Exhibit No.:	
Issues:	Residential Rate Design, Standby Service
Witness:	Jamie W. Scripps
Sponsoring Party:	Renew Missouri
Type of Schedule:	Direct Testimony
Case No.:	ER-2018-0145; ER-2018-0146
Date Testimony Prepared:	July 2, 2018

MISSOURI PUBLIC SERVICE COMMISSION

CASE NOS. ER-2018-0145 and ER-2018-0146

DIRECT TESTIMONY OF

JAMIE SCRIPPS

ON BEHALF OF

RENEW MISSOURI

July 6, 2018

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Kansas City Power & Light Company's Request for Authority to Implement a General Rate Increase for Electric Service	))))	File No. ER-2018-0145
In the Matter of KCP&L Greater Missouri Operations Company's Request for Authority To Implement a General Rate Increase for Electric Service	))))	File No. ER-2018-0146

AFFIDAVIT OF JAMIE SCRIPPS

STATE OF MICHIGAN)
) ss
COUNTY OF LEELANAU)

COMES NOW Jamie Scripps, and on her oath states that she is of sound mind and lawful age; that she prepared the attached direct testimony; and that the same is true and correct to the best of her knowledge and belief.

Further the Affiant sayeth not.

____
Jamie Scripps

Subscribed and sworn before me this 2nd day of July 2018.

Mary K Bush
____
Notary Public

MARY K. BUSH
NOTARY PUBLIC, STATE OF MICHIGAN
COUNTY OF LEELANAU
MY COMMISSION EXPIRES JUNE 5, 2020
ACTING IN LEELANAU COUNTY

My commission expires: 06/05/2020

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BACKGROUND AND EXPERIENCE

Q. State your name, business name and address.

A. My name is Jamie Scripps and I am a partner with 5 Lakes Energy LLC located at 115 West Allegan, Suite 710, Lansing, Michigan 48933.

Q. On whose behalf are you appearing in this case?

A. I am appearing here as an expert witness for Renew Missouri Advocates.

Q. Are you sponsoring any schedules?

A. Yes, I am sponsoring the following schedules:

1. Schedule JWS-1: Résumé of Jamie Scripps
2. Schedule JWS-2: S. Borenstein and J. Bushnell, Are Residential Electricity Prices Too High or Too Low? Or Both?, The National Bureau of Economic Research (NBER) Working Paper No. 24756, June 2018.
3. Schedule JWS-3: J. Lazar, Regulatory Assistance Project, "Use Great Caution in Design of Residential Demand Charges," Natural Gas & Electricity, February 2016.
4. Schedule JWS-4: Synapse Energy Economics, Inc., Caught in a Fix: The Problem with Fixed Charges for Electricity, February 2016.

Q. Summarize your educational background.

A. I have a law degree from the University of Michigan Law School, conferred in May 2005. I also have a Master's in Leadership Studies from North Central College in Naperville, Illinois, conferred in June 2002, and a Bachelor's in Education from the University of Michigan, conferred in May 1999.

Q. Summarize your experience in the field of electric utility regulation.

A. I have worked at 5 Lakes Energy since July 2012 as a consultant in energy policy and utility regulation. I have been a partner at 5 Lakes Energy since November 2014. From 2009-2010, I worked at the Michigan Department of Energy, Labor and Economic Growth (DELEG) as the Assistant Deputy Director for energy programs, where I provided research and support for the application of scientific, engineering, and economic principles to the formation and adoption of energy policies for the State of Michigan. From 2008-2009, I worked as an associate attorney at Sondee, Racine & Doren LLP in Traverse City, where I assisted in providing legal representation to the local municipal utility. From 2007-2008, I served as Deputy Policy Director for the Michigan Environmental Council, where I provided research and advocacy on issues related to energy policy and utility regulation. From 2005-2007, I worked as an associate attorney at Venable LLP in Washington, D.C., where I assisted in the legal representation of a large investor-owned utility serving the Mid-Atlantic region. My work experience is set forth in detail in my résumé, attached as Schedule JWS-1.

Q. Summarize your professional development coursework in the field of electric utility regulation.

A. I have completed the following EUCI[1] courses:

[1] EUCI provides training and continuing professional education targeted to representatives from the utility industry around topics related to electric utility rates, regulation and markets. EUCI is accredited by the International Association for Continuing Education and Training (IACET) and issues continuing education units through the association. EUCI is also recognized by the North American Electric Reliability Corporation (NERC) as a continuing

- Integrated Resource Plan Design Fundamentals
- Introduction to Cost-of-Service Concepts and Techniques for Electric Utilities
- Evolution of Electricity Markets: Disruptive Innovation & Economic Impacts
- Introduction to Rate Design for Electric Utilities

Q. Have you previously testified as an expert witness before this commission?

A. No.

Q. Have you previously testified as an expert witness before any public utility commission in another state?

A. Yes. I previously testified as an expert witness before the Michigan Public Service Commission in U-18255 (DTE general rate case) and U-18322 (Consumers Energy general rate case) and before the Pennsylvania Public Utility Commission in R-2018-3000124 (Duquesne Light Company Distribution Rate Case).

Q. What is the purpose of your testimony?

A. I am testifying that:

1. The Commission should avoid increases to Kansas City Power & Light ("KCP&L") and Kansas City Power & Light – Greater Missouri Operations ("GMO") residential customer charges;
2. The Commission should continue to fully migrate KCP&L and GMO residential tariffs away from declining and toward inclining block rates;

education provider who adheres to NERC continuing education program criteria. More information is available at http://www.euci.com.

3. The Commission should require KCP&L and GMO to expand their use of residential time-of-use pilots and exercise caution as to residential demand charges; and
4. The Commission should require that KCP&L and GMO continue to exempt solar generating facilities from application of the proposed standby service riders.

Q. What materials have you reviewed in preparation for your testimony?

A. I reviewed KCP&L and GMO's applications in this case and subsequent submissions to the docket, including the KCP&L Greater Missouri Operations Company Seasonal Rate Structure Study, the KCP&L Block Rate Study, and the KCP&L - Greater Missouri Operations Time of Use Rate Study, which were filed in ER-2018-0146. I have also reviewed key documents from KCP&L's previous general rate case ER-2016-0285, including the Commission's Report and Order dated May 3, 2017.

THE COMMISSION SHOULD AVOID INCREASES IN CUSTOMER CHARGES

Q. Please summarize the effects of KCP&L and GMO's proposed tariff changes with respect to customer charges.

A. KCP&L proposes that monthly customer charges for "Schedule R Residential General Use" customers be increased from $12.62 to $15.17, "Residential General Use and Space Heat-One Meter" customers be increased from $12.62 to $15.17, and "Residential General Use and Space Heat-2 Meter" customers be increased from $14.95 to $17.53. KCP&L is also requesting that monthly customer charges for "Schedule ROU Residential Other Use" customers be increased from $12.62 to $15.17 and for "Schedule RTOD Residential Time of Day" to be increased from $15.94 to $16.13. Customer charges for "Schedule RTOU –

Residential Time of Use Pilot," "Schedule RD – Residential Demand Service Pilot," and "Schedule RDTOU – Residential Demand Service plus Time of Use Pilot" are all set at the proposed increased amount of $15.17 per month. GMO proposes that monthly customer charges for Residential Service Electric and Residential Service Other Use Electric customers be increased from $10.43 to $14.50.

Q. How do the proposed increases in customer charges compare to average fixed charges included in residential electricity bills in other states?

A. In a June 2018 working paper published by the National Bureau of Economic Research (attached as Schedule JWS-2) the residential electricity tariffs of 2,090 electric utilities were evaluated, and the average fixed charge included on residential electricity bills, weighted by sales, was calculated to be $10.57.[2] In this proceeding, KCP&L proposes to increase its fixed customer charge to $15.17, which is 43.5% higher than average. GMO proposes to increase its fixed customer charge to $14.50, which is 37.2% higher than average. Customer charges should only attempt to collect utility costs that vary with the number of customers, such as metering, meter reading, billing, payment processing, and some customer service expenses.[3] These utility costs were estimated in 2011 by the Regulatory Assistance Project to fall in the $4 to $7 range.[4] As the proposed increases in customer charges by KCP&L ($15.17) an GMO ($14.50) are well above the NBER average

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[2] *See* Schedule JWS-2: S. Borenstein and J. Bushnell, Are Residential Electricity Prices Too High or Too Low? Or Both?, The National Bureau of Economic Research (NBER) Working Paper No. 24756, June 2018, *also available at* http://www.nber.org/papers/w24756.pdf

[3] J. Lazar, Regulatory Assistance Project, "Pricing Do's and Don'ts," April 2011, p.3, *available at* http://www.raponline.org/wp-content/uploads/.../rap-lazar-pricingdosanddonts-2011-04.pdf

[4] Ibid.

customer charges and the Regulatory Assistance Project estimate of the range of customer-related utility costs, these increases are concerning.

Q. Please describe the underlying reasons for your concerns about the proposals by KCP&L and GMO to increase customer charges.

A. High customer charges have a negative impact on customers and are inconsistent with a variety of public policy objectives. First, in view of set utility revenue requirements, high fixed customer charges lower the prices associated with electricity consumption, sending the wrong price signal[5] and undermining other efforts by the utility to encourage energy efficiency through rate design (*e.g.*, use of an inclining block rate). High customer charges also restrict a customer's ability to lower her bills through reduced consumption. Similarly, high customer charges are harmful to overall low-usage customers. In its Report and Order in ER-2016-0285, the Commission stated in its findings of fact that "[l]ow-income customers tend to be lower usage customers."[6] The Regulatory Assistance Project and National Consumer Law Center found that low-income household usage is about 70 percent of average household usage nationally.[7] High customer charges also place an unreasonable and unjust burden on customers residing in apartment buildings. Of all residential customers, those residing in apartments represent the utility's lowest cost of service.[8] This is due to the fact that these customers are located close together and served

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[5] *See* J. Lazar, Regulatory Assistance Project, "Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs," November 2014, *available at* https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-electricutilityresidentialcustomerchargesminimumbills-2014-nov.pdf

[6] Missouri Public Service Commission, Case No. ER-2016-0285, Report and Order dated May 3, 2017, p. 55.

[7] Schedule JWS-3: J. Lazar, Regulatory Assistance Project, "Use Great Caution in Design of Residential Demand Charges," Natural Gas & Electricity, February 2016, p. 17.

