an ongoing basis. On the generation side, utilities need to procure ancillary services to help integrate distributed generation to the grid. DG resources are for the most part-intermittent and flexible capacity needs to be procured to meet intra-hour variability in generation as well as rapid ramping requirements for the evening when load peaks and the sun goes down. On the distribution and transmission side, system upgrades may need to be made to deal with two-way power flows and voltage quality issues. Further upgrades could be required for communication networks and the IT infrastructure. On the customer support side, customer-generators may have more complex billing, metering and support needs.

The electric system benefits (e.g. cost savings) attributable to DG can include energy, capacity, transmission and distribution (T&D) system deferral, and line loss reductions, as well as environmental and other benefits as assessed in each jurisdiction. The National Renewable Energy Laboratory recently summarized these potential benefits in a report about the value of solar.[7]

II. Menu of Rate Reform Options

A. Demand Charges

Demand charges provide accurate price signals and have been used widely in the industry, along with fixed monthly charges and energy charges, in the industry for commercial and industrial rates for the better part of the last century. Utilities can introduce a demand charge ($/kW) for customer-generators, to better collect the capacity costs associated with providing them electric service, in addition to collecting from them a monthly fixed charge ($/month) and a variable energy charge ($/kWh). A demand charge is a charge based on a customer's maximum kW demand over a specified time period – typically the monthly billing cycle. It is typically based on the customer's maximum demand across all hours of the month or on their maximum demand during peak hours of the month, or sometimes on both. Since most capital grid investments are driven by demand, the idea is that demand charges will better align the price that customers pay with the costs that they are imposing on the system. The primary function of the demand charge is to accurately convey the cost structure of electricity to customers so that they can make informed decisions about how much power to consumer and at what time. Whether customers reduce demand in response to a demand charge is a

7 Mike Taylor, Joyce McLaren, Karlynn Cory, Ted Davidovich, John Sterling, and Miriam Makhyoun, "Value of Solar: Program Design and Implementation Considerations," NREL Technical Paper NREL/TP-6A20-6236.1, 2015.

secondary benefit. There is some evidence that residential customers do respond to the price signal given by demand charges.[8]

When faced with demand charges, residential customer-generators would have the incentive to buy smart digital technologies such as thermostats, load controllers, home energy management systems and smart appliances, along with batteries and other storage options. This will promote economic efficiency in both a static and dynamic sense.

B. Buy-Sell Arrangement

Many NEM policies compensate customer-generators at the full variable charge in the retail rate. As discussed previously, when rates disproportionately collect revenue through that variable charge, customer-generators are overcompensated for the electricity they generate. Under a "buy-sell" arrangement, customer-generators would pay for all of the electricity that they consume at the full retail rate, and would separately be compensated for all of the electricity that they generate at a price that more accurately reflects the value of the electricity being generated. Such compensation can be at the wholesale price, at the "avoided cost" rate, or at the "value of renewables" rate. One advantage of such plans is that it separates compensation for customers' generation from the retail rate structure, allowing separate consideration of the pluses and minuses of each. Another advantage is that a customer's incentives for conserving electricity or shifting load are aligned with those of other customers, since the customer pays the full retail rate for all energy consumed. This approach is also commonly referred to as a "value of solar" model, a feed-in-tariff (or "FIT"), or a dual meter tariff since it requires a second meter to measure on-site generation.[9]

C. Fixed Monthly Charge

Most residential rates currently offered in the U.S. include a fixed monthly charge (sometimes called a customer charge, basic service charge or customer service charge) that is approximately in the range of \$5-\$15/month along with an energy charge. While the size of the customer charge may be consistent with the magnitude of fixed customer costs like metering, billing, customer care and other

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8 See:

- Andreas Stokke, Gerard Doorman, and Torgeir Ericson, "An Analysis of a Demand Charge Electricity Grid Tariff in the Residential Sector," Discussion Paper 574, Statistics Norway Research Department, January 2009;
- Thomas Taylor and Peter Schwartz, "A Residential Demand Charge: Evidence from the Duke Power Time-of-Day Pricing Experiment," *Energy Journal* 7(2)(April 1986): pp. 135–151;
- Douglas Caves, Laurits Christensen, and Joseph Herriges, "Modeling Alternative Residential Peak-Load Electricity Rate Structures," *J. Econometrics*, 1984;
- Thomas N. Taylor, "Time-of-Day Pricing with a Demand Charge: Three-Year Results for a Summer Peak," in *Award Papers in Public Utility Economics and Regulation*, Michigan State University Institute of Public Utilities, Michigan, 1982.

9 There are nuanced differences in these approaches, mostly revolving around how to determine the price that is paid to customer-generators for their power generation. But at a basic level, all of these approaches include a bifurcation of power purchases from the grid from power sales to the grid.

administrative services, it typically does not account for the fixed costs of generation, transmission, and distribution capacity that must be recovered by the utility over time. Increasing the fixed charge allows some or all of that capital investment to be recovered with relative certainty for the utility. Fixed charges do not offer the pricing signal to reduce peak demand that is accomplished with demand charges.

D. Time-Varying Rates

The variable charge can also be modified to include time-differentiated prices, with a higher price being charged during on-peak hours and a lower price during off-peak hours, reflecting the corresponding variation in utility capacity and energy costs by on-peak and off-peak periods. While this change by itself would not eliminate the cross-subsidies created by net energy metering, it would be consistent with the idea of modifying rates to better reflect the underlying cost structure. Time-varying energy charges can be combined with other rate design options, such as a demand charge, to better reflect the utility's underlying cost structure. When faced with time-varying rates, residential customer-generators would have better incentives to buy smart digital technologies such as thermostats, home energy management systems and smart appliances, along with batteries and other storage options. Customer-generators would also be better incentivized to site DG facilities so as to maximize the value of production, not just the volume of output. This will help to promote economic efficiency in both a static and dynamic sense.

E. Capacity Charge

A charge can be levied based on the size of a customer's connected load. This limits the amount of demand that a customer can place on the system. Customers whose load exceeds the capacity that they have reserved will be temporarily disconnected until they reduce their load, much like when a circuit breaker is tripped. These rates are deployed for all residential customers in France, Italy and Spain.

F. Installed Capacity Fee

A charge can be levied on customer-generators based on the installed capacity of their DG systems. This results in an additional fixed monthly charge for customer-generators, with the size of that charge being determined by the customer's generation capability. The reasoning behind this design is that customers with larger systems will self-generate more electricity, thereby avoiding paying a larger portion of their grid costs and justifying a larger offsetting incremental monthly charge on their bill. While redressing some of the cross-subsidies caused by net energy metering, the relationship to cost-causation with this approach is less direct than with the other approaches described above.

G. DG Output Fee

Somewhat similar in concept to the capacity charge, a DG output fee would charge customer-generators based on the total amount of electricity that they produce from on-site generation each month. In other words, the customer-generators would still be paid for the electricity that they generate, but some of this payment would be offset by the DG output fee. Whereas the capacity charge is a dollars-per-kilowatt charge, the DG output fee is a dollars-per-kilowatt-hour charge. The DG output fee reflects the customer's cost of using the distribution system. This approach has also been referred to as a "bidirectional distribution rate."[10]

H. Interconnection Fee

Customer-generators are increasingly being charged a one-time grid interconnection fee at the time that they install on-site generation. These fees are generally proposed to cover one-off costs incurred in setting up a customer-generator on the utility's system, for example account and billing set-up, application review, engineering review, interconnection facilities, secondary meters, etc. Interconnection charges that are solely focused on recovering interconnection costs are usually proposed concurrently with other rate reforms, since they do not address the key NEM cost-shift issue. Theoretically an interconnection fee could be levied to recover the cost of the sunk investment in the grid that would still be used to serve these customers, but which would otherwise no longer be recovered through their rates (under NEM conventions) once the DG system is installed.

I. Minimum Bill

An alternative to a higher fixed monthly charge is a minimum bill. The minimum bill ensures that all customers will pay a minimum threshold amount each month. For instance, with a minimum bill of \$50/month, a customer whose bill would have been \$30 under the existing rate for a given month would be billed \$50 for that month. In a different month, if the customer's bill under the existing rate would be \$60, then the minimum bill feature would not come into play and their bill would remain unchanged. The theory is that the minimum bill amount can be associated with the average customer's cost of using the grid and therefore guarantee that amount to be recovered on a monthly basis.

J. Standby Rates

Standby rates are generally levied on large "partial requirements" customers who generate all or some of their own electricity. Under the normal run of business, these facilities will generate their own power and their draw from the grid will be limited. However, in the event of a scheduled or emergency outage of their generation equipment, they will need to rely entirely on power purchased from the grid. Along with an energy charge, standby rates generally consist of a demand charge which attempts to cover the cost to the utility of providing capacity to meet the facility's peak demand, in the eventuality that it will be required to do so, as well as an energy charge.

III. Key Decisions in the DG Rate Reform Transition

A. Customer-Generators or All Residential Customers

[10] Carl Linvill, John Shenot, and Jim Lazar, "Designing Distributed Generation Tariffs Well," prepared for the Regulatory Assistance Project, November 2013.

A key question is whether the new rate should apply only to customer-generators or all residential customers. Modifying the rate only for customer-generators has the advantage of restricting the immediate bill impacts of the rate change to a small subset of the utility's customers. This limits the number of customer considerations that must be made when evaluating the rate. Since customer-generators have a different load profile than other customers and are acting both as consumers and as generators, their unique status warrants the creation of a specific rate class. Offering special rates to customer-generators is analogous to the development of "standby rates" for "partial requirements" customers in the commercial and industrial classes. Alternatively, if the proposed rate changes are cost-based and represent an overall improvement upon the existing rate structure according to sound principles of rate design, then it could be argued that only making these changes for customer-generators is a missed opportunity to improve the rate design of the entire residential class.

B. Grandfathering

Typically, significant changes to the DG rate and/or the NEMpolicy have been accompanied by a grandfathering rule that allows existing customer-generators to continue to be billed under the old pricing policy. The argument for this approach is that those customers made the decision to purchase their DG systems under a pre-established pricing agreement with the utility – or at least with the expectation that the existing arrangement would continue to be honored in the future. The grandfathering policy avoids placing an unexpected financial burden on those customers under the new pricing structure. The counterargument to such a grandfathering policy is that all investments are subject to the risk that future policies can change, and that DG investments are no different in this regard and should therefore not be given any special treatment. Good rate design early on will create cost reflective rates that mean that grandfathering will never become an issue.

Some of the issues with not pursuing a grandfathering policy have recently come to the fore in Nevada, where in December 2015, regulators created both a new rate and rate class for customer-generators, and retroactively applied this to existing solar customers. The decision by the Nevada Public Utilities Commission sparked a class action lawsuit against Nevada utility NV Energy, with plaintiffs alleging the utility misled them into purchasing solar systems "that do not provide the promised rebates, discounts and rates."[11] Other critics also have challenged the legality of the decision, claiming it may violate the contracts clause of the U.S. Constitution by undermining existing agreements between solar companies and electricity consumers.[12] However, in a February 2016 filing, NV Energy said it supported a plan to grandfather existing solar customers under the old rate for twenty years. Shawn Elicegui, a senior vice president for regulation and planning at NV

11 Julia Pyper, "Solar Customers Launch a Class Action Lawsuit Against NV Energy," Greentech Media, February 4, 2016, accessed on February 8, 2016, http://www.greentechmedia.com/articles/read/solar-customers-launch-a-class-action-suit-against-nv-energy

12 Julia Pyper, "Does Nevada's Controversial Net Metering Decision Set a Precedent for the Nation?" Greentech Media, January 17, 2016, accessed on February 8, 2016, http://www.greentechmedia.com/articles/read/nevada-net-metering-decision.

Energy, said for any grandfathering plan to be accepted, it "needs not only to be fair, but, equally important, broadly perceived and accepted as fair."[13]

C. Transition Plan

In general, all customers will need to be educated about the new rate in order to improve their understanding of the rate's design as well as ways that they can manage demand and the impact on their bill. Beyond a broad educational outreach campaign, more targeted outreach may be needed for those specific customers who are likely to experience a bill increase on the new rate, particularly low income or vulnerable customers. Those customers could be identified through bill impact analysis of utility load data, surveys, and other analyses based on locational socio-demographic data.

In addition to education, a rate transition plan might include any of the following elements, though it is important to recognize that the applicability of these options will vary from one state to the next depending on the objectives goals of the local regulators, utilities, and their stakeholders:

- A gradual multi-year phase-in of the new rate regime, so that customers do not experience the full impact of the new rate overnight.
- Temporary bill protection, so that customers have time to become accustomed to the impact and explore energy and demand management opportunities before it impacts their bills.
- Optional rate exemptions for a limited subset of the residential class who are considered low income or vulnerable, to avoid the possibility of bill increases for these customers.
- Primary market research, such as focus groups and surveys, to determine the most effective ways to market the rate to customers.

D. Decoupling

Revenue decoupling is a mechanism that disassociates energy sales from revenue recovery. Under net energy metering, customer-generators do not pay their full cost of service. In the short-run, (between rate cases) this shifts the cost burden of this lost revenue to the utility. This can create uncertainty over future revenues for the utility and increase its cost of capital (due to increased risk). However, in the long-run rates for all customers, including those without DG, will increase. In this way, customer-generators shift their costs onto other customers. Revenue decoupling will make the utility whole, by creating an adjustment mechanism for "lost" sales from customer-generators. However, since these "lost" sales did not cause a drop in grid and customers costs, this adjustment mechanism means that other non-DG customers will be paying for the costs that customer-generators continue to incur.

IV. The National Landscape of DG Rate Reforms

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[13] Daniel Rothberg, "NV Energy: Let existing solar customers keep old rate for 20 years," Intelligent Utility, February 5, 2016, accessed on February 8, 2016, http://www.intelligentutility.com/article/16/02/nv-energy-let-existing-solar-customers-keep-old-rate-20-years?utm_source=2016_02_08&utm_medium=eNL&utm_campaign=IU_DAILY&utm_content=69764

This section describes major DG policy activities across 13 states. The list is neither exhaustive nor static, since DG policy reform is moving forward at a rapid pace across the US.

A. Arizona (Status: Complete / Pending)

In February 2015, the Salt River Project ("SRP") Board of Directors approved E-27, the Customer Generation Price Plan for Residential Service.[14] Unlike investor-owned utilities ("IOUs"), SRP is a publicly-owned utility that is regulated by a board of directors elected by landowners. E-27 is a three-part rate which only applies to residential customers who elect to install distributed generation ("DG").[15] The fixed charge varies with a customer's amperage and ranges from $32.44/month to $45.44/month, both higher than the $20 monthly fixed charge to non-DG customers. The demand charge is structured as an increasing block rate and varies by season and, ranging in the peak summer months of July and August from $9.59/kW-month for a customer's first 3 kW of demand, to $17.82/kW-month for the next 7 kW of demand, to $34.19/kW-month for demand in excess of 10 kW.[16] Customers who installed DG or had a contract submitted to SRP on or prior to December 8, 2014 are grandfathered on the non-DG suite of price plans.

In July 2013, Arizona Public Service ("APS") proposed a new net metering policy for customer-generators. APS proposed two rate options: the first option would put customer-generators on a three-part rate and continue to compensate them for their generation at the full retail rate; the second option was a buy-sell arrangement under which customer-generators would have all consumption billed under one of the existing rate options, but they would be paid a lower wholesale rate for the total amount of electricity that they generate.

In November 2013, the Arizona Corporation Commission ("ACC") instead voted to implement a $0.70/kW grid access charge on installed solar photovoltaic ("PV") capacity, equating to a surcharge of roughly $5/month for a typical residential rooftop solar installation.[17] In April 2015, APS requested an increase from $0.70/kW to $3.00/kW on its monthly grid access charge on installed solar PV capacity.[18] However, the ACC staff asked the Commission to reject the increase and asked the

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14 Scott Harelson, "SRP Board Approves Reduced Price Increases," Salt River Project press release, February 26, 2015, accessed on July 1, 2015, http://www.srpnet.com/newsroom/releases/022615.aspx.

15 Ahmad Faruqui and Ryan Hledik, "An Evaluation of SRP's Electric Rate Proposal for Residential Customers with Distributed Generation," prepared for Salt River Project, January 2015, p.14, accessed February 3, 2016, http://www.srpnet.com/prices/priceprocess/pdfx/DGRateReview.pdf,.

16 "SRP Standard Electric Price Plans: Salt River Project Agricultural Improvement and Power District, Temporary Prices Effective November 2015 – April 2016 Billing Cycle," Salt River Project, October 6, 2015, pp. 29-30, accessed February 3, 2016, http://www.srpnet.com/prices/priceprocess/pdfx/April2015RatebookPUBLISHED.pdf.

17 "APS's Proposal to Change Net-Metering," ASU Energy Policy Innovation Council, updated December 2013, pp. 2, 3, and 5, accessed February 1, 2016, https://energypolicy.asu.edu/wp-content/uploads/2013/12/APS-Net-Metering-Brief-Sheet-Draft-_-Final_updated-Dec-2013.pdf.

18 "APS Asks to Reset Grid Access Charge for Future Solar Customers," APS press release, April 2, 2015, accessed on July 20, 2015, https://www.aps.com/en/ourcompany/news/latestnews/Pages/aps-asks-to-reset-grid-access-charge-for-future-solar-customers.aspx.

company to include the rate increase in its next general rate case application.[19] On September 25, 2015, APS offered to withdraw the proposed grid access charge in favor of opening a modified hearing that would exclusively address the cost of serving solar and non-solar customers, as well as the structure of how those costs would be collected. On October 20, 2015, the ACC ordered the proceeding closed and found that it is in the public interest to require APS to file a rate case no later than June 30, 2016.[20] Additionally, on October 20, 2015, the ACC ordered APS's cost of service issues to be included in a generic document on net metering issues and the value of distributed energy.

UNS Energy Corporation, the Arizona-based parent company of Tucson Electric Power and UniSource Energy Services, asked the ACC to approve a mandatory three-part rate for customer-generators who submit connections for new DG facilities after June 1, 2015. While this three-part rate would be optional for standard residential customers, UNS is also proposing an increased fixed charge for all residential customers that would be set at $20/month, an increase from the current $10/month.[21] Additionally, the utility is proposing to purchase excess energy from new rooftop systems using the Renewable Credit Rate, which would be set to the market price for power generated by large solar arrays.[22] This will initially be set at $0.0584/kWh and updated on an annual basis.[23] Currently, customer-generators can participate in a net metering program in which excess generation is credited at the standard retail rate.[24]

B. California (Status: Final Order)

In October 2013, California Assembly Bill 327 ("AB 327") was enacted, directing the California Public Utility Commission ("CPUC") to reform residential rates by December 31, 2015.[25] This state legislation requires deriving a new framework for analyzing the benefits and costs that DG produces for the grid and for the public. This initiative was called "NEM 2.0".

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19 Robert Walton, "AZ Regulatory Staff Rejects Solar Net Metering Changes outside Full Rate Case," Utility Dive, June 12, 2015, accessed on July 20, 2015, http://www.utilitydive.com/news/az-regulatory-staff-rejects-solar-net-metering-changes-outside-full-rate-ca/400656/.

20 Arizona Corporation Commission, *Order Rescinding Decision No. 75251, Dismissing APS's Motion to Reset and Closing Docket No. E-01345A-13-0248*, Docket No. E-01345A-13-0248, October 27, 2015.

21 "Unisource Energy Service Seeks Approval of New Electric Rates to Better Reflect Customers' Use of its Upgraded Utility System," UniSource Energy Services press release, May 5, 2015, accessed on July 10, 2015, https://www.uesaz.com/news/newsroom/release/index.php?idRec=342.

22 Arizona Corporation Commission, *Application*, Docket No. E-04204A-15-0142, May 5, 2015, pp. 8-9, https://www.uesaz.com/doc/UNSE_Rate_Application.pdf.

23 "UES Seeks New Electric Rates to Reflect Higher Costs," UniSource Energy Services, accessed on July 10, 2015, https://www.uesaz.com/news/updates/e-rates/.

24 Herman K. Trabish, "What's Solar Worth? Inside Arizona Utilities' Push to Reform Net Metering Rates," Utility Dive, June 1, 2015, accessed July 28, 2015, http://www.utilitydive.com/news/whats-solar-worth-inside-arizona-utilities-push-to-reform-net-metering-r/399706/.

25 California State Assembly, *Assembly Bill No. 327*, October 7, 2013, pp. 91-92, http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

On January 28, 2016, the CPUC voted 3 to 2 approving a NEM 2.0 successor tariff.[26] In this decision, the Commission declined to "impose any demand charges, grid access charges, installed capacity fees, standby fees, or similar fixed charges on NEM residential customers while the CPUC is working on how, if at all, any such fees should be developed for residential customers."[27] The decision upholds the current retail rate for customer-generators, preserving the basic features of the existing NEM tariff. In reference to the three IOU proposals as a whole, the CPUC commented, "The differing methods of analysis and proposed charges strongly suggest that more work is indicated before any major shifts in the paradigm for the NEM successor tariff are implemented."[28]

However, the CPUC did accept three notable changes to the NEM tariff, specifically related to Time-of-Use ("TOU") rates, non-bypassable charges, and interconnection fees. With respect to TOU rates, the CPUC explained, "participation in available TOU rates can be an effective way to align the incentives of customers on the NEM successor tariff with the system needs."[29] As a result, the NEM 2.0 requires that all participating customers must be on a TOU rate with no option to opt out.[30] The default TOU rates for residential customers are anticipated to be in place by 2019.[31] The Commission also changed its treatment of non-bypassable charges that NEM customers are required to pay. Under the original NEM tariff, customers pay the non-bypassable charges embedded in their volumetric rates. They do so, however, only on the quantity of energy delivered from the grid less any generation credits. Under NEM 2.0, the tariff mandates customers pay non-bypassable charges on the full amount of electricity delivered from the grid, rather than the portion netted for generation credits. However, the CPUC did eliminate transmission charges from the bundle of charges that qualify as non-bypassable.[32] Lastly, the CPUC agreed with the IOUs' proposals to institute a one-time interconnection fee that will "allow the utility to recover the costs of providing the interconnection service from the customer benefitting from the interconnection."[33] Based on the IOUs' proposals, this interconnection fee is estimated to range from $75 to $150 depending on the utility.[34]

C. Hawaii (Status: Final Order – Phase 1)

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26 Public Utilities Commission of the State of California, *Decision Adopting Successor to Net Energy Metering Tariff*, Rulemaking 14-07-02, January 28, 2016.

27 Ibid, p. 2.

28 Ibid, p. 75.

29 Ibid, p. 76.

30 Ibid, p. 92.

31 Ibid, p. 92.

32 Under NEM 2.0, non-bypassable charges include Public Purpose Program Charge, Nuclear Decommissioning Charge, Competition Transition Charge, and Department of Water Resources bond charges; Ibid, pp. 89-90.

33 Ibid, pp. 87-88.

34 Jeff St. John, "California Net Metering 2.0 Keeps Retail Rates for Rooftop Solar," Greentech Media, December 15, 2015, accessed February 5, 2016, http://www.greentechmedia.com/articles/read/breaking-california-net-metering-2.0-keeps-retail-rates-for-rooftop-solar.

In January 2015, Hawaiian Electric Company ("HECO") proposed to the Public Utilities Commission of Hawaii to close NEM to new customer-generators and replace it with a Transitional Distributed Generation ("TDG") tariff that would cut the rate paid for power sold back to the grid by approximately fifty percent.[35] This proposal includes a $25 minimum monthly bill for all future residential customer-generators on all islands.[36] On June 29, 2015, HECO submitted a final position to the Commission in which it reiterated closing the current NEM program to new customer-generators.[37]

On October 12, 2015, the Commission responded to HECO's request with an order that approved "revised interconnection standards to streamline and improve HECO Companies' interconnection process, closes the HECO Companies' net energy metering program to new participants, and approves new options for customers to interconnect distributed energy resources to the HECO Companies' electric grids."[38] The order approved HECO's 'Grid-Supply' tariff, under which customer-generators are credited for their excess energy at $0.1507/kWh in Oahu, $0.1514/kWh in Hawaii, $0.1716/kWh in Maui, $0.2407/kWh in Molokai, and $0.2788/kWh in Lanai.[39] The Commission's order marked the completion of Phase 1 of a multi-phase distributed energy resources ("DER") policy change project. Phase 2 will address further long-term modifications to DER policies including how to enhance the value of DER.[40] Additionally the Commission approved the $25 minimum bill for residential customer-generators and a $50 minimum bill for small commercial customer-generators that are interconnecting under HECO's self-supply tariff.[41]

D. Illinois (Status: Pending)

In March 2015, Senate Bill 1879 ("SB 1879") and House Bill 3328 ("HB 3328") were introduced in Illinois' state Senate and Assembly, proposing to add a demand charge to the current residential rates

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[35] Public Utilities Commission of the State of Hawaii, *Hawaiian Electric Companies' Motion for Approval of New Program Modification and Establishment of Transitional Distributed Generation Program Tariff,* Docket No. 2014-0192, January 20, 2015.

[36] Ibid, p. 6.

[37] Public Utilities Commission of the State of Hawaii, *Final Statement of Position of the Hawaiian Electric Companies,* Docket No. 2014-0192, June 29, 2015, pp. 5-8, 91.

[38] Public Utilities Commission of the State of Hawaii, *Decision and Order Resolving Phase 1*, Docket No. 2014-0192; Order No. 33258, October 12, 2015, p. 1.

[39] Customer Grid Supply and Self Supply Programs, HECO, https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/customer-grid-supply-and-self-supply-programs.

[40] Ibid, p. 2

[41] Ibid, p. 122.

design (among a number of other items concerning Illinois' electric grid).[42] As of February 5, 2016, neither bill had been passed by its respective house.[43]

E. Kansas (Status: Deferred)

In its 2015 general rate case, Westar Energy proposed to introduce two new rates for its residential customers.[44] One rate, the "Residential Stability Plan" (RSP), would include a $50/month fixed basic service fee and a lower volumetric charge.[45] The other new rate, referred to as the "Residential Demand Plan" (RDP), would be a three-part rate with a demand charge, a fixed basic service fee, and a volumetric rate.[46] In its filing, Westar also proposed to make the RSP and RDP rates the only two residential rate options that would be available for net metering customers.[47] Westar's proposal to introduce the RSP and RDP rates was withdrawn as part of a settlement which was approved by the Kansas Corporation Commission in September 2015.[48] However, in the same order, the Commission approved Westar's proposal for the creation of a Standard Residential Distributed Generation Tariff. The order stated that the decision of how to redesign and restructure rates for customer-generators, including potential revision of the new Standard Residential Distributed Generation Tariff, would be revisited at a later time in a generic docket.[49]

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42 "HB 3328/SB1879 Offers a Comprehensive Plan for Illinois' Energy Future," Commonwealth Edison, news release, March 19, 2015, accessed July 27, 2015, https://www.comed.com/newsroom/pages/newsroomreleases_03192015.pdf?FileTracked=true.

43 Illinois General Assembly, "Bill Status of SB1879," accessed February 5, 2016, http://www.ilga.gov/legislation/BillStatus.asp?DocNum=1879&GAID=13&DocTypeID=SB&SessionID=88&GA=99; Illinois General Assembly, "Bill Status of HB3328," accessed February 5, 2016, http://www.ilga.gov/legislation/BillStatus.asp?DocTypeID=HB&DocNum=3328&GAID=13&SessionID=88&LegID=89510.

44 State Corporation Commission of the State of Kansas, *Application of Westar Energy Volume II Minimum Filing Requirements*, Docket No. 15-WSEE-115-RTS, March 2, 2015, pp. 293-295, 332-334, http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150302143551.pdf?Id=74e4c4cf-8c4d-4f30-95cc-59ce1417777b.

45 State Corporation Commission of the State of Kansas, *Direct Testimony of Ahmad Faruqui on behalf of Westar Energy*, Docket No. 15-WSEE-115-RTS, 2015, p. 20, https://www.westarenergy.com/Portals/0/Resources/Documents/RateCasePDF/Direct_Testimony_of_Ahmad_Faruqui_on_behalf_of_Westar_Energy.pdf.

46 Ibid, p. 20-21.

47 Ibid, p. 3-4.

48 State Corporation Commission of the State of Kansas, *Order Approving Stipulation and Agreement*, Docket No. 15-WSEE-115-RTS. September 24, 2015, p. 17, http://estar.kcc.ks.gov/estar/ViewFile.aspx/20150924104744.pdf?Id=29b7b55e-b40c-4f66-9335-153bfe44a81e.

49 Ibid, p. 44.

F. Maine (Status: Pending)

In response to legislation enacted by the Maine legislature in 2014, the Maine Public Utilities Commission released a study in March of 2015 that estimated the value of DG based on ten different components.[50] The report concluded the long-term value of solar equates to $0.337/kWh,[51] which is higher than the approximate net metering retail rate of $0.13/kWh.[52] In an effort to allow customer-generators to capture more of the estimated value of solar, lawmakers passed a bill in June of 2015 that would require the legislature to develop an alternative pricing mechanism to net metering by the end of January 2016.[53] Proposals to the alternative pricing mechanism include a declining block program in which a centralized "Standard Buyer" would purchase residential solar at a rate set by the Commission.[54] The Standard Buyer would purchase solar at the rate set by the Commission until a pre-designated block of capacity was met, after which the price the Standard Buyer would drop to a lower rate. A regulatory decision was expected by the end of January 2016, but is still pending at time of writing.

G. Minnesota (Status: Final Order)

In April 2014, Minnesota was the first state to approve an alternative to NEM through its Value of Solar Tariff ("VOST").[55] In 2013, House Bill 729 ("HB 729") required that the Minnesota Department of Commerce ("DOC") develop a methodology for calculating the value of solar which

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50 The study estimated the value of distributed solar generation based on avoided energy costs, avoided generation capacity costs, avoided natural gas pipeline costs, solar integration costs, avoided transmission costs, avoided distribution costs, voltage regulation, net social cost of carbon, sulfur dioxide, and nitrous oxides, market price response, and avoided fuel price uncertainty. Maine Public Utilities Commission, "Maine Distributed Solar Valuation Study," presented to The Joint Standing Committee on Energy, Utilities and Technology - 127th Main Legislature, March 1, 2015.

51 Ibid, p. 6.

52 Herman K. Trabish, "Maine Lawmakers Propose Groundbreaking Way out of Net Metering Wars," Utility Dive, June 8, 2015, accessed February 5, 2016, http://www.utilitydive.com/news/maine-lawmakers-propose-groundbreaking-way-out-of-net-metering-wars/400074/.

53 State of Maine 127th Maine Legislature, "Resolve, to Create Sustainable Growth in Maine's Distributed Energy Sector that Uses Market Forces to Fairly Compensate Energy Producers," HP 863, LD 1263, June 30, 2015, http://legislature.maine.gov/legis/bills/getPDF.asp?paper=HP0863&item=3&snum=127.