[8] Ibid.

at a single point of delivery through a single distribution transformer.[9] The marginal cost of connecting and serving customers residing in apartment buildings is lower than the marginal cost of connecting and serving customers residing in detached housing, and yet these customers would experience the same increase in fixed charges under the company's proposed increases. KCP&L and GMO customers residing in apartment buildings would be disproportionately harmed.

Q. Why are fixed customer charges an abuse of market power?

A. High customer charges are an abuse of market power because they rely on the utility's monopoly position to shift to the customer ordinary business risks. Imposing a fixed charge just for the privilege of being added as a customer is not something customers experience in other sectors of the economy with significant fixed costs, such as hotels and airlines.[10]

Q. What have other Commissions decided about fixed charges?

A. Recently, Commissions in many other states have rejected utility proposals to increase fixed charges. This trend and a summary of results were highlighted in a 2016 Synapse Energy Economics, Inc. report titled Caught in a Fix: The Problem with Fixed Charges for Electricity (attached as Schedule JWS-4). These proposals have been rejected on several grounds, including on the grounds that increased fixed charges send inefficient price signals, reduce customer incentives to invest in energy efficiency and renewable energy, and disadvantage low-usage and low-income customers.[11] In states where Commissions

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[9] *See* J. Lazar, Regulatory Assistance Project, "The Specter of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power," August 2015, at D-3, *available at* https://www.raponline.org/knowledge-center/the-specter-of-straight-fixedvariable-rate-designs-and-the-exercise-of-monopoly-power/

[10] J. Lazar and W. Gonzalez, Regulatory Assistance Project, "Smart Rate Design for a Smart Future," July 2015, p. 19, *available at* https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

[11] Schedule JWS-4: Synapse Energy Economics, Inc., Caught in a Fix: The Problem with Fixed Charges for Electricity, February 2016, p. 3-4

have allowed utilities to increase fixed charges, they have typically been approved at much smaller degree than requested by utilities.[12]

THE COMMISSION SHOULD FULLY MIGRATE RESIDENTIAL TARIFFS TOWARD INCLINING BLOCK RATES

Q. Please summarize the effects of KCP&L's and GMO's proposed tariff changes with respect to inclining block rates and declining block rates.

A. For "Schedule R Residential General Use," KCP&L proposes to retain its inclining block rate design for the summer season. KCP&L currently offers a declining block rate for the winter season and is proposing to retain this rate design instead of migrating to an inclining block rate or a flat rate for the winter season. The proposed summer inclining block rate starts at 13.044 cents/kWh for the first 600 kWh. The second and third blocks (next 400 kWh and over 1000 kWh) are proposed to remain flat at 15.09 cents/kWh. The proposed winter declining block rate starts at 12.374 cents/kWh for the first 600 kWh. The second block is proposed at 7.483 cents/kWh for the next 400 kWh and the third block is proposed at 6.638 cents/kWh for over 1000 kWh. GMO proposes a flat summer rate of 12.089 cents/per kWh and a declining block rate for the winter starting at 10.660 cents/kWh for the first 600 kWh; 7.826 cents/kWh for the next 400 kWh and 7.825 cents/kWh for over 1000 kWh.

Q. How has the Commission previously ruled concerning inclining block rates and declining block rates?

A. In its Report and Order in ER-2016-0285, the Commission stated in its findings of fact:[13]

- A declining block rate sends poorer efficiency signals to customers, since the

[12] Ibid. at p. 4
[13] Missouri Public Service Commission, Case No. ER-2016-0285, Report and Order dated May 3, 2017, p. 53.

effective price signal is that higher amounts of usage cost less;

- Flat rates provide slightly better price signals, but the best efficiency-inducing price signals are provided by inclining block rates ("IBR") which charge more per amount of energy used after a certain threshold or thresholds of usage;
- Inclining block rates signal to customers that higher use incurs higher costs, encouraging greater energy efficiency.

Further, in its decision in ER-2016-0285, the Commission stated: "KCPL shall implement the inclining block rate structure for residential customers proposed by [the Missouri Division of Energy], which would move KCPL towards charging flat volumetric rates for residential general use customers during the winter, and inclining block rates for residential general use customers during the summer."[14]

Q. Do KCP&L and GMO appear to be moving toward inclining block rates for residential general use customers during the summer?

A. Yes in the case of KCP&L and no in the case of GMO. KCP&L's proposed "Schedule R Residential General Use" retains an inclining block rate structure between the first and second blocks and retains a flat structure between the second and third blocks. However, in the case of GMO, the proposed summer rate is flat and the winter rate retains the declining block rate structure.

Q. Do KCP&L and GMO appear to be moving toward charging flat volumetric rates for residential general use customers during the winter?

[14] Missouri Public Service Commission, Case No. ER-2016-0285, Report and Order dated May 3, 2017, p. 57.

A. No. KCP&L's proposed "Schedule R Residential General Use" retains a declining block rate structure with marked differentiation between all three blocks (*e.g.*, no "flatness" between blocks two and three as we see in the summer rates). In the case of GMO, there is flatness between blocks two and three, but the differentiation between blocks one and two still marks a decline.

Q. How should the Commission improve upon the summer inclining block rate proposed by KCP&L?

A. While KCP&L has taken a good first step in implementing an inclining block rate for the summer season, the rate structure would be more effective in achieving policy goals if the inclining rates were carried through to all three rate blocks. Currently, the rates between the second and third blocks (next 400 kWh and over 1000 kWh) reflect a flat rate, which the Commission has found to be not as effective as the inclining block rate at encouraging efficiency.[15]

Q. Why should the Commission continue to migrate away from declining block rates and toward inclining block rates for residential customers?

A. A key deficiency of the declining block rate is that it artificially inflates the price of consumption for the first 600 kWh of usage. In its Report and Order in ER-2016-0285, the Commission found that "The first 500-600 kilowatt hours (kWh) is considered the minimum amount needed for the residents of a typical home to survive. This is also known as the 'lifeline block.'"[16] Because customers rely on this first block for survival, an increase in the rate charged for this "lifeline block" is effectively an additional fixed customer

[15] Missouri Public Service Commission, Case No. ER-2016-0285, Report and Order dated May 3, 2017, p. 53
[16] Ibid. at p. 55

charge. As covered previously in my testimony, there are numerous harmful impacts from increasing fixed customer charges (whether accomplished through ramping up the explicit customer charge and/or increasing the price attached to the first block of consumption in a declining block rate). This approach hits low-income customers hardest, and the effects of the proposed rate structure would be particularly disproportionate during the winter season.

Q. How will moving away from declining block rates in the winter help with concerns about price signals during seasonal cross-over?

A. In "KCP&L Greater Missouri Operations Company Seasonal Rate Structure Study" filed in ER-2018-0146, the authors discuss the issue of seasonal cross-over: "Under the current two season rate structure, a customer who is billed on June 1 … would be billed at the June summer rate for usage that occurred in May, which is a winter rate month … In October, the transition month from summer to winter, this customer would encounter the same effect of billing at a seasonal rate different than the usage month."[17] The mismatch between cost-of-service and monthly rates that can occur due to regular seasonal cross-over is exacerbated when the change of seasons triggers a changeover to an opposing rate design. Under the KCP&L proposal for residential rates, the transition from the summer season to the winter season means a sudden changeover from the price signals of an inclining block rate (*i.e.*, inducing energy efficiency) to the price signals of a declining block rate (*i.e*,, higher amounts of usage cost less, so go ahead and consume more). Add to this the arbitrariness of the timing of the customer's meter-read during the month and the potential for this to shift customers into a different season for billing purposes,[18] and the policy

[17] KCP&L Greater Missouri Operations Company, Seasonal Rate Structure Study, December 12, 2017, submitted as Schedule MEM-1 with the testimony of company witness M. Miller in ER-2018-0146, p. 23
[18] Ibid.

objectives of implementing the inclining block rate for the summer months are further undermined. By moving away from a declining block rate in the winter months, there is less risk of rendering price signals meaningless or counterproductive during seasonal cross-over.

Q. In her testimony, company witness Marisol Miller raised the concern that inclining block rates can create a disincentive for beneficial electrification.[19] Do you share this concern?

A. In this case, no. Beneficial electrification has been widely recognized as an emerging source of business opportunity for electric utilities[20] – but significant progress toward a cleaner grid is a pre-requisite to electrification being environmentally beneficial. According to the Great Plains Energy 2016 Annual Report, KCP&L's fuel mix based on percent of net MWh generated reflected a 79% reliance on coal.[21] In light of this fuel mix, the benefits of an inclining block rate outweigh the risk of dis-incenting additional electrification in the near term.

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[19] Missouri Public Service Commission, Case No. ER-2018-0145, testimony of company witness M. Miller, p. 8

[20] *See, e.g.*, K. Colburn, Regulatory Assistance Project, "Beneficial Electrification: A Growth Opportunity," *available at* http://www.raponline.org/blog/beneficial-electrification-a-growth-opportunity/

[21] Great Plains Energy 2016 Annual Report, *available at* http://www.greatplainsenergy.com/index.php/financial-filings/annual-reports

THE COMMISSION SHOULD REQUIRE KCP&L AND GMO TO STRENGTHEN AND EXPAND THEIR TIME-OF-USE PILOTS AND SHOULD EXERCISE CAUTION AS TO RESIDENTIAL DEMAND CHARGES

Q. How has the Commission previously ruled concerning time-of-use rates?

A. In its Report and Order in ER-2016-0285, the Commission found:

- Similar to inclining block rates, time-varying rates can also reduce peak demand;
- Time-varying rates can be more beneficial to reduce peak demand than inclining block rates;
- Time-of-use rates better reflect cost-causation than the current rate design and would create beneficial incentives for customers to reduce usage during system peak times;
- KCPL has smart meters installed for over 90 percent of its customers yet does not have tariffs in place that would allow customers to benefit from demand response rates those meters would allow.[22]

The Commission ordered that KCP&L "propose time-varying rate offerings for residential customers in its next rate case."[23]

Q. Please summarize the proposals by KCP&L and GMO regarding time-varying rate offerings for residential customers.

A. KCP&L proposes to add two time-of-use rate pilots: 1) Residential Time-of-Use (RTOU) Pilot; 2) Residential Demand Service plus Time-of-Use (RDTOU) Pilot. KCP&L also proposes a new demand-services pilot (without Time-of-Use) for residential customers called the Residential Demand Services Pilot. GMO likewise proposes a Residential Time-

[22] Missouri Public Service Commission, Case No. ER-2016-0285, Report and Order dated May 3, 2017, p. 53
[23] Ibid. at p. 57

of-Use Electric Piot, a Residential Demand Pilot, and a Residential Demand plus Time-of-Use Pilot.