54 State of Maine Office of the Public Advocate, "A Ratepayer Focused Strategy for Distributed Solar in Maine," Strategen Strategies for Clean Energy, 2015, http://www.maine.gov/meopa/news/Maine%20VOS%20White%20Paper%20V2%202.pdf.

55 Minnesota Public Utilities Commission, *Order Approving Distributed Solar Value Methodology*, Docket No. E-999/M-14-65, April 1, 2014, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={FC0357B5-FBE2-4E99-9E3B-5CCFCF48F822}&documentTitle=20144-97879-01; Herman K. Trabish, "Can Minnesota's Value of Solar End the Net Metering Debate?" Utility Dive, April 11, 2014, accessed February 11, 2016, http://www.utilitydive.com/news/can-minnesotas-value-of-solar-end-the-net-metering-debate/250451/.

included evaluating the value of energy as well as the costs and benefits of solar to utilities.[56] VOST is a type of buy-sell arrangement, where electricity bought by the customer is valued at the retail rate, while electricity sold back to the utility is priced at the value of solar.[57] Customer-generators under VOST are locked into a 25-year contract, the lifespan of a solar panel.[58] IOUs may voluntarily elect to use VOST with approval of the Minnesota Public Utilities Commission ("MPUC"); however, as of November 2015, no IOU had elected to implement the VOST in place of NEM.[59]

On June 13, 2015, the Minnesota State Governor signed the 2015 Jobs and Energy Bill, approving a fixed charge for new customer-generators of municipal utilities and electric cooperatives.[60] This fixed charge is only applicable to new customer-generators with a facility capacity less than 40 kW. While the bill does not specify the magnitude of the charge for each individual utility, it stipulates that each utility may elect a charge that is "reasonable and appropriate for that class of customer" given the most recent cost of service study. The additional charge is intended to allow utilities to recover fixed costs not already being recovered through the customer's current billing schedule. In addition to granting the fixed charge, the bill stipulates that customer-generators with less than 40 kW capacity may receive the "average retail utility energy rate" for their net input of electricity onto the grid. These changes became effective July 1, 2015 for customers installing NEM after that date.[61]

H. Mississippi (Status: Final Order)

On December 3, 2015, the Mississippi Public Service Commission unanimously voted on an approval for a net metering proposal.[62] The approved proposal indicates that energy produced onto the grid from the customer-generator will be netted against the energy the customer-generator uses from the grid at the retail rate until the customer bill reaches net zero. At this point the customer-generator will be compensated at the wholesale avoided cost rate plus a $0.025/kWh adder for additional excess energy produced onto the grid.[63] Entergy Corp. and Mississippi Power Company are additionally required to

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56 "Value of Solar Tariff," DSIRE, updated November 12, 2015, accessed February 11, 2016, http://programs.dsireusa.org/system/program/detail/5666.

57 Herman K. Trabish, "Can Minnesota's Value of Solar End the Net Metering Debate?" Utility Dive, April 11, 2014, accessed February 11, 2016, http://www.utilitydive.com/news/can-minnesotas-value-of-solar-end-the-net-metering-debate/250451/.

58 Ibid; *see also* Minnesota Public Utilities Commission, *Order Approving Distributed Solar Value Methodology*, Docket No. E-999/M-14-65, April 1, 2014, p. 11, https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={FC0357B5-FBE2-4E99-9E3B-5CCFCF48F822}&documentTitle=20144-97879-01.

59 "Value of Solar Tariff," DSIRE, updated November 12, 2015, accessed February 11, 2016, http://programs.dsireusa.org/system/program/detail/5666.

60 State of Minnesota House of Representatives, "2015 Jobs and Energy Bill," accessed February 11, 2015, https://www.revisor.mn.gov/bills/text.php?number=HF3&version=0&session=ls89&session_year=2015&session_number=1&format=pdf.

61 Ibid, p. 74-75.

62 Public Service Commission of the State of Mississippi, *Order and Adopting Metering Rule*, Docket No. 2011-AD-2, December 3, 2015.

63 Ibid, p. 11-16.

provide an added $0.02/kWh to the first 1,000 low-income customers to install net-metered DG projects.[64] The IOUs are expected to adopt these changes in early 2016 while the utility cooperatives have nine months to comply with the new rule or propose their own net metering rules.[65]

I. Nevada (Status: Final Order)

On June 5, 2015, Nevada's Governor signed Senate Bill 374 ("SB 374"), which establishes a framework for transitioning between the existing NEM rules ("NEM1") and new NEM rules ("NEM2").[66] Under NEM1, customer-generators are credited at the retail electricity rate for the electricity their systems supply to the grid. On July 31, 2015, Nevada Energy, holding company of Nevada Power and Sierra Pacific Power, submitted an application to the Public Utilities Commission of Nevada requesting to approve new rules and rates for NEM2 customers, including a three-part rate that reflects the cost of providing standby service to NEM2 customers.[67]

On December 22, 2015, the Public Utilities Commission of Nevada approved NV Energy's application of new NEM2 tariffs and established separate rate classes for NEM ratepayers.[68] However, instead of approving a three-part rate, the Commission approved a two-part tariff consisting of a modified basic service charge and a volumetric commodity charge.[69] In its decision, the Commission citied inequities between NEM ratepayers and non-NEM ratepayers as justification for creating separate rate classes for NEM customers. The Commission explained, "NEM ratepayers are under-paying, and the difference has to be collected from non-NEM ratepayers… if NEM ratepayers are not in separate rate classes. By placing NEM ratepayers in a separate rate class, the Commission can design rates that effectively collect those costs through an alternative rate structure."[70]

Addressing net excess energy, the Commission stated, "Banking the net excess energy at the retail rate as some parties propose is not just and reasonable because the energy delivered by the NEM ratepayers is not the same as the energy delivered by NV Energy."[71] Rather than the retail rate, the Commission ordered NV Energy to use the "average annual long-term avoided energy cost… from NV Energy's last

[64] Dan Testa, "Balancing interest of utilities, solar, Miss. PSC approves net metering policy," SNL, December 4, 2015, accessed on February 1, 2016, https://www.snl.com/InteractiveX/article.aspx?ID=35210449&KPLT=4.

[65] Julia Pyper, "Mississippi Regulators Strive for Compromise with New Net Metering Rule," Greentech Media, December 7, 2015, accessed on February 1, 2016, http://www.greentechmedia.com/articles/read/Mississippi-Regulators-Strive-for-Compromise-With-New-Net-Metering-Rule.

[66] Nevada State Senate, *Senate Bill No. 374-Senator Farley: Revises provisions relating to energy*, BDR 58-800, June 5, 2016.

[67] Public Utilities Commission of Nevada, *Application for Approval of Cost of Service Study and Net Metering Riders and Request for Interim Order*, Docket No. 15-07041, July 31, 2015.

[68] Public Utilities Commission of Nevada, *Order*, Docket No. 15-07041/Docket No. 15-07042, December 22, 2015.

[69] Ibid, p. 91-92.

[70] Ibid, p. 44.

[71] Ibid, p. 94.

approved integrated resource plan filings with an adder for avoided distribution line losses."[72] Additionally, the Commission finds that the new NEM2 rate structure should also apply to NEM1 customers. The Commission does not believe it is appropriate to use NEM1 data to establish NEM2 rates and then not apply those same rates to NEM1 ratepayers.[73] However, NV Energy disagreed with the decision to not 'grandfather' in existing customers under the NEM1 tariff. In a February 5, 2016 filing, NV Energy said it supports a plan allowing about 27,000 existing solar customers to pay the old rate for twenty years.[74]

Lastly, consistent with the bill stability principle of rate design, the Commission outlined a time frame to gradually shift ratepayers to the revised NEM rate structure.[75]

J. New York (Status: Pending)

On April 24, 2014, the state of New York released its Reforming Energy Revision ("REV") initiative proposal which poses key utility questions and proposed five policy objectives that include: customer knowledge and tools for effective energy bill management, market animation and leverage of ratepayer contributions, system wide efficiency, fuel and resource diversity, and system reliability and resiliency.[76] One overarching goal of the initiative is to reform the business and regulatory functions of utilities and transform utilities into Distribution System Platform Providers ("DSPP").[77] As DSPPs, utilities will continue operations of third-party owned energy generation, but will be also be functioning as facilitators of a network platform to coordinate a distribution network which will largely include energy input from customer-generators.[78] The initiative is expected to take roughly ten years before it is fully implemented.[79]

The REV initiative proposes a revised ratemaking framework which will be derived from results from the valuation of grid service and DER.[80] The deadline for the valuation of DER is expected near the end of

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72 Ibid, p. 95.

73 Ibid, p. 48.

74 Daniel Rothberg, "NV Energy: Let existing solar customers keep old rate for 20 years," Intelligent Utility, February 5, 2016, accessed on February 8, 2016, http://www.intelligentutility.com/article/16/02/nv-energy-let-existing-solar-customers-keep-old-rate-20-years?utm_source=2016_02_08&utm_medium=eNL&utm_campaign=IU_DAILY&utm_content=69764

75 Gradual shifts towards the revised rate structure are scheduled to occur on the first of January in 2016, 2017, 2018, 2019, and 2020; Ibid, pp. 96-97.

76 "Reforming the Energy Vision," NYS Department of Public Service Staff Report and Proposal, Case No. 14-M-0101, April 24, 2014, p. 1.

77 Ibid, p. 11.

78 "New York's REV: Seeking a Greener Utility Grid for the Environment and Investors," Moody's Investor Service, p. 3.

79 Ibid, p. 4.

80 "Reforming the Energy Vision," NYS Department of Republic Service Staff Report and Proposal, Case No. 14-M-0101, April 24, 2014, p. 3.

2016.[81] One of the more recent policy changes resulting from the REV valuation policy was the interim lift of net metering caps. On October 16, 2015, the New York Public Service Commission released an order which would lift the ceiling on the net metering cap, originally six percent of electric demand, until the REV valuation is complete due to utility expectations of increased net metered generation.[82] No other major decisions are expected during 2016.[83]

K. Oklahoma (Status: Pending)

In April 2014, Oklahoma passed Senate Bill 1456 ("SB 1456"), which allows regulated utilities to charge customer-generators a separate rate, effective November 2014. The Senate introduced the act to address subsidy issues prevalent in the DG marketplace, and the act does not apply to customers who installed solar panels prior to November 2014.[84] Utilities are required by law to have supporting tariffs filed, approved, and implemented by January 1, 2016. In August 2015, Oklahoma Gas and Electric ("OG&E") filed an application before the Corporation Commission of Oklahoma to approve a new DG tariff in compliance with SB 1456. The proposed three-part tariff includes a customer charge of $18.00/month, a demand charge of $2.68/kW-month, an on-peak energy charge of $0.173/kWh, and an off-peak energy charge of $0.0137/kWh.[85]

L. South Carolina (Final Order)

In June 2014, South Carolina's General Assembly passed Act 236 which outlined solar policy in the state.[86] Act 236 requires that utilities make NEM available to all customers on a first-come, first-serve basis until the generating capacity of the NEM system is equal to "two percent of the previous five-year average of the electrical utility's South Carolina retail peak demand."[87] The Act also requires that regulators approve a Value of Solar ("VOS") methodology that utilities can use to value DER and develop DG rates.[88] Additionally, Act 236 also permits solar leasing or

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81 Krysti Shallenberger, "10 State Rooftop Solar Debates to Watch in 2016 and Beyond," Utility Dive, January 25, 2016, accessed on January 29, 2016, http://www.utilitydive.com/news/10-state-rooftop-solar-debates-to-watch-in-2016-and-beyond/412087/.

82 State of New York Public Utilities Commission, *Order Establishing Interim Ceilings on the Interconnection of the Net Metered Generation*, Case No. 15-E-0407, October 16, 2013.

83 Krysti Shallenberger, "10 State Rooftop Solar Debates to Watch in 2016 and Beyond," Utility Dive, January 25, 2016, accessed on January 29, 2016, http://www.utilitydive.com/news/10-state-rooftop-solar-debates-to-watch-in-2016-and-beyond/412087/.

84 Oklahoma State Legislature, *Senate Bill 1456*, April 15, 2014, http://www.oklegislature.gov/BillInfo.aspx?Bill=sb1456&Session=1400.

85 Corporation Commission of the State of Oklahoma, *Direct Testimony of Roger D. Walkingstick on behalf of Oklahoma Gas and Electric Company*, Cause No. 201-500274, July 31, 2015, p. 18.

86 South Carolina General Assembly 120th Session, *Act No. 236*, June 2, 2014, http://www.scstatehouse.gov/sess120_2013-2014/bills/1189.htm.

87 Ibid, Section 58-39-130(C).

88 Herman K. Trabish, "Is South Carolina solar about to explode?" Utility Dive, November 18, 2014, accessed February 2, 2016, http://www.utilitydive.com/news/is-south-carolina-solar-about-to-explode/334164/.

third party ownership ("TPO") of rooftop solar. This Act applies to the state's IOUs, including the two largest utilities: South Carolina Electric and Gas and Duke Energy. Publicly-owned utilities, such as South Carolina Public Service Authority ("Santee Cooper"), are exempt from several conditions under the legislation because they do not fall under direct regulation from the South Carolina Public Service Commission.[89]

In August 2015, the Santee Cooper Board approved an interim installed capacity fee, called a Grid Access Charge ("GAC") through April 1, 2016. The GAC ranges between $4.20 and $4.70/kW-month of installed DG capacity.[90] On December 7, 2015, Santee Cooper's Board authorized a two-year rate adjustment effective in 2016 and 2017. Under the adjustment, customer-generators will now be subject to a monthly fixed charge of $2.00, a monthly stand-by charge of $4.40/kW of installed capacity, and energy charges as set forth in the applicable rate schedule.[91] In addition, customer-generators are compensated for their excess output at a rate of $0.0389/kWh during the summer and $0.0381/kWh during winter. Lastly, Santee Cooper stated on October 16, 2015 that it would also include rebates of $0.65/watt for residential customers who want to purchase solar panels for their homes, provide an additional $0.03/kWh of compensation for excess energy produced to the grid for the first 500 residential customers who sign up, and establish a community solar project for customers who cannot install rooftop solar.[92]

M. Texas (Status: Pending/Completed)

The El Paso Electric Company ("EPE") applied for a series of rate changes on August 10, 2015 which are pending approval from the Public Utilities Commission of Texas ("PUCT").[93] Among these rate changes are an increase is residential monthly fixed charges for standard residential and residential customer-generators.[94] Residential customer-generators would also be subject to a

89 Santee Cooper is regulated by a board of directors appointed by the governor and confirmed by the state senate. Herman K. Trabish, "As IOUs Push Solar, Santee Cooper Rate Plan Draws Ire of South Carolina Greens," Utility Dive, December 7, 2015, accessed February 2, 2016, http://www.utilitydive.com/news/as-ious-push-solar-santee-cooper-rate-plan-draws-ire-of-south-carolina-gre/410305/.

90 Interim Distributed Generation Rider (Retail) RIDER DG-15, South Carolina Public Service Authority, p. 1-3, https://www.santeecooper.com/pdfs/rates/distributed-generation/interim-dg-rider-dg-15.pdf.

91 South Carolina Public Service Authority Rate Schedules Effective for Bills Rendered on or after April 1, 2016, South Carolina Public Service Authority, December 7, 2015, accessed on February 2, 2016, https://www.santeecooper.com/pdfs/about-santee-cooper/rates/2016/2016-and-2017-final-rates.pdf.

92 "Santee Cooper Board approves solar incentive package," Santee Cooper press release, October 16, 2015, https://www.santeecooper.com/about-santee-cooper/news-releases/news-items/santee-cooper-board-approves-solar-incentive-package.aspx?ht.

93 Public Utility Commission of Texas, *El Paso Electric Company's Petition and Statement of Intent to Change Rates*, Docket No. 44941, August 10, 2015, http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/44941_2_861533.PDF.

94 Herman K. Trabish, "El Paso Council Rejects Texas Utility's Proposal to Create Solar Customer Class," Utility Dive, December 10, 2015, accessed February 5, 2016, http://www.utilitydive.com/news/el-paso-council-rejects-texas-utilitys-proposal-to-create-solar-customer-c/410578/.

demand charge, but a decreased volumetric rate. EPE has also proposed the creation of a new solar customer class. While El Paso's City Council has unanimously rejected the proposal, the decision from the PUCT is still pending and is expected in early 2016.

Southwestern Public Service Company ("SPS"), a subsidiary of Xcel Energy, applied for an increase to its fixed charges in December 2014.[95] A year later in December 2015, the PUCT approved the fixed charge increase for residential customers from $7.60/month to $9.50/month.[96] SPS's Distributed Generation Interconnection Tariff is identical to the "tariff for applicable class or service" customer-generators with a generating capacity of 100 kW or less, indicating that the residential fixed charge rate increase also applies to residential customer-generators within the 100 kW capacity level.[97]

N. Wisconsin (Status: Final Order)

Approved by the Wisconsin Public Service Commission in December 2014, We Energies offers a mandatory net metered rate to residential customers with less than 300 kW of installed generation capacity.[98] The rate consists of a fixed charge of about $1.82/month in addition to a residential facilities charge of $16.04/month,[99] with additional energy charges determined by the customer's otherwise applicable tariff schedule.[100] The monthly capacity charge of $3.794/kW was removed from the tariff as a result of a court order in October 2015.[101] The company credits net energy supplied by the customer using a Buy-Back Energy Rate which is either based on a flat rate or TOU rate dependent on the residential customer's otherwise applicable tariff schedule.

95 Public Utilities Commission of Texas, *Order*, Docket No. 43695, December 18, 2015, http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/43695_1018_876737.PDF.

96 Ibid, p. 54.

97 Electric Tariffs: Distributed Generation Interconnection, Xcel Energy – Southwestern Public Service, Section No. IV, Sheet No. IV-159, p. 3 of 23, http://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/TX/tx_sps_e_entire.pdf.

98 Public Service Commission of Wisconsin, *Final Decision*, Docket No. 5-UR-107, December 23, 2014.

99 The total monthly fixed charge is the daily generation facilities charge plus a DG rider multiplied by 30.5 days. This calculation is ($0.05951/day x 30.5 days) + ($0.52602/day x 30.5 days) = $1.82/month + $16.04/month. $0.52602/day from Residential Service tariff. Residential Service - Rate Schedule Rg 1, We Energies, http://www.we-energies.com/pdfs/etariffs/wisconsin/ewi_sheet21.pdf.

100 Customer Generating Systems – Net Metered (CGS NM) Less than 300 KW - Rate Schedule CGS NM, We Energies, http://www.we-energies.com/pdfs/etariffs/wisconsin/ewi_sheet2016-2018.pdf.

101 Krysti Shallenberger, "10 State Rooftop Solar Debates to Watch in 2016 and Beyond," Utility Dive, January 25, 2016, accessed on January 29, 2016, http://www.utilitydive.com/news/10-state-rooftop-solar-debates-to-watch-in-2016-and-beyond/412087/.

Madison Gas and Electric Company ("MGE") also received approval by the Commission in December 2014 for an increase in residential fixed charges.[102] The $19.00/month residential rate,[103] up from $10.44/month, is composed of a customer charge of $14.97/month and a grid connection service charge of $4.03/month.[104] According the Commission, the MGE fixed charge increase would realign costs more appropriately with fixed charges, rather than variable charges.[105] MGE compensates customers' excess energy at the appropriate retail rate unless they are net energy sellers for over 12 months.

In addition to the above recent fixed charge decisions, the Wisconsin Public Service Corporation ("WPS") has also received two separate fixed charge rate increases in the last two years for residential customers.[106] The Commission approved the increased fixed charges "to better align the charge with fixed costs of providing service, regardless of the amount of energy used."[107] The Commission stated that they "continue to support customers who want to own their own generation; however, the Commission also has an obligation to those customers who do not want to or who cannot afford to own generation to make sure these customers are not subsidizing the costs for those who choose to and are able to own their own generation."[108] Customer-generators are currently credited at weighted average rate, dependent on peak generation, in addition to $0.00831/kWh for the excess energy they supply to the grid.[109]

[102] Public Service Commission of Wisconsin, *Final Decision*, Docket No. 3270-UR-120, December 23, 2014.

[103] MGE's approved fixed charge increase applies to all standard residential customers and is not specific to customer generators; Residential Service – Schedule Rg-1 and Residential Time-of-Use Rate – Schedule Rg-2, Madison Gas and Electric, https://www.mge.com/Images/PDF/Electric/Rates/ElecRates.pdf.

[104] Public Service Commission of Wisconsin, *Final Decision*, Docket No. 3270-UR-120, December 23, 2014, p. 35.

[105] Ibid, p. 36.

[106] WPS's approved fixed charge increase applies to all standard residential customers and is not specific to customer generators.

[107] Public Service Commission of Wisconsin, *Final Decision*, Docket No. 6690-UR-123, December 18, 2014, p. 42.

[108] Ibid, p. 44.

[109] Parallel Generation – Net Energy Billing – Schedule PG-4, Wisconsin Public Service Corporation, http://www.wisconsinpublicservice.com/company/wi_tariffs/PG4.pdf.

Table 1: Summary of Proposed and Accepted Distributed Generation Rates by State

			Demand Charges	Buy-Sell	Fixed Charge	Capacity Charge	Installed Capacity Fee	DG Output Fee	Inter-Connection Fee	Minimum Bill	Standby Rates	TOU Energy Charges	Grand-fathering	DG-Specific
[1]	Arizona	Arizona Public Service	X	X	X		✓					X	Yes	Yes
[2]	Arizona	Salt River Project	✓		✓							✓	Yes	Yes
[3]	Arizona	UNS Energy Corporation	(✓)	(✓)	(✓)								Yes	Yes
[4]	California	Investor-Owned Utilities	X	✓	X	X	X		✓			✓	Yes	Yes
[5]	Hawaii	Hawaiian Electric Company		✓						✓			Yes	Yes
[6]	Illinois	Statewide	(✓)											
[7]	Kansas	Westar Energy	X		X								Yes	Yes
[8]	Maine	Statewide		(✓)										Yes
[9]	Minnesota	Statewide		✓	✓								Yes	Yes
[10]	Mississippi	Statewide		✓										Yes
[11]	Nevada	Nevada Energy	X	✓	✓							✓	No	Yes
[12]	New York	Statewide												
[13]	Oklahoma	Oklahoma Gas and Electric	(✓)		(✓)							(✓)	Yes	Yes
[14]	South Carolina	Investor-Owned Utilities		(✓)										Yes
[15]	South Carolina	Santee Cooper		✓	✓		✓						No	Yes
[16]	Texas	El Paso Electric Company	(✓)		(✓)									Yes
[17]	Texas	Southwestern Public Service Co.			✓									No
[18]	Wisconsin	Madison Gas and Electric			✓								No	No
[19]	Wisconsin	We Energies		✓	✓		X						Yes	Yes
[20]	Wisconsin	Wisconsin Public Service Corp.		✓	✓									No

Note: This is drawn from utility-specific summaries in Section IV of this report. Each utility rate offering is unique and may not correspond exactly with the categories defined above.

Key:
- ✓ Approved
- (✓) Proposed (decision pending)
- X Proposed & rejected or withdrawn

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VALUE OF THE GRID TO DG CUSTOMERS

IEE Issue Brief
September 2013
Updated October 2013

IEE | INNOVATION ELECTRICITY EFFICIENCY
An Institute of The Edison Foundation

Value of the Grid to DG Customers

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September 2013
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Prepared by

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VALUE OF THE GRID TO DG CUSTOMERS

Some advocates of distributed generation (DG) claim that the DG customer derives no benefit from being connected to the host utility's distribution system.[1] While it is easy to say that a DG customer is "free from the grid," that is simply not true – even for a DG customer (or a micro-grid) that produces the exact amount of energy that it consumes in any given day or other time interval.[2]

This paper describes how a DG customer (or a micro grid) that is connected to the host utility's distribution system 24/7 utilizes grid services on a continuous, ongoing basis. The point is to recognize the value of these grid services and to develop a methodology for the DG customer to pay for using the services. The utility's cost of providing grid services consists of at least four components – the typical fixed costs associated with: (i) transmission, (ii) distribution, (iii) generation capacity, and (iv) the costs of ancillary and balancing services that the grid provides throughout the day for the DG customer.

There is a related question about how much DG customers should be paid, or credited, for the excess electric energy they produce on-site and inject into the grid. This paper does not explicitly address this "value of on-site energy" issue.

The Benefits of Remaining Connected to the Distribution System

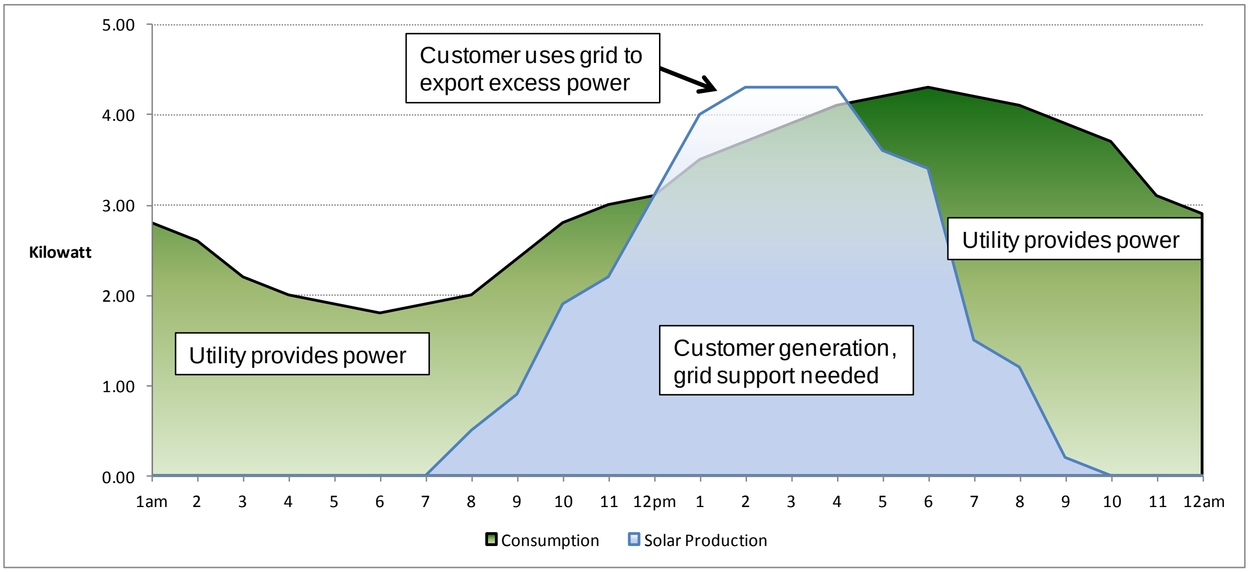
Consider a residential or small commercial customer with solar PV panels on its rooftop. Figure 1 displays a typical hourly pattern of energy production and consumption for such a customer. The green area is the energy delivered by the host utility and consumed by the customer. The area under the blue curve is the energy produced on-site by the solar panels. The area below the blue curve and above the green line is the excess energy injected into the utility's distribution system. The key take-away from this graphic is that the customer's consumption and generation are almost never equal; consequently, most of the time the customer is using the external power system to offset the difference between the customer's consumption of electric energy and its on-

1 A recent Forbes article, "Distributed Generation Grabs Power from Centralized Utilities," August 8, 2013, ignores and fails to mention the grid services that are provided to DG customers continuously by the host utility.

2 The term, DG, refers to small retail customers with on-site generation that are net metered.

site production. In most cases the customer will be taking energy from the grid during many hours of the day. For example, the customer depicted in Figure 1 takes power from the grid in all hours except from noon to about 4:30 pm.

Figure 1: Typical Energy Production and Consumption for a Small Customer with Solar PV



Customers with any type of DG that are connected to the grid will be utilizing external grid services to:

- balance supply and demand in sub-second intervals to maintain a stable frequency *(i.e.*, regulation service);
- resell energy during hours of excess generation and deliver energy during hours of deficit generation;
- provide the energy needed to serve the customer's total load during times when on-site generation is inoperable due to equipment maintenance, unexpected physical failure, or prolonged overcast conditions (*i.e.*, backup service);
- provide voltage and frequency control services and maintain high AC waveform quality.

Clearly, even if the customer's total energy production over some time interval (*e.g.*, a monthly billing cycle) exactly equals its consumption over that same interval, that customer is still utilizing at least some, if not all, of the above grid services during that time interval.

So what value does a customer with solar PV generation derive from remaining connected to the grid? Let's begin by examining the charges that a typical residential customer consuming an average of about 1000 kilowatt-hours (kWh) per month [average consumption based on Energy Information Administration (EIA) data and rounded] will pay for grid services, <u>excluding the charges for the electric energy itself</u>. These charges are designed to allocate to the customer its fair share of the fixed costs associated with the transmission system, the distribution system, balancing and ancillary services, and the utility's (or the retail supplier's) investment in generation capacity.[3] As stated earlier, the electric energy charges designed to recover the cost of the energy (kWh) consumed by the customer (including the associated transmission and distribution losses), are excluded here. Table 1 illustrates these charges for a typical residential customer.[4]

Table 1 – Non-Energy Charges Paid by a Typical Residential Customer on a Retail Tariff

Average Residential Customer: Non-Energy Charges as Percent of Typical Monthly Bill	
Average Monthly Usage (kWh)*	1000
Average Monthly Bill ($)*	$110
Typical Monthly Fixed Charges	
Ancillary/Balancing Services	$1
Transmission Systems	$10
Distribution Services	$30
Generation Capacity ^	$19
Total Fixed Charges for Customer	$60
Fixed Charges as Percent of Monthly Bill	**55%**

*Based on Energy Information Administration (EIA) data, 2011
^The charge for capacity varies depending upon location. This is just an estimate.

In this example, the typical residential customer consumes, on average, about 1000 kWh per month and pays an average monthly bill of about $110 (based on EIA data). About half of that bill (*i.e.,* $60 per month) covers charges related to the non-energy services provided by the grid,

3 In "retail choice" states the retail customer can choose its energy supplier, which may not be the utility. In all other states the utility will be the retail supplier.

4 Other charges, such as sales and franchise taxes and environmental charges could be added to the table; however, the focus of this paper is on the grid services that are provided by the host utility.

including a charge for generation capacity. Because residential retail rates are almost always designed to recover most of the power system's fixed costs through kWh charges, a DG customer will avoid paying some or all of its fair share of the fixed costs of grid services. Ultimately the fixed costs that the DG customer does not pay, which are significant, will be shifted to other retail customers. In this example, each DG customer shifts up to $720 per year in costs (*i.e.,* $60 * 12 months) to other retail non-DG customers. To put this into context, if 50 percent of the residential customers in a given utility service territory had DG, the non-DG residential customers in that service territory could experience bill increases of up to 55 percent – from $110 per month to $170 per month. Clearly this cost shift is substantial and simply not fair.