Q. Do you have any concerns about the rollout of the proposed time-of-use rate pilots being contingent upon their approval in the company's Missouri Energy Efficiency Investment Act (MEEIA) programs?

A. Yes. Advanced metering infrastructure has already been deployed to 90% of KCP&L customers, yet without access to time-of-use rates, these customers are paying for this equipment in current rates and not yet getting any benefit from the advanced metering capabilities. In the KCP&L Greater Missouri Operations Time-of-Use Rate Study submitted in ER-2018-014, authors state: "GMO and KCP&L would like to take advantage of new Advanced Metering Infrastructure (AMI), Meter Data Management (MDM), and Customer Information System (CIS) currently being designed and implemented."[24] Making the availability of the time-of-use pilots contingent upon MEEIA approval calls into question the company's intent to move forward with time-varying rates and undermines the value proposition of advanced metering infrastructure. Even while seeking approval of the proposed rate designs in this proceeding, company witness Tim Rush testified that there is uncertainty about MEEIA approval of the Time-of-Use Pilots.[25] The AMI is in place and customers are already paying for it; they have waited long enough. Time-varying rates should be available to residential customers, as ordered by the Commission in KCP&L's previous rate case. Additionally, many details about the time-of-use rate pilots, particularly with regard to program evaluation, have been omitted from

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[24] KCP&L Greater Missouri Operations Company, Time of Use Rate Study, December 12, 2017, submitted as Schedule MEM-3 with the testimony of company witness M. Miller in ER-2018-0146, p. 22

[25] Missouri Public Service Commission, Case No. ER-2018-0145, testimony of company witness T. Rush, p. 7

this proceeding because KCP&L and GMO plan to flesh out those details in the MEEIA process. The lack of detail in the present rate case makes it difficult to meaningfully evaluate the company's plans as to these time-of-use offerings.

Q. Do you have any concerns about the stakeholder process used in the KCP&L Greater Missouri Operations Time-of -Use Rate Study submitted in ER-2018-0146?

A. Yes, it would have been preferable had GMO consulted, in addition to internal representatives, stakeholders outside of the utility, namely residential customers and customers with electric vehicles. In section 1.3 ("Internal Stakeholder Input") of the KCP&L Greater Missouri Operations Time-of -Use Rate Study, authors state: "BMcD met with stakeholders throughout KCP&L, who work on behalf of GMO, which included individuals in Regulatory Affairs, Energy Resource Management, Energy Solutions, Customer Service, Market Insights, Information Technology, Measurement Technologies and Revenue Management."[26] There is no reference in the study to the consideration of external stakeholder input, evidencing a missed opportunity to potentially improve upon the proposed rate designs. According to a January 2018 rate design report by Advanced Energy Economy: "Meaningful stakeholder collaboration is one of the most important tools for making sure new rate designs succeed."[27] Experience has shown that proposed changes to rates, including and perhaps especially the creation of new rates, should include input from a variety of stakeholders so that regulators can take into consideration the impact of

[26] KCP&L Greater Missouri Operations Company, Time of Use Rate Study, December 12, 2017, submitted as Schedule MEM-3 with the testimony of company witness M. Miller in ER-2018-0146, p. 9.
[27] Advanced Energy Economy, Rate Design for a DER Future, January 2018, p. 2, *available at* https://info.aee.net/hubfs/PDF/Rate-Design.pdf

the changes on all market participants.[28]

Q. Do you have any concerns about the application of demand charges to the residential customer class in the Residential Demand and Resident Demand plus Time-of-Use (TOU) Pilots?

A. Yes. Demand charges based on a residential customer's peak usage in a month are not a good approximation for that customer's demand during system peak periods.[29] In a February 2016 article for the journal Natural Gas & Electricity titled "Use Great Caution in Design of Residential Demand Charges" (attached as Schedule JWS-3), Jim Lazar of the Regulatory Assistance Project explains: "Great caution should be applied when considering the use of demand charges, particularly for smaller commercial and residential users. Severe cost shifting may occur. Time-varying energy charges result in more equitable cost allocation, reduce bill volatility, and improve customer understanding."[30]

While utilities may have needed such an approximation in the past, the value of guessing a residential customer's contribution to system peak by looking at her monthly peak demand has been mostly eliminated with smart meters that record usage in hourly or shorter intervals.[31] With advanced metering infrastructure already in place for 90% of KCP&L customers, there is no longer a need to rely on the clumsy approximation required by demand charges. In the present proceeding, KCP&L and GMO both propose time-of-use

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[28] Ibid.

[29] L. Wood et al, Future Electric Utility Regulation, Recovery Of Utility Fixed Costs: Utility, Consumer, Environmental And Economist Perspectives, prepared for Lawrence Berkeley National Laboratory, June 2016, p. 60, *available at* https://emp.lbl.gov/publications/recovery-utility-fixed-costs-utility

[30] Schedule JWS-3: J. Lazar, Regulatory Assistance Project, "Use Great Caution in Design of Residential Demand Charges," Natural Gas & Electricity, February 2016.

[31] L. Wood et al, Future Electric Utility Regulation, Recovery Of Utility Fixed Costs: Utility, Consumer, Environmental And Economist Perspectives, prepared for Lawrence Berkeley National Laboratory, June 2016, p. 60, available at https://emp.lbl.gov/publications/recovery-utility-fixed-costs-utility

rates with and without a demand component for residential customers. The Commission should proceed with caution as to the time-of-use rate pilots relying on residential demand charges.

Q. Can time varying rates be combined with inclining block rates?

A. Yes. Time-varying rate offerings can be relatively easily combined with inclining block rates. This combination has been done successfully in Washington and California and provides customers with a clear price signal.[32] The mechanics are straightforward: a time-varying rate can be the underlying rate design, and a credit can be deployed to constrain the cost of the first block of consumption. Alternatively, an inclining block rate can be the underlying rate design, with a surcharge for all power used during on-peak periods.[33]

Q. What is your assessment of the time-of-use pilot rates proposed in this proceeding?

A. In addition to my concern about a lack of customer input in the rate design process, my other main concern is the relatively small size of the pilot – 1,000 customers – coupled with the lack of a separate residential electric vehicle (EV) charging rate. The pilot's small size will mean either that EV customers crowd out non-EV customers or that non-EV customers will be turned away and limited to the standard residential rate, which for KCP&L is an inclining block rate in the summer. The Commission has properly urged the use of inclining block rates as KCP&L and GMO ramp up to greater use of time-varying rates, and there are many benefits to the use of an inclining block rate, including the fact that these rates encourage energy efficiency and align with cost causation. However, if an

[32] J. Colgan et al, Guidance for Utilities Commissions on Time of Use Rates: A Shared Perspective from Consumer and Clean Energy Advocates, July 2017, p. 6, *available at* https://votesolar.org/files/9515/0039/8998/TOU-Paper-.17.17.pdf

[33] Ibid. p. 13-14

EV customer does not have a time-varying rate available to her, and is limited to an inclining block rate (which could be costly when applied to EV charging), this could have a negative impact on the EV customer and could frustrate efforts to encourage EV adoption.

Q. Do KCP&L and GMO propose an electric vehicle (EV) specific rate in this proceeding?

A. No. Instead, the company states that residential customers with EVs may access the proposed time-of-use rate pilot programs if the programs are approved under MEEIA.

Q. Is an EV-specific rate necessary for optimally addressing residential EV charging?

A. Not necessarily, as long as residential customers with EVs have ready access to a whole-house time-of-use rate. Both EV-specific rates and whole-house time-varying rate options have the potential to yield positive results for load management by shifting EV charging to off-peak hours and reducing grid impacts.[34] In this proceeding, the small size of the proposed time-of-use rate pilot programs could restrict residential customers with EVs from having ready access to the time-of-use rate offerings. Because the company is resistant to creating an end-use specific rate for customers with EVs, it will likely be necessary to increase the participation caps attached to the proposed time-of-use rate pilot programs to accommodate the need for customers with EVs to access the time-of-use rates while not harming the ability of non-EV customers to likewise access the company's time-varying rate offerings and make use of the company's investment in advanced metering infrastructure.

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[34] MJ Bradley & Associates, Accelerating the Electric Vehicle Market: Potential Roles of Electric Utilities in the Northeast and Mid-Atlantic States, March 2017, p. 16, *available at* https://www.mjbradley.com/sites/default/files/MJBA_Accelerating_the_Electric_Vehicle_Market_FINAL.pdf

Q. How do residential customers with electric vehicles (EVs) present unique challenges and opportunities in rate design?

A. EVs present utilities with unique challenges and opportunities in rate design. Customer use of EV technology presents significant potential benefits for the grid, including the ability to offset variability in wind and solar production, and potential cost-savings for all utility customers.[35] In order to obtain these advantages and cost savings, a utility must be mindful of what makes EV charging special. EV charging is distinct from other uses of electricity in two important ways: EVs represent relatively large loads and EVs have energy storage capability. First, on the subject of load size, EV charging systems can draw significantly more power than the most energy-intensive residential appliances, meaning that if an EV is charged during a time of peak demand with a standard Level 2 charger, an EV's load could be roughly equivalent to that of an entire household.[36] Second, there is the issue of energy storage. When customers charge their EVs, the electricity is not immediately used to make the vehicle run, and instead is stored in a battery for use when it is needed. Because customers tend not to care as much when their EV charges (as long as the vehicle is ready to go when needed), utilities enjoy significant flexibility to encourage efficient EV charging without inconveniencing consumers.[37] A utility that has deployed AMI has many options for providing a rate for residential EV owners that is attractive to both the customer and the utility.[38] These can include a simple time-of-use rate, a multi-period time-of-use

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[35] "After reviewing over 150 pieces of recent literature on EVs, we summarized the quantifiable benefits, including greenhouse gas reduction, gasoline savings, savings for all utility customers, savings in system investment, fuel and maintenance savings, and the potential for managed charging of EVs to deliver various grid benefits." Rocky Mountain Institute, From Gas to Grid, October 2017, *available at* https://www.rmi.org/wp-content/uploads/2017/10/RMI-From-Gas-To-Grid.pdf

[36] A. Allison and M. Whited, Synapse Energy Economics, A Plug for Effective EV Rates, March 2017, p. 1, *available at* http://www.synapse-energy.com/sites/default/files/A-Plug-for-Effective-EV-Rates-S66-020.pdf

[37] Ibid.

[38] Ibid.

rate with a super-off-peak period (as proposed by KCP&L and GMO in this proceeding), a critical peak pricing rate, or a real-time price.[39] While an EV-specific rate is not necessarily required in order to optimize the grid benefits of EV charging, the goal should be to provide these customers with ready access to a time-varying rate, and to send these customers the proper price signals to move EV charging to off peak times. If the utility gets this wrong, customers charging during times of peak demand could result in higher electric system costs, which could outweigh the potential operational energy savings associated with electric vehicles.[40]

Q. How do time-of-use rates relate to the concept of managed charging for EVs?

A. When EV-charging loads are managed well, there are utility system savings as well as reduced costs to delivering electricity. Time-of-use rates are a kind of indirect management of EV charging because they rely on customer behavior; direct managed charging would build upon time-of-use rates to activate infrastructure and communication signals to control a charging event.[41] In this proceeding, EV customers would potentially have access to the proposed time-of-use pilot programs (though the 1,000 customer cap is a concern). These time-of-use rates are a good first step toward indirectly managing EV loads by encouraging customers to charge EVs during off peak times. As the company gains more experience with EVs in the future, they may wish to build upon this foundation of time-varying rates to use advanced network technology to more directly manage EV charging.

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[39] J.Lazar and W. Gonzalez, Regulatory Assistance Project, Smart Rate Design for a Smart Future, July 2015, p. 18, *available at* https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

[40] A. Allison and M. Whited, Synapse Energy Economics, A Plug for Effective EV Rates, March 2017, p. 1, *available at* http://www.synapse-energy.com/sites/default/files/A-Plug-for-Effective-EV-Rates-S66-020.pdf

[41] Smart Electric Power Alliance, Utilities and Electric Vehicles: The Case for Managed Charging, April 2017, p. 9, *available at* http://go.sepapower.org/l/124671/2017-08-22/wpzn2/124671/39829/SEPA091_Managed_EV_Report_print__1_.pdf

Q. What is your recommendation for resolving the issue of the small size of the time-of-use rate pilot programs?

A. In light of the company's preference to avoid an end-use specific rate, and cognizant of the fact the AMI has been deployed to over 90% of KCP&L customers who are already paying for these meters in their rates, I recommend enlarging the size of the pilot programs to accommodate a larger total number of customers broken out by these three types of residential customer: non-EV residential; EV-residential and residential customers with solar generation. The rate design would remain the same, so the rate itself would not be end-use specific, but end-use specific participation caps could alleviate concerns about one of these groups taking over or otherwise skewing the pilot programs. The new pilot program size could be 3,000 total, with 1,000 spots allocated to each of these segments of the residential class. In this way, the company would reduce the risk of the time-of-use rate becoming a de facto end-use specific rate by allowing over-subscription by one of these segments (*e.g.*, customers with electric vehicles). Reasonably expanding the overall size of the pilot programs in this way would also represent an important step toward realizing the value proposition of the advanced metering infrastructure that has already been deployed.

THE COMMISSION SHOULD REQUIRE KCP&L AND GMO TO CONTINUE TO EXCLUDE SOLAR GENERATION IN STANDBY SERVICE RIDERS

Q. Please summarize the rate proposals by KCP&L and GMO applicable to standby service.

A. KCP&L and GMO each propose a Standby Service Rider - Schedule SSR. The proposed standby rate design includes a capacity reservation charge based on standby capacity reserved (kW), a demand charge (per kW of monthly backup or maintenance demand) and an energy charge (per kWh of monthly backup or maintenance energy).

Q. Do the KCP&L and GMO proposed standby service riders apply to solar generating facilities?

A. No. Per the language of the proposed KCP&L and GMO standby service riders: "Customers with emergency backup, intermittent renewable generation, or energy storage systems are excluded from this Schedule SSR." As solar generating facilities would be considered to be intermittent renewable generation, they would be excluded from application of the standby service rider.

Q. Should the standby service riders apply to solar generating facilities?

A. No, it is proper for solar generating facilities to be excluded from the proposed standby service riders. To take an example from another state, when the Michigan Public Service Commission Staff published its Standby Rate Working Group Report, the authors explained: "A high-reliability, baseload-type generator will almost always experience a bill reduction by taking standby service under a tariff with daily or prorated power supply demand charges. However, because of the intermittent nature of solar generation, the customer will utilize on-peak power every on-peak day and the bill reduction advantage of daily or prorated power supply demand charges on the standby service tariff is not realized"[42] The authors concluded that because customers with solar generation need access to power every day, the utility should allow these customers to take service under the time-of-use rate instead.[43] This recommendation was taken up by the Michigan Public Service Commission in two recently-concluded general rate cases: U-18322 (Consumers Energy) and U-18255 (DTE). In its order in the DTE rate case, the Michigan Public Service

[42] Michigan Public Service Commission Staff Standby Rate Working Group Report, Solar Focus, August 2016, p. 26, *available at* https://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html
[43] *See* Ibid.

Commission stated that it agreed with the staff recommendation that solar self-generation projects should be exempt from standby charges due to the intermittent nature of solar generation.[44] I would note that the alternative rate suggested in the Michigan example is the time-of-use rate for customers with solar generation. Previously in my testimony, I expressed concern over the small size of the pilot programs (1,000 customers) due to the lack of a separate residential electric vehicle (EV) rate. That the proper rate for customers with solar generation is also the time-of-use rate puts additional pressure on the small size of the time-of-use pilot programs.

Q. Does this conclude your testimony?

A. Yes.

[44] Michigan Public Service Commission, Case No. U-18255, Order dated April 18, 2018 , p. 77.

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PROFESSIONAL EXPERIENCE

5 Lakes Energy LLC
Partner
JULY 2012 – PRESENT (Lansing, MI)

- Co-owner of Michigan-based consulting firm offering services in advanced energy and corporate sustainability research, engagement, and advocacy.
- Provides expert research, analysis and testimony regarding rates of electric utilities with attention to principles of cost-of-service and sound rate design.
- Completed following professional coursework related to expert witness qualification:
    - EUCI Course "Integrated Resource Plan Design Fundamentals" – August 2016
    - EUCI Course "Intro. to Cost-of-Service Concepts/Techniques for Electric Utilities" – July 2017
    - EUCI Course "Evolution of Electricity Markets: Innovation & Econ. Impacts"– January 2018
    - EUCI Course "Introduction to Rate Design for Electric Utilities" – March 2018
- Counsels clients regarding renewable energy and energy efficiency policy recommendations and regulatory solutions.
- Advises clients regarding research and data management solutions around conservation-oriented business organizing efforts.
- Leads Michigan-based education and engagement efforts related to combined heat and power (CHP) among stakeholders including end-users (commercial, industrial, institutional), utilities, trade associations, non-profit organizations, state policymakers and regulators, and other stakeholders.
- Recognized as 2016 Midwest Energy News *"40 under 40"* awardee.

Kaplan University
Academic Department Chair
AUGUST 2010 – JULY 2012

- Supervised and provided coaching to online faculty teaching in Master of Public Administration, MS in Legal Studies, and MS in Environmental Policy programs.
- Served as subject matter expert (SME) in development of curriculum for courses in public administration and environmental policy.

Michigan Department of Energy, Labor & Economic Growth
Assistant Deputy Director for Energy
FEBRUARY 2009 – JULY 2010 (Lansing, MI)

- On behalf of the state's Chief Energy Officer, assisted in hosting and facilitating engagement by a variety of stakeholders, including representatives from environmental groups, manufacturing associations, labor unions, utilities and ratepayers on the development of state-level clean energy policy and programs.

- Participated on the executive team strategically deploying energy-related stimulus funds through the state energy office, including weatherization, green schools, and the creation of the Michigan Saves energy efficiency financing program.
- Worked with legislature and regulators on implementation of utility energy efficiency programs.

Sondee, Racine & Doren, PLC
Associate Attorney
JANUARY 2008 – DECEMBER 2008 (Traverse City, MI)

- Practiced law at firm specializing in municipal law.
- Provided legal representation to clients such as the Grand Traverse County Brownfield Redevelopment Authority and Traverse City Light & Power.

Michigan Environmental Council
Deputy Policy Director
APRIL 2007 – DECEMBER 2007 (Lansing, MI)

- Researched and advocated before the state legislature on policy proposals related to CHP and WHP deployment, renewable energy standard, and utility energy efficiency programs.

Venable LLP
Associate Attorney
SEPTEMBER 2005 – MARCH 2007 (Washington, DC)

- Provided legal defense for shipping and manufacturing clients under investigation for federal environmental crimes.
- Supported legal representation of both municipally-owned and investor-owned utilities.
- Represented clients in civil litigation in Virginia and the District of Columbia, including extensive factual investigation related to energy and environmental matters.

EDUCATIONAL BACKGROUND

University of Michigan Law School – Ann Arbor, MI

- Juris Doctor awarded May 2005
  - Admitted: State Bar of Michigan, District of Columbia Bar, Virginia State Bar

North Central College – Naperville, IL

- Master's Degree in Leadership Studies awarded June 2002

University of Michigan School of Education – Ann Arbor, MI

- Bachelor's in Education (with honors) awarded May 1999

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ARE RESIDENTIAL ELECTRICITY PRICES TOO HIGH OR TOO LOW? OR BOTH?