IEE submits that DG customers should pay their fair share of the cost of the grid because pushing any of this cost onto non-DG customers raises serious economic efficiency and fairness issues. Indeed this is one of the key issues in the current debate over net metering.

To illustrate the value provided by the grid for a solar PV customer, consider what it would cost that customer to self-provide the technical equivalent of these services through some combination of energy storage and/or thermal generation (*e.g.,* a Generac home generator).

Preliminary estimates of the monthly costs that a typical residential customer would have to incur to self-provide the balancing and backup services that the grid currently provides are substantially higher than the $60 charge shown in Table 1.[5] Furthermore, this cost estimate of self-provision excludes the additional cost of maintaining the level of voltage and frequency control and AC waveform quality currently provided by the grid. An off-the-grid DG customer (or micro-grid) simply cannot provide, at reasonable cost, the same quality of service that a large power system provides. So, in fact, most DG customers remain connected to the grid today and utilize grid services.

This straightforward cost comparison to "self providing" grid services reveals three things. First, the balancing and backup services that the grid provides to DG customers are needed and have substantial value. Second, it does not make economic sense for a DG customer to self-provide these services. Third, it is unfair for DG customers to avoid paying for these grid services,

5 The Electric Power Research Institute (EPRI) is developing estimates of the cost of self-providing grid services and expects to release its results in 2014.

thereby shifting the cost burden to non-DG customers. Obviously, DG customers should pay their fair share of the cost of the grid services that the host utility provides.

Economies of Scale Associated with Power Systems

In many ways, the growth of DG and micro grids today goes full circle back to the early days of the electric power industry. Initially power systems were isolated and each served its own service area. As service areas expanded, utilities began to interconnect. PJM was the first entity to interconnect utilities for reliability purposes and to centrally provide balancing services. This evolution was driven by the substantial economies of scale that still exist today as ISO/RTO markets continue to grow and expand.[6]

These interconnection entities developed for good reasons. When a small power system interconnects with a larger one, all members of the resulting combined entity benefit. However, it has been observed that the small system benefits disproportionately more than the incumbent members. For example, the small system's operating reserve margin will decrease substantially. This phenomenon is even more pronounced when a micro-grid interconnects with a power system.

DG Market is Growing, Pricing it Right is Key

Although net metering was a convenient vehicle for kick-starting the DG market, there are now serious questions among state policymakers regarding its continuation and needed reforms. *One main concern, addressed by this paper, is that net-metered customers are avoiding payment of their fair share of the grid services described earlier, thereby causing those lost revenues to be recovered from other customers.* As also demonstrated in this paper, these "grid" costs are quite significant – about 55 percent of the monthly electric bill for a residential customer as demonstrated in Table 1. Although this may not have been a major problem when the DG market was in its infancy, sending the wrong price signals to both customers and to the DG industry is a major problem as the DG market rapidly grows and develops.

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6 Entergy's decision to join MISO is a recent example.

Revenue Decoupling Will Not Resolve The DG Cost-Shifting Issue

Revenue decoupling is currently being used to promptly restore utility net revenues that would otherwise be lost due to declining electricity sales resulting from utility investments in energy efficiency (EE). Although revenue decoupling makes the utility whole, it does so by explicitly shifting costs from participating EE customers to nonparticipating EE customers using a public or system benefits charge (which is typically visible and transparent to all customers as a charge on their utility bills). Decoupling causes the same cost shifting problem that is created by DG with net metering. However, a fundamental difference is that the magnitude of the "cost shifting" to non DG customers is on a much larger scale than the cost shifting due to energy efficiency. A recent study revealed that decoupling rate adjustments for energy efficiency are quite small – about 2 to 3 percent of the retail rate.[7] In contrast, as described earlier in this paper, a DG customer could shift up to 55 percent of the retail rate onto non-DG customers (and, unlike efficiency charges, which are transparent, the DG cost shifting is essentially invisible to customers).

The amount of cost-beneficial energy efficiency is limited because the more you achieve, the less cost-beneficial the next increment of energy savings becomes. This "diminishing return" aspect means that energy efficiency increases only when it makes economic sense. In contrast, no such economic limit applies to DG. In fact, costs – particularly for rooftop solar PV – are expected to decline over time. *Although regulators have been willing to accept a relatively limited amount of cost shifting to promote utility investments in energy efficiency (about 2-3 percent of rates, on average), they are unlikely to accept the magnitude of cost shifting that will accompany the rapid expansion in net-metered DG unless some reforms to net metering are put into place.*[8]

Alternative Approaches To End Cost Shifting Due to Net Metering

Three basic approaches to net metering are under examination across the nation, each of which seeks to ensure that a DG customer using grid services pays its fair share of the costs of those services while still receiving fair compensation for the excess energy that it produces:

7 "A Decade of Decoupling for US Energy Utilities: Rate Impacts, Designs, and Observations." Pamela Morgan, Graceful Systems LLC. February 2013.

8 Distributed generation and net metering were very hot topics at the Summer 2013 NARUC meetings with at least five panel discussions addressing them.

- Redesign retail tariffs such that they are more cost-reflective (including adoption of one or more demand charges);
- Charge the DG customer for its gross consumption under its current retail tariff and separately compensate the customer for its gross (*i.e.,* total on-site) generation; and
- Impose transmission and distribution (T&D) "standby" charges on DG customers.

These three approaches are illustrative and are further described below.

Redesign Retail Tariffs (APS Proposal). To address the fundamental issue that a residential customer with rooftop solar should be compensated at a fair rate for the power it exports (sells) to the grid and also pay a fair price for its use of grid services, APS is proposing two options.[9] The first option requires the customer to take service under an existing demand-based rate schedule. The demand charge would cover a reasonable portion of the cost of grid services.

The second option allows the customer to choose an existing APS rate schedule for its total electric consumption and APS will purchase all of the customer's rooftop solar generation at market-based wholesale rates. This option ensures recovery of grid services and sends more accurate price signals to DG customers. It is also conceptually very close to what Austin Energy has already put in place.

Treat On-site Generation and Consumption Separately (Austin Energy Tariff). Austin Energy has implemented a solar tariff that fully compensates its DG customers for their gross on-site generation while separately charging them for their gross consumption under its existing retail tariff.[10] This approach effectively ensures that the cost of grid services are recovered from DG customers while also compensating DG customers for their generation at the utility's full avoided cost of procuring energy. The Public Utility Regulatory Policies Act (PURPA), under Title II, provides an established precedent for such compensation.[11] This approach requires a separate meter for on-site generation.

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9 APS conversation, July 2013.

10 Rabago, K.R., *The 'Value Of Solar' Rate: Designing An Improved Residential Solar Tariff*, Solar Industry, February, 2013. Available at www.solarindustrymag.com.

11 Although PURPA only applies to generating resources that are Qualified Facilities (QFs), this condition has not been applied if the customer receives a credit on its electric bill, rather than a monetary payment for its generated energy.

Implement T&D Standby Charges for DG Customers (Dominion Tariff). Dominion requires a residential net-metered DG customer with a solar installation whose rated output is greater than 10kW and up to 20kW, to pay a monthly transmission standby charge of $1.40 per kW and a monthly distribution standby charge of $2.79 per kW. However, these standby charges are respectively reduced, dollar for dollar, by the customer's transmission and distribution charges that are recovered through kWh charges applied to the customer's monthly electricity consumption up to the point where each standby charge is fully phased out. This became effective on April 1, 2012. Dominion also proposed a placeholder for a future generation standby charge, but it was not approved. The Commission ruled that a generation standby charge should be studied and filed in a future proceeding.

A Final Thought

In light of the rapid growth in net-metered DG, it is critical that these customers pay their fair share of the cost of grid services provided to them – and sooner rather than later. Updating net metering policies to put an end to the cost shifting that is occurring today should be done now.

About IEE

IEE is an Institute of The Edison Foundation focused on advancing the adoption of innovative and efficient technologies among electric utilities and their technology partners that will transform the power grid. IEE promotes the sharing of information, ideas, and experiences among regulators, policymakers, technology companies, thought leaders, and the electric power industry. IEE also identifies policies that support the business case for adoption of cost-effective technologies. IEE's members are committed to an affordable, reliable, secure, and clean energy future.

IEE is governed by a Management Committee of electric industry Chief Executive Officers. IEE members are the investor-owned utilities that represent about 70% of the U.S. electric power industry. IEE has a permanent Advisory Committee of leaders from the regulatory community, federal and state government agencies, and other informed stakeholders. IEE has a Strategy Committee of senior electric industry executives and 30 smart grid techology company partners.

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RECOVERY OF UTILITY FIXED COSTS: UTILITY, CONSUMER, ENVIRONMENTAL AND ECONOMIST PERSPECTIVES

Lisa Wood, Institute for Electric Innovation and The Edison Foundation, and **Ross Hemphill**, RCHemphill Solutions

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Foreword by U.S. Department of Energy

The provision of electricity in the United States is undergoing significant changes for a number of reasons. The implications are unclear.

The current level of discussion and debate surrounding these changes is similar in magnitude to the discussion and debate in the 1990s on the then-major issue of electric industry restructuring, both at the wholesale and retail level. While today's issues are different, the scale of the discussion, the potential for major changes, and the lack of clarity related to implications are similar. The U.S. Department of Energy (DOE) played a useful role by sponsoring a series of in-depth papers on a variety of issues being discussed at that time. Topics and authors were selected to showcase diverse positions on the issues to inform the ongoing discussion and debate, without driving an outcome.

Today's discussions have largely arisen from a range of challenges and opportunities created by new and improved technologies, changing customer and societal expectations and needs, and structural changes in the electric industry. Some technologies are at the wholesale (bulk power) level, some at the retail (distribution) level, and some blur the line between the two. Some technologies are ready for deployment or are already being deployed, while the future availability of others may be uncertain. Other key factors driving current discussions include continued low load growth in many regions and changing state and federal policies and regulations. Issues evolving or outstanding from electric industry changes of the 1990s also are part of the current discussion and debate.

To provide future reliable and affordable electricity, power sector regulatory approaches may require reconsideration and adaptation to change. Historically, major changes in the electricity industry often came with changes in regulation at the local, state or federal levels.

DOE is funding a series of reports, of which this is a part, reflecting different and sometimes opposing positions on issues surrounding the future of regulation of electric utilities. DOE hopes this series of reports will help better inform discussions underway and decisions by public stakeholders, including regulators and policy makers, as well as industry.

The topics for these papers were chosen with the assistance of a group of recognized subject matter experts. This advisory group, which includes state regulators, utilities, stakeholders and academia, works closely with DOE and Lawrence Berkeley National Laboratory (Berkeley Lab) to identify key issues for consideration in discussion and debate.

The views and opinions expressed in this report are solely those of the authors and do not reflect those of the United States Government, or any agency thereof, or The Regents of the University of California.

Introduction to This Report

Utilities recover costs for providing electric service to retail customers through a combination of rate components that together comprise customers' monthly electric bills. Rates and rate designs are set by state regulators and vary by jurisdiction, utility and customer class. In addition to the fundamental tenet of setting fair and reasonable rates, rate design balances economic efficiency, equity and fairness, customer satisfaction, utility revenue stability, and customer price and bill stability.[1]

At the most basic level, retail electricity bills in the United States typically include a fixed monthly customer charge — a set dollar amount regardless of energy usage — and a volumetric energy charge for each kilowatt-hour consumed.[2] The energy charge may be flat across all hours, vary by usage level (for example, higher rates at higher levels of usage), or vary based on time of consumption.[3]

While some utility costs, such as fuel costs, clearly vary according to electricity usage, other costs are "fixed" over the short run — generally, those that do not vary over the course of a year. Depending on your point of view, and whether the state's electricity industry has been restructured or remains vertically integrated, the set of costs that are "fixed" may be quite limited. Or the set may extend to all capacity costs for generation, transmission and distribution. In the long run, all costs are variable.

In the context of flat or declining loads in some regions, utilities are proposing a variety of changes to retail rate designs, particularly for residential customers, to recover fixed costs.

In this report, authors representing utility (Chapter 1), consumer (Chapter 2), environmentalist (Chapter 3) and economist (Chapter 4) perspectives discuss fixed costs for electric utilities and set out their principles for recovering those costs. The table on the *next page* summarizes each author's relative preferences for various options for fixed cost recovery, some of which may be used in combination.[4] The specific design of any ratemaking option matters crucially, so a general preference for a given option does not indicate support for any particular application.

A literature review at the end of the report (Chapter 5) defines each of these options and highlights current practices, potential pros and cons, and the diversity of views held by a wide range of energy experts.

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[1] See, for example, Hledik and Lazar (2016), report #4 in the Future Electric Utility Regulation series: feur.lbl.gov.
[2] Large customers also have a demand charge based on their highest electricity demand during a specified time interval, typically not limited to coincidence with the utility system peak, such as any 15-minute period over the course of the billing period.
[3] Several other charges may be separately shown on electric bills, such as taxes, franchise fees, rate credits and public purpose charges (also called system benefit charges, a percentage-based fee on electric bills that provides stable funding for energy efficiency programs and sometimes additional programs — for example, to support renewable resources and services for low-income households).
[4] The order in which these options are addressed varies among authors.

Table i. Summary of Authors' Preferences on Approaches to Fixed Cost Recovery

	Wood/Hemphill (utility)	Howat (consumer)	Cavanagh (environmental)	Borenstein (economist)
Higher fixed charges	◓	○	○	◒[1]
Minimum bills	○	●	●	○
Demand charges	◓	○	◓[2]	○
Time-varying rates	○	●	●	●[3]
Tiered rates	○	●	●	○
Revenue decoupling	○	●[4]	●[5]	○
Frequent rate cases	◓[6]	◒	○	○
Formula rate plans	●	◓[7]	◓	○
Lost revenue adjustment mechanisms	○	○	○	○

○ **Poor** ◒ Better ◓ Good ● Preferred

[1] First set volumetric price to reflect actual social marginal costs, including costs of externalities whether or not the utility has to pay those costs.
[2] Linked to periods of coincident peak and subject to negotiated resolution of important technical issues.
[3] Reflecting full social marginal cost, with the remaining revenue requirement balanced between higher volumetric rates and higher fixed charges.
[4] Assuming a number of safeguards are implemented (see report).
[5] Necessary but not sufficient.
[6] In combination with a formula rate plan and only for setting revenue requirement; rate design issues to be addressed less frequently (e.g., every three years).
[7] Implementation of formula rates should not deny utility customers and other stakeholders the ability to periodically review and litigate a utility's cost structure.

Poor - Poorly address fixed cost recovery

Better - Somewhat better way to address fixed cost recovery but may not be sufficient

Good - Address fixed cost recovery reasonably well

Preferred - Preferred way to address fixed cost recovery

1. Utility Perspective: Providing a Regulatory Path for the Transformation of the Electric Utility Industry

By Lisa Wood, Executive Director, Institute for Electric Innovation, and Vice President, The Edison Foundation

Ross Hemphill, President, RCHemphill Solutions, and Former Vice President of Regulatory Policy & Strategy, Commonwealth Edison

The electric utility industry is in the midst of a profound transformation. This transformation, more evolutionary than revolutionary, is being driven largely by:

- technological innovation;
- federal and state policies; and
- changing customer needs and increasing expectations.

Key Trends Driving Change in the Electric Utility Industry

Three "megatrends" are at the core of this transformation.

The Transition to a Clean Energy Future

The portfolio of energy resources we use to meet our electricity needs is changing. As a nation, we are investing increasingly in renewable energy, transitioning from coal to natural gas, continuing to generate electricity using nuclear energy and pursuing energy efficiency. At the same time, modernization and digitization of the grid enable the integration of more carbon-free renewable resources, both large-scale and distributed. In fact, we expect continued growth in wind and exponential growth in solar over the next decade.[5] Projected solar growth is a mix of utility solar — the dominant market segment — followed by private residential solar and nonresidential solar.[6]

A More Digital and Distributed Grid

The power grid itself is changing, becoming "smarter" by virtue of a digital communication overlay with millions of sensors that will make the grid more controllable and potentially self-healing. The electric utility industry is investing more than $20 billion per year in the distribution grid alone, which will enable the connection of distributed energy resources, as well as new devices in our homes and businesses.[7] Many of these resources and devices will interact with the grid, resulting in more reliable, resilient and efficient grid operations. The digital grid is evolving into a multi-path network of power and information flows that will use data analytics for grid management and optimization from end to end.[8]

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[5] Greentech Media and SEIA (2016).
[6] Ibid.
[7] Edison Electric Institute (2015).
[8] While the digital power grid offers many benefits, it also raises cyber security risks which the utilities are addressing through a variety of measures, often with government cooperation, and which will add to the costs of maintaining the grid.

Individualized Customer Services

As the grid becomes increasingly digital and distributed, customization of services for electricity customers will continue to grow. Large commercial customers, for example, increasingly want renewable energy to meet their corporate sustainability goals; cities and towns are requesting customized services, such as help with microgrids, smart city services or renewable energy; and some residential customers want greater control over their energy use and/or renewable power or private rooftop solar to generate their own electricity. But, some customers simply want plain vanilla electricity at an affordable price.

Although these megatrends are driving change, the speed of transformation to a great extent will depend on whether regulation evolves to accommodate these changes. The business model of electric utilities must change to reflect the changing generation mix. At the same time, the grid is more complex and customers have different expectations and needs, meaning that the regulatory model also must change.[9] The utility business model can only change to the extent that regulation adjusts to facilitate these changes.

Over the next decade, regulation will have to provide a way for utilities to achieve new corporate and policy goals that meet the needs of their customers. That means meeting the traditional goals of providing safe, reliable and affordable electricity, as well as the new goals of providing even cleaner electricity and individualized customer services, while also integrating and connecting more distributed energy resources and devices.[10]

Value of the Distribution Grid

In the United States, the movement toward a more digital and distributed power grid is well underway. The need for more reliable and resilient grid operations, for greater efficiency and control, and for the connection and interaction with the "Internet of Things" (IoT) — every device with an IP address — creates new challenges, roles and opportunities. The deployment of more than 60 million digital smart meters to U.S. households is one key building block.[11] The integration of ever more distributed energy resources is another. Utilities are playing a central role as the integrators and enablers of the evolving Grid of Things™.

Given recent trends, the utility industry's current $20 billion annual investment in the distribution grid is expected to continue over the next several years.[12] But for the grid to continue to evolve to provide the services that customers want, and to integrate an increasing number of "things," all customers who use the grid will need to continue to share in the cost of maintaining and operating it. This will entail moving toward a services model rather than a throughput model, which requires regulatory change.

For example, a distributed generation (DG) retail customer or a microgrid that is connected to the host utility's distribution system utilizes grid services around the clock on a continuous, ongoing basis.[13] Figure 1.1 shows how a DG customer is using grid services continuously throughout a 24-hour period to import power, to export power and to continuously balance

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[9] Rather than changing rates for all customers, we may see the development of rates for specific customized services.
[10] A similar discussion is included in the introduction to the Institute for Electric Innovation's recent book, *Thought Leaders Speak Out: Key Trends Driving Change in the Electric Power Industry.* Institute for Electric Innovation (2015).
[11] Ibid, pages 24 and 25.
[12] Edison Electric Institute (2015). Table 9.1. 2014 data.
[13] We are discussing a retail customer connected to a utility under a retail rate, not a power purchase agreement.

supply and demand throughout the day. The utility's cost of providing grid services consists of at least four components — the typical fixed costs associated with: (1) transmission, (2) distribution, (3) generation capacity and (4) ancillary and balancing services that the grid provides throughout the day. How should the customer pay for these grid services?[14]

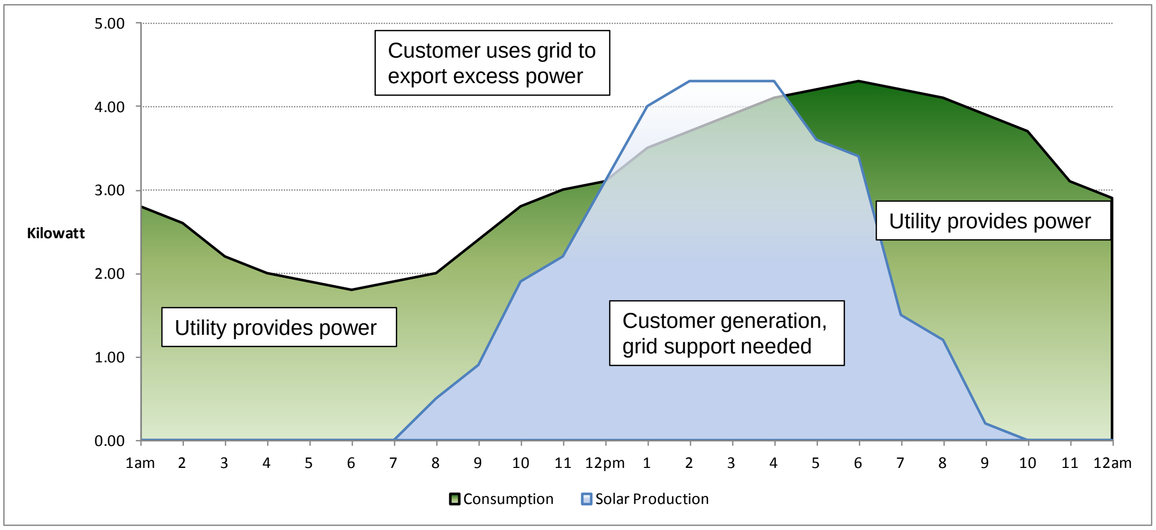

Figure 1.1 A Typical Private Rooftop Solar Photovoltaic (PV) Customer Interacts With the Grid Continuously Throughout the Day to Import Power, Export Power and Balance Supply and Demand.

Table 1.1 shows an example of actual non-energy or fixed charges as a percent of a residential customer's monthly bill; the actual percentage will vary from utility to utility. However, today, most of a utility's fixed charges are collected indirectly via a volumetric usage charge rather than directly via a fixed charge. Despite the fact that actual fixed charges comprise a very large percentage of a typical residential customer monthly bill, only a small percentage of this amount is collected via a fixed or customer charge. The result is that today's electricity customers have little idea of the actual fixed costs incurred to provide non-energy (e.g., grid and customer) services to them. We describe alternative approaches for customers to pay for grid services (without unnecessarily shifting costs onto other customers) and recommend a few specific ways forward. In light of the rapid growth in distributed energy resources, it is critical that all customers who use the grid continue to pay for the cost of grid services provided.

[14] From an economist's perspective, a "fixed cost" does not change as the quantity consumed (and produced) changes during some defined time increment. With respect to the subject matter discussed in this paper, the time increment is month-to-month and year-to-year.

Table 1.1 Example of Non-energy Charges as a Percent of Monthly Bill

Average Residential Customer: Non-Energy Charges as Percent of Typical Monthly Bill	
Average Monthly Usage (kWh)*	911
Average Monthly Bill ($)*	$114
Typical Monthly Fixed Charges	
Ancillary/Balancing Services	$1
Transmission Systems	$10
Distribution Services	$30
Generation Capacity ^	$19
Total Fixed Charges for Customer	$60
Fixed Charges as Percent of Monthly Bill	**53%**

*Usage and bill are based on Energy Information Administration (EIA) 2014 data.
^The charge for capacity varies depending upon location. This is just an estimate.

Guidelines for Pricing Grid Services

The transformation of the power sector that is well underway requires both regulatory and policymaker support, including modifying cost-recovery allocation and pricing mechanisms.

The term "transformation" aptly describes what is happening in the electric utility industry today. It is the beginning of a journey rather than a known destination. This journey is being taken by electric utilities, their customers, regulators, legislators and other stakeholders. The journey begins with utilities providing customers new options and services that they want and that technology and policy allow. With a transformation afoot but uncertainty as to the outcome, it is important to think about providing guidance to both utilities and their regulators.

Bonbright's "Criteria of a Desirable Rate Structure," first printed in 1961, has been held tightly as a regulatory doctrine by many.[15] The manuscript captures much of what should have been taken into consideration when setting rates historically. However, utility ratemaking has never been a static process. Wholesale rate practices have changed considerably in the past 20 years to emphasize competitive market principles. Retail regulation also has evolved and changed, although more slowly, to respond to new technologies, policies and changing customer needs. Given the transformation underway in the electric utility industry, rigid adherence to historical retail ratemaking policies and practices is not adequate to ensure the provision of robust grid services in the future.

We offer the following guidance to shape future regulatory policies and practices. Electric utility regulation should be designed to:

1. *Rationalize rate designs.* The age-old regulatory principle of assigning costs to cost causers grows ever more important as customers of all sizes have new opportunities to generate and store electricity. Customers increasingly are differentiated by how they use and even generate power. And more accurate cost allocation is becoming possible through smart

[15] Bonbright, Danielsen and Kamerschen (1988), pp. 377–407.

meters and information technology advances. We must carefully examine rate designs, and to the extent possible, move toward economically efficient rates. Any changes should be publicly acceptable in terms of average bills, year to year increases, and other social considerations.

2. *Provide a fair return consistent with the utility's cost of capital and ensure the maintenance of adequate cash flow.* This principle has always been part of the regulatory compact. Financially healthy utilities remain essential for providing safe, reliable and increasingly clean electricity at an affordable price.

3. *Provide opportunities for utilities to offer additional services that benefit customers and enhance revenue.* Regulators should look at the needs and desires of customers for new services and new technologies, and should give utilities flexibility to offer different options to customers. If these are potentially competitive services, rules to prevent cross subsidies and unfair advantages are necessary. But in each case regulators should consider whether customers are well-served by having the opportunity to choose a utility-provided option.

4. *Create more satisfied and empowered customers.* Some customers may want to understand and play a role in their own energy choices and usage patterns. On the other hand, some customers may want to know nothing more about electricity other than how to flip a switch. Customers are very capable of making good choices and managing energy usage, but there is a big educational task ahead. Regulators should support utilities playing a key role in this education process.

5. *Align policies, rate designs and business models with public policy objectives*, such as protection for low-income customers, development of low-carbon resources, development of distributed energy resources, enhanced system resilience and reliability and cybersecurity.

6. *Create affirmative incentives or other mechanisms to optimize outcomes and utility performance.* Well-designed incentive mechanisms can be valuable tools to align utility, customer and regulatory objectives, but they must have symmetry — the utility should be rewarded for superior performance and penalized for poor performance. Performance may be related to several outcomes including policy goals.

7. *Maintain a manageable level of regulatory risk but avoid undue regulatory review and unduly prescriptive oversight.* New regulatory models should encourage the innovation that will enable utilities to remain forward-looking and responsive to the challenges and opportunities associated with the evolving energy landscape and ever-changing technology. When rapid changes in circumstances or technology occur, both utilities and their customers will benefit from management that has the flexibility to adapt and respond to risk (on both the upside and the downside).

How these recommendations are translated into regulatory policy will vary by state and by region. Using the same guidance, regulatory policy in a state with competitive generation and retail sales may look very different than regulatory policy in a state with a vertically integrated utility system.

Paying for the Evolving Grid

Today's utilities are providing safe, reliable, affordable and increasingly clean electricity. In addition to this, tomorrow's utilities will be providing even cleaner electricity, providing more individualized customer services, integrating and connecting more and more distributed energy resources and providing greater reliability and resilience. The fundamental question is this: How do we change current ratemaking and rate design practices to accommodate the increasingly important role of the distribution grid and the grid services it provides? A recent report by the Edison Electric Institute addresses this issue in some length.[16] Here, we first discuss two approaches that we recommend (if implemented properly): formula ratemaking and appropriate cost-based approaches (i.e., fixed charges and demand charges) that satisfy the recommendations specified in the prior section. Then, we briefly discuss additional approaches for recovery of fixed costs that have been discussed by others, and we identify their shortcomings.

Recommended Approaches for Recovery of Fixed Costs

Alternative approaches can lead to the appropriate recovery of a utility's fixed costs; there is no "one size fits all." Ultimately, the agreed upon approach will depend upon the utility, state regulators, state legislators and other stakeholders. First we discuss the concept of using more frequent rate cases to recover fixed costs through the formula ratemaking process. Then we discuss two cost-based rate approaches: full recovery of fixed charges and demand charges. Each of these approaches — if implemented properly — will lead to the appropriate recovery of a utility's fixed costs.

Regular Rate Cases Through Formula Ratemaking

One approach to improving the recovery of fixed costs is to increase the frequency of rate cases through formula ratemaking. Formula ratemaking is an approach to setting the appropriate level of revenue recovery on an annual (or other time period) basis in a streamlined regulatory process. This approach provides the utility with more stability regarding cost recovery, as opposed to periodic rate cases, and results in larger customer benefits with regular, needed investments in the utility's infrastructure. This concept was applied in Alabama during the 1980s with "Rate Stabilization and Equalization" plans for Alabama Power and Alabama Gas.[17] Most recently, the approach was codified into public utility law in Illinois as described by Hemphill and Jensen.[18] The Illinois law, which was enacted in 2011, put into place a process where the legislature authorized a number of investments (including smart meters, cable replacement and poles) and required an annual process to determine the distribution utility's revenue requirement. The formula requires the electric utility to file a revenue requirement in May for setting rates starting January 1 of the following year (i.e., a May 2016 filing would set rates for calendar year 2017).

The filing is for setting only the revenue requirement and does not include any aspects of rate design (cost of service allocations or intraclass rate design issues). Separately, rate design issues are addressed every three years.

[16] EEI (2016).
[17] See Lowry et al. (2013).
[18] Hemphill and Jensen (2016).

In addition, the allowed return on equity (ROE), which is a major part of the revenue requirement formula, is a simple calculation based on components outside of the control of the utility or the regulator. The allowed ROE for Illinois, for example, is the 30-year Treasury bond rate plus 580 basis points (e.g., the ROE is set as 8.64 percent in the 2016 filing that sets 2017 rates). The calculated revenue requirement experienced for a given year is reconciled with the revenue requirement forecasted for that year, one year hence, to assure that the utility is fully compensated for costs prudently incurred.

In Illinois, a number of consumer benefits metrics must be met, including improvements in reliability and efficiency gains related to the deployment of smart meters. If the utility does not achieve the target levels, up to 38 basis points can be reduced on the calculated ROE.

The results have been striking in Illinois. Smart grid investments are being made even ahead of schedule. Customer reliability is at historically high levels. Storm response to outages that do occur (resiliency) has improved. And customer satisfaction is growing. The process of determining the utility's revenue requirement is very much like an annual budget approval process, with an assessment of whether the previous budget was appropriate.

In Illinois, rate design issues are determined every three years. The benefit of this approach is that it separates the determination of an annual revenue requirement from the determination of what pricing is best for each of the distribution services.