Severin Borenstein
James B. Bushnell

Working Paper 24756
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NATIONAL BUREAU OF ECONOMIC RESEARCH
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Are Residential Electricity Prices Too High or Too Low? Or Both?
Severin Borenstein and James B. Bushnell
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ABSTRACT

Advocates of market mechanisms for addressing greenhouse gases and other pollutants typically argue that it is a necessary step in pricing polluting goods at their social marginal cost (SMC). Retail electricity prices, however, deviate from social marginal cost for many reasons. Some cause prices to be too low–such as pollution externalities–while others cause prices to be too high–such as recovery of fixed costs. Furthermore, because electricity is not storable, marginal cost can fluctuate widely within even a day, while nearly all residential retail prices are static over weeks or months. We study the relationship between residential electricity prices and social marginal cost, both on average and over time. We find that while the difference between the standard residential electricity rate and the utility's average (over hours) social marginal cost is relatively small on average in the US, there is large regional variation, with price well above average SMC in some areas and price well below average SMC in other areas. Furthermore, we find that for most utilities the largest source of difference between price and SMC is the failure of price to reflect variation in SMC over time. In a standard demand framework, total deadweight loss over a time period is proportional to the sum of squared differences between a constant price and SMC, which can be decomposed into the component due to price deviating from average SMC and the component due to the variation in SMC. Our estimates imply if demand elasticity were the same in response to hourly price variation as to changes in average price, then for most utilities the majority of deadweight loss would be attributable to the failure to adopt time-varying pricing. Nonetheless, the majority of deadweight loss nationally would be attributable to a few areas–led by California–where price greatly exceeds average SMC.

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The efficient functioning of markets relies on prices accurately reflecting the short-run social marginal cost of supply to both producers and consumers. However, in utility industries that have traditionally been viewed as natural monopolies, the theoretical ideal of marginal cost pricing has been elusive in practice. One stream of research dating back to Ramsey (1927) has examined how price discrimination and non-linear tariffs can be used to mitigate or even eliminate deadweight loss while still allowing a utility with declining average cost to recover its total costs. Another research literature, growing out of Pigou's (1920) seminal work, has shown that environmental externalities lead firms to charge prices below social marginal cost. A third and somewhat more recent literature – starting with Boiteaux (1960) and Steiner (1957) – has emphasized that the highly time-varying costs of delivering electricity, due to its high cost of storage, suggests the need for dynamic pricing in order to reflect the constantly changing cost.

In this paper, we examine the relationship between marginal retail prices and the social marginal cost of supply in the electricity industry. We focus on the most common residential electricity tariffs. In the $174 billion residential market, the efficiency implications of a gap between the marginal cost of service and the marginal price paid by consumers are growing more serious with the availability of substitute technologies such as rooftop solar photovoltaics and small-scale battery storage. These technologies make the demand of end-use consumers more price elastic, and therefore can magnify the deadweight loss from mis-pricing. Utilities around the world have expressed concern about the prospect of a "death-spiral," in which reduced consumption leads to higher regulated prices which in turn leads to more customer departures (Costello and Hemphill 2014).

Retail pricing in electricity market suffers from at least three distortions: (a) because neither buyers nor sellers bear the pollution costs of electricity generation, prices will tend to be below their optimal level, (b) because there are significant economies of scale in electricity distribution, and possibly other parts of the value chain, a linear price likely will need to exceed private marginal cost of the utility in order to recover its total costs, and (c) because electricity is not storable and demand fluctuates continuously, the private marginal cost changes continuously, yet retail prices do not reflect those fluctuations. Notably, these distortions do not all work in the same direction and can at times potentially offset one another. Research on the electricity industry and the policies that impact it, however, has tended to focus on each of these distortions in isolation. Since at least Buchanan (1969) it has been well understood in economics that markets with multiple distortions may not be improved by addressing one of the distortions in isolation.

In this paper, we take a step towards a holistic view by attempting to measure, with high frequency, the departure of residential electricity prices from the economic ideal of short-run social marginal cost (SRSMC). We then decompose the departure from SRSMC into the component caused by charging a price that differs from the average SRSMC and the component caused by charging a constant price that does not vary over short time periods as SRSMC does. The analysis is primarily an exercise in measurement of various aspects of SRSMC and the marginal price faced by the customer. Some of these measures are available in public data, some we take from previous research on the electricity industry, and some we need to estimate, because direct measures are not available.

We break the construction of price versus social marginal cost into three components: retail price, private marginal cost, and external marginal cost. Section II presents the residential electricity price data and our calculation of marginal electricity price. Section III discusses private marginal cost, for which we begin with wholesale electricity price data, but then make adjustments to incorporate time-varying costs associated with local distribution. Section IV brings in externalities, relying heavily on recent work by Holland, Mansur, Mueller, and Yates (2016). In section V, we bring the three measures together to analyze the deviation of price from SRSMC, then calculate and decompose the associated deadweight loss. In section VI we discuss several potential policy applications for our calculation. We conclude in section VII with a discussion of the broader implications of our findings.

I. Related Literature

This paper relates to three strands of literature that have examined electricity pricing from different perspectives. The first concerns itself with the central challenge of natural monopoly pricing: minimizing deadweight loss while ensuring the recovery of average costs (Brown and Sibley 1986, Kahn 1988, Braeutigam 1989, Borenstein 2016). Here the main concern has been the inclusion of fixed and sunk costs in volumetric prices, potentially driving prices above marginal cost. Various solutions have been proposed and at least partially implemented, including price discrimination with linear tarrifs (Ramsey 1927, Boiteux 1960, Boiteux 1971), two-part pricing (Feldstein 1972, Littlechild 1975), and more sophisticated nonlinear pricing (Wilson 1997, Laffont, Rey and Tirole 1998). Yet, despite a plethora of complex rate structures in use, there is a general perception that utility rates do not closely approximate (private) marginal costs (Friedman 1991, Puller and West 2013). In closely related papers, Davis and Muehleggar (2010) estimate marginal tariff rates for natural gas utilities and find that they do not adjust fully to fluctuations in wholesale gas supply costs, while Borenstein and Davis (2012) examine the equity effects of these departures from marginal cost pricing of natural gas. We are not aware of any comprehensive effort to measure the departure from marginal cost of retail electricity prices.

A second literature on electricity pricing is concerned with the variation of costs over time, particularly those driven by scarcity or capacity constraints. Early theory focused on forms of peak-load, or capacity, pricing that could at least partially capture scarcity effects in otherwise static tariff structures(Boiteux 1960, Steiner 1957, Joskow 1976, Oren, Smith and Wilson 1985, Crew and Kleindorfer 1976). The advent of advanced metering technology made feasible the prospect of dynamic electricity pricing (Borenstein 2005, Joskow and Wolfram 2012) that could capture scarcity costs through frequently varying linear prices. However, despite a growing literature on its practical effectiveness (Jessoe and Rapson 2014), dynamic pricing is still quite rare. As we describe below, only 4% of residential US customers are on a time-varying price, and the bulk of those customers are on static time-of-use prices. The lack of dynamic retail pricing has been widely cited as a source of inefficiency in the electricity industry (Borenstein and Holland 2005, Borenstein 2005, Joskow and Wolfram 2012, Puller and West 2013).

The most recently active strand of literature on the efficiency of electricity prices concerns their relationship with the external costs of electricity production and consumption (Cullen 2013, Graff Zivin, Kotchen and Mansur 2014, Novan 2015, Callaway, Fowlie and McCormick 2018). The environmental impacts of electricity supply, particularly with respect to climate change, are significant and have been the focus of policy activity for at least two decades. Environmental economists have generally advocated for the pricing of external costs, through either Pigouvian taxation or cap-and-trade systems, in this and other industries. However, alternative approaches, such as subsidies for clean energy through either tax credits or performance standards, and non-market interventions relating to energy efficiency have been more common in practice than the pricing of externalities.[1] These latter programs have been criticized by economists on several grounds.

Several papers have addressed the optimality of environmental policies with respect to consumer incentives. These studies have raised concerns about policies that limit the pass-through of externality costs. For example, the impact of intensity standards for limiting carbon emissions (Bushnell et al. 2017), the use of output-based allocation of allowances in cap-and-trade systems (Fischer and Fox 2012), and energy efficiency interventions (Allcott and Greenstone 2017). A common theme is that many “green” policies tend to promote over-consumption as they fail to properly reflect marginal environmental damages in electricity costs (Borenstein 2012). However, these papers address the design of optimal externality policies from an underlying assumption that retail prices accurately reflect private (but not social) marginal cost. To the extent that pre-existing distortions to retail prices, due to natural monopoly pricing for example, have already distorted retail prices, the optimal environmental policy can look very different from the one applied in a system with prices reflecting private marginal costs.

II. Residential Electricity Pricing

The challenge in constructing data on residential electricity pricing is to accurately characterize the marginal price that a customer faces. While data on aggre-

[1] For example, the Obama-era EPA regulatory initiative known as the Clean Power Plan offered States several options for compliance, including an intensity standard or direct subsidies of zero-carbon generation sources, as alternatives to carbon pricing (Fowlie et al. 2014).

gate revenues and quantity sales to residential customers by utility are available, those data alone only allow inference about the average price paid by residential customers. In theory, however, customers should respond to the marginal price of electricity, not the average price. Thus, we must adjust the analysis in order to get a more accurate measure of marginal price.

Our primary source of utility sales data is the Energy Information Administration's Form EIA-861 survey (Energy Information Administration 2015*a*). The EIA-861 is an annual survey of electric utilities that covers many aspects of their commercial activities.[2] The EIA-861 data include for every utility annual total revenues from residential customers, total number of customers, and total kWh sold. Dividing total revenues by total kWh yields an average price.

However, many utilities have monthly fixed charges. In order to calculate the marginal price, we remove the fixed charges. The utility fixed charges for residential customers come from the National Renewable Energy Laboratory's Utility Rate Database (URDB) (National Renewable Energy Laboratory 2017*b*). The URDB is described in more detail in the appendix. It includes many residential rates for each utility. For each utility we chose what appeared to be the primary or basic rate (the process of determining this rate is described in the appendix) and took the fixed charge from that rate. We used this fixed charge to approximate fixed revenues – total customers multiplied by fixed charge – and subtracted that amount from the total residential revenues. We divided the remainder by kWh sold to get the average variable rate, which we take as our measure of marginal price.

In some parts of the country, the electricity sector has been restructured such that customers can choose their retail providers. For about 15% of residential consumers in the US – those who have chosen retail providers that are not vertically integrated with the firm that owns the distribution lines – data on sales and revenues for these customers are reported slightly differently in the EIA-861. This is particularly true for Texas, where these data are submitted by retail providers rather than the distribution utilities. To incorporate such areas, we reformatted the EIA-861 data on sales and revenues and incorporated additional information from the Texas Public Utilities Commission (Public Utility Commission of Texas 2017*b*, Public Utility Commission of Texas 2017*a*). Rates for these retail providers are also not available from the URDB. We therefore identified the largest retail providers in these markets and manually collected additional rate information on fixed charges directly from provider websites. Full details can be found in the appendix.

Removing the fixed component of customers' bills still does not fully capture marginal rates if those rates vary with the level of consumption, such as from increasing-block or decreasing-block pricing – under which marginal price rises

[2] A smaller number of major utilities are surveyed monthly, covering about 70% of the household customers in the annual survey (Energy Information Administration 2015*b*). We are in the process of carrying out similar analysis using these data to account for seasonal changes in retail rates.

or falls in steps as a household's consumption increases. Thus, some customers of a given utility are likely to have a higher marginal rate, and others a lower marginal rate, than the one we use. Based on the 1743 retail electricity providers with rates in the URDB, about 58% of residential customers are served by a retail provider for which it appears that the marginal price in the primary residential tariff varies with consumption, of which about 37% face increasing-block pricing and about 21% face decreasing block pricing.[3]

Similarly, we do not capture variations in rates across customers of a utility. This occurs for most utilities because some customers are on rates targeted to low income households. But it could also occur if a utility charges rates that vary by geographic region. It is worth noting, however, that the failure to reflect variations in marginal rates across customers that are not based on marginal cost is very likely to lead to understated estimates of the deadweight loss associated with residential rates. This is because deadweight loss more than proportionally with the difference between price and marginal cost. Thus, for linear pricing, if all customers have the same demand elasticity, deadweight loss is minimized by charging all customers the same linear price.

In all cases, we also have assumed that the primary residential rate had no time-varying component, including no time-of-use variation, no critical peak pricing, no demand charges, and no real-time pricing. The prevalance of these kinds of tariffs is very low among residential customers. In 2015, about 4% of customers were on some form of time-varying pricing, and about 5% of customers were part of some form of demand response rebate program.[4]

Our final dataset on residential electricity pricing covers 128.2 million residential customers in 2015, with 1.382 trillion kWhs of sales and revenues of $174.4 billion. After incorporating our estimates of fixed charges we were able to calculate the average variable per-kWh price faced by just over 94% of residential customers and kWh sales.

A. Is marginal price the correct measure?

A number of papers, most recently Ito (2014), have challenged the belief that electricity consumers respond strictly to marginal price.[5] Ito finds that in the context of steeply increasing-block electricity pricing at two large utilities in California, consumers are more accurately characterized as responding to the average price they face, rather than the marginal price. None of the analyses we are aware

[3] The share of *quantity* sold on non-linear pricing is somewhat smaller, as the retail providers utilizing increasing-block pricing serve smaller average residential demand per customer. Overall, providers serving larger numbers of customers are more likely to use increasing-block pricing. Of the 1743 retail electricity providers in our URDB sample, about 39% utilize non-linear marginal pricing, with about 15% using increasing-block pricing and about 24% using decreasing block pricing in their primary residential rates.

[4] The EIA-861 data that are the source of these figures do not allow one to calculate the overlap between these two sets of customers, but presumably it is probably significant. Furthermore, a very large share of the customers on time-varying pricing are on simple peak/off-peak rates with fixed time periods and fairly small differentials between peak and off-peak.

[5] See also Shin (1985) and Borenstein (2009).

of, however, addresses the extent to which consumers are able to separate recurring fixed charges from volume-based charges.[6] Understanding and distinguishing a monthly fixed charge from volumetric pricing seems likely to be less difficult than diagnosing which step of an increasing-block marginal price schedule the household is likely to end up on at the end of the month.

Luckily, for our analysis, the three large utilities in California that have steep increasing-block electricity price schedules, where the steps differ by more than 4 cents per kWh, are outliers in the US as a whole. Using data from the URDB we find that among 673 utilities with non-constant marginal price, the median absolute difference between the lowest and highest tier across all US utilities was 1.9 cents per kWh, with 75% of the rates featuring a difference of less than 3.7 cents per kWh. Furthermore, even in California the variation in marginal price across the steps has shrunk significantly in the last decade from a ratio of more than 3 to 1, to a ratio of less than 1.4 to 1 in 2017.[7] Nonetheless, the existence of marginal pricing that changes with consumption quantity should be recognized in interpreting our results.

B. Residential Electricity Pricing Results

We present many results graphically through maps of the contiguous United States with measures primarily at the ZIP Code level. Of course, nearly all utilities serve multiple ZIP Codes, so these are not independent observations. Rather, we use ZIP Codes to approximate the shapes of each utility's service territory as accurately as possible. Our primary source for this is information in the URDB on the ZIP Codes served by each utility (National Renewable Energy Laboratory 2017*a*). For utilities not included in the URDB ZIP Code lookups, we use county information from the EIA-861 and the US Census Bureau (US Census 2017*a*, US Census 2017*b*, US Census 2017*c*). The error created by imperfect matching to ZIP Codes affects only the visual presentation in the maps. The other empirical analysis is by utility, so is not affected.[8]

Figure 1 presents the average price per kilowatt hour by ZIP code. (Here, and in all of the maps, areas with no data are represented by a dark gray shade, such

[6] The customers in Ito's sample faced increasing-block pricing, but no fixed charge.

[7] This is true for the vast majority of households. There remains a "superuser" rate that applies for usage over 400% of the baseline quantity, but that is relevant for just a few percent of households.

[8] The URDB ZIP Code assignments are based on service territory spatial data taken directly from individual utilities. However, it also appears to be the case that for many smaller utilities no such spatial data were available and so the lookups are based on the same county information taken from the EIA861 survey. Here all ZIP Codes within a county are designated as part of the utility's service territory. We have not searched the database to find all such county-level data. We also adopt the same approach of using the county-level information to fill in any remaining utilities that were not in the URDB lookups, although this is a fairly small number. In total there are 40,552 ZIP Codes in the contiguous United States as of 2016. Excluding those that have no associated area, such as large volume single site ZIP Codes (e.g. government, building, or organization addresses) we present results for 30,105 ZIP Codes, only three of which had no residential population (Environmental Systems Research Institute 2017). Of those, 40% are assigned to a single utility based on the matching described in the previous paragraph. For the remaining 60% we use the median value in any map plots.

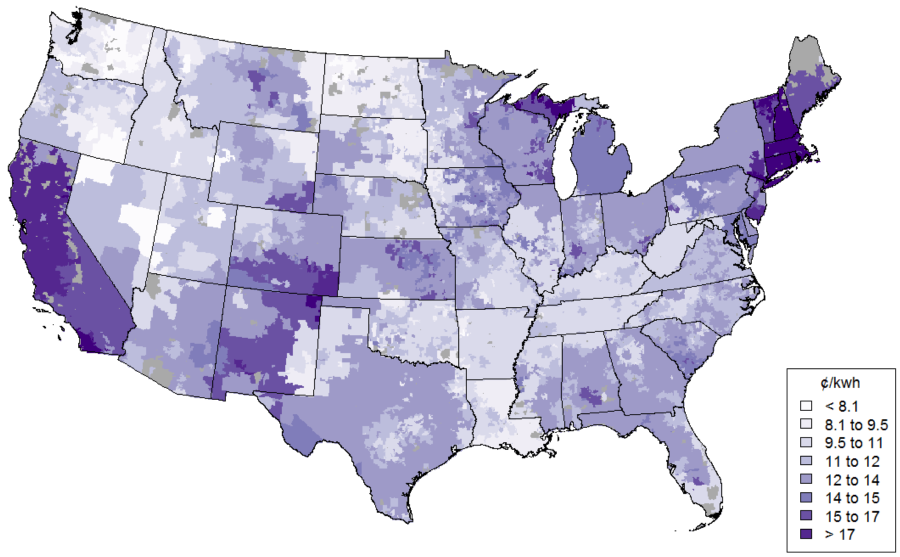


Figure 1: Average Price per kWh

as in northern Maine.) It shows, for instance, that California has among the highest average prices per kilowatt hour for residential customers, but that the very highest prices are in the Northeast. The lowest prices can be found in much of the Northwest and the South. It also shows that even in fairly high-priced states like California, New York, and Massachusetts, there are some areas with substantially lower prices.

Figure 2 presents monthly fixed charges as discussed above. Much of California has zero or slightly negative fixed charges – which occurs because of a semi-annual "climate rebate" that each residential customer gets as part of the State's cap and trade program – while some utilities in the center of the country have fixed charges of $30 per month or higher.

Figure 3 shows the results from adjusting the average price for the monthly fixed charges to get an average variable price. We would expect this to be a fairly accurate indicator of the marginal price that consumers face if the utility uses a simple two-part tariff. For those utilities that utilize increasing-block or decreasing-block pricing, as discussed earlier, this captures the average variable price across customers.[9] The average variable prices shown in this figure are used

[9]How closely this reflects the average of the marginal prices faced by customers depends on the distribution of customers across the tiers of the block pricing. See Borenstein (2009) and Ito (2014) for further discussion.

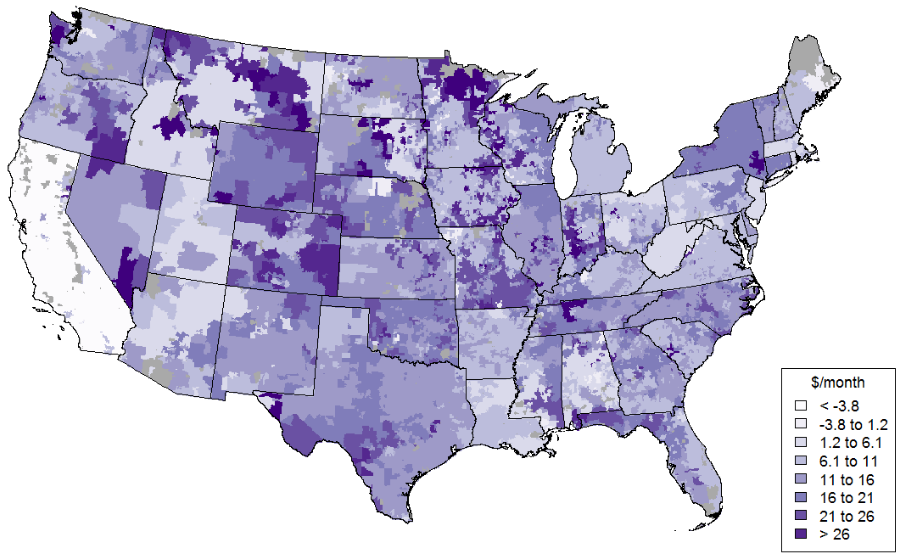


Figure 2: Fixed Monthly Charge

in our calculation of the gap between marginal price and social marginal cost.