The annual performance-based formula ratemaking process provides stability for the recovery of distribution system costs, which allows the utility to plan and execute investments that benefit customers in many ways, including enhanced reliability and infrastructure that enable other beyond-the-meter services. At the same time, it holds the utility accountable for delivering these consumer benefits.

Cost-Based Rate Approaches

Cost causation has always been a linchpin of appropriate electric utility rate design. When rate structures are not reflective of the cost structure, customers receive signals that lead them to behave in inefficient and costly ways, which result in a misallocation of resources. The issue we are discussing in this paper is about providing grid services to customers and recovering the fixed costs associated with providing those grid services. The issue is not about the price of energy. As the transformation of the electric utility industry proceeds, the independence of the cost of grid services and energy supply is underscored.

What is the appropriate role of time-varying rates, as some have suggested this as an approach to recovering grid costs?[19] It is well known from dozens of pilot programs over the past few decades that residential customers respond to time-varying rates.[20] Time-varying rates are usage-based and provide no signal to customers about the cost of the distribution system that is

[19] For example, see Rubin (2015).

[20] Despite this finding, few utilities have a significant percentage of their customers on time-varying rates. One notable exception is OGE Energy, whose goal is to enroll and maintain about 20 percent of its residential customers on a time-varying rate program called SmartHours.

designed to meet their needs, including instantaneous demand for electricity as well as the integration of distributed energy resources.[21]

The drivers of the costs of distribution grid services are almost completely independent of energy supply costs. We know that customers respond to price signals, as well as to their total bill. Hence, rate designs that misallocate costs send customers inaccurate price signals. We support time-varying rates and believe such rates are appropriate to implement in addition to a truly cost-based distribution or grid charge. However, time-varying rates alone do not address the issue of paying for the cost of the grid since these rates reflect only the cost of energy.[22]

Two cost-based approaches that properly reflect and recover the costs of grid services are (1) increasing fixed charges and (2) implementing demand charges.

Fixed Charges

The most straightforward approach to cost-based rate design for distribution or grid services is to support rate design with cost causation by properly aligning the fixed and variable price signals sent by delivery rates with the fixed and variable costs imposed by customers' demand of the delivery system. At the extreme, this is sometimes called a straight fixed-variable rate design.

These types of rates establish fixed and variable charges that are commensurate with the fixed and variable costs of serving each customer or customer class.[23] For residential customers in the United States, delivery or fixed costs range from about 40 percent to 65 percent of a customer's total bill.[24] Yet today, the highest fixed charge on a residential monthly electric utility bill in the United States is about $25 per month, and the average fixed charge is about $10 per month.[25] Currently, most of a utility's fixed charges are collected via a usage charge rather than directly via a fixed charge.

Recognizing the growing importance of the grid and the need to pay for grid services, many utilities are proposing increases to their monthly fixed charges. Recently, state regulators in several states have approved higher fixed charges for residential customers.[26] In some cases,

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[21] Although many fixed costs associated with grid services in the United States are recovered today via a usage charge, we believe that separating energy charges from grid charges in the future is a sensible way forward.
[22] Another approach, the tiered rate, has occasionally been discussed. This approach has been used to incent electricity conservation. As with time-varying rates, tiered rates alone do not address the issue of paying for the cost of the grid. We of course recognize that rates can be "designed" to capture more than just the price of energy, but we fundamentally believe that the cost of the grid and the cost of energy should be separated and that educating customers about these two distinct electricity services is critically important.
[23] Some argue against this approach. However, the fundamental concept of separating fixed and variable costs is a sound concept. We believe that the current approach of embedding fixed costs in a usage or volumetric charge, which is widespread in electricity pricing in the United States, is flawed.
[24] This range is based on conversations with individual investor-owned utilities. At Commonwealth Edison, a distribution utility, fixed costs comprise over 90 percent of the cost of distribution, which is roughly 47 percent of the total customer bill.
[25] Institute for Electric Innovation, internal document showing fixed costs for each of its member utilities.
[26] There are also a number of jurisdictions that have considered and rejected this approach.

utilities are proposing specific fixed charges for DG customers based on the size of a customer's DG system because such customers use the grid differently than non-DG customers.[27]

Today's fixed charges are far below the utility's cost of providing grid services, which includes transmission, distribution, generation capacity, and ancillary and balancing services.[28] We believe that educating customers about what they are paying for when they purchase electricity — both grid services and energy — is critically important. Yet, the public does not understand this distinction because we — utilities, regulators and other stakeholders — have made electricity pricing far from transparent. We also recognize that a utility's fixed costs may be difficult to allocate because some costs are customer-specific and some are systemwide.[29]

Some are opposed to billing customers directly for the fixed costs associated with providing grid services:

- Consumer advocates express concerns about bill impacts on low-usage and low-income customers. We understand this concern but do not believe it should be resolved via rate design. In our view, issues related to low-income customers should be treated through specific programs.
- Environmental advocates express concerns about reducing the marginal price signals to customers, thereby reducing incentives for energy efficiency. Since a large percentage of each residential customer's bill still would be based on usage, we believe there are ample opportunities to incent efficiency.
- And most recently, rooftop solar industry advocates have expressed concerns about DG customers paying directly for the grid services that they use around the clock on a continuous ongoing basis.[30] We believe that DG customers should share in the cost of the grid services that they use and that these costs should not be shifted onto non-DG customers. Current net energy metering practices result in a "subsidy" to DG customers specifically because these customers are not paying fully for the grid services that they use. The simple solution to this is to charge DG customers directly for the grid services they use via a fixed charge.

Increasing fixed charges to cover the cost of grid services and letting customers know what they are paying for makes the purchase of electricity — both energy and grid services — more transparent to customers. This is long overdue, and we believe that increasing fixed charges is a step in the right direction.

[27] It is well known that the load shape for a DG customer is different than for a non-DG customer; in particular, energy usage from the utility is typically low during afternoon hours, and the peak demand occurs at a different time of day. This is often referred to as the "duck curve." For a good explanation, see California ISO (2013), pp. 6–7.
[28] See Table 1.1 for an example, and also Wood and Borlick (2013). We recognize that not all utilities will provide all of these services. Utilities in deregulated wholesale markets will provide different services than vertically integrated utilities, for example.
[29] Severin Borenstein discusses this issue in a blog post, "What's so Great about Fixed Charges?" Energy Institute at Haas, Nov. 3, 2014, https://energyathaas.wordpress.com/2014/11/03/whats-so-great-about-fixed-charges/.
[30] Much of the controversy surrounding net energy metering for rooftop solar is related to the cost shift that occurs because private solar customers with rooftop PV do not pay their fair share of the cost of grid services that they use due to a rate structure where much of the cost of grid services is collected via volumetric rates. For a discussion of this issue, see Borlick and Wood (2014a,b). See also Energy and Environmental Economics, Inc. (2013), p. 6.

Demand Charges

Another cost-based alternative for pricing distribution services is adding demand-based rates or demand charges (e.g., a demand charge is a kilowatt (kW) charge that is added to existing rates which typically have a fixed charge and an energy charge).[31] Demand charges have been used for commercial and industrial customers for decades. With the deployment of advanced metering infrastructure (AMI, or smart meters) to more than half of all U.S. households, demand charges are now feasible for many residential customers. Demand charges result in an allocation of distribution costs based on the facilities required to meet each customer's peak demand during a specific period of time (e.g., one month). This is consistent with a longstanding method of allocating distribution facility costs across the different classes of customers. In this case, under current rate structures, without demand charges customers with low demand (typically smaller customers) subsidize customers with high demand (typically larger customers).[32]

Demand charges have many positive attributes:

- Demand charges ensure that customers with a higher load factor will face a lower bill. Under volumetric rates, a customer with high kilowatts but very few kilowatt-hours pays very little compared to a customer with the same level of kilowatts but a commensurate level of kilowatt-hours.
- Demand charges incentivize more demand response and energy efficiency because customers can respond and reduce their electricity bills. This ultimately reduces the costs of the entire electricity system because load factors increase across the system, and the need to build peaking plants is reduced.
- Demand charges are a reasonable way to recover system-specific grid costs since some portion will vary with peak demands on the system.

Demand charges have not been used widely in the United States for residential customers. A handful of utilities have optional demand charges for residential customers.[33] And a few utilities are now proposing a demand charge as part of a three-part rate (i.e., a demand charge, a fixed charge and an energy charge) for DG customers. We believe that adding a demand charge as part of a three-part rate is a step in the right direction.[34] However, this will require educating customers about what they are paying for when they purchase electricity.

Other Approaches for Recovery of Fixed Costs

As utilities provide even cleaner electricity, provide more individualized customer services, integrate and connect more and more distributed energy resources, and provide greater

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[31] A demand charge can be designed in a number of ways: the customer's maximum kW during each month; the customer's maximum kW during a specified (peak) period or periods of each month; the maximum kW during a year; the kW during the system peak of the year; and so forth. This design element matters — it impacts the bill as well as customer incentives. However, for the discussion in this paper, most practicable designs of a demand charge will have the attributes discussed in this section.

[32] A description of the process of allocating distribution facility costs by coincident and non-coincident demand can be found in National Association of Regulatory Utility Commissioners (1992).

[33] Dominion, Duke Energy, Georgia Power, and Xcel Energy are some of the utilities that have optional demand charges for residential customers.

[34] We recognize that this is not a perfect solution; however, flattening customer load profiles via a demand charge, a critical peak price, or another mechanism has a positive impact on the power system. Hence, demand charges are a step in the right direction.

reliability and resilience, the role of the distribution grid and grid services is becoming increasingly important. As discussed throughout this chapter of the report, the fundamental question is how do we pay for this evolving power grid? In the prior section, we discussed different approaches that we believe could lead to the appropriate recovery of a utility's fixed costs for developing an increasingly dynamic grid that empowers customers.

Non-cost-based approaches that attempt to recovery a utility's fixed costs (and that have worked in other settings) — revenue decoupling, lost revenue adjustment mechanisms (LRAMs) and minimum bills — have serious shortcomings given the major transformation of the electric utility industry that is underway.

Decoupling has worked well for energy efficiency, and over half the states in the United States have adopted decoupling or some type of lost revenue adjustment mechanism.[35] However, given the significant growth in distributed energy resources (including energy efficiency, demand response, DG and distributed storage) expected over the next decade, decoupling, LRAM and minimum bill approaches have serious shortcomings as a means for recovering a utility's fixed costs. Each of these approaches is discussed briefly below.

Revenue Decoupling

Revenue decoupling (or simply, "decoupling") is an adjustment mechanism that separates (or decouples) the recovery of a utility's fixed costs from the volume of its sales. Under decoupling, an external "true-up" mechanism is used to ensure that the utility collects revenues based on its regulatory-determined revenue requirement and, thereby, recovers its fixed costs. Decoupling is one method to recover a utility's fixed costs (to the extent they are not recovered under ratemaking practices that tie the recovery of fixed costs to volumetric consumption charges).

Today, revenue decoupling is used in many states to "true-up" utility net revenues that otherwise would be lost due to declining electricity sales resulting from utility investments in energy efficiency.[36] Although revenue decoupling makes the utility whole, it does so explicitly by shifting costs from participating energy efficiency customers to nonparticipating customers using a public or system benefits charge (which is typically visible and transparent to customers as a charge on their utility bills).

Decoupling causes a cost-shifting problem that is similar in concept to the cost shift created by distributed generation customers under net metering.[37] However, a fundamental difference is that the magnitude of the "cost shifting" from DG to non-DG customers is on a much larger scale than the cost shifting due to energy efficiency. A recent study revealed that decoupling rate adjustments for energy efficiency are extremely small — about 2 percent to 3 percent of the retail rate.[38] In contrast, as described in a prior Institute for Electric Innovation paper, a DG customer could shift up to 55 percent of the retail rate onto non-DG customers and, unlike

[35] For details on how decoupling works in each state, see Cooper (2014).
[36] In total, 32 states have some type of fixed-cost recovery mechanism in place – 14 with revenue decoupling and 19 with LRAMs. See Cooper (2013); also see Cooper and Smith (2015).
[37] Borlick and Wood (2014a,b).
[38] Morgan (2013).

efficiency charges which are transparent (to both customers and regulators), the DG cost shifting is essentially invisible under a net metering scheme.[39]

The amount of cost-beneficial energy efficiency is limited because the more you achieve, the less cost-beneficial the next increment of energy savings becomes. State regulators will only approve utility-funded energy efficiency programs that pass a cost-benefit test. This means that energy efficiency increases only when it makes economic sense. In contrast, no such economic limit applies to DG. In fact, costs — particularly for private rooftop solar PV — are expected to decline over time, and forecasts show increasing amounts of distributed energy resources in the United States over the next decade.

Decoupling has worked well for utility investments in energy efficiency, and the associated cost shift has been relatively minor (about 2 percent to 3 percent of rates, on average, as described above). Neither regulators nor customers should be willing to accept the magnitude of cost shifting that will accompany the rapid expansion in net-metered DG unless fundamental reforms to net energy metering are put into place. In fact, recognizing this need for reform, regulatory proceedings are underway in several states to address the cost shifting associated with net energy metering.

As distributed energy resources grow and the role of the distribution grid becomes increasingly important, the ability of a utility to recover its fixed costs associated with providing grid services is a significant issue. We do not support decoupling as a solution to recovering fixed costs given the transformation underway. Decoupling will only exacerbate the cost shifting issue.

Lost Revenue Adjustment Mechanism

An LRAM is another general approach to recover a utility's fixed costs. Whereas a decoupling mechanism operates to recover lost revenue due to changes in all utility sales — thereby decoupling the utility's revenue and profit from sales, an LRAM applies specifically to revenue lost due to energy efficiency measures or programs. An LRAM approach requires more sophisticated measurement. An LRAM causes the same cost-shifting problem that was described earlier under decoupling, and this is not a solution to recovering fixed costs given the transformation underway in the electric power industry. As with decoupling, an LRAM will exacerbate the cost shifting issue.

Minimum Bill

Under this approach, the fixed-variable price signals remain the same (presumably a high kilowatt-hour charge) but the customer is required to pay a minimum bill amount. This is sometimes viewed as a compromise approach because the utility is assured a specific level of fixed-cost recovery, but, at the same time, customers see relatively high price signals and still are incented to use energy efficiently. This approach is not transparent because the customer is not shown the full cost of the grid services provided. In addition, it is highly unlikely that the minimum bill amount actually would recover the full cost of grid services, which could range from 40 percent to 65 percent of a typical residential electricity bill (e.g., for a typical residential bill of $114 per month as Table 1.1 shows, the fixed costs associated with the grid might range

[39] Wood and Borlick (2013).

from $46 to $74 per month).[40] We believe that it is critically important to provide transparency to customers regarding the purchase of electricity services. A minimum bill lacks transparency because it still does not show the customer the full costs of the different services being provided — energy and grid services.

In a nutshell, electricity pricing in the United States is confusing, and we support greater transparency going forward. One way to do this is to simply recognize the different electricity services being provided to customers and create rates for different types of services.

Conclusion

Change is afoot in the electric utility industry, driven by technology, policy and customers. There are varied opinions on the exact course and timing of the change. Still, many of us would agree that a decade from now the industry will look something like the following:

- We will have a cleaner electricity generation mix, with lower carbon emissions.
- The power grid increasingly will integrate a mix of central and distributed resources.
- The grid will become more digital, more controllable and more interconnected. Pacific Gas and Electric (PG&E) aptly calls this the Grid of Things™.
- A mix of entities — both utilities and other companies — will provide both supply-side and demand-side distributed energy resources.
- Utilities and others will offer customers a wide range of individualized and customized services.

Technology innovation also requires business and regulatory innovation. Because electric utilities are trustees of essential infrastructure and service, the business model must be sustainable as well as nimble and efficient, and it must be able to earn the support of long-term investors.

Both technology and business innovation require regulators and policymakers to support the transition, including modified cost recovery and pricing mechanisms, and also to support more collaborative ways to make decisions and provide guidance. Wholesale regulation has changed considerably in the past two decades. Retail regulation similarly now must change to allow utilities the ability to adjust to technological innovations, provide customers more choices, and improve the overall delivery system. As we have advocated in this paper, this means adopting regulatory approaches that will lead to the appropriate recovery of a utility's fixed costs, and that make the purchase of electricity — both energy and grid services — more transparent to customers.[41]

[40] As noted in Table 1.1, the typical residential bill of $114 is based on Energy Information Administration data for 2014. The range of fixed costs is based on conversations with individual utilities around the United States.

[41] Some argue that pricing grid services separately from energy services could drive customers off the grid. This is only true if the power grid does not provide a cost-effective essential service. Our view is that the power grid is becoming increasingly important and is critical to our economy and our way of life, and that its value and essential nature will increase in the future.

Collaboration, good public policy and appropriate regulatory policies are critical for the successful transformation of the regulated electric utility industry. Ultimately, as this transition unfolds, it is about balancing affordability, reliability, clean energy and individualized customer services. This is largely the job of regulators and other policymakers. But the ultimate challenge is to make the transition of the electric utility industry affordable to all Americans! And this is the job of all stakeholders.

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2. A Consumer Advocate's Perspective on Electric Utility Rate Design Options for Recovering Fixed Costs in an Environment of Flat or Declining Demand

By John Howat, Senior Energy Analyst, National Consumer Law Center

Introduction

Context

While technological advances and energy resource economics are driving sweeping change across the electric utility industry, one constant from the residential consumer's perspective is that home energy service remains a basic necessity of life. Generation, end-use technologies, advanced communication capabilities, and utility business model assumptions may be in flux, but reliable, affordable home energy service is still required to meet basic heating, cooling, lighting and refrigeration needs. Without uninterrupted access to these end uses, health, safety and effective participation in society are undermined.

Amidst this sweeping industry change — indeed as a result of the confluence of several of its component parts — electricity usage and sales to end-use customers in the United States have flattened out after decades of strong, sustained growth. From 1949 through 2007, electricity usage among residential, commercial and industrial end-use consumers grew at an average annual rate of 4.9 percent. From 2008 through 2014, usage grew nationally at an average of 0.1 percent.[42] Looking ahead, the U.S. Energy Information Administration projects total electricity usage to grow at a rate of just 0.7 percent annually between 2015 and 2040, with variability among Census Divisions ranging from 0.1 percent in the Mid Atlantic Division to 1.0 percent in the West South Central and Mountain Divisions.[43]

The 21st century energy system, including electric utility rates, must be designed and implemented to accommodate a broad range of public policy objectives, including those related to affordability, reliability, consumer protection, fairness and carbon emission mitigation. While these consumer and environmental objectives sometimes conflict, regulators, policymakers, advocates and utilities can work creatively to ensure that both sets of objectives are achieved, particularly during this transitional period when access to energy saving, load management, storage and small-scale generation technologies is anything but universal.

This chapter of the report examines from a consumer advocate's perspective a range of options available to electric utilities for recovering fixed costs in an altered usage and sales environment.

Underlying Assumptions

At the outset it is appropriate to identify the assumptions and biases that inform this discussion. From the perspective of an advocate concerned with residential consumers' access to affordable, uninterrupted home energy service, it is paramount to control costs that affect consumers' rates and bills, preserve the long-term viability of utility distribution companies that retain an obligation to serve all residential electricity service customers, and retain effective

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[42] Calculated from U.S. Energy Information Administration (EIA) (2015a), Table 7.6.

[43] Calculated from EIA (2015b), Table A.2.

regulatory oversight of distribution utility procurement, pricing, billing, customer service, and credit/collections operations.

This bias is steeped in the belief that many residential consumers will not fare well if the role of the existing utility is compromised, service obligations are diminished, and the resulting distribution company void is filled by nonregulated vendors, competitive suppliers and others aiming to sell their wares. The potential to benefit from many energy resource technologies marketed outside of the utility sphere is often dependent upon a consumer's access to upfront capital or financing on favorable terms. Further, detailed knowledge of energy markets, emerging energy resource technologies, and financial analysis are often required for individual consumers to make prudent energy investment decisions. Clearly, not all customers fit this new energy investor profile. "The market" at the distribution level will not serve all customers well, so utility rates should be designed to provide the sufficient, stable revenues required to ensure that the company will continue in its role as a full service provider for those customers not inclined to go elsewhere.

It is important to note that concerns related to secure access to basic electric service are not limited to those households with income so low that they qualify to participate in means-tested programs such as the Low Income Home Energy Assistance Program (LIHEAP).[44] A report issued as the country was emerging from the Great Recession demonstrated that in 2011, 45 percent of U.S. residents lived in households that lacked sufficient income to pay for basic necessities. The report further demonstrated for that many family types, income sufficient to pay for necessities far exceeded LIHEAP income-eligibility guidelines.[45] Thus, the need for a well-functioning utility franchise, regulatory oversight and effective consumer protection extends well beyond households that are typically considered to be "low income."

An additional bias that informs the rate design commentary in this chapter is that energy efficiency is the least-cost resource and the "throughput incentive"[46] should cease to exist. The comparative costs and benefits of energy efficiency are well documented. Comparing the unsubsidized costs of the full range of "conventional" and "alternative" energy resources, energy efficiency is reflected as the cheapest of all available resources, with the levelized cost of efficiency estimated at $0 to $50/megawatt-hour (MWh), versus natural gas combined-cycle generation, with its sensitivity to fuel prices, at $52 to $78/MWh.[47] Further, under appropriate rate design models, energy efficiency improvements provide a relatively low-cost means for utility consumers to control their usage and their bills, assuring payments that are more affordable. In addition, energy efficiency brings a range of other benefits, including those related to greenhouse gas emission reductions, employment and other macroeconomic metrics, and health. Thus, rate design options that undermine energy efficiency incentives should be avoided.

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[44] The U.S. Department of Health and Human Services caps LIHEAP income-eligibility at 200 percent of the Federal Poverty Guidelines or 60 percent of the State Median Income, whichever is higher. Many state programs limit eligibility to 150 percent of the Federal Poverty Guidelines.
[45] McMahon (2013), p. 3.
[46] The term "throughput incentive" refers to the interest of the utility in traditional ratemaking to maximize sales to recover authorized costs, increase revenues and maximize profits.
[47] Lazard (2015).

Discussion of Rate Design Options

High Fixed Charges

Since 2014 proposals to increase fixed charges have been the predominant utility rate design response to changes in revenues and sales. In the past two years, electric utilities in at least 34 states have proposed to shift recovery of revenue requirements from the volumetric portion of customer bills to the monthly, fixed charge.[48] While shifting cost recovery to non-bypassable fixed charges may reduce utility sales risk and stabilize revenues, the shift penalizes low-volume consumers within a rate class and raises equity and social justice concerns. Further, high fixed charges undermine price incentives for energy efficiency and usage reduction while limiting the ability of customers to control their bills. Finally, high fixed charges that undermine usage reduction incentives may lead to the need for greater investment in large-scale generation and transmission, imposing higher rates and bills on all customers and imposing the greatest harm on those residential customers already strapped with the highest home energy burdens.[49]

Regulators over the past 30 years have typically limited fixed charges to cover those costs that are directly related to the number of customers served, including metering, billing and customer assistance. Historically, customer charges have comprised a small fraction of the total bill — $5 to $10 per month for a residential customer.[50] However, many recent utility proposals would increase the existing fixed charge by 100 percent or more. For example, in 2014 Madison Gas and Electric Company proposed to increase the monthly residential fixed charge from $10.44 to $19, with an eye toward raising the monthly non-volumetric charge to $70 over a period of a few years to resolve its revenue stability concerns and eliminate "subsidies" to low-volume consumers.[51]

1. The Cost Shift

As indicated above, providing for utility cost recovery through rate modifications that increase fixed charges while reducing cost recovery from volumetric charges causes disproportionate harm to low-volume consumers. Dramatic increases in fixed charges with reductions, or only moderate increases, in energy charges increases the total monthly bill of low-volume consumers by a higher percentage than that of higher-volume consumers. Table 2.1 shows a bill impact example applicable to Madison Gas and Electric Company's 2014 proposal.

[48] Regulatory and legislative developments in fixed charge rate design are tracked closely by the "Nix the Fix Network," a collaboration among consumer, environmental and distributed generation advocates.
[49] The term "energy burden" refers to the proportion of household income devoted to home energy and utility service.
[50] Lazar (2015), p. 36.
[51] Content (2014). The proposal is typical in scope and structure to others that have been filed over the past year.

Table 2.1 Comparative Bill Impact for Madison Gas and Electric Company's Proposal to Increase Fixed Charges: Low-Volume, Average and High-Volume Residential General Service Customers[52]

	Low-Volume Customer	Average-Volume Customer	High-Volume Customer
Monthly Usage (kWh)	450	900	1,400
Initial Monthly Customer Charge	$10.44	$10.44	$10.44
Revised Monthly Customer and Grid Connection Charge	$19.00	$19.00	$19.00
Initial Volumetric Charge	$0.13992	$0.13992	$0.13992
Revised Volumetric Charge	$0.12986	$0.12986	$0.12986
Initial Monthly Bill	$73.40	$136.37	$206.33
Revised Monthly Bill	$77.44	$135.87	$200.80
$ Increase (Decrease)	$4.03	($0.49)	($5.52)
Percent Increase (Decrease)	5.5 percent	(0.4 percent)	(2.7 percent)

In this example, an increase in monthly fixed charges from $10.44 to $19.00, along with a decrease in volumetric charges from $0.13992 per kWh to $0.12986 per kWh, produces a 5.5 percent bill increase for a low-volume consumer using 450 kWh monthly, in contrast to a slight decrease for an average-volume consumer using 900 kWh per month. For a high-volume consumer using 1,400 kWh per month, the adjusted bill declines by nearly 3 percent. The hypothetical low-volume consumer in this example experiences a monthly bill increase of just over $4, while the high-volume consumer saves over $5.50. Obviously, the cost shift under a $70 monthly customer charge would be far more dramatic.

2. Equity and Social Justice Concerns

The fixed charge increase penalty to low-volume consumers raises profound equity and social justice concerns. Data from the Energy Information Administration's Residential Energy Consumption Survey (RECS) demonstrates that in states and regions across the United States, median household electricity usage among low-income, elderly and African-American headed households is lower than that of their respective counterparts. As an example, comparative median electricity usage from the Indiana and Ohio "reportable domain"[53] is reflected in the following tables.[54]

Results of these analyses clearly demonstrate that in the Indiana-Ohio reportable domain — on average — low-income, African-American and elderly households use less electricity than their counterparts. As Tables 2.2 through 2.4 indicate, fixed charge increase proposals, by penalizing low-volume consumers, will disproportionately harm these groups of ratepayers.

[52] Monthly bill calculations are based on the following equation: Customer and Grid Connection Charge + (Monthly Usage x Volumetric Charge).
[53] See Table 2.5 for national data, which demonstrate consistent patterns in all regions surveyed.
[54] Tables were generated by tabulating microdata from the U.S. Department of Energy, Energy Information Administration's 2009 Residential Energy Consumption Survey (RECS; EIA 2009). The 2009 RECS includes detailed residential energy consumption and expenditure information from 27 U.S. geographic areas referred to as "reportable domains." Indiana and Ohio comprise one of the reportable domains.

Table 2.2 2009 Median Household Electricity Usage by Poverty Status — Indiana and Ohio

Household Income	Usage (kWh)	Percent Difference
At or Below 150 Percent Poverty	7,831	-21.7 percent
Above 150 Percent Poverty	9,999	
Total All Households	9,365	—

Table 2.3 2009 Median Household Electricity Usage by Race of Householder — Indiana and Ohio

Householder's Race	Usage (kWh)	Percent Difference
Black or African-American	7,900	-19.8 percent
Caucasian	9,846	

Table 2.4 2009 Median Household Electricity Usage by Elder Status — Indiana and Ohio

Householder's Age	Usage (kWh)
65 or More	6,976
Less than 65	10,351

Some utilities have asserted that low-income residential customers use more electricity than other residential customers.[55] Utility companies generally base this assertion on billing and consumption distribution data from utility customers participating in energy assistance programs. However, such programs cannot be used to reliably approximate the entire universe of low-income households. With reported consumption levels based on utility program participants, a concern arises that the low-income results are biased on the high side, assuming that utility programs are often targeted toward high-use/high-bill customers, and in the case of low-income energy efficiency programs, to homeowners rather than renters and multifamily dwellers whose electricity usage tends to be relatively low. Therefore, to better understand low-income usage, it is critical to look at samples that include both program participants and nonparticipants. The only national data set that reflects such sampling is the Residential Energy Consumption Survey (RECS). The RECS includes detailed usage data, as well as information

[55] See, e.g., Indiana Utility Regulatory Commission, Cause No 44688, NIPSCO Direct Testimony Exhibit No. 2, Attachment 2.C.

regarding household income, age, race, ethnicity and numerous other characteristics. All of this is broken into 27 geographic areas.

Analysis of the RECS data shows that in 26 of 27 regions surveyed, average electricity consumption among households living at or below 150 percent of the federal poverty guidelines is less than that of higher-income households. Table 2.5 shows median electricity consumption in each of the RECS reportable domains. Given the consistency of the regional RECS consumption data and the restricted universe of low-income customers utilities rely on to conduct consumption comparisons, it is appropriate to conclude that, on average, low-income customers use less electricity than their counterparts.

Table 2.5 Median 2009 Site Electricity Usage (kWh), by Poverty Status and for All Households

	At or Below 150% Poverty Guideline	Above 150% Poverty Guideline	All Households
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	4,708	7,468	6,961
Massachusetts	4,222	6,056	5,686
New York	4,544	5,969	5,355
New Jersey	4,969	7,497	7,231
Pennsylvania	8,402	9,690	9,306
Illinois	7,350	9,116	8,432
Indiana, Ohio	7,831	9,999	9,365
Michigan	7,073	8,190	7,764
Wisconsin	7,449	7,889	7,727
Iowa, Minn., N. Dakota, S. Dakota	6,241	9,285	8,940
Kansas, Nebraska	8,808	9,402	9,302
Missouri	11,705	12,232	11,991
Virginia	10,997	13,859	13,231
Delaware, District of Columbia, Maryland, West Virginia	10,381	13,063	12,848
Georgia	12,727	13,816	13,499
North Carolina, South Carolina	12,105	14,343	13,651
Florida	11,905	13,760	13,212
Alabama, Kentucky, Mississippi	11,802	15,847	14,656
Tennessee	12,537	14,480	13,782
Arkansas, Louisiana, Oklahoma	12,628	13,646	13,421
Texas	10,602	13,799	12,878
Colorado	5,216	6,516	6,231
Idaho, Montana, Utah, Wyoming	10,665	9,588	9,804
Arizona	10,088	13,056	12,105
Nevada, New Mexico	7,637	9,434	9,164
California	4,739	5,939	5,628
Alaska, Hawaii, Oregon, Washington	10,597	10,799	10,754
Total	**8,432**	**10,072**	**9,687**

Source: U.S. Department of Energy, Energy Information Administration's 2009 Residential Energy Consumption Survey.