The top panel of table 1 presents unweighted summary statistics on average price, fixed charge and average variable charge across the 2,090 utilities in the entire sample.[10] The bottom panel presents the same statistics weighted by utility sales.

III. Private Marginal Costs

Provided that wholesale electricity markets are competitive, the primary component of the private marginal cost of supplying electricity is captured in the wholesale price. We collected wholesale prices from regions that are part of Independent System Operator (ISO) control areas. ISOs calculate and report locational marginal prices (LMPs), which reflect the marginal cost of electricity generation plus high-voltage transmission congestion and losses.

Some parts of the country, particularly the Southeast, have large areas that are not covered by ISOs. In those areas, we collected data that grid operators are

[10]In reality, our sample contains 2,090 retail provider/state combinations. Utilities report their operations separately by state to the EIA. In states with retail competition, data are reported separately by both the retail provider and the local distribution company, except in Texas where only retail provider reports. See the appendix for further details.

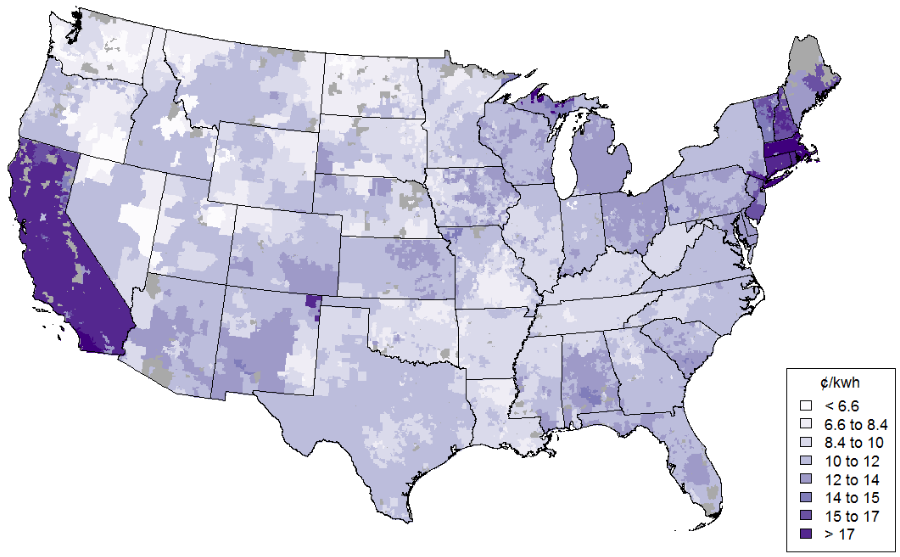


Figure 3: Marginal Price per kWh

required to file as part of FERC's Form-714 survey (Federal Energy Regulatory Commission 2017). This survey includes a requirement to report the "system lambda", which is the engineering calculation of the shadow cost of changing production by one unit. Thus, ideally, it would correspond with the marginal cost, as reflected by competitive market price, in the ISOs. For three reasons, however, we suspect that the system lambdas will be less than the ISO prices.[11] First, the ISO prices likely incorporate market power in some hours, although analysis by oversight divisions suggests very modest if any market power averaged over all periods (Bushnell et al. 2017). Second, the system lambdas likely do not fully incorporate scarcity rents in constrained hours. It is very difficult to know, however, how big these effects are. Third, system lambda incorporations of marginal transmission losses and congestion costs are likely to be incomplete.

We calculate private marginal cost based on LMP prices or system lambda values that are closest to the ZIP Codes served by a given utility, which should allow those costs to include transmission losses and transmission congestion costs. Full details of this calculation can be found in the appendix.

[11]In areas with ISOs, they typically report the market price for the system lambda.

	Mean	StDv	Min	P10	P90	Max
Retail Fixed Charge ($/month)	13.56	8.83	-16.83	4.25	25.00	74.50
Retail Variable Price (¢/kWh)	10.92	3.06	2.35	7.91	14.28	38.63
Retail Average Price (¢/kWh)	12.39	3.28	2.95	9.21	16.04	43.50
Retail Fixed Charge ($/month)	10.57	7.45	-16.83	2.43	19.25	74.50
Retail Variable Price (¢/kWh)	11.45	3.05	2.35	8.77	16.09	38.63
Retail Average Price (¢/kWh)	12.55	3.00	2.95	9.75	16.51	43.50

N=2090 utilities. Top panel is unweighted and bottom panel is weighted by sales

Table 1: Summary Statistics of Residential Rates

A. Distribution Losses

The private marginal costs calculated based on wholesale prices do not include the losses from lower-voltage distribution lines downstream from the transmission grid. Losses from low-voltage distribution lines fall into two categories: a smaller share is attributed to "no-load" losses that occur in transformers, and a larger component is "resistive" losses that are a function of the flow on the line. No load losses are fairly constant for a utility and vary across utilities as a function of the size of their systems. Resistive losses change constantly scaling with the square of the flow on a line.[12] On average, around 25% of distribution losses are no-load with the remainder attributed to resistive losses.

A range of factors affect the magnitude of losses, including the distance electricity must be carried (approximately, the inverse of geographic demand density), the density of load on circuits, the use of equipment to optimize voltage, and the volatility of demand. Demand volatility increases losses for a given average demand level due to the quadratic relationship between flow and losses. Many of these factors are likely to differ between residential customers and commercial or industrial customers. Importantly, many industrial and some commercial customers take power from the distribution system at higher voltages than residential customers, which can greatly reduce the level of line losses.

Unfortunately, the only systematic data available on distribution line losses are reported on an annual basis by utility in the EIA-861, with no breakdown by class of customers, or by hour. We attempt to approximate hourly losses by first estimating an equation for annual average losses and then converting that average hourly rate to a time-varying hourly loss rate recognizing that losses increase with the square of energy delivered. The equation for annual losses of a utility could be written as

[12] Lazar and Baldwin (1997) have a very accessible discussion of distribution line losses.

$$
\begin{aligned}
(1) \qquad L_i &= \alpha_0 Qtot_i + \alpha_1 Qres_i + \alpha_2 Qcom_i + \alpha_3 Qtot_i Density_i \\
&+ \alpha_4 Qtot_i VoltOpt_i + \alpha_5 Qtot_i (Qpeak/Qavg_i) \\
&+ \alpha_6 Qtot_i CVsales_i + \alpha_7 Q_t ot_i Transmission_i \\
&+ \sum_{u=1}^{U} \gamma_u UtilityType_{ui} Qtot_i + \sum_{s=1}^{S} \beta_s State_{si} Qtot_i + \epsilon_i
\end{aligned}
$$

where the Qs are total, residential, and commercial electricity delivered, $Density$ is $Qtot/area$, $VoltOpt$ is the share of circuits with voltage optimization equipment, and $Transmission_i$ is an indicator that the utility also owns transmission lines (and reported losses include from transmission). $Qpeak/Qavg_i$ is the ratio of the utility's peak to average load, and $CVsales_i$ is the utility's coefficient of variation of hourly sales over the year. Both of these measures are intended to capture the volatility of demand that the utility faces, which one would expect to have a positive effect on losses due to the quadratic relationship of losses to flow. However, they are each imperfect measures and come from different data sources, as explained in the appendix, so we include both. The equation includes fixed effects for type of utility (investor-owned, municipal, cooperative, etc.) and state. The coefficient α_0 alone would represent the losses associated with an additional unit of electricity delivered to an industrial customer. The derivative of equation (1) with respect to $Qres$ (recognizing that $dQtot/dQres = 1$) would then give the change in annual losses from delivering one additional unit of electricity.

$$
\begin{aligned}
(2) \qquad dL_i/dQres_i &= \alpha_0 + \alpha_1 + \alpha_3 Density_i \\
&+ \alpha_4 VoltOpt_i + \alpha_5 (Qpeak/Qavg_i) \\
&+ \alpha_6 CVsales_i + \alpha_7 Transmission_i \\
&+ \sum_{u=1}^{U} \gamma_u UtilityType_{ui} + \sum_{s=1}^{S} \beta_s State_{si} + \epsilon_i
\end{aligned}
$$

Equation (1), however, would be highly heteroskedastic in the form shown, so we normalize (1) by total quantity and estimate

$$
\begin{aligned}
(3) \qquad Lavg_i &= \alpha_0 + \alpha_1 Qres_i/Qtot_i + \alpha_2 Qcom_i/Qtot_i + \alpha_3 Density_i \\
&+ \alpha_4 VoltOpt_i + \alpha_5 (Qpeak/Qavg_i) \\
&+ \alpha_6 CVsales_i + \alpha_7 Q_t ot_i Transmission_i \\
&+ \sum_{u=1}^{U} \gamma_u UtilityType_{ui} + \sum_{s=1}^{S} \beta_s State_{si} + \epsilon_i
\end{aligned}
$$

where the interpretation of the coefficients is the same as in (1) and (2).

We estimate (3) on 2015 annual observations for the cross-section of 1669 distribution utilities for which these data are available. The results are presented in table 2. From this regression, we then impute average distribution losses for residential customers of all utilities in the dataset by calculating the predicted value of $Lavg_i$ with $Qres_i/Qtot_i = 1$ and $Qcom_i/Qtot_i = 0$.[13] Clearly, this is an imperfect approximation to average distribution losses for residential customers. It assumes implicitly that the relative losses of residential versus commercial and industrial customers are the same for all utilities. Furthermore, we have no information on the extent to which voltage optimization or variation in hourly sales relates to residential circuits. Without making very strong assumptions about the correlates of residential losses, it is unclear how to improve on this estimate.