3. The Energy Efficiency Incentive, Customer Control Over Bills and Consumer Concerns

Increasing fixed charges undermines the price incentive for consumers to reduce usage through energy efficiency or conservation and handicaps the customer's role in in the industry transformation. Holding the revenue requirement constant, increasing the fixed charge reduces volumetric charges and reduces the value of a kilowatt-hour saved. Customers considering efficiency improvement investments will be faced with longer payback periods, and those who have already made such investments will be penalized. Devaluation of the energy efficiency incentive inherent in volumetric pricing presents the real threats of increasing systemwide usage, expanding investment in more expensive generation resources, increasing greenhouse gas emissions, and undermining the viability of programs and policies intended to promote efficiency.[56] On a very basic level, increased fixed charges diminish the ability of consumers to assert control over utility bills. For many of the reasons outlined here, the National Association of State Utility Consumer Advocates adopted a resolution unequivocally opposing increases in electric and natural gas utility fixed charges.[57]

Revenue Decoupling

In the traditional utility ratemaking process, a company's revenue requirement — based on approval by regulators of a company's demonstrated level of expenses, recovery of allowable capital investments and a reasonable rate of return — is allocated among rate classes according to the cost of delivering service to the class. Rates for each class, usually comprising a combination of fixed and volumetric charges, are designed to generate revenue equal to each class' allocated revenue requirement. After rates are set through this process, a company's revenues and earnings fluctuate according to the level of sales to customers.

Under revenue decoupling, cost of service determinations are initially set in the same manner. Subsequently, rates are adjusted periodically, usually through application of a revenue-per-customer mechanism, to stabilize utility revenues and reconcile for changes in sales. Rates are adjusted upward under declining sales scenarios and downward if sales increase. Decoupling mechanisms are intended to make utilities indifferent to changes in the level of sales and to stabilize revenues. When a utility can demonstrate conclusively that it faces a long-term decline in revenue, a well-designed decoupling mechanism, as long as it includes the safeguards identified below, is a ratemaking option that provides revenue stability without undermining customer incentives to use less and without penalizing low-volume consumers.

1. The Debate

Proponents of revenue decoupling argue that such a mechanism is required to remove the incentive for utility companies operating under traditional cost-of-service ratemaking to increase sales between rate cases (the throughput incentive) and remove the revenue loss disincentive to implement effective energy efficiency initiatives.[58]

[56] For a thorough analysis of fixed charge impacts and regulatory proceeding, see Whited, Woolf and Daniel (2016).
[57] See NASUCA (2015), https://nasuca.org/customer-charge-resolution-2015-1/.
[58] See, e.g., New Mexico Public Regulatory Commission (2016).

Many consumer advocates' concerns regarding revenue decoupling are that the mechanism results in rate increases under declining sales scenarios irrespective of whether the decline is attributable to utility energy efficiency investment. In addition, advocates have stated that decoupling serves to lock in revenue for the utility and shift sales risk to ratepayers, and is not required as a policy to promote energy efficiency. Finally, consumer advocates have argued that decoupling reflects a piecemeal, automated rate-setting mechanism and deprivation of the regulatory process.[59]

2. Safeguards

A well-designed decoupling mechanism can play a pivotal role in stabilizing utility revenues while mitigating the incentive to increase sales between rate cases. Further, research shows that 37 percent of electric and natural gas utility rate adjustments between 2005 and 2013 resulted in refunds to consumers; some providing a modicum of relief to consumers after a period of extreme weather and high bills.[60]

A well-designed revenue decoupling mechanism should include a number of safeguards to protect against realization of concerns raised by consumer advocates. Approval of decoupling should include a requirement that the utility implement meaningful energy efficiency programs. The utility should also be directed to file a full rate case periodically — allowing regulators and stakeholders to review any changes in the company's cost structure and risk profile. Time between required rate case filings should strike a balance between safeguarding against autopilot cost recovery and creation of undue litigation burden on regulatory agencies, intervenors and utilities. In addition, limiting rate increases in any annual adjustment period to 3 percent will safeguard against excessive price spikes and bill volatility. Finally, revenue decoupling should be implemented in conjunction with an inclining block rate structure, with adjustment surcharges applied to the high-volume "tail block" (last tier of energy consumption) and refunds to the "head block" (first tier of energy consumption).

In addition to incorporation of the safeguards referenced above, it is important to consumers that implementation of revenue decoupling only occur in conjunction with or subsequent to regulatory approval of distributed generation pricing that does not inappropriately shift costs from distributed generation participants to nonparticipants. Getting this pricing "right" is necessary to ensure against the potential for a significant cost shift to renters and other consumers lacking the ability to benefit economically from distributed generation technology. Approval of revenue decoupling prior to implementation of appropriate distributed generation pricing reduces the utility incentive to push back against such a cost shift.

Time-Varying Rates

Time-varying rates, if properly designed and implemented, may allow individual consumers to reduce their energy bills, improve system utilization and reduce peak demand. If consumers respond to the price signals that time-varying rates provide, time-varying rates can also reduce supply and delivery costs for all consumers. However, time-varying rates can have adverse impacts on consumers, especially on those who may have less ability to shift their usage and obtain any benefits from time-varying rates. Low-income consumers, already faced with

[59] See, e.g., Public Service Commission of the State of Missouri (2015).
[60] Morgan (2013).

disproportionately high home energy burdens and rates of service disconnection, should not be further burdened by penalties that may come from time-varying rate design.

Because advanced metering is a prerequisite to offering time-varying rates, it is important to identify guiding principles with regard to both advanced metering infrastructure deployment, as well as time-varying rate design. Following are recommended principles:[61]

- All existing consumer protections, including a customer premise visit prior to involuntary disconnections and the full value of existing low-income discount rates, must be retained.
- Prepaid electric service poses health and safety risks to vulnerable and low-income customers and should be prohibited.[62]
- Cost-benefit analysis should be used to determine the scope and design of time-varying rate programs. Distribution utilities should compare the costs and benefits of different rate structures and implementation scenarios. Sensitivity analysis should capture the uncertainty associated with highly variable factors, such as the level of customer response, behavior change and persistence. The cost-benefit analysis should also provide a comparison of how different approaches or technologies may achieve the same objectives.
- The design of time-varying rates should be sector-specific and informed by cost-benefit analysis and evaluation results, while being thoughtful to minimizing customer confusion.
- Simple and clear consumer education is key to achieving the individual and systemic benefits of time-varying rates, and will help avoid customers being unintentionally harmed due to lack of information. Distribution utilities should be required to provide consumer education, and the existing (utility energy efficiency program) platform should be leveraged.
- Reductions in peak demand can reduce the cost of the energy delivery system, as well as lowering the average supply cost. Thus, time-varying rates should be applied to both supply and distribution rates.

In addition, time-varying rates should be optional for non-distributed generation residential customers: “Customers should have the ability to select a time-varying rate offered by the utility in response to customer education, while others may choose to remain on flat rates because of their own assessment of bill impacts, need for price stability, and convenience trade-offs.”[63]

In addition, safeguards for time-varying rates should also include a “shadow billing” component, where customers are informed in advance of implementation what their billing would be under each of the available rates offered by the utility. This would enhance consumer understanding of time-varying rates and provide guidance on whether to choose a different rate.

[61] Anthony and Howat (2014).
[62] As documented in Howat and McLaughlin (2012), deployment of residential advanced metering infrastructure has coincided with an increase in utility proposals to implement prepaid service. The report further documents that prepaid service results in increased rates of service disconnections and is concentrated among lower-income residential consumers.
[63] Anthony and Howat (2014).

Finally, from the perspective of residential consumers, it is important to distinguish between time-of-use (TOU) rates, critical peak pricing (CPP) and real-time pricing (RTP). TOU rates are pre-set in the tariff and vary predictably by time of day or by season. CPP is characterized by pre-set pricing for a specified number of days or hours during peak months. Critical peak periods are announced by the utility when it anticipates high wholesale prices or strained power system conditions. Under CPP, customers lack certainty as to the timing of critical peak events and pay substantially higher prices during those events. RTP is tied to volatile wholesale power markets and therefore brings considerable uncertainty and lack of predictability.

With effective outreach, education and access to energy management resources, many residential consumers may adapt to predictable, modest TOU price differentials. CPP and RTP spikes during heat waves and other peak events are less predictable and bring more severe penalties for those consumers without the ability to safely reduce usage during such events. Making peak-time rebates available to residential consumers is a less punitive approach to providing price signals to these customers.

Other Rate Design Options for Fixed Cost Recovery

1. The Status Quo or Frequent Rate Cases

As indicated previously, consumption and sales have leveled out in recent years and are forecast to remain flat into the foreseeable future. However, electric utility revenues from sales reached an all-time high in 2014 and approached 2014 levels in 2015.[64] From these data it may be inferred that not all utilities face an immediate revenue sufficiency or stability crisis. In cases where no such crisis is demonstrated and a utility company is implementing a robust portfolio of effective energy efficiency programs, sweeping changes to rate design may not be warranted.

2. Lost Revenue Adjustment Mechanisms

These mechanisms are intended to make utilities whole for loss of revenues that can be attributed to energy efficiency program sales. They are viewed by some as an alternative to revenue decoupling. They often involve data-intensive litigation, with utilities striving to demonstrate high levels of energy savings and intervenors working to refute the utility data. In addition, they provide utilities with an incentive to overstate savings and provide the perverse incentive to undermine efficiency program effectiveness so that sales between full rate cases increase. Under this scenario, a utility double-collects through the lost revenue adjustment mechanism and retained sales revenue.

3. Minimum Bills

A minimum bill structure is intended to obtain a minimum payment from customers whose usage is very low, but who nonetheless are dependent on the utility system. A minimum bill bears some resemblance to a high customer charge, with the notable distinction that it does not apply to customers who consume more than the preset minimum bill threshold. In essence it is a high customer charge that is only applicable to very low-volume consumers. Because

[64] "Form EIA-826, Monthly Electric Utility Sales and Revenue Report with State Distributions," Energy Information Administration, https://www.eia.gov/electricity/data/eia826/.

minimum bills only apply to a very small number of customers, they are unlikely in most service territories to effectively address pressing fixed-cost recovery problems.

4. Residential Demand Charges

Large commercial and industrial customers have long been subject to paying a demand charge in addition to a fixed customer charge and volumetric charges. Demand charges are based on a customer's peak usage during a billing period or over a longer period — e.g., over the previous 12-month period. Recently, some utilities that have deployed advanced meters have proposed demand charges on residential customer bills. In theory, demand charges send consumers a price signal to reduce peak consumption. However, there is little evidence indicating that large numbers of residential consumers have the wherewithal to respond to demand charge price signals. It is also reasonable to expect that considerable time and effort will be required to build a broad understanding of demand charges among residential customers who have not dealt with the concept in the past. In addition, because advanced metering is required to implement demand charges, the advanced metering infrastructure principles that are pertinent to the time-varying rates discussion are applicable to residential demand charges.

5. Tiered Fixed Charges

At least one large investor-owned utility has proposed to implement a tiered fixed charge structure. National Grid proposed the structure to regulators in its Rhode Island and Massachusetts Service territories. Proposals in both states entail imposing a fixed charge based on maximum usage during the previous 12-month period. Proposed changes to the Massachusetts general residential tariff are reflected in Table 2.6.

Table 2.6 National Grid's Proposed Tiered Fixed Charge Structure — Massachusetts

Current Customer Charge (all bills)	$4.00
Revised Monthly Customer Charge For maximum bill 0–250 kWh	 $4.20
For maximum bill 251–600 kWh	$8.15
For maximum bill 601–1,200 kWh	$13.00
For maximum bill over 1,200 kWh	$18.00

Even though they are tiered, the proposed fixed charge increases, combined with concomitant reductions in volumetric charges, will infringe on customers' ability to control their bills, and will have the most adverse impacts on customers with average usage but a slightly higher peak usage. The rate design suffers from some of the same defects as high, flat fixed charges, but will be more difficult for customers to understand. In the midst of its rate case in Rhode Island, National Grid filed a motion to withdraw its rate design proposal, stating that it was aware of lack of support for the proposal among intervenors.[65]

[65] Rhode Island Public Utilities Commission (2015).

6. Formula Rates

Formula rate plans, after regulatory approval, provide utilities with a mechanism to adjust base rates outside of a fully litigated general rate case when earnings fall outside of a predetermined band.[66] Formula rates can provide utilities with enhanced revenue stability and reduce operational and sales risk. In approving formula rates, regulators should establish clear performance standards to address reduced utility incentive to control costs and deliver reliable service under this rate design. In addition, similar to revenue decoupling, implementation of formula rates should not deny utility customers and other stakeholders the ability to periodically review and litigate a utility's cost structure.

Conclusion

All of the options addressed in this report have some potential to at least partially stabilize utility revenues. However, none of the rate design options addressed is without the potential to bring adverse impacts to large groups of residential consumers. Some options, particularly the high fixed-charge approach, move the fairness and equity needle in the wrong direction and also erode customer control over bills. Among the rate design options explored as a means to provide for cost recovery in the face flat or declining sales, a revenue decoupling mechanism that includes the full complement of safeguards and consumer-minded design features identified in this chapter of the report has potential to provide a degree of revenue stability without undermining the potential for continued growth of energy efficiency resources. However, in the case of a utility that delivers effective energy efficiency programs, and where no threat to revenue stability is demonstrated, the status quo may be just fine.

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[66] Costello (2010), ii.

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3. Environmentally Preferred Approaches for Recovering Electric Utilities' Authorized Costs of Services: Options for Setting and Adjusting Electricity Rates

By Ralph Cavanagh, Energy Program Co-Director, Natural Resources Defense Council

Statement of the Problem

In the United States, electricity production contributes more greenhouse gas emissions than any other sector of the economy (more than 30 percent).[67] Utilities also are by far the nation's largest investors in energy technology and infrastructure; electric utilities alone will commit $1.5 to $2 trillion over the next two decades, exceeding analogous federal expenditures by an order of magnitude.[68]

It is important to acknowledge at the outset that the United States has many flavors of "regulated utilities." They come in both investor-owned and publicly owned varieties, with a host of in-state and regional differences regarding the extent to which distribution systems own transmission and generation assets. Fully integrated behemoths like the Southern Company and Florida Power & Light coexist with distribution-only utilities like Oncor, National Grid and most of the membership of the National Rural Electric Cooperatives Association (NRECA). A vast intermediate category of distribution companies with competitively procured portfolios of generation and energy efficiency resources includes the likes of giant municipal systems in Seattle, Austin and Los Angeles, along with Western and MidWestern investor-owned utilities like Pacific Gas & Electric, Southern California Edison, Idaho Power, Ameren and Kansas City Power & Light. But in every state and every electricity system, core functions associated with integrating and distributing power from diverse sources remain subject to price regulation and critical to clean energy progress.

If, as many believe, climate stability requires the decarbonization of power generation, utilities will need to be able to invest with confidence and recover their authorized costs. The decisionmakers will be state regulators and (for publicly owned utilities) local boards; as a practical matter, the federal government's ability to influence these decisions is limited to Congress's periodic efforts, upheld by the Supreme Court in FERC v. Mississippi, to get state regulators to consider particular ratemaking options within a specified time, without dictating the outcome.[69]

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[67] The most recent economy-wide EPA emissions data are in "Sources of Greenhouse Gas Emissions," U.S. Environmental Protection Agency, https://www3.epa.gov/climatechange/ghgemissions/sources.html.
[68] The Brattle Group (2008), p. 2.
[69] *FERC v. Mississippi,* 102 S. Ct. 2126 (1982) (rejecting Tenth Amendment challenge to the ratemaking agenda-setting sections of the Public Utility Regulatory Policies Act of 1978 by a 5-to-4 vote). According to the Court, if the federal government wanted to dictate ratemaking outcomes, it would have to "preempt the states completely in the regulation of retail sales by electric and gas utilities," an outcome unlikely enough to eliminate any need for further exploration here. See 102 S. Ct. at 2137.

Utilities' ability to recover their authorized costs of service has been complicated by a shift since 2000 in a longstanding trend of robust growth in retail electricity sales. Prior to that year, for decades, electricity use consistently increased at a rate at least double that of the U.S. population, but since 2000, the average rate of sales growth has lagged consistently behind population growth, and total consumption in 2014 was actually lower than that in 2007[70] (Figure 3.1).

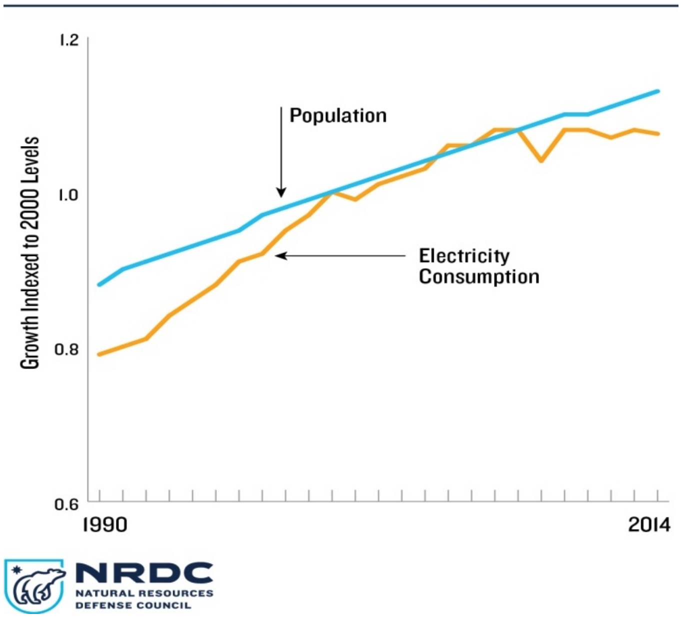

Figure 3.1 Growth in National Electricity Consumption and Population

This trend has helped ensure increased attention to broader aspects of utility business model reform and rate design that are critical to maintaining a clean energy transition. Many are captured in a February 2014 joint statement issued by the Natural Resources Defense Council (NRDC) and the Edison Electric Institute (EEI).[71] The statement notes that net metering programs in wide use across the United States have helped valuable distributed technologies such as solar power gain traction and improve performance, but additional approaches are needed now. Although such generation can reduce a grid's needs for central station generation and other infrastructure, it typically does not eliminate its owners' needs for grid services. When they use distribution and transmission systems to import and export electricity, owners and operators of onsite/distributed generation should provide reasonable cost-based compensation for the utility services they use, while also being compensated fairly for the services they provide. EEI and NRDC also note and endorse a longstanding tradition of utility investment in cost-effective energy efficiency resources, in coordination with upgrades in state and federal efficiency standards, yielding significant reductions in customer and environmental costs, but reinforcing a declining trend in electricity sales growth.

[70] This conclusion and the graph in the text (created by my colleague Sierra Martinez) are based on data from U.S. Department of Energy, Energy Information Administration, Monthly Energy Review.
[71] See "EEI/NRDC Joint Statement to State Utility Regulators," Edison Electric Institute and NRDC, http://docs.nrdc.org/energy/files/ene_14021101a.pdf.

These recommendations are entirely consistent with a core ratemaking principle that regulatory expert Scott Hempling recently summarized as follows:

> Economic efficiency comes first. Economic efficiency requires that we allocate costs to those who cause the costs, while allocating benefits to those who take the risks and bear the burdens. Economic efficiency comes first; allocating the gains from efficiency comes second. Inevitably we will fight over who gets the biggest slice. Let us first cooperate to make the biggest pie.[72]

Three crucial questions emerge, for purposes of this paper: (1) given declining growth in commodity sales, how do utilities secure the reasonable revenue certainty required to make enduring provision for clean, reliable and affordable services, without reducing customers' incentives to use electricity efficiently or to generate it themselves in ways that provide economic and environmental benefits; (2) how can regulators allocate the costs of enhanced electricity grids equitably among all who use them; and (3) how can rate designs best signal to customers the actual costs of the electricity services they use, to encourage efficient choices? And are there ratemaking approaches that can advance all of these objectives, or are zero-sum trade-offs inevitable? The EEI/NRDC statement is optimistic on all counts, but lacking in specifics. This chapter aims to provide them.

Summary of Recommendations

I begin with a procedural observation that may be more important than any substantive recommendation: The most promising ratemaking solutions will emerge from collaborative discussions in open settings among regulators, their utilities, and diverse groups of stakeholders. As regards major changes in utility business models, regulatory fiat is an unpromising course with few if any successful U.S. precedents.

In devising consensus-based solutions, I recommend starting with what is characterized below as a "necessary but not sufficient" element of any successful package: revenue decoupling. It does not affect rate design (it can work with any rate design), but it serves the crucial purpose of freeing regulated utilities from an outdated commodity business model that links financial health to robust growth in retail kilowatt-hour sales. As the most promising rate design options, individually or in combination, I advance three basic approaches: minimum bills, time-varying rates (which can take many forms) and tiered rates. All are responsive to concerns about equity, efficiency and customers' incentives to embrace energy efficiency and distributed generation. I then address options that I view as far inferior, including more frequent rate cases, increased fixed charges, and lost revenue adjustments. These are likely to be ineffective, counterproductive, and/or costly for many if not most customers.

[72] Hempling (2016). This passage is in part a homage to the field's classic work, James C. Bonbright's *Principles of Public Utility Rates* (1961), which suffers in contemporary application from the author's then understandable obsession with increasing the utilization rates of utility-owned baseload power plants.

The Curse of Throughput Addiction

For the past century, regulated utilities have recovered most of their costs of service through volumetric charges on electricity consumption and demand. Since the provision of reliable electricity service is dominated by utility expenditures that do not vary with short-term consumption shifts, this means that utilities' financial health is tied directly to their retail sales volumes, with every drop in consumption bringing a corresponding reduction in recovery of the utilities' authorized costs, and the reverse resulting whenever sales increase, for whatever reason.[73] This means that utilities gain by promoting increased electricity use and are punished automatically for investing successfully in energy efficiency programs, peak load reductions and distributed generation that reduces electricity throughput. Utilities are discouraged from investing in the best-performing and lowest-cost resource — energy efficiency — because it hurts them financially. Utilities' interest in increasing sales conflicts with customers' interest in reducing their energy costs. The problem was highlighted more than four decades ago by a prescient utility regulator, Leonard Ross, of California:

> At present, the financial incentives for utilities are for increased sales, not for conservation. Whatever conservation efforts utilities undertake are the result of good citizenship, rather than profit motivation. We applaud these efforts, but we think the task will be better accomplished if financial and civic motivations are not at cross purposes.[74]

A straightforward solution to this dilemma was filed at the California Public Utilities Commission (PUC) in 1981 by a consumer advocate (still active today) named William Marcus.[75] Marcus proposed the use of modest annual rate adjustments to prevent fluctuations in sales (either up or down) from resulting in over- or under-recovery of utilities' previously approved nonfuel costs. Without this "revenue decoupling," utilities and their customers would have automatically conflicting interests on even the most cost-effective energy efficiency.

A Necessary But Partial Solution: Revenue Decoupling

Revenue decoupling makes utilities indifferent to retail energy sales without abandoning the tradition of volumetric pricing and its incentives for customers to use energy efficiently. More than half the states have now adopted this approach for at least one electric or natural gas utility, and a comprehensive order by the Washington Utilities and Transportation Commission is a primer on how to do it effectively, using modest annual true-ups in rates that few if any customers even notice.[76] Revenue decoupling results in very modest rate adjustments that go both ways and do not materially affect rewards to consumers for reducing their use of electricity and natural gas. As the Oregon Public Utility Commission found when it adopted a decoupling mechanism for Portland General Electric in January 2009, responding to claims that decoupling would rob customers of the rewards of conservation: "We believe the opposite is true: an individual customer's action to reduce usage will have no perceptible effect on the decoupling

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[73] Sometimes the retail sales reduction results in a wholesale transaction, if the utility can resell the unused power, but wholesale rates typically are well below retail rates, and often utilities are required to refund to customers any wholesale revenues exceeding the cost of production (on the theory that customers paid for the generation used in making the sales and should reap any gains).

[74] California Public Utilities Commission, D. 84902 (September 16, 1975), quoted in Barkovitch (1987), pp. 134–35.

[75] See Marcus (1981, Revised July 1981), cited and summarized in Cavanagh (2009), p. 89, n. 14.

[76] Washington Utilities and Transportation Commission (2013).

adjustment, and the prospect of a higher rate because of actions by others may actually provide more incentive for an individual customer to become more energy efficient."[77]

In January 2008, five states had adopted revenue decoupling for at least one electric utility and 13 states had done so for natural gas. The count of decoupled electric utilities stood at seven; the count for natural gas utilities was approximately 20. National campaigns to expand the model were beginning under the joint sponsorship of NRDC, the Edison Electric Institute and the American Gas Association. Just starting to emerge was a worrisome countervailing trend to displace decoupling with rate designs that moved increasing fractions of utility customers' bills into fixed charges, reducing rewards for efficiency improvements (discussed further below).[78]

As of January 2016, the state revenue decoupling counts were 15 for electric utilities and 23 for natural gas utilities, and the number of utilities covered stood at 33 and 53, respectively (more than a three-fold increase in the total from five years earlier). [79] The past year saw Minnesota adopt electricity decoupling for Xcel Energy (March 2015), New York adopt electricity decoupling for the Long Island Power Authority (March 2015), and Idaho adopt electricity and natural gas decoupling for Avista (December 2015). Additional electricity decoupling proposals are pending in Louisiana (Entergy New Orleans), New Mexico (PNM), Oregon (Avista) and Washington (PacifiCorp), with preliminary proceedings also underway before the Missouri and Pennsylvania Commissions, and a filing likely soon from Xcel in Colorado. Currently decoupled investor-owned and publicly owned utilities account for about 25 percent and 12 percent, respectively, of regulated retail electricity revenues for the two sectors.[80]

Extensive empirical evidence attests the minimal rate and bill impacts of revenue decoupling in practice. Based on 1,269 separate rate adjustments produced by decoupling mechanisms from 2005 to 2013, an exhaustive assessment concluded that annual rate changes were "mostly small." The adjustments did not exceed 2 percent for 85 percent of the electricity and 75 percent of the gas rate adjustments. Some 37 percent of the adjustments involved refunds from the utilities to their customers.[81] Put another way, the typical electricity rate adjustment averaged about seven cents a day (up or down); for natural gas utilities it was less than five cents a day.[82]

Revenue decoupling does not guarantee profits or affect a utility's incentive to control costs. The Regulatory Assistance Project has observed that, "[i]n fact, precisely the opposite is true."[83,84] Decoupling provides assurance to a utility and its customers that the utility will recover only authorized revenues (that is, the amount that regulators have already determined is necessary and prudent in order to deliver energy services to customers). A utility's profit will

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77 Oregon PUC Order No. 09-020, p. 28 (Portland General Electric, Jan. 2009).

78 The 2008 and 2015 state and utility numbers reflect my own annual assessments, prepared and circulated internally, since 2008; a full list of all decoupling orders since 2005 appears in Morgan (2013), pp. 3–4.

79 Within the past six years, 18 states have approved electricity decoupling, but three of those (Arizona, Michigan and Montana) do not currently have mechanisms in place. The count of decoupled electric utilities does not include three in Michigan with what I expect to be temporarily expired mechanisms; remedial legislation overturning an anomalous court decision is pending.

80 I am indebted for these calculations to my NRDC colleague Amanda Levin.

81 Morgan (2013).

82 Morgan (2013).

83 Lazar, Weston and Shirley (2011), p. 45.

84 Lazar, Weston and Shirley (2011), p. 45.

continue to be driven by both its revenues and its costs. Without decoupling, profit is tied both to sales growth and cost control. With decoupling, controlling costs takes on even greater importance, since the utility can no longer increase profits by increasing sales.

A barrier to decoupling for many investor-owned utilities has been a concern that their regulators might link its adoption to a reduction in their authorized return on equity, on the ground that decoupling somehow generates a significant net reduction in utilities' overall financial risks, reducing the cost of equity. Few Commissions have actually done this, however, and none since 2010.[85] The best available empirical evidence, assembled by The Brattle Group in 2014, argues strongly against such prospective reductions. Brattle conducted a rigorous assessment of the effect of revenue decoupling on electric utilities' cost of capital, following up on two earlier studies involving natural gas distribution companies. The authors concluded that decoupling has not had a statistically significant impact on electric utilities' cost of capital.[86]

Most revenue decoupling mechanisms also address an issue that arises in the context of formula rates: How should regulators deal with predictable increases in utilities' costs in the period following the establishment of an authorized annual revenue requirement in a rate case? Many decoupling mechanisms allow annual increases in cost recovery based on changes in utilities' customer counts or other indices.

The Washington Utilities and Transportation Commission recently incorporated anticipated annual escalation in Puget Sound Energy's grid costs in the utility's decoupling mechanism, in the form of a 3 percent annual increase called a "K Factor."[87] Formula rates are another way of providing assurance that authorized multi-year utility costs will be recovered, independently of kilowatt-hour sales. The utility tracks revenue recovery for the cost categories specified in the "formula" and regularly adjusts rates up or down to ensure full (but not excessive) recovery of authorized revenues on a schedule specified by the regulator.[88] The Puget Sound Energy decision is an illustration of what I view as a reasonable integration of the revenue decoupling and formula rate approaches, in a way that eliminates "throughput addiction" while providing reasonable assurances that the utility will recover escalating multi-year costs of grid enhancement.

Decoupling does not moot all rate design issues, although it solves the problem of revenue volatility associated with sales fluctuations. Utilities and other stakeholders still worry, appropriately, about equitable allocation of costs among all grid users, a problem not automatically solved by uniform true-ups in rates to correct for sales fluctuations.

[85] For a comprehensive overview of these precedents, see Morgan (2013).
[86] Vilbert et al. (2014).
[87] See Washington Utilities and Transportation Commission (2013).
[88] See Chapter 5 of this report.

The Most Promising Rate Design Reforms

Time-Varying Rates

The category of "time-varying rates" includes numerous variants; included for purposes of this discussion are "time-of-use" rates, critical peak pricing and demand charges linked to a customer's peak usage coincident with system peak usage. The core issue is whether all or part of an electric bill should reflect the higher cost to the system of consumption at certain times. Historically, advocates for residential and business interests sparred fiercely over this question, because residential users tended to have "spikier" daily consumption patterns than larger users, causing them to face potentially higher bills as a class if utility rates included significant time-of-use features.

Revenue decoupling can be used, however, to ensure that each customer class pays only its assigned share of revenues[89] and, if so, the real question is whether reflecting time-varying electricity costs in electricity rates is in the public interest. The scholarly consensus in favor (on economic efficiency grounds) is overwhelming, although there are numerous disputes over details (e.g., what time intervals should be used in applying time-varying charges, how steep should the differentials be across time periods, how should time-varying charges be calculated, and how often should the calculations be revised to reflect changing market conditions?). As advanced metering technology expands its deployment, utilities will be able to test multiple approaches with all customer classes; today, many residential customers lack the digital meters needed to determine their time-varying electricity use, but "smart" meters will soon become the norm. EEI estimates that by the close of 2015, 60 million had been installed across the United States (out of about 140 million).[90]

From the perspective of energy efficiency and distributed resources, there are significant upsides potentially associated with time-varying rates, and certainly no cause for reflexive opposition. Evidence has been accumulating that diversified energy efficiency portfolios tend on balance to yield disproportionately positive impacts during periods of peak system use, and the Northwest Power and Conservation Council has recently published findings that reinforce this conclusion in its draft Regional Plan (Figure 3.2).[91] But these same findings counsel against demand charges not linked to systemwide peak periods, which would also lack a comparable grounding in cost and reliability considerations, and could impede beneficial shifts in demand such as off-peak charging of electric vehicles.

[89] If any given rate design proves to extract more or less revenue from a customer class than expected and authorized, the decoupling mechanism will correct the anomaly within a year through a modest rate adjustment for the affected class.
[90] Communication with T.D. Smith, Edison Foundation, Jan. 6, 2016.
[91] See "Seventh Northwest Conservation and Electric Power Plan, Chapter 12: Conservation Resources," The Northwest Power and Conservation Council, p. 12-6, https://www.nwcouncil.org/media/7149675/7thplandraft_chap12_consvres_20151020.pdf, ("Using best-available load shapes, the Council estimates the 5,100 average megawatts of [long-term cost-effective regional energy efficiency potential] translates to 10,000 megawatts of capacity savings during the regional peak winter hour (6 pm on a weekday in December, January, and February) and 6,200 megawatts of capacity savings during the regional peak summer hour (6 pm on a weekday in July)." The Council is widely recognized as among the nation's most experienced and credible evaluators of energy efficiency potential and results.

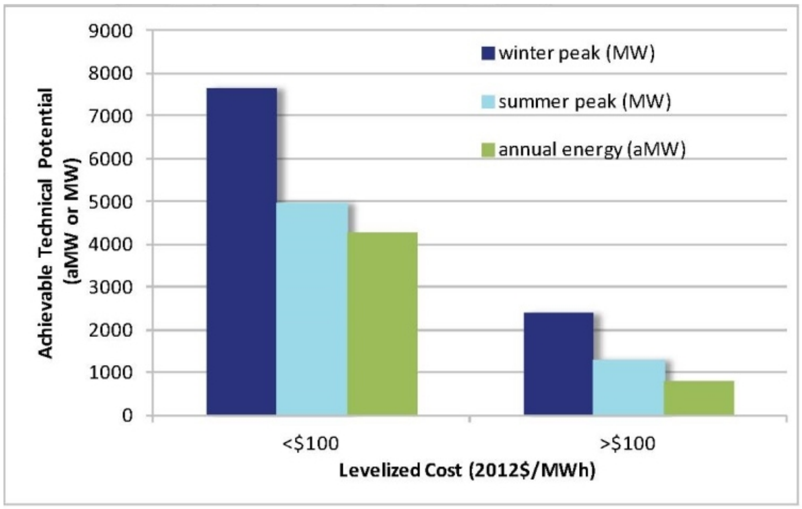

Figure 3.2 Peak and Energy Impacts by Levelized Cost Bundle for 2035 — Northwest Power and Conservation Council

For their part, DG proponents like to emphasize rooftop solar's potential contributions to meeting on-peak system needs.[92] All of this yields optimism about the potential for including a strong time-varying dimension in consensus-based rate design proposals for all customer classes. An excellent starting place for participants in such discussions is the comprehensive rate design manual published recently by the Regulatory Assistance Project.[93,94]

Tiered Rates

Commodity prices in unregulated markets reflect the marginal cost of an additional unit of product, whereas regulated electricity rates are based on the average cost of service. (The average U.S. cost of electricity at the beginning of 2016 was about 11 cents per kilowatt-hour.[95]) In a dialogue that has endured for decades,[96] advocates have sparred over whether to charge different amounts for different levels of consumption within a customer class, yielding either a promotional incentive ("the more you use, the less you pay") or the reverse.

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[92] See, e.g., Ho (2016).

[93] See "Smart Rate Design," Regulatory Assistance Project, http://www.raponline.org/featured-work/smart-rate-design.

[94] Lazar and Gonzalez (2015).

[95] The U.S. average electric rate (based on most recent available data) is 10.44 cents/kWh. US EIA, Average Price by State by Provider (EIA-861), January 2016, https://www.eia.gov/electricity/data/state/.

[96] See, e.g., Northwest Conservation Act Coalition (1982), pp. 364–377 (reviewing the debate over how to "promote equitable and resource-conservative rate structures" in terms that remain strikingly relevant in 2016).

With a national average electricity rate of roughly 11 cents per kilowatt-hour for residential customers, and less for nonresidential customers, a tiered structure that raises rates as consumption increases will enhance energy efficiency and DG prospects among those with the largest opportunities to save electricity. As Rich Sedano of the Regulatory Assistance Project points out:

> If the long run marginal cost of electricity is higher than the average rate, a tiered rate is an excellent way to associate marginal use for higher consuming customers with the cost of serving additional energy needs over time. This will tend to promote dynamic efficiency — meaning a sound price signal to promote investment by customer and utility in the proper balance to minimize societal costs, which should be a goal we all share. States can include [various] externalities in their calculation of LRMC [long-run marginal cost] if that is their priority.[97]

Such "tiered rates" also increase revenue volatility for utilities, since they accentuate the revenue impact of consumption increases or reductions at the margin. Here again, revenue decoupling is an important potential source of reassurance that progressive rate design will not come at the expense of utilities' recovery of their authorized costs of service.[98]

Minimum Bills

Minimum utility bills are often confused with monthly fixed charges on utility bills, but in fact they provide a compelling alternative way of ensuring that all grid-connected customers make a reasonable contribution to maintaining the critical infrastructure that they are using. Fixed charges reduce all customers' reward for saving energy and installing distributed generation, by moving revenue out of volumetric charges; minimum bills have this effect only on those who use little or no electricity in a given month (e.g., owners of vacation homes or exceptionally large rooftop solar arrays). Once consumption rises above a predetermined threshold, full volumetric pricing resumes and minimum bills cease to have any adverse effect on incentives to reduce consumption.

For their part, utilities sometimes worry that setting a minimum bill at a small fraction (say, 10 percent to 20 percent) of a customer class's average bill won't yield much incremental revenue or revenue certainty, since most customers in the class are already paying more than the minimum — so why bother with instituting a minimum bill that is irrelevant to most bill payers?

But if one takes seriously the prospect of dramatic increases in both energy efficiency and distributed generation, the number of grid-connected customers potentially at or below the "minimum" threshold could increase significantly before long. The minimum bill would then serve the important function of ensuring that everyone who uses the grid is contributing a guaranteed amount to its maintenance. It may be mostly an insurance policy for the time being, but in an era of concerns about possible utility "death spirals," the policy is very much worth acquiring. The California PUC, long a bastion against any fixed charges in ratemaking, is warming

[97] The quote comes directly from Sedano's review of the initial draft of this paper (March 2016).

[98] An example of a settlement agreement pairing revenue decoupling with tiered rates is the 2010 submission to the Montana Public Service Commission by the Natural Resources Defense Council, Human Resources Council District XI, and Northwestern Energy, for which the author supplied expert testimony, along with Professor Thomas Power of the University of Montana.

now to minimum bills for residential customers, albeit at a low initial level ($10 per month).[99] The Hawaii PUC has also recently approved the concept, at a higher level ($25 per month for residential customers and $50 for small commercial customers).[100] Those paying these minimum bills are not rewarded for reducing consumption further, but given the small quantity of kWh they are drawing from the grid (10 percent to 20 percent of the typical residential customer's needs), their relative environmental and grid impacts are already modest.

Ineffective or Counterproductive Reforms

Frequent Rate Cases

Some have contended that utilities can be made whole for reduced growth in electricity sales by frequently adjusting rates to reflect changes in demand. Putting aside the nontrivial expense to both public agencies and utility customers of more frequent adversarial clashes over electricity rates, the premise is wrong. Rate regulation never makes utilities whole for losses since the previous rate case; the best it can do is to readjust assumptions in an attempt to avoid such losses in the future. And once the rates are reset, any subsequent reduction in commodity sales costs utilities an increment of fixed cost recovery, with no hope of compensation. No matter how often rate case decisions occur, utilities will spend most of their time between them, and without revenue decoupling, utilities' throughput addiction will continue undiminished.

Higher Customer Fixed Charges

One way of ensuring recovery of authorized costs would be to stop charging for electricity service based on volumetric electricity use, and to make all or most of an electricity bill independent of consumption. This pricing model may work well in some sectors of the U.S. economy, but none have environmental and equity dimensions comparable to electricity service. An extreme version of fixed charge mania has surfaced in Texas, where Reliant's "Predictable 12" plan charges customers a predetermined monthly amount (based on historical consumption) regardless of their electricity use. In the words of NRDC's Amanda Levin:

> Reliant designed this plan to give ultimate bill security to customers, but this new plan has quickly been dubbed the "all you can eat plan." There is no incentive for customers to invest in energy efficiency and no penalty for keeping the AC on at 60 F all summer — even if not at home. During peak summer hours, this plan provides an almost perfectly perverse price signal.[101]

The argument for higher fixed charges is often made on economic efficiency grounds: If much of an electricity bill represents fixed charges, critics argue, using volumetric pricing overstates the short-term cost of meeting demand and makes additional consumption look more costly than it should. This amounts to contending that most utilities today are suppressing beneficial increases in electricity use through their rate designs. Yet the rationale for efficiency programs and standards rests in part on the conclusion that extensive market failures continue to block energy

[99] See id.
[100] See "Hawaii PUC ends net metering program," Utility DIVE, http://www.utilitydive.com/news/hawaii-puc-ends-net-metering-program/407328/.
[101] Levin's findings will appear in a forthcoming chapter of a Fereidoon Sioshansi-edited book on utility business model issues, Utilities of the Future (in press, 2016).

savings that are much cheaper than additional energy production at today's electricity prices. The last thing we need, under those circumstances, is rate designs that encourage additional electricity waste.

Raising fixed charges improves revenue certainty for utilities (although not as effectively as decoupling, unless scaled to the level achieved by Reliant in Texas). But it adversely affects customers with below-average use and is a particularly sensitive issue for low-income advocates.[102] And, unlike minimum bills, it effects an across-the-board reduction in all customers' rewards for saving energy and installing distributed generation. The past year saw the emergence of a nationwide campaign to fight fixed-charge increases, co-chaired by NRDC, Vote Solar and the National Consumer Law Center. The success of that campaign in 32 of 38 cases over its first year adds another reason to rethink any infatuation with higher fixed charges as a promising business model strategy.[103]

Lost Revenue Adjustment Mechanisms

The theory behind lost revenue adjustment mechanisms (LRAMs) sounds benign: Regulators can regularly calculate the "lost revenue" associated with electricity savings delivered by utility programs and incentives, and restore them through rate increases, eliminating the financial penalties that such measures otherwise would inflict on the utilities involved. In that sense LRAMs, if perfectly designed and executed, would partially substitute for revenue decoupling.

But unlike decoupling, LRAMs create a powerful and perverse new incentive for the company to promote programs that look good on paper but deliver little or no savings in practice (because then the company would get a double recovery).[104] For example, poorly designed efficiency measures that customers later replaced or disconnected might well result initially in lost revenue recovery, while allowing the utility also to gain later from higher energy sales after the measures ceased to function. By contrast, revenue decoupling removes any prospect of that wholly inappropriate upside opportunity for the utility when efficiency measures fall short for any reason. Moreover, an LRAM leaves unimpaired strong utility incentives to promote increased electricity use, since (unlike revenue decoupling) it allows utilities to keep any non-fuel revenues secured in excess of those authorized by the commission. Paying a utility bonuses for both increases in its retail electricity sales and its programmatic electricity savings is the metaphorical equivalent of encouraging the CEO to drive with one foot on the brake and the other on the accelerator. Finally, an LRAM yields an automatic rate increase whenever it is applied, whereas rate adjustments under revenue decoupling can be (and have been) either positive or negative.

LRAMs also are unlike decoupling in that they result in automatic utility penalties, in the form of reduced fixed-cost recovery, for all cost-effective electricity savings not directly associated with the load-reducing impacts of utility-sponsored energy efficiency. Cost-effective savings in this

[102] See, e.g., Direct Testimony of John Howat on behalf of Coalition for Clean Affordable Energy, New Mexico Public Regulation Commission, Case No. 1500261-UT (January 2016), and sources cited therein.
[103] Data on fixed-charge increase results were supplied to the author in a personal communication from Devra Wang of the Energy Foundation, November 2015.
[104] See, e.g., Washington Utilities and Transportation Commission (1991), p. 10: "Furthermore, the Commission believes that a mechanism that attempts to identify and correct only for sales reductions associated with company-sponsored conservation programs may be unduly difficult to implement and monitor. The company would have an incentive to artificially inflate estimates of sales reductions while actually achieving little conservation."

category include those from efficiency standards administered by government agencies, which can benefit greatly from utility support;[105] informal intervention by utility staff to encourage customer patronage of independent energy efficiency contractors; and effective public education campaigns with multiple participants, including utilities.

Conclusion

In order to fulfill their crucial role in a national (and global) clean energy transition, utilities need and deserve reasonable assurances that recovery of their authorized costs will not vary with fluctuations in electricity use and will reflect appropriate contributions by all grid users. This does not require rate designs that reduce rewards to all or most customers for using less electricity. Alternatives include minimum bills that convert to volumetric charges if the customer exceeds a monthly consumption threshold, time-varying rates that increase with stresses on grids, and inverted rates that raise energy efficiency incentives for the largest electricity users.[106]

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105 In the Pacific Northwest, over the past 30 years, efficiency standards have achieved results comparable in aggregate to all utility programs combined. See p. 8 of the most recent assessment by the Northwest Power and Conservation Council (Charles and Eckman 2011): http://www.nwcouncil.org/energy/rtf/consreport/2010/2011_10presentation.pdf.

106 An excellent resource on the "minimum bill" concept is http://www.raponline.org/document/download/id/7361. For a discussion of variable demand charges, see http://www.brattle.com/news-and-knowledge/news/778.

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4. The Economics of Fixed Cost Recovery by Utilities

By Severin Borenstein, Professor of Business Administration and Public Policy in the Economic Analysis and Policy Group of the Haas School of Business, Co-Director of the University of California Energy Institute

Among the many claims about the lessons that economics teaches for fixed-cost recovery, the most common is that fixed costs should be recovered with fixed charges. Standard microeconomics, however, has very little to say directly about how utilities should recover fixed costs, and certainly nothing as simple as this claim. Rather, microeconomics has fairly clear direction on how volumetric prices for electricity should be set to maximize efficiency, that is, to generate the greatest total value for the economy.

The simple guidance on volumetric pricing of electricity is that the retail price of a kilowatt-hour (kWh) should reflect society's full short-run marginal cost of supplying it. To be clear, "Society's" cost includes not just the marginal fuel, labor, capital and other production costs of the utility, but also the externalities caused by generating and selling that incremental kWh of power. Those externalities include greenhouse gas emissions, local air pollution, and other disamenities from the presence of generating stations, as well as transmission and distribution lines.[107] The focus is on short-run social marginal cost, because at any point in time price should reflect the incremental cost of producing one more unit, which will likely be higher when production capacity is strained than when there is plenty of excess capacity.

Largely because of the existence of fixed costs, however, setting the volumetric price of electricity equal to its full social marginal cost in many cases won't raise sufficient revenue to cover the utility's total costs, though the size of the shortfall will depend on many attributes of costs and demand.[108] The shortfall raises the critical question of the most efficient and equitable way for the utility to raise additional revenue. In this chapter of the report, I present an economist's view of a number of alternatives that have been proposed to allow a utility to recover its costs, including fixed going-forward costs that the utility incurs each period, as well as sunk costs that result from past decisions and actions.

In the next section, I briefly outline the foundational principle of economic efficiency in market transactions, which underlies all economic analyses of pricing. In the second section, I apply this principle to electricity pricing and explain why it is likely to lead to a revenue shortfall. The third section then analyzes an array of alternative proposals that allow utilities to recover additional revenue. Though the focus is primarily on economic efficiency, I also discuss equity considerations and impact on lower-income customers. My conclusion is that there is no perfect approach to increasing revenue, but some approaches make much more sense than others.

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[107] Of course, the true cost of pollution is itself controversial, but any policy to address externalities confronts this issue, either implicitly or explicitly, when costly actions are taken to reduce pollution. Addressing the externality cost question directly is critical to arriving at transparent and credible environmental and energy policy.

[108] It is worth noting that because economic efficiency starts with setting price equal to short-run marginal cost, it avoids the debate about which costs are fixed. Rather, the focus of revenue collection is on covering total costs (a much less controversial figure), and the question becomes how much additional revenue must be raised to do so starting from the point at which price equals short-run social marginal cost.

Once the options are narrowed, policymakers face a fundamental trade-off between economic efficiency and equity.

The Economic Efficiency of Pricing

The idea that economic efficiency is maximized when price reflects full short-run social marginal cost (SMC) is a bedrock principle of microeconomics, because it is straightforward to show that any departure from SMC is likely to reduce the economic value that the industry can create. Producing a good requires inputs — labor, fuel, machinery, land, etc. — and those inputs have alternative uses. The price of an input is generally a good indicator of its value in its next best use, so economics suggests that the inputs should only be brought together to produce this good if the value of this good to whoever consumes it exceeds the value of all the inputs necessary to make it. Setting price equal to short-run SMC creates the incentive to consume an incremental unit of the good if and only if one values it more than the value that the inputs would create in their next best use.[109] At the same time, customers who are considering an investment in energy efficiency receive a price signal that accurately reflects the social value of the savings such an investment would create.

To illustrate, let's say the incremental input costs of producing one additional unit of a hypothetical good add up to $7.25, but the production process also creates a negative externality (some sort of pollution, for instance) that imposes an additional cost of $1.75. If one sets the price for this good at $9, then everyone who buys it values it more than $9. As a result, there is no unit purchased that is valued less than the collection of inputs (including pollution) that went into making it and every unit valued more than the collection of inputs is purchased.

But what if the price for the good were set at $12? Then anyone who valued an additional unit of the good more than $9, but less than $12, would not buy it. This would be value-destroying, because the value that could have been created by putting together inputs with a cost to society of $9 in order to create a good that gives some specific buyer with a value of, say, $11 would not be created. The failure to make that deal is a loss of $2 of value to society.[110] And there are likely to be many such losses among customers who value the good more than $9 and less than $12. To economists, these losses — illustrated in Figure 4.1 by the upper (pink) triangle — are known as "deadweight loss" or, equivalently, a loss in economic efficiency.

[109] Some analysts have argued that price should reflect *long-run* marginal cost (LRMC) in order to reflect the capital costs of production. This would not in general yield economic efficiency. For instance, if a system is underbuilt and has a shortage of capacity, economic efficiency dictates that price increase to reflect the scarcity value of the electricity at each moment, regardless of the cost of capital to expand the system's capacity in the longer run. LRMC is appealing as a rough guideline for financing capital expansion, but it is not a good guide to economic efficiency of pricing. Precise economic analysis starts with pricing efficiently, which then makes clear the size of the revenue shortfall. The question of how to make up that shortfall is the subject of this volume. Electricity also differs from many markets due to the need to balance supply and demand with no storage. Borenstein (2000), particularly footnote 1, discusses application of the concepts to that case.

[110] Who bears that loss depends on the price at which a particular deal would have been made. The point is that when the buyer values the good more than it would cost the seller to supply it, there are gains from trade, and failure to make such deals imply a failure of anyone to capture those gains.

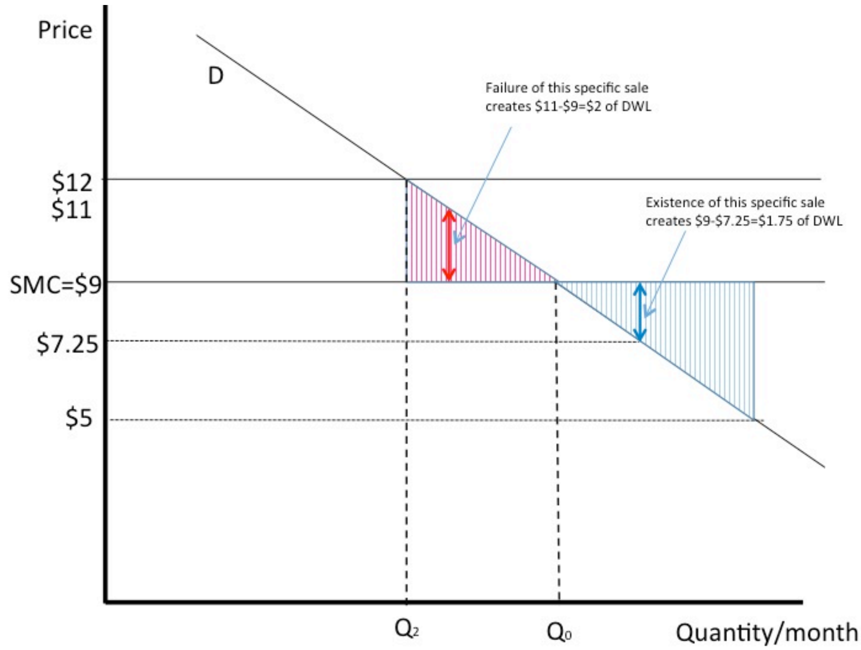

Figure 4.1 Illustration of Deadweight Loss (DWL) From Pricing Above or Below Social Marginal Cost

In practical terms, for example, if we price electricity at $0.22 per kWh when its true SMC is $0.12 (including all pollution externalities), then we might discourage someone from purchasing an electric vehicle when they would have done so had they been able to buy electricity at the true SMC.

Deadweight loss also is created if a good is priced below its SMC. If the hypothetical good illustrated in Figure 4.1 were priced at $5, then anyone who valued the good above $5 would purchase it. But if they valued it less than $9, the value they would be getting from the good would not be great enough to justify all the inputs (including pollution) that went into making it. The deadweight loss created by such underpricing is illustrated by the lower (blue) triangle in Figure 4.1. For instance, if there is a buyer who values the good at $7.25, that purchase of the good would generate $1.75 in deadweight loss or, put differently, would lower the total value created in the economy by $1.75. In practical terms, for example, if the true SMC of electricity is $0.12 per kWh and the price is set at $0.08 per kWh, then we will encourage people to leave some lights on when the value they are getting from doing so is less than the cost they are imposing on society.

Efficient Pricing of Electricity

In textbook competitive markets, price equals marginal cost, and all gains from trade are realized. But the relationship can break down for at least three reasons:

1. *Externalities.* If sellers in the market are highly competitive, but producing the good generates negative externalities, then competition will set a price below the social marginal cost to reflect only the marginal cost that the sellers have to bear. Because

those sellers don't internalize the cost of externalities (by definition), the price will be too low, and too many sales will occur.

2. *Market power of sellers.* If the market is not highly competitive, then sellers may be able to make greater profit by raising prices above competitive levels. Because sellers have such "market power," prices will be too high, and too few sales will occur. Some transactions that would have created economic value will be stifled.

3. *Failure to cover costs when price is equal to marginal cost.* In some cases, generally ones in which firms have significant fixed costs, competitive pricing might not be sustainable because it does not generate enough revenue to cover a firm's total costs. In economics, these situations are referred to as "natural monopoly," because the presence of large fixed costs suggest that it would be more economically efficient to have one firm do all production. Standard examples include local distribution lines for electricity or telephones, because it is widely agreed that it does not make economic sense to have duplicate wires running down the street.

All three of these potential distortions exist in regulated electric utility markets. There are clearly large fixed costs and natural monopoly tendencies in local distribution, and probably also transmission, of electricity. As a result of this tendency toward monopoly, electric utilities are either regulated by a state agency or owned by a local government or consumer-owned cooperative, in part to prevent the electricity provider from exercising market power and raising price above competitive levels. At the same time, generation and distribution of electricity creates negative externalities.

So then what does economics bring to the question of how to recover fixed costs? The answer begins by recognizing the ideal scenario, in which the price of each kWh is set to reflect the social marginal cost of providing it, and customers understand that price and optimize their consumption in response to it. This would involve the price changing second by second, and consumers — or their "smart" devices — responding to those second by second changes.[111] And it would involve price reflecting not just the utility's marginal cost of production, but also the cost of all externalities created.

In this scenario, the price would be very high at times when demand is strong, and there is a high probability of a supply shortage so that the marginal cost of producing one more kWh is potentially very high and would be much lower at low demand times. It has long been known that such pricing could produce more or less revenue than the firm needs to cover its costs.[112] But if there are fixed costs — which don't scale up with peak or total quantity sold — then there will be a tendency toward a revenue shortfall. That is, true fixed or sunk costs tend to create a revenue shortfall problem when electricity is priced to reflect marginal cost.

There is a countervailing effect, however, which is the failure to price externalities. Utilities seldom have to pay for the negative externalities that their business creates, but in order to

[111] Though we are institutionally quite far from this scenario, all the technology for it exists and is, in fact, already used for trading financial instruments. It would also be straightforward to offer alternatives to customers who don't want to be exposed to such price volatility (Borenstein 2013).
[112] Borenstein (2000) presents a more technical version of this argument. Boiteaux (1949) and Steiner (1957) first made these points.

create appropriate incentives for consumption they should still be adding those social costs to the volumetric price of electricity. Doing so would increase their revenues without increasing costs and bring them closer to breaking even, including covering their fixed costs. There is no logical or theoretical reason that the net effect of fixed costs and pricing-in externalities would necessarily cause efficient volumetric pricing of electricity to generate either positive or negative profits for the utility. But realistic calculations suggest that charging efficient volumetric prices would likely still lead the utility to lose money.[113] And if society ever requires utilities to pay for the externalities they create, that will increase utility costs further and move utilities further from being able to recover their total costs while charging economically efficient prices.

Of course, utilities depart from this ideal pricing scenario in many ways, most importantly by charging prices that vary little, if at all, over time. Commercial and industrial customers typically face just a two-tier peak/off-peak pricing structure, while the vast majority of residential customers face no time variation in price at all. Absent a strong reason to think demand is more or less elastic at peak times, the most efficient time-invariant price is the average of the prices that would be charged in the ideal scenario (in which prices change minute by minute), which yields the same total revenue as under time-varying pricing.[114] So the fact that utilities actually charge prices that vary little or not at all over time doesn't change the fundamental issue of how to recover fixed costs. Nor would appropriate time-varying pricing solve the problem.

In recent years, the fixed cost recovery problem has grown as more costs have been added to utility operations that are not directly tied to providing an incremental kWh of electricity. For instance, energy efficiency programs, discounts to low-income customers, and subsidies for installing distributed generation are now all costs that the utility must recover, but are not part of the social marginal cost of providing a kWh to a specific customer. In addition, energy efficiency programs and distributed generation have reduced demand and thus required that the revenue shortfall from marginal-cost pricing be made up over a smaller number of kWh. More generally, declining demand, regardless of the cause, is likely to increase the revenue shortfall that utilities (and regulators) will face if volumetric prices are set efficiently to equal SMC.

The variety of fixed costs that a utility incurs raises a distinction between customer-specific fixed costs and systemwide fixed costs. Customer-specific fixed costs vary according to whether the customer receives service from the utility, regardless of how many kWh the customer consumes. These include incremental metering and billing costs for that customer, and maintaining the connection from the distribution system to the customer's meter. Systemwide fixed costs cannot be attributed to a specific customer and are independent of the kWh consumed on the system. These include construction and maintenance of the local distribution networks, the corporate structure and public purpose programs, such as energy efficiency and distributed generation programs. The distinction has particularly important implications for discussions of equity or cost causality.

113 See Borenstein and Bushnell (2015), footnote 26.

114 Borenstein and Holland (2005), p. 475.

GLOSSARY OF STANDARD ECONOMIC COST TERMS

Variable Costs: Costs that vary with the quantity of output the firm produces within a period of time

Fixed Costs: Costs that do not vary with output within a period of time

Sunk Costs: Costs that have already been incurred (even if not yet paid) and for which no refund is possible

Short-Run Marginal Cost (or Incremental Cost): The additional cost a firm incurs when it increases production by one unit within a period of time, recognizing that some inputs (typically capital) cannot be adjusted within the period

Total Costs: All costs that the firm has attributed to production within a period of time. Some fixed and sunk costs are amortized over multiple periods, with only a part attributed to production in each period.

Alternative Approaches to Covering a Revenue Shortfall

Departures from pricing at SMC have implications for both economic efficiency and equity concerns. In discussing utility rate structures, the term "equity" can have two different meanings — the first consistent with some notion of fairness across customers with different consumption levels and patterns, and the second consistent with some notion of fairness across customers of different levels of income or wealth. For clarity, I will use "equity" for the first concept and "distributional effects" for the second.

I will assume from this point forward that efficient pricing, price set equal to SMC, results in a revenue shortfall. However, the opposite situation, excess revenue from setting price equal to SMC, can also occur.[115] So I will focus on the question of how to increase revenues to the point that the utility can break even, including a fair return on capital invested.

Average-cost Pricing

For most of the history of utilities, the answer to such a revenue shortfall has been to raise the volumetric price of the electricity. Because utilities are generally monopolies facing fairly inelastic demand, it is almost always possible to raise the price enough to allow the firm to break even. This approach is often referred to as "average-cost pricing" because the price is set at a level to cover the average cost per kWh, where that average is inclusive of both variable costs and fixed costs. As the example in Figure 4.1 demonstrated, however, setting price above SMC creates deadweight loss by impeding some consumption that is socially valuable. Much of the economic analysis of regulatory pricing and taxation over the last 90 years has attempted to improve economic efficiency by developing alternate ways to raise the needed additional revenue while creating less deadweight loss.

[115] For instance, utilities that have a large supply of hydroelectric power from dams built many decades ago, but still must generate incremental power from fossil-fuel plants, may very well have a SMC that now exceeds their average cost per kWh.

Still, average-cost (AC) pricing remains widespread because it is so attractive on equity grounds. In its simplest implementation, AC pricing implies charging every customer — rich or poor, heavy user or light, residential or commercial — the same price per kWh. Equally important, it means that all customers make payments above marginal cost to help cover the fixed costs, and that a customer's contribution to the extra revenue needed to cover fixed costs is proportional to that customer's usage.[116]

For instance, assume the marginal cost is $0.12 per kWh, but there are significant fixed costs so the utility must charge $0.22 per kWh — an extra $0.10 per kWh — to break even. Then a customer who consumes 100 kWh is making a $10 contribution toward the additional required revenue, while a customer who consumes 400 kWh is making a $40 contribution. Many people and policymakers find this allocation equitable.