	$L_i/Qtot_i$
Share of Sales (Residential)	0.0270***
	(0.0065)
Share of Sales (Commercial)	0.0071
	(0.0042)
Log(Sales per sq. km)	−0.0066***
	(0.0008)
Share of Circuits w. Volt. Optim.	−0.0032**
	(0.0011)
Ratio of Peak to Average Load	0.0079**
	(0.0023)
Coef. of Variation for Load	−0.0184
	(0.0422)
Transmission	−0.0000
	(0.0019)
R^2	0.3265

N=1669 utilities

Dependent Variable: Avg. Proportion Total Losses

Fixed Effects: State and Utility Type

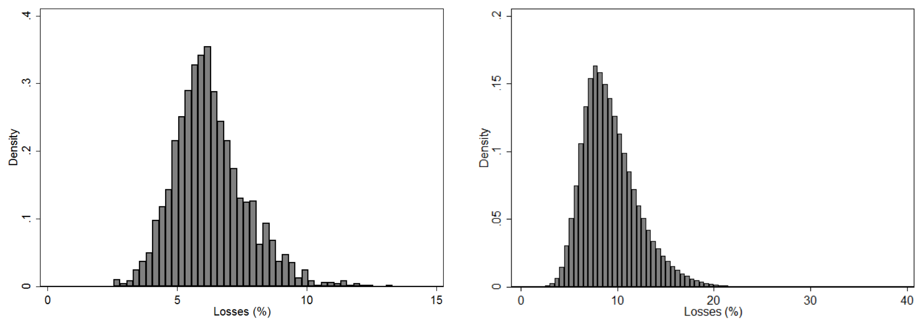
Cluster Variable: State

Table 2: Estimates of Average Distribution Losses

Using the standard engineering approximation that losses increase with the square of flow, we then calculate marginal losses in each hour for each utility assuming that 25% of losses are invariant to load and 75% are proportional to the square of load. The details are presented in the appendix. To do this, however, we

[13] Summary statistics of the variables are presented in the appendix. We predict losses for all utilities in the data set. For those for which some of the right-hand side variables are not available, we use the average value of the variable from the 1669 utilities in the regression.

need data on the pattern of hourly consumption by residential customers, which don't exist for most utilities. FERC form 714 provides hourly consumption of all customers of a utility. We use that load profile, scaled by the share of total demand that comes from residential customers, to approximate the residential demand in each hour. This is not ideal. The alternative, however, is to use an engineering model of residential energy use patterns, which also is highly imperfect.



(a) Average annual residential distribution losses

(b) Marginal hourly residential distribution losses

Figure 4: Estimates of residential distribution losses

Distribution losses turn out to be significant in the overall analysis. Figure 4a presents the spread of average annual distribution losses from residential customers for the utilities in our analysis. Table 3 shows that on a sales-weighted basis the estimated average distribution loss rate is 6.1%. Furthermore, because the externalities associated with electricity consumption take place upstream from the distribution losses, the loss rate scales up both the private marginal cost and the external marginal cost. After assuming that 25% of losses are non-marginal and the other 75% vary with the square of load, figure 4b presents the spread of marginal hourly distribution losses from residential service that we estimate. These average about 9% but vary greatly hourly with load.

B. Other private cost considerations

The energy costs captured by the LMP and system lambda data used in this analysis constitute the vast majority of the average wholesale electricity costs that must be covered by customers over the year. The remainder is made up of capacity costs, ancillary services costs and other uplift payments. Across the seven ISOs energy costs comprised between 74% and 98% of the total wholesale cost of electricity in 2015, as shown in table 4. More detail on the source and interpretation of these costs is in the appendix.

We do not include long-run reserve costs, sometimes called capacity costs, in our calculation of short-run private marginal cost. In energy-only markets, such

	Mean	StDv	Min	P10	P90	Max
Avg. Total Losses (%)	5.02	1.53	0.42	3.10	7.09	10.02
Avg. Res. Dist. Losses (%)	6.44	1.45	2.56	4.74	8.41	12.23
Marg. Res. Dist. Losses (%)	9.27	2.11	3.61	6.82	12.04	17.93
Avg. Total Losses (%)	4.82	1.40	0.42	3.28	6.64	10.02
Avg. Res. Dist. Losses (%)	6.14	1.34	2.56	4.63	7.82	12.23
Marg. Res. Dist. Losses (%)	8.78	1.94	3.61	6.65	11.26	17.93

N=2090 utilities. Top panel is unweighted and bottom panel is weighted by sales

Table 3: Summary Statistics of Distribution Losses

	Energy	Capacity	Ancillary	Uplift
CAISO	89%	9%	1%	1%
PJM	74%	23%	2%	1%
ISO-NE	81%	15%	3%	1%
NYISO	74%	22%	3%	1%
ERCOT	92%	-	4%	4%
SPP	98%	-	1%	1%
MISO	95%	4%	0%	1%

Note: Percentages may not sum to 100 due to rounding

Table 4: Estimates of the composition of total wholesale costs by ISO

as ERCOT or SPP, there are no explicit capacity costs. In other markets that do have capacity requirements, capacity requirements have to be adjusted in the medium or long run in response to variation in demand. These costs can sometimes be substantial. In 2015 capacity costs comprised between 4% and 22% of the total wholesale cost of electricity at the five ISOs that make these payments. The link between incremental consumption in a given hour and the capacity requirement is complex. However, conditioned upon the capacity at any point in time, the wholesale energy market price should reflect the true marginal resource cost of delivering one more kWh. Thus, from a strict economic efficiency vantage, longer-run investments triggered by current demand would not be a short-run marginal cost.[14]

We also do not incorporate short-run operating reserve, or “ancillary service”,

[14]One complication to this interpretation of short-run marginal cost arises when there is scarcity of supply. When electricity systems experience short-term violations of operating constraints, such as unit ramping or transmission flow constraints, prices include penalty values to reflect the cost of the scarcity of appropriate supply. To the extent these values do not reflect the true underlying value of electricity to end-users, they are rough approximations of the short-run marginal costs in these periods. There were relatively few such periods during 2015.

costs into our marginal cost calculation. Fortunately these costs are relatively small, even in aggregate. In 2015 ancillary service costs at the seven ISOs comprised between less than 1% and 4% of the total wholesale cost of electricity. Furthermore, it is likely the case that many of these costs should not be included in our calculation of marginal costs. The primary marginal impact of reserves is reflected in the energy prices or system lambda values used to reflect cost. This is because most reserves operate as stand-by resources and do not incur marginal cost unless a contingency event occurs. The main cost impact of an expansion of reserves arises when lower cost units are held back to provide reserves, while more expensive units are deployed to supply energy in their place. However this effect is captured in the marginal energy price when the more expensive units set those prices.

Finally, some non-convex incremental costs, such as "start-up" costs that are incurred to supply energy are at times not captured in the energy price and are instead paid as "uplift" payments to specific units. We do not currently adjust our costs for these considerations. Again though, these costs are very small. In 2015 "uplift" payments amounted to between less than 1% and 4% of the total wholesale cost of electricity.

Including all of the non-energy wholesale electricity costs would have a modest effect on the average wholesale price of electricity, and therefore on the gap between the marginal retail price and the average social marginal cost. It could, however, have a significant effect on the SMC during peak hours if reserve costs were considered marginal and were attributed entirely to the highest-demand hours. In that case, SMC would be more volatile than our analysis suggests and the deadweight loss of static pricing would be greater.

C. Private Marginal Cost Results

Figure 5 presents the private marginal cost calculations. It is worth noting how low these numbers are, many below levels generally considered sufficient to cover long-run average cost of a modern combine-cycle natural gas power plant, even at today's very low gas prices. In part, that reflects the fact that much of the country had excess capacity in 2015, and still does today, due to a combination of mistakes or bad luck in planning and policies of carrying large quantities of excess capacity. Consistent with such policies, this also reflects the fact that in most deregulated markets, power plant owners receive revenues from capacity payments as well as energy payments. Summary statistics on private marginal cost are presented in table 5 in the next section along with external marginal costs and total social marginal cost.

Wholesale prices (and implied private marginal costs) well below levels necessary to cover long-run average cost are certainly a concern for generators and policymakers, but if measured accurately, such a shortfall does not have direct bearing on our analysis of the efficiency of residential retail price and their deviation from SRSMC. Economic theory dictates that if short-run marginal costs

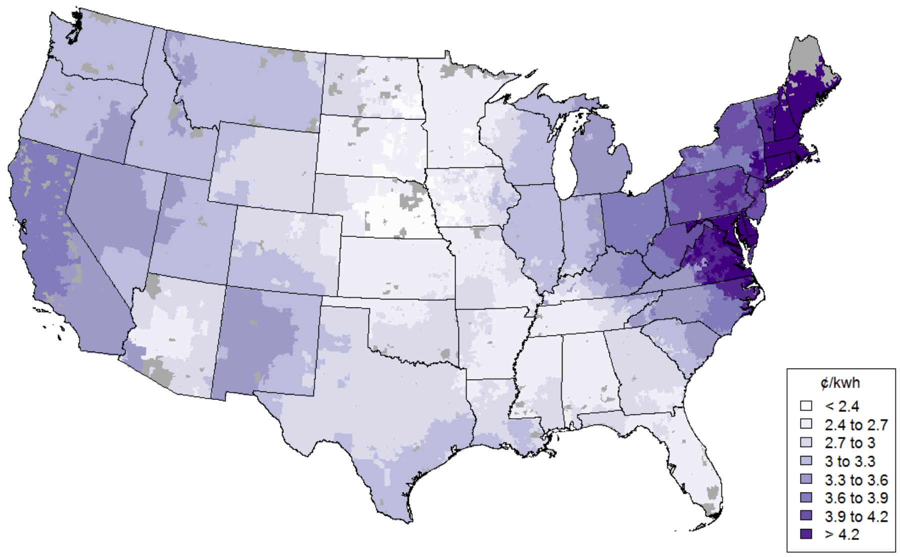


Figure 5: Average Private Marginal Cost per kWh

are indeed quite low, then efficient pricing should reflect that, even if such prices are not sufficient to cover average cost.[15] Furthermore, even if policymakers believe that additional revenue must be raised in order to cover the past investments of suppliers, such revenues need not come from marginal energy prices. Fixed charges, subscription charges (*e.g.,* based on the customer's circuit breaker capacity) and demand charges are among the alternatives that can be used to increase revenue collection without raising marginal price.

IV. External Marginal Costs and Total Social Marginal Costs

For external marginal cost, we rely on Holland, Mansur, Muller, and Yates (2016). As explained in detail in their paper, the data are imperfect, but they represent the most sophisticated calculation of the environmental