Even on equity grounds, however, it is not obvious that one customer consuming four times as much electricity as another customer should make a four times larger contribution to the additional required revenue, when that additional revenue is needed to cover costs that are independent of the level of consumption by an individual or even by all customers in aggregate. For instance, it might be the case that the customer consuming only 100 kWh receives a very high value from those units of consumption, while the heavier consumer might have a readily available alternative (e.g., self-generation), so is getting much less value from the utility.

"Ramsey" Pricing — Differentiated Pricing Based on Demand Elasticity

The earliest contribution on the issue of raising revenue while minimizing deadweight loss[117] pointed out that if a consumer has more elastic (i.e., price-sensitive) demand, raising the price charged to that consumer creates greater deadweight loss relative to the amount of additional revenue it creates compared to another consumer with less elastic demand. Raising the price to customers with more elastic demand simply causes them to cut back their consumption substantially even though they value those units greater than SMC, creating more deadweight loss while purchasing fewer units and thus contributing less to the revenue requirement. Figure 4.2 illustrates that both D1 and D2 consume Q0 when the price is set equal to SMC. But if the price is raised to AC, much more additional revenue is extracted from D1, and less deadweight loss is created, than when price is raised for D2.

[116] AC pricing can also be implemented in a time-varying context by imposing either a constant dollar adder to price in each period or a constant proportional markup. See Borenstein (2005).

[117] Ramsey (1927).

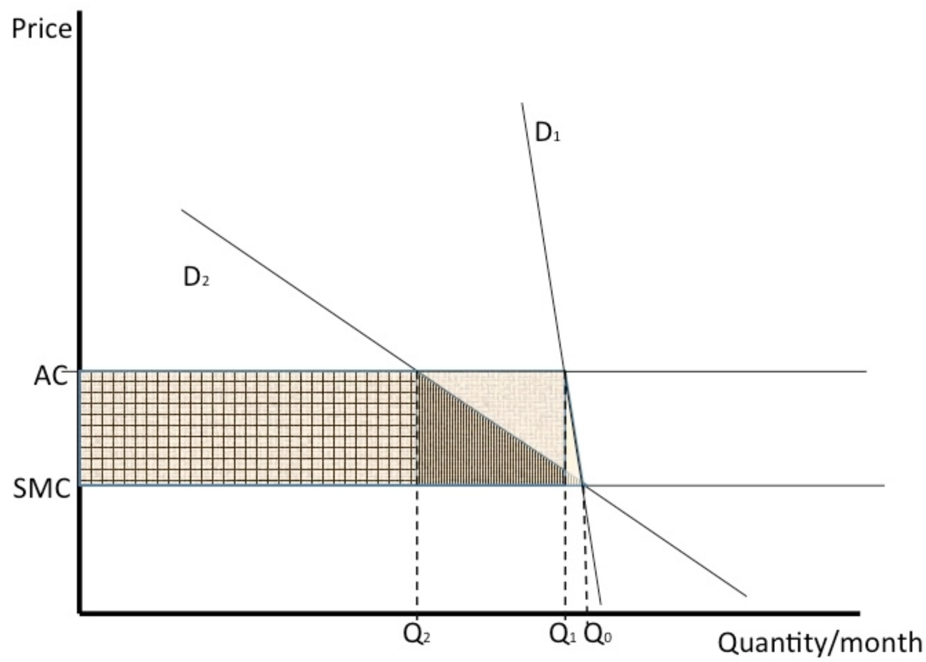

Figure 4.2 Illustration of the Impact of Demand Elasticity on DWL From Raising Price

The resulting "Ramsey pricing rule" says that in order to minimize deadweight loss while meeting the breakeven revenue requirement for the utility, groups of consumers with very inelastic demand should pay higher markups over marginal cost than groups of consumers with very elastic demand. This is much more than an abstract theoretical result. In fact, it describes well the outcome in which a utility gives special rates to commercial and industrial (C&I) customers who credibly argue that they would otherwise locate elsewhere. The willingness of businesses to locate elsewhere if electricity rates are too high demonstrates high demand elasticity and implies that raising the rate to these customers will do more to reduce their demand than to actually bring in greater revenue. That resulting deadweight loss manifests as fewer jobs and less economic value created by these C&I customers.[118]

Application of the Ramsey pricing rule, however, nearly always raises significant equity concerns. Customers with very inelastic demand, who receive higher prices under the rule, are those who have few alternatives and "need" the good. Charging those customers higher prices conflicts with many notions of equity.

Fixed Charges

In most of the United States, residential electricity customers pay a fixed charge each month that is independent of the quantity they consume, though the size of the charge ranges across utilities from just a couple of dollars to $20 or more. Fixed charges are a very attractive way to minimize deadweight loss while raising additional revenue, because they give customers no incentive to change their electricity consumption choices. Thus, if setting the volumetric price of

[118] C&I customers that are willing to relocate demonstrate that elasticity comes not just from a customer changing quantity consumed, but also from the customer relocating to purchase from a different seller.

electricity at SMC yields insufficient revenue, one common suggestion is to set a fixed charge that raises sufficient additional revenue to cover the revenue requirement.

A fixed monthly charge of $10, $20 or $30 is unlikely to lead any customers to disconnect from the utility, because at least a basic level of electricity consumption is a necessity.[119] And once customers decide to pay the fixed charge, they rationally would consider it no more relevant to how much electricity they consume than the same increase in rent, medical insurance, food or any other expense. The decision of how much to consume would still be based on the incremental price of electricity.

Still, questions about the economic efficiency of such an approach have also been raised if customers base their decisions on imperfect information. If consumers don't pay much attention to their bills, they may not distinguish between the marginal price of electricity and their average price, inclusive of the fixed charge, or understand the impact on their overall bill. Convincing evidence of a similar information failure has been presented for more complex tiered billing structures that I will discuss below. Research, however, has not determined whether or not consumers are generally able to sort out a monthly fixed charge from the marginal price of electricity when making consumption decisions. Nonetheless, this is an area deserving of further study.

Practical concerns have also been raised about how the fixed charge concept might be applied beyond residential customers. A fixed monthly charge for commercial or industrial customers is rarely suggested. The reason for this distinction is clear: While households do range substantially in size, most still have between one and 10 individuals and a similar range in square footage of living space and other determinants of electricity demand. In contrast, C&I customers have a much wider range of employees, sales, square footage and other demand determinants. It would seem arbitrary and objectionable to impose the same fixed charge on an auto assembly plant as on a corner store, or a family living in a small apartment.

Some have suggested using a fixed charge that increases when the customer crosses certain consumption thresholds. If no customers are near the thresholds, then this approach could potentially segment customers into different fixed charge categories without creating perverse incentives for changing behavior. In reality, however, the distribution of customer usage is smoothly populated across nearly all consumption levels found among household customers, and the distribution among small commercial customers overlaps significantly with household customers. So such graduated fixed charge tariffs would create incentives for many consumers to reduce usage in order to drop down to a lower fixed charge. Effectively, the thresholds are points at which the price for an incremental kWh is drastically greater than SMC and is thus likely to create substantial deadweight loss.

Applying a uniform fixed charge even among residential customers nearly always raises objections on equity and distributional grounds. The equity argument is just the flip side of the

[119] The argument is not as convincing in natural gas distribution, because some households could indeed be on the margin of disconnecting from the utility and using only electricity or liquefied petroleum gas, as discussed by Borenstein and Davis (2012). Virtually all U.S. households are customers of an electric utility, but only about half of households are customers of a natural gas utility. If distributed electricity storage becomes more cost-effective, however, high fixed monthly charges for electric service might one day also lead to "cutting the cord."

discussion in favor of AC pricing: Why should a customer who consumes very little have to make as large a contribution toward covering fixed costs as a customer who consumes much more? The distributional argument is based on the accurate, but sometimes overstated, claim that wealthier households consume more electricity. For example, while this is true for customers of the three large investor-owned California utilities, most low-income customers are already on a separate tariff targeted specifically at the poor.[120] Among moderate- and high-income customers, there is still a difference in average consumption, but it is much more modest.

Tiered Pricing

Under tiered pricing the marginal price a customer faces changes with the quantity consumed. It also is often referred to as increasing-block or decreasing-block pricing, depending on whether the marginal price rises or falls with the customer's consumption. For example, an increasing-block price schedule might charge the customer $0.12 for each of the first 300 kilowatt-hours (kWh) the customer consumes during the month, $0.18 for each additional kWh between 300 kWh and 500 kWh, and $0.30 for each kWh above 500 kWh.

Tiered pricing was originally introduced in the decreasing-block form. That can be seen as a compromise of sorts between AC pricing and a fixed charge with lower constant pricing. As shown by the dashed vertical line in Figure 4.3, a fixed charge is just a very high price for the first tranche of kWh consumed during the billing period, and then a lower price for all additional kWh, while AC pricing charges the same price for all kWh. Under AC pricing, the additional revenue above SMC is raised proportionally to consumption, while with a fixed charge it is equally allocated among all customers regardless of consumption. Declining-block pricing (the dotted line in Figure 4.3) allocates more of the additional revenue needed to higher-demand consumers (the vertically striped area plus the horizontally striped area, for D_{high}) than to lower-demand consumers (just the horizontally striped area, for D_{low}), but not proportionally more.

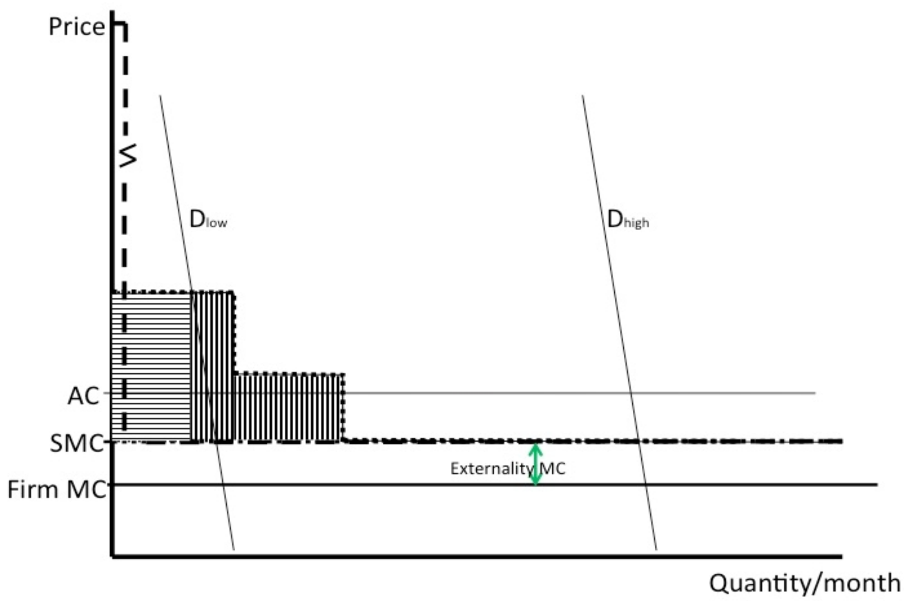

Figure 4.3 From Fixed Charges to Decreasing-Block Pricing to Flat Rates

[120] Borenstein (2011).

At the same time, because decreasing-block pricing implies above-AC pricing for lower-quantity units of consumption, the marginal price for higher-quantity units can be closer or equal to SMC, and can thus generate less deadweight loss for those units. Compared to fixed charges, however, decreasing-block pricing has the drawback that lower-consuming customers will face a very high marginal price and will respond by inefficiently cutting back consumption. To the extent that there are few or no customers on the lower-quantity tiers (if all customers have demand around D_{high} or greater), the impact is very similar to a fixed monthly charge, because nearly all customers contribute the same amount toward the additional revenue requirement. In that case, nearly all customers face the lowest marginal price.

In the last 20 years, increasing-block pricing has become much more prevalent in residential U.S. electricity tariffs than decreasing-block pricing. Arguments for increasing-block pricing are based on both distributional concerns and conservation goals. The distributional argument is that low-income households are more likely to be consuming more of their electricity at low tier rates, and therefore increasing-block structures redistribute the revenue burden to wealthier households on average. Analysis suggests that the redistribution is quite modest if the utility also has a separate tariff for low-income households, as most utilities do. Furthermore, many lower-income households are made worse off by the increasing-block structure, and many higher-income households benefit from it. Overall, if the goal is to help lower-income households, programs that are more accurately targeted at them are likely to be more effective.[121]

The foundational economic analysis I present earlier demonstrates that reducing consumption creates net benefits to society only if the value of that consumption is less than the full social marginal cost. Thus, charging a price that includes the cost to society of externalities makes sense, but charging a price that is substantially above the full SMC will cause some consumption to be discontinued for which the customer values the service more than marginal cost, even inclusive of the external marginal costs it imposes. Put differently, reduction of consumption that is not valued highly enough to justify the external costs it imposes on society is a worthy goal, but not all conservation is beneficial. Electricity regulators almost always recognize this reality even when they adopt increasing-block pricing, resulting in a plethora of special rates (or special baseline quantities that determine the quantities at which the increasing-block steps occur) for favored activities, such as electric heating or charging electric vehicles. That approach, however, puts the regulator in the position of trying to discern the consumer's value of each electricity use, a task that market economies eschew in general, because they recognize how poorly the government performs that task.

It is also not clear that increasing-block pricing actually lowers aggregate consumption among residential customers. While it does raise the marginal price for high-use customers above a revenue equivalent AC price, it also lowers it for low-use customers below the revenue equivalent AC price. If all customers are well-informed and respond efficiently to marginal price, then aggregate consumption is likely to fall. But customers' response to complex, multi-step, increasing block tariffs corresponds more closely to a model in which they use a heuristic that reflects the average price they face.[122] If the increasing-block tariff is revenue neutral with the

[121] Borenstein (2012).
[122] Ito (2014).

AC price schedule, then the average price across all units consumed must be the same, and increasing-block pricing would generate no net reduction.[123] Analysis of a very steep increasing-block tariff in place for a large California utility yielded an estimated 2.3 percent reduction in residential consumption assuming customers responded efficiently, but in practice the tariff probably causes an *increase* of about 0.3 percent.[124]

The economic efficiency of increasing-block pricing, compared to AC pricing, depends on the reduction in deadweight loss for customers who respond to a price that is less than AC (but still presumably above SMC) versus the increase in deadweight loss for customers who respond to a price that is greater than AC. The net effect on economic efficiency will almost surely be negative.[125] Analysis for one California utility estimates that compared to AC pricing, the increasing-block tariff the utility uses increases deadweight loss by an amount equal to about 3 percent of revenues received from residential customers.

Finally, for the same reason as with monthly fixed charges, tiered pricing makes very little sense in the context of C&I customers. Because there is a much wider range of electricity demand across companies than across residential customers, it is hard to see how a common tiered pricing structure could be applied to all C&I customers, or even large subsets of them. Some have suggested that the baseline quantities on which the tiers are based could be a function of past usage by the customer, but this creates incentives for distorting consumption in order to alter the baseline.[126]

Minimum Bills

The mathematics of a minimum bill is simple, but frequently ignored: A minimum bill is a combination of a fixed charge and a certain quantity of free electricity. For instance, if the price of electricity is $0.10 per kWh and there is a minimum bill of $8 per month, that is identical to a fixed charge of $8 per month plus receiving the first 80 kWh for free. Thus, a minimum bill is the combination of a fixed charge and an extreme version of increasing-block pricing, as illustrated in Figure 4.4. If the minimum bill is small enough, implying a quantity of free electricity that is less than nearly every customer uses, then the fixed charge and free electricity exactly offset, and the minimum bill has no impact on either the bills of the customers or the finances of the utility.

[123] This argument assumes that the average demand elasticity is the same for lower-consuming customers as for higher-consuming customers. Ito tests that assumption and finds no statistical difference between the groups.
[124] Ito (2014).
[125] Borenstein (2012). The reason for this is that the amount of deadweight loss generated by pricing above SMC goes up approximately with the square of the P-SMC differential. In that case, a simple mathematical proof shows that the minimum deadweight loss results from charging all customers the same differential — that is, AC pricing.
[126] Borenstein (2014) discusses a similar issue in which the baselines used to determine what customers are paid for reducing consumption in a billing period are based on each customer's past usage.

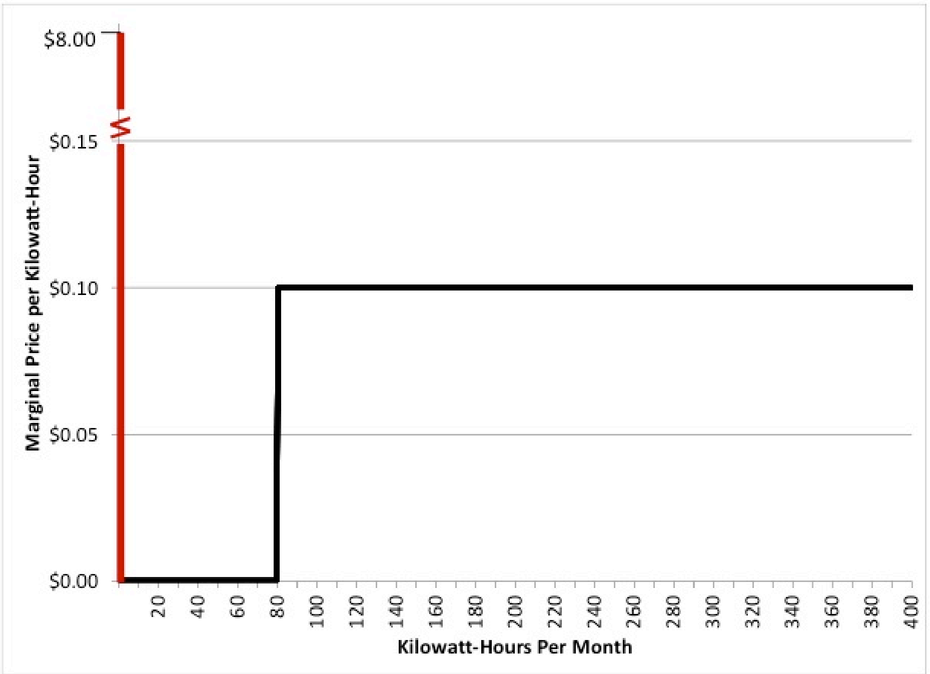

Illustration of Rate Structure with Minimum Bill (Min Bill $8, p=$0.10/kWh)

Figure 4.4 Illustration of Effective Marginal Price of Electricity Under Minimum Bills

If the minimum bill is high enough to actually raise the amount owed to the utility by a significant number of customers, then it creates very perverse incentives for those customers, reducing their cost of incremental consumption to zero until they hit the minimum bill. Zero is well below the SMC for nearly every unit of electricity a utility sells, so a minimum bill has the effect of encouraging electricity consumption from which the customer gets much less value than is imposed on society by its production.

Thus, from both an efficiency and equity point of view, minimum bills are inferior to the alternative of setting price equal to SMC for the equivalent quantity and then charging a fixed charge that is smaller than the minimum bill. For instance, returning to the example above with a minimum bill of $8 and marginal price of $0.10 per kWh, let's say the true SMC is $0.06 per kWh. In that case, it would be more economically efficient and more equitable to charge $0.06 per kWh for the first 80 kWh plus have a fixed charge of $3.20. That would have no impact on the bills of customers consuming more than 80 kWh. It would lower the bill of customers consuming less than 80 kWh, but it would still give them an efficient incentive not to waste electricity.[127]

[127] The fact that some customers use less than 80 kWh and the volumetric price is above marginal cost implies a slight revenue shortfall. This could be offset by a small increase in either the fixed charge or the lower-tier volumetric price. To be concrete, in this example if 10 percent of customers were below 80 kWh and that group of customers consumed an average of 50 kWh, then this alternative tariff would require either setting the fixed charge (for all

Demand Charges

It is unclear why demand charges still exist. Charging customers for their peak usage during a billing period has been supported as an approximation to a customer's demand during system peak periods, but it was never a very good approximation, as the customer's peak may not be coincident with the system peak.[128] Furthermore, the single highest consumption hour of the billing period is not the only, and may not even be the primary, determinant of the customer's overall contribution to the need for generation, transmission and distribution capacity.

In any case, the value of such approximations has been mostly eliminated with smart meters that record usage in hourly or shorter intervals. Smart meters permit time-varying price schedules that can easily be designed to more effectively capture the time-varying costs that a customer imposes on the system. Demand charges could be justified when "dumb" meters could only record aggregate consumption and peak consumption, but could not even log information on when that peak occurred.[129]

An additional explanation for demand charges is that they capture the customer-specific fixed cost of providing a certain level of service capacity to the customer's site. Such capacity, however, is established by making up-front and largely sunk investments in the local distribution network and the final connection to the customer. These may constitute a substantial share of the fixed costs that create the concerns addressed in this report, but the cost of such capacity is determined by the attributes of the connection, not by the customer's peak usage after the connection is established. A monthly fixed charge based on the customer's service capacity would more appropriately capture these costs.

The use of demand charges has also created a large market of consultants advising customers on how to reduce their peak demand that is wasteful from a societal point of view. Customers faced with demand charges place high private value on reducing their very highest hour of usage, even if there are other hours in which usage is nearly as high, and even if none of those hours are coincident with system peak times.

At their very best, demand charges may not do a bad job of capturing some customer-specific fixed costs and may quite imperfectly reflect the time-varying costs of the customer's consumption. But customer-specific fixed charges that reflect service levels, and time-varying pricing, accomplish these goals much more effectively, so why would one use demand charges?[130]

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customers) at $3.32 instead of $3.20 or setting the volumetric charge at about $0.0616 instead of $0.06 for quantities up to 80 kWh. Either would leave the utility with the same profits as the proposed minimum bill.

[128] Recently, some have started using "demand charge" to refer to a fee that is based on a customer's use during the systemwide peak demand. This is a form of time-varying pricing similar, though inferior, to what is known as "critical peak pricing." The discussion of demand charges here does not apply to that newer definition.

[129] Most C&I customers now have meters that can record time-varying consumption. The majority of residential customers do not yet have such "smart" meters, but the meters they have also cannot record peak consumption needed for a demand charge. Switching them to the technology for a demand charge would cost nearly as much as the technology for time-varying pricing.

[130] Berg and Tschirhart (1988) propose a system under which customers purchase fuse capacities from the utility, which limits their maximum power consumption. With the progress in technology over the last few decades, this could no doubt be done in a more sophisticated way, but still only makes sense to the extent it reflects real costs imposed by the customer's peak usage.

Frequent Rate Cases, Formula Rate Plans and Decoupling

Infrequent rate adjustments, especially when a utility's costs and sales quantities are highly uncertain, create a mismatch between actual revenues and targeted cost recovery.[131] If the regulatory commission is forward looking and attempts to equalize actual with targeted revenues on average, then the errors will cancel out over time.[132] But if the commission systematically underestimates cost increases or overestimates quantities demanded, then infrequent resetting of rates will create a perpetual revenue shortfall. Although this is a concern for utilities and the regulatory process, it is quite apart from the problem of recovering utility fixed costs. Even if rates were reset daily, the presence of significant fixed costs would mean that economically efficient electricity prices would still likely fail to raise sufficient revenue to cover all of the utility's costs, for the reasons discussed above.

One mechanism for addressing the revenue and cost uncertainty a utility faces is known as a Formula Rate Plan (FRP). FRPs provide for an automatic adjustment of rates when revenues deviate from either target revenue or some formula for pro forma costs. In this way, rate adjustments can be made between formal rate cases in a way that is transparent and can be debated ex ante. While FRPs can help to align revenues with costs, like frequent rate cases they do not address the fundamental conflict between marginal-cost pricing and full-cost recovery. Even if costs and revenues could be predicted perfectly, the tension between economic efficiency and utility cost recovery presented earlier in this chapter of the report would remain.

FRPs are related to "decoupling," which has been adopted in electricity rate setting to align utility incentives with the goals of energy efficiency programs. If sales fall short of expectations due to improved energy efficiency, or generally due to weak demand, the utility will suffer a shortfall, because its costs will decline by less than revenues. This shortfall is caused by the fact that volumetric prices are generally set above the utility's marginal cost in order to recover fixed costs. Decoupling assures the utility that it will be able to recover the lost revenue through price adjustments going forward. In doing so, it reduces or eliminates the incentive of a utility to oppose, or drag its feet on, energy efficiency programs. But as with frequent rate cases and FRPs, the problem that decoupling is meant to solve is quite apart from the general problem of recovering utility fixed costs. Even if decoupling works perfectly, and utilities make all-out efforts to promote energy efficiency, economically efficient volumetric electricity prices would still likely raise insufficient funds without other measures to address the revenue shortfall.

Conclusion

In the end, there is no good answer to the question of how a utility should recover fixed costs, but there are less bad ones. Ratemaking should begin by setting prices to reflect the full time-varying short-run social marginal cost of generating and delivering electricity. These prices should include "adders" for the externalities created, even if the utility is not required to make explicit payments for those social costs, as is the case for most externalities today. As a result, the revenue from these adders can be used to close the gap between the revenue collected from efficient pricing and the revenue the utility needs to cover its costs.[133]

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[131] Frequent rate cases could be full-blown rate cases or smaller rate-adjustment filings.

[132] Even in those cases, short-term revenue shortfalls can still create financial stresses that end up raising the costs of the utility and, eventually, the prices to customers.

[133] Even if regulators are unwilling to, or restricted from, imposing explicit adders to reflect externalities, this still suggests that when they mandate markups of volumetric prices above the utility's marginal cost — as virtually all

In general, however, efficient pricing that reflects full social marginal cost will still not cover all fixed and variable costs of the utility. Increasing the volumetric price of electricity has appeal on equity grounds, because it allocates the revenue shortfall across users based on the quantity they consume. However, it also raises the marginal price of electricity above social marginal cost and therefore distorts consumption choices. As customers have more choices of energy supply — e.g., between electrified and liquid fuel-based transportation or between distributed generation and grid supply — the deadweight loss from sending distorted price signals is likely to rise.[134] While raising the volumetric price has been the most common policy choice for many decades, it is particularly important now to consider alternatives.

The leading alternative is higher fixed charges, but they can lead to significant equity concerns and even some potential efficiency issues. Recovering customer-specific fixed costs through fixed charges — calibrated to reflect cost differences in service levels — is quite appealing on both equity and efficiency grounds. But a fixed charge that is the same for customers with massively different demands will violate a common sense of equity, and a so-called "fixed charge" that is based on past or current usage is effectively volumetric and creates deadweight loss.

Objections to any level of fixed charge based on distributional consequences ignore the fact that the alternative of recovering all revenues through volumetric charges arbitrarily harms many low-income customers and benefits many high-income customers. Targeted means-tested programs that help low-income households are a more appropriate response to these concerns.

The more difficult fixed cost recovery issue results from systemwide fixed costs that cannot be attributed to any one customer. Because such costs are substantial, pricing electricity at social marginal cost and having a fixed charge that reflects customer-specific fixed costs is still likely to leave a revenue shortfall. There is no ideal policy for recovery of the additional needed revenue, but the least bad from both an efficiency and equity point of view is almost surely a combination of higher fixed charges and an adder to time-varying volumetric rates. For the reasons I have discussed, it is very difficult to justify demand charges, tiered rates or minimum bills as part of the solution. Nor would frequent rate cases, formula rate plans or decoupling solve the fixed cost recovery problem.

While it may be unsatisfying that economics and policy analysis does not yield a clear solution, it does yield valuable guidance. Incorporating that guidance in electricity ratemaking would be a very useful first step in rationalizing prices.

regulators do — those markups would be more economically efficient if they were calibrated to reflect variations in the externalities created by incremental generation.

[134] See Borenstein (2015).

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5. Literature Review

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This chapter briefly describes the ratemaking options discussed in this report through a review of publications by a wide range of energy experts to highlight current practices, potential pros and cons, and the diversity of views. The references cited provide additional information.

Higher Fixed Charges

A fixed charge, also called a customer charge or basic service charge, is a fee each billing period that does not vary with the consumer's energy usage. Typically, fixed charges for electric utilities cover metering, meter reading and billing costs. Fixed charges also may cover other costs, such as the utility's customer call center and a portion of distribution costs.[135]

Increasing the fixed charge is one way to ensure utilities have more stable revenues to cover fixed costs, and fixed charges have increased over time. Raising fixed charges also is one response to concerns about revenue loss from higher levels of distributed energy resources (DERs), particularly associated with customers with onsite solar photovoltaic (PV) systems (typically rooftop). Solar PV customers with net-zero consumption from the grid still pay the fixed charge portion of their electricity bills.[136]

A major change in the level of the fixed charge is under consideration in many jurisdictions. Utilities in 25 to 30 states have proposed increasing fixed charges for all customers, only for customers with onsite distributed generation, or only for net metering customers.[137] Many of the proposed increases have been significant — more than doubling previous fixed charges. Utility regulators have allowed some of these proposed increases, often modified downward, but have disallowed more proposals than they have allowed.[138]

Higher fixed charges stabilize utility revenues[139] and customer bills[140] because a smaller share of costs varies based on weather and other uncontrollable factors. Higher fixed charges also reduce the need for more frequent rate cases to resolve utility cost recovery shortfalls because more of a utility's fixed costs are recovered through the fixed charge.[141] And, unlike revenue decoupling or lost revenue adjustment mechanisms (discussed later in this chapter), higher fixed charges preserve utility revenues while reducing, rather than enhancing, cross-subsidies from energy efficiency or distributed energy program participants to nonparticipants.[142]

However, when fixed charges are raised substantially, volumetric energy prices often are lowered in order to collect the revenue requirement from the combination of rate components.

135 Lazar (2013); Costello (2014).
136 Bird et al. (2015).
137 Stanton (2015); NC Clean Energy Technology Center and Meister Consultants (2016).
138 Stanton (2015); Kind (2015).
139 Blank and Gegax (2014); Faruqui et al. (2012); Whited et al. (2015).
140 Testimony of Greg Bollom, Madison Gas and Electric (2014).
141 Lowry et al. (2015).
142 Kind (2013).

Reducing the volumetric price weakens customer incentives for energy efficiency.[143] For the same reason, potential cost savings from distributed generation and other distributed energy resources are lower, reducing their attractiveness[144] and leading the rooftop solar industry to oppose higher fixed charges.[145] On the other hand, higher fixed charges mitigate a disincentive for utilities to promote energy efficiency, since their revenues are less dependent on variable sales,[146] although the disincentive related to fewer investment opportunities persists.

In addition, customers will demand more electricity if volumetric prices are reduced. The extent of this impact depends on the longevity of the price change. In the short run, customers may run their air conditioners and other electric appliances more, but the effect is likely limited. In the longer run, however, customers would tend to switch to electric devices from devices directly fueled by natural gas or other fuels, leading to larger changes in electricity consumption.[147]

Higher fixed charges may disproportionally burden low-income households, which also tend to be lower-usage customers.[148] Depending on how much the fixed charge increases, moderate-income households that live paycheck to paycheck also may be significantly impacted. Service may be unaffordable for these households, particularly when electricity bills increase regardless of how much energy they consume, resulting in disconnections.[149] Other industries (e.g., telephone and cable services) have witnessed customer attrition in response to raising fixed charges.[150] Concerns over impacts on low-income households generally have led consumer advocates to favor low fixed charges.[151] Some proponents of high fixed charges recommend offering optional rate structures more similar to current rate designs for lower-income customers to opt into.[152]

The principle of economic efficiency dictates that, in general, goods and services should be priced according to the true cost of their production, delivery and consumption.[153] However, this principle leads different observers to different conclusions regarding the appropriate level of fixed charges. Importantly, views also vary as to what costs should be considered "fixed."

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143 Hledik (2014); Bird et al. (2015); Whited et al. (2015).
144 Bird et al. (2015); Whited et al. (2015).
145 Hledik (2014); Lazar and Gonzalez (2015).
146 Costello (2014).
147 In the short run, a 10 percent reduction in the residential retail price of electricity could be expected to increase consumption by 2 percent to 4 percent. If such a reduction persisted over the long run, we would expect increases from 3 percent to 10 percent. See Paul et al. (2009).
148 Bird et al. (2015); Lazar et al. (2011); Whited et al. (2015); Kind (2015).
149 Lazar (2015).
150 Lazar and Gonzalez (2015); Graffy and Kihm (2014).
151 Blank and Gegax (2014); Hledik (2014); Lazar and Gonzalez (2015); National Association of State Utility Consumer Advocates (2015); also see https://nasuca.org/customer-charge-resolution-2015-1/.
152 Testimony of Greg Bollom, Madison Gas and Electric (2014).
153 Ackerman and De Martini (2013); Braithwait et al. (2007); Testimony of Greg Bollom, Madison Gas and Electric (2014); Lazar and Gonzalez (2015); Parmesano (2007).

Utilities generally view investments in generation, transmission and distribution infrastructure as fixed, in that they are not sensitive to how much energy an individual customer consumes.[154] Most of these costs are currently recovered through variable rates, and utilities are increasingly seeking to correct what they see as a pricing mismatch.[155]

Others note that in the long run, all or almost all of a utility's costs other than direct customer service (metering, billing, accounting) are variable.[156] Some argue that high fixed costs push variable prices below the long-run marginal cost of supplying electricity.[157] If retail rates are below long-run marginal cost, utility customers may not make all of the energy-saving investments that are optimal from a societal point of view because the payoffs will be too low, and utilities will make more costly investments to meet higher customer demand. Moreover, even costs that are fixed in the short run may be dependent on customer usage.[158] For example, according to this view, it may be appropriate to recover power plant and transmission investments in proportion to usage.[159] Firms in competitive industries generally recover all costs through variable pricing even when a portion of their costs is fixed. A basic role of utility regulation is to better approximate such markets.[160] Thus, high fixed charges "are a poor method to recover utility system costs,"[161] "have the most adverse impacts" among various options to recover utility fixed costs,[162] and "provide utilities with stable revenues, but have many adverse impacts on electric[ity] consumers and energy policy."[163]

While revenue stability is an overarching reason for utilities' interest in higher fixed charges, utilities also are concerned that current levels of fixed charges may fall short of the actual cost of providing grid services to distributed generation customers.[164] Some utilities have proposed different rate classes for distributed generation customers.[165] For example, utilities in at least eight states have proposed fixed charge increases for solar PV customers, all distributed generation customers, or all customers who are net-metered.[166] McLaren et al.[167] state that these charges may be appropriate for customers whose systems exceed a certain size threshold or a certain percentage of load.

In addition, utilities are concerned about spreading fixed costs over a shrinking base of retail electricity sales, as penetration of customer-hosted distributed generation (and energy efficiency) increases. That could create a feedback loop: Utilities raise volumetric rates, which in turn makes distributed generation (and energy efficiency) more attractive, causing increased

154 Blank and Gegax (2014).
155 Ackerman and De Martini (2013); Testimony of Greg Bollom, Madison Gas and Electric (2014); Lazar and Gonzalez (2015).
156 Lazar (2013); Whited et al. (2015).
157 Lazar et al. (2011).
158 Blank & Gegax (2014); Lazar (2013); Whited et al. (2015).
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160 Bonbright (1961).
161 Lazar (2013).
162 Lazar and Gonzalez (2015).
163 Lazar (2015).
164 Borlick and Wood (2014); see also Satchwell et al. (2014), which shows that two "prototypical" U.S. utilities experience increasing cost recovery shortfalls as PV penetration increases.
165 Ackerman and De Martini (2013).
166 Bird et al. (2015); Stanton (2015).
167 Bird et al. (2015).

deployment and further revenue shortfalls.[168] Alternatively, increasing fixed charges also could create a feedback loop: Higher fixed charges increase customers' incentive to defect from utility services entirely. Fewer utility customers means that each remaining customer must bear a greater share of system costs, which could cause fixed charges to rise further, leading to greater defection and so on.[169]

Minimum Bills

A minimum bill sets a lower limit that a customer will pay the utility each billing period, even if the customer's energy usage is zero. Under common proposals for a minimum bill, the fixed charge plus energy charges will typically exceed the minimum for the majority of customers. Thus, a minimum bill structure would have no impact on most customers, who would effectively continue to pay a volumetric rate to cover both power supply and distribution costs. However, customers that reduce their energy usage to very low levels, particularly through the use of distributed energy systems that provide for most or all of their electricity needs, could trigger the minimum bill.[170]

Minimum bills are not currently widespread. However, a few utilities have implemented them, notably in California.[171]

Minimum bills are more targeted than fixed charges, as they apply only during months when energy usage is low (for example, for vacation homes and vacant property) or where rooftop solar generation is high.[172] Customers most likely to trigger minimum bills are households that are strongly seasonal in their electricity usage and households with distributed generation systems.[173] Because a minimum bill will rarely be triggered if the minimum is set low, it will result in much less utility revenue, and therefore a much smaller decrease in volumetric rates, compared to a fixed charge of the same amount.[174]

Therefore, minimum bills do not discourage energy efficiency or increase electricity consumption as much as equal-sized fixed charges. Minimum bills may better align electricity prices with the long-run marginal cost of consumption, because nearly all costs vary in the long run. In months when usage dips below the minimum bill amount, consumers have poor incentives for energy efficiency as the cost of electricity consumption becomes zero. However, this would apply to relatively few customers.[175]

[168] Darghouth et al. (2015).
[169] Graffy and Kihm (2014).
[170] Lazar (2014); Bird et al. (2015).
[171] Stanton (2015).
[172] Bird et al. (2015).
[173] Lazar and Gonzalez (2015).
[174] Lazar (2014).
[175] Lazar (2014).

Solar PV users who offset their consumption completely would still pay the minimum bill, which would reflect at least in part the value of the grid services they receive.[176] However, minimum bills may reduce solar PV system sizing, as customers will attempt to avoid reducing their usage below the minimum bill amount.[177]

Demand Charges

A demand charge is based on the customer's highest energy usage in a specified time interval — for example, 15 minutes or an hour — over the course of the billing period, typically a month. Some demand charges include a "ratchet," meaning that the highest demand a customer registers in a billing period may apply over the course of the following year. The rationale for a demand charge is that the utility must maintain available capacity (for distribution at a minimum, and generation and transmission as well in vertically integrated regions) to meet the customer's peak demand at all times. The demand charge is measured in kilowatts (demand), rather than kilowatt-hours (energy usage). Rate structures with demand charges have a relatively lower energy charge than rate structures without demand charges because they work in combination to collect the utility's revenue requirement.

Demand charges have typically been applied to the individual peak demand of each customer, regardless of whether that occurs during peak periods for the utility system. However, demand- (capacity-) related costs are primarily associated with the peak demand of the utility system, not the individual customer's peak demand. Only highly local components of the distribution system (e.g., service drop, line transformer) are sized to the individual customer load.[178] Therefore, under a typical demand charge — based on *non*-coincident usage — customers who use the most electricity at times that are not coincident with the system peak pay to offset system peak costs nonetheless.

Demand charges already are in place for large commercial and industrial customers. Demand charges are currently offered in optional residential rate structures by at least nine utilities, though most have not seen significant enrollment,[179] and have recently been proposed for solar PV customers in a handful of states.[180]

[176] Lazar (2015).
[177] Bird et al. (2015).
[178] Lazar and Gonzalez (2015); Bird et al. (2015).
[179] Hledik (2014).
[180] Bird et al. (2015).

Demand charges have historically been unpopular with residential customers.[181] They may find demand charges difficult to understand[182] and are generally less equipped to monitor and shift load than commercial and industrial customers.[183] On the other hand, demand charges provide customers an incentive to reduce utility system costs through improved load management[184] — if the charge is based on demand that is coincident with the utility system peak. Utilities also would avoid a potential cost recovery shortfall due to customers who reduce their overall energy consumption but not their peak consumption.[185]

Implementing demand charges requires metering that can measure demand. Smart meters have been deployed in about half of U.S. homes.[186] In the absence of metering capable of measuring residential demand, some recommend charging all customers in a rate class (for example, all residential customers) according to the average peak customer demand in that class (which is effectively a higher fixed charge) because costs to serve customers are similar across the class.[187] Others argue that, due to the high correlation between usage and peak demand, in the absence of smart meters it is more appropriate to recover most demand-related costs through variable rates.[188]

Compared to high fixed charges, demand charges are less likely to discourage energy efficiency[189] or distributed solar PV[190] and are not as burdensome on low-income households.[191]

Perspectives differ on the relationship between traditional demand charges (charges based on the customer's own peak demand, as opposed to the customer's usage during the utility system's peak demand) and the drivers of actual costs. According to Lazar, demand charges "track cost causation very poorly"[192] as the only costs driven by a customer's individual peak usage are transformer costs.[193] In contrast, other energy experts point out that 50 percent or more of a typical customer's bills are due to capacity-related costs.[194]

Much of the literature on demand charges is coincident with discussion of time-varying rates (discussed next). Some energy experts find time-varying rates more appropriate than demand charges.[195] Others support rates that include both a charge based on customer peak demand and a time-varying rate structure.[196]

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[181] Braithwait et al. (2007).
[182] Lazar and Gonzalez (2015); Lazar (2013).
[183] Glick et al. (2014); Bird et al. (2015).
[184] Testimony of Greg Bollom, Madison Gas and Electric (2014); Hledik (2014).
[185] Hledik (2014).
[186] Wood (2016).
[187] Testimony of Greg Bollom, Madison Gas and Electric (2014).
[188] Blank and Gegax (2014).
[189] Bird et al. (2015).
[190] Glick et al. (2014); Hledik (2014).
[191] Hledik (2014); Bird et al. (2015).
[192] Lazar (2013).
[193] Lazar and Gonzalez (2015); Lazar (2015).
[194] Blank and Gegax (2014); Testimony of Greg Bollom, Madison Gas and Electric (2014); Electric Power Research Institute (2014).
[195] Lazar and Gonzalez (2015); Lazar (2015); Parmesano (2007).
[196] Glick et al. (2014).

Time-Varying Rates

Time-varying rates encompass both traditional time-of-use rates, such as daily on- and off-peak rates and rates that vary by season (typically higher in summer or winter, depending on the time of utility system peak), as well as newer dynamic pricing rates such as critical peak pricing and real-time pricing.[197]

While time-varying rates have been the default rate design for many years for large commercial and industrial customers,[198] who are equipped with meters that can measure energy usage in short time intervals, only about 5 million U.S. households participated in dynamic pricing programs of any kind as of 2014.[199] However, more utilities have begun offering optional residential rate schedules that vary by time of day. And some utilities are moving toward a default time-of-use tariff for residential customers.[200]

Most energy experts note the significant mismatch between static electricity rates and the dramatic temporal variation in the actual cost of electricity production — and the poor price signals static rates send to customers.[201] Time-varying rates can partially or even fully remedy this problem.[202] Many experts identify time-varying pricing as a best practice for rate design.[203] Well-designed time-varying pricing encourages customers to minimize electricity use during high cost periods, helping to reduce utility system costs over time.

Time-varying rates may offset cost recovery issues caused by deployment of solar PV technology: As solar PV deployment rises, it will shift the utility's peak system demand to times when solar PV output is lower, thus dampening the impacts of solar deployment on cost recovery.[204] This shift already has occurred, for example, in California at certain times of year, when afternoon solar PV production is offsetting enough load that system peak demand has shifted into the evening — the so-called "duck curve" load profile.[205]

Consumer advocates tend to be skeptical of time-varying rates in part because low-income households, households with older or very young members or with medical conditions, and some shift workers may have limited ability to shift load.[206] In addition, some time-varying rate designs make customer bills less stable and shift price risk from the utility to consumers.[207] That's particularly the case with real-time pricing, where electricity rates fluctuate frequently (e.g., every hour) to reflect changes in market prices. Recent studies have found that residential consumers can adjust their usage effectively under other forms of time-varying rates, such as

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[197] Faruqui et al. (2012); U.S. Department of Energy (2010).
[198] Faruqui et al. (2012).
[199] EIA (2014).
[200] For example, see the statement by the Sacramento Municipal Utility District (https://www.smud.org/en/residential/customer-service/rate-information/rates-2016-2017/) and the California Public Utilities Commission's decision on rate reform for residential customers. (http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M153/K110/153110321.PDF).
[201] Braithwait et al. (2007); Glick et al. (2014).
[202] Costello (2014).
[203] Lazar (2013); Parmesano (2007); Glick et al. (2014); Kind (2015); Hledik (2014).
[204] Darghouth et al. (2015).
[205] Lazar (2016).
[206] Lazar and Gonzalez (2015).
[207] Testimony of Greg Bollom, Madison Gas and Electric (2014).

traditional time-of-use rates with on- and off-peak periods — and critical peak pricing variations that add a very high price during a very limited number of hours of the year.[208]

Another consideration is that under flat rate pricing, "peaky" customers — who use more electricity when it is most expensive for the utility to acquire — are subsidized by less "peaky" customers who use more off-peak, inexpensive electricity.[209]

Noting the variation in customer tolerance for this price risk, some recommend maintaining different rate options that allow customers to choose depending on their tolerance.[210] Some consumer advocates question the overall cost-effectiveness of the advanced metering infrastructure required to support time-varying rates, and some public utility commissions have disallowed proposed charges to support the purchase of such equipment.[211] Other observers hold that time-varying rates are "cost-effective for virtually all customers" due to falling costs of advanced metering.[212]

Time-varying rates may cause their own problems for fixed cost recovery. Depending on the details of the rate structure, this might occur if fewer peak price events occur than expected or if customers reduce consumption in response to time-varying rates.[213] Studies have shown that time-of-use rates reduce overall consumption by as much as 5 percent.[214] Decoupling, discussed further below, could help address this issue.[215] However, Braithwait et al.[216] note the problem of adverse selection: Customers who can save money on time-varying rates are more likely to enroll in them, where enrollment is optional. Increasing rates for default flat pricing structures, which can be justified by the extra cost and risk to the utility in maintaining such static pricing, may address this issue.[217] Opt-out, time-varying pricing also may mitigate this problem, as enrollment rates in recent studies have been 3.5 times higher than for opt-in enrollment (93 percent versus 24 percent),[218] so the pool of time-varying customers would include most "typical" users.

Tiered Rates

Inclining (or increasing) block rate structures charge a higher rate for each incremental block of electricity consumption. Conversely, under declining (decreasing) block rates, prices decrease as usage increases. Declining block rates have largely fallen out of favor because they do not reflect the increased utility costs associated with greater energy usage.

Inclining block rates are common for residential customers. They can be justified on several grounds. Since air conditioning use is a large component of electricity usage and also is a driver of peak consumption, inclining block rates serve as a proxy for time-varying rates to some

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208 Cappers et al. (2015).
209 Hledik and Lazar (2016).
210 Braithwait et al. (2007).
211 AARP (2012); also see Baltimore Gas and Electric Company (2015) for denial of the requested surcharge.
212 Parmesano (2007).
213 Faruqui et al. (2012).
214 King and Delurey (2005).
215 Faruqui et al. (2012).
216 Braithwait et al. (2007).
217 Braithwait et al. (2007).
218 Cappers et al. (2015).

extent.[219] Inclining block rates also lower costs for low-usage customers, providing an allocation of low-cost electricity to meet basic needs.[220] Consumer advocates favor them for this reason.[221] On the other hand, steeply inclining rates may create poor price signals on one or both ends of the tiering (in other words, the head block and tail block) and may place undue burden on the subset of low-income households with higher consumption.[222]

Many favor inclining block rates as a strategy to promote energy efficiency by deterring high levels of electricity usage.[223] However, some evidence suggests that they may not do so in practice.[224] Evidence does suggest that inclining block rates redistribute cost from small to large volume users; usage correlates weakly with income.[225]

Declining block rates are more rare today, but can be justified on the bases of declining economies of scale to serve larger users and as a substitute for higher fixed charges to ensure that customers pay closer to their share of system costs.[226]

Tiered rates can be combined with other rate structures presented here. For example, utility rate structures can combine inclining blocks with time-varying features and low fixed charges.[227]

FORWARD TEST YEARS

Forward test years involve a forecast of utility revenues and costs for a future time period, rather than relying on a historical test year to set rates. In an environment where utility costs are rising, using a forward test year in a general rate case to determine the utility's revenue requirement and billing determinants can help alleviate under-recovery of utility costs. Forward test years also can anticipate energy efficiency efforts and thereby alleviate under-recovery of costs from the remaining sales, reducing utility disincentives to pursue these programs. Forward test years raise the evidentiary burden on utility rate-setting processes, though well-understood methods have developed. Forward test years are only an option where authorized by state law and utility regulators; they are not currently an option in all states.

For more information, see Lowry et al. (2015); Lowry et al. (2010).

[219] Lazar and Gonzalez (2015); Lazar (2013); Parmesano (2007).
[220] Lazar (2013); Orans et al. (2009).
[221] Lazar and Gonzalez (2015).
[222] Costello (2014).
[223] Kind (2015); Orans et al. (2009).
[224] Ito (2014).
[225] Borenstein (2012).
[226] Lazar (2013).
[227] Lazar (2013); Kind (2015).

Decoupling

Decoupling is a regulatory tool that breaks the link between utility revenues and energy sales. Specifically, it is a price adjustment mechanism that ensures the utility recovers its allowed revenue for fixed costs, as determined by the state public utility commission, regardless of the utility's actual energy sales. Under a typical revenue-per-customer allowance, decoupling tends to lead to small annual increases in revenues. Whether prices increase or decrease under decoupling depends on whether average energy consumption by customers is declining or rising as the number of customers changes.[228]

About a third of U.S. states have decoupled one or more of the electric utilities they regulate. Additional proposals for decoupling are underway and expected in the future,[229] though some states have turned down decoupling proposals.[230]

According to Lazar and Gonzalez, "a well-designed revenue regulation framework [i.e., decoupling] is the best option to address utility revenue attrition that energy efficiency or renewable energy deployment may cause."[231] The authors point out that, under decoupling, rates are still predominantly volumetric, customer bills are predictable, cost recovery is not regressive, and fewer rate cases are necessary. Further, decoupling can focus utility management efforts on cost control, which provides benefits both for utility customers and shareholders. Decoupling also reduces the utility's disincentive to embrace energy efficiency and other distributed resources as a cost-effective strategy.[232] Braithwait et al.[233] note that decoupling can ameliorate cost recovery concerns brought on by time-varying pricing. According to Costello, decoupling does "not seriously violat[e] any core regulatory objective" and reduces the risk of excessive utility returns.

However, others note that decoupling reduces risk to utilities and therefore should be accompanied by lower authorized rates of return.[234] Moreover, decoupling reduces revenue risk from lost sales regardless of whether the cause is energy efficiency improvements or other factors, some of which may not be a desirable reason for adjustments.[235] Costello finds that customer benefits are less clear than utility benefits, which has led consumer advocates to oppose decoupling in some cases.[236]

An issue raised against decoupling is that it insulates a utility from some risks — such as macroeconomic shocks — that have nothing to do with the policy rationales decoupling is intended to address.[237] If poorly designed, decoupling can create perverse incentives, potentially causing greater rate instability and additional cross-subsidies among consumers.[238] Kihm notes that utilities whose regulated rate of return exceeds their cost of capital will wish to

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[228] Moskovitz et al. (1992); Eto et al. (1994); Lazar et al. (2011).
[229] Costello (2014).
[230] AARP (2012).
[231] Lazar and Gonzalez (2015), p. 20.
[232] Lazar et al. (2011).
[233] Braithwait et al. (2007).
[234] AARP (2015).
[235] Testimony of AARP (2013).
[236] Costello (2014); AARP (2012).
[237] AARP (2012); Parmesano (2007); Meehan and Olson (2006).
[238] Meehan and Olson (2006).

increase energy sales even in the presence of decoupling because volume of electricity sales, not earned rate of return, will remain the primary driver of their valuation.[239]

Decoupling can cause rates to fluctuate year to year due to conditions in the previous year, such as weather, that cause utilities to over- or under-recover their fixed costs. Morgan[240] shows that these adjustments have generally been small.

Lost Revenue Adjustment Mechanisms

Under these mechanisms, rates are adjusted periodically, such as annually, to specifically address revenue loss resulting from energy efficiency and potentially other distributed energy resources. In so doing, lost revenue adjustment mechanisms (LRAMs) improve utility revenue stability, reduce utility disincentives related to energy efficiency, and protect against under-recovery of utility costs due to utility energy efficiency programs. According to the Institute for Electric Innovation, 19 states had LRAMs as of December 2014.[241] These mechanisms are currently the most popular mechanism, ahead of decoupling, for "relaxing the link between revenue and system use in the U.S. electric utility industry."[242]

LRAMs are accompanied by their own challenges. They are strongly dependent on estimated impacts of energy efficiency programs, which may not match actual load impacts and related revenue shortfalls, as well as other controversial assumptions such as avoided costs and discount rates.[243] These mechanisms encourage optimistic estimates of impacts from utilities. They also tend to force activity into utility programs and away from other viable energy efficiency mechanisms.[244] The adjustments may not receive the same scrutiny as utility costs considered during a general rate case, thus diminishing incentives for utilities to control costs.[245] If rate cases are infrequent, LRAM adjustments relative to old baselines can result in windfall gains to utilities.[246]

[239] Kihm (2009). Kihm shows that about half of utilities fell into this category during the period of his analysis. Such utilities remain averse to energy efficiency, distributed generation and other measures that decrease sales, although decoupling would still preserve utility revenues in the face of these deployments.
[240] Morgan (2013).
[241] Institute for Electric Innovation (2014).
[242] Lowry et al. (2015), p. 17.
[243] Gilleo et al. (2015).
[244] Lazar (2013); Lazar et al. (2011).
[245] AARP (2012).
[246] Gilleo et al. (2013).

PERFORMANCE INCENTIVES

Performance incentives for shareholders of investor-owned utilities are mechanisms that provide rewards for reaching goals specified by utility regulators. Some mechanisms also impose a penalty for performance below these goals. Performance incentives for energy efficiency or other distributed energy resources may allow utilities to earn a return on these resources, in a manner similar to the return on investments in capital assets such as distribution substations or generating plants.[247]

Some 29 states had some form of performance incentive for energy efficiency in place as of 2014.[248] Most, though not all, of these states also had either decoupling or a lost revenue adjustment mechanism.

Performance-based incentives for energy efficiency and other distributed energy resources are an option to recover revenue shortfall caused by adoption of those resources.[249] Analysis has shown that utility incentives for energy efficiency can lower customer bills[250] and improve a utility's business case for energy efficiency.[251] Correct calibration of these incentives is a regulatory challenge.[252] Careful incentive design is necessary to avoid unintended consequences such as disputes around performance measurement[253] and potential strategic behavior or gaming on the part of utilities.[254]

Going beyond performance-based incentives, comprehensive performance-based regulation also includes multiyear rate plans. Instead of filing a rate case every year or two, the utility operates under a rate plan that generally lasts four to five years. Formulas (attrition relief mechanisms) trigger automatic adjustments to the utility's allowed revenues between rate cases without linking these adjustments to a utility's actual cost, encouraging utility management efficiency and cost containment. Performance incentives may apply to such measures as service quality and customer service, as well as energy efficiency. This is the topic of another report in the Future Electric Utility Regulation series.[255]

[247] Institute for Electric Innovation (2014).
[248] Institute for Electric Innovation (2014).
[249] Lazar and Gonzalez (2015); Lazar (2015); Nowak et al. (2015).
[250] Satchwell et al. (2011).
[251] Cappers et al. (2009).
[252] Lazar and Gonzalez (2015); Lazar (2015).
[253] Chandrashekeran et al. (2015); Kaufman and Palmer (2012).
[254] Costello (2014).
[255] Lowry and Woolf (2016).

Frequent Rate Cases

Frequent rate cases are another option for ensuring utility revenue stability. However, most stakeholders view frequent rate cases as an incomplete and generally undesirable solution. In addition, if there is only a small change in underlying costs but a large change in retail sales, a general rate case may not be an appropriately targeted tool. Decoupling and formula rate plans can reduce the frequency of general rate cases, a point cited in support of these options.[256] Further, even annual rate cases may not solve cost recovery problems.[257]

Formula Rate Plans

Mark Newton Lowry and Matthew Makos, Pacific Economics Group Research, drafted this section of the literature review.

A cost-of-service formula rate plan (FRP) allows a utility to reset rates to better recover its cost of service without a rate case when its earnings fall above or below a predefined earnings "deadband."[258] Unanticipated changes in revenues or costs that result in earnings surpluses or deficits that exceed the deadband trigger true-up mechanisms that adjust rates so that earnings variances are reduced or eliminated.[259] An FRP can thus serve as both a revenue tracker and a broad-based cost tracker.[260]

FRPs are often implemented as substitutes for cost of service regulation in situations where frequent rate cases are likely due to a tendency for costs to grow more rapidly than delivery volumes and other billing determinants.[261] Conditions that cause earnings attrition include a surge in system modernization investment and slow growth in the delivery volume per customer.[262] While FRPs can address the problem of declining average use of the electric system that other states address through revenue decoupling, FRPs often are accompanied by revenue decoupling or LRAMs.[263]

FRPs do not always address major plant additions.[264] In state-regulated FRPs for retail electric services, for instance, major investment programs are generally approved separately through such means as hearings on certificates of public convenience and necessity. The resultant cost often is recovered through a separate tracker.[265]

Key issues in the design of an FRP include the design of the earnings true-up mechanism, performance standards and monitoring, the duration of the plan, treatment of major capital expenditures, the frequency of rate adjustments, and the procedure under which the plan and utility's performance would be assessed by the regulator during the FRP period.[266] Earnings true-up mechanisms in FRPs commonly move the return on equity all, or almost all, of the way

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[256] Lazar and Gonzalez (2015); Lowry et al. (2013).
[257] Lowry et al. (2013).
[258] Costello (2010).
[259] Lowry et al. (2015).
[260] Lowry et al. (2013); Costello (2011).
[261] Edison Electric Institute (2011).
[262] Costello (2014).
[263] Lowry et al. (2015).
[264] Lowry et al. (2015); Entergy Mississippi (2015).
[265] Lowry et al. (2015); Schlissel and Sommer (2013).
[266] Costello (2014).

to its regulated target *without* sharing variances in earnings.[267] This is an important distinction between the earnings true-up mechanism of an FRP and the earnings *sharing* mechanisms found in some multiyear rate plans under performance-based regulatory approaches.

Proponents of FRPs cite some of the same benefits that are attributed to multiyear rate plans.[268] Regulatory cost is markedly lower than frequent rate cases.[269] Formula rates can mitigate rate shock.[270] Senior utility management can devote more attention to their basic business. Operating risk is reduced, and utilities are less likely to experience significant over- or under-earning.

A common argument against FRPs is that they reduce incentives for a company to operate efficiently.[271] Costello emphasizes that the design of the earnings true-up mechanism is essential to the efficacy of an FRP, as it significantly impacts cost-containment incentives for the utility and the distribution of risks between utility stakeholders and utility customers.[272] For example, Costello notes that an FRP that reduces rates too quickly in response to cost reductions eliminates incentives for the utility to improve efficiency, while an FRP that allows a utility with poor cost management to immediately adjust rates upward to meet its target return on equity rewards the utility with essentially "cost plus" regulation. In some FRPs, the rate of return on equity is not updated and can become stale if the FRP operates for an extended period of time, leading to rates being reset to a point that is too high or too low.[273]

This concern is exacerbated by provisions in some FRPs that provide insufficient opportunity to review the causes of variances in earnings. Limits sometimes are placed on the review of formula rate filings that are far more restrictive than those in general rate cases.[274] In retail jurisdictions, time periods for the review of filings are sometimes limited to two months or less, and intervenors are sometimes excluded from the review process.[275] Review is sometimes limited to verification that the formula has been correctly implemented.[276] This situation can lead to the recovery of imprudent costs that would be disallowed in general rate cases.[277]

To address these concerns, mechanisms are sometimes added to an FRP to encourage better operating performance. For example, escalation of revenue that compensates the utility for its operation and maintenance expenses may be limited by a formula tied to an inflation index.[278] FRPs in Illinois and Mississippi contain several targeted performance incentive mechanisms.[279]

Formula rates have been used by the Federal Energy Regulatory Commission (FERC) and its predecessor agency the Federal Power Commission to regulate interstate services of energy

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[267] Lowry et al. (2015).
[268] Costello (2014).
[269] Hemphill and Jensen (2016).
[270] Lowry et al. (2015); Entergy Mississippi (2015). In practice, however, major plant additions are often subject to alternate ratemaking treatments.
[271] Costello (2014).
[272] Costello (2011).
[273] Schlissel and Sommer (2013).
[274] Costello (2014); Schlissel and Sommer (2013).
[275] Entergy Mississippi (2015); Schlissel and Sommer (2013).
[276] Entergy Mississippi (2015); Schlissel and Sommer (2013).
[277] Costello (2014); Hempling (2012).
[278] Mobile Gas Service (2015).
[279] Aggarwal (2014).

utilities for decades.[280] Lowry et al. provides a detailed list of precedents for retail formula rates.[281] Alabama was an early innovator, approving "Rate Stabilization and Equalization" plans for Alabama Power and Alabama Gas in the early 1980s.[282] Formula rates also are used for Illinois power distributors. The use of formula rates to regulate natural gas distributors has grown rapidly in the Southeast and South Central States.[283]

280 Lowry et al. (2013).
281 Lowry et al. (2015).
282 Edison Electric Institute (2011).
283 Lowry et al. (2015).

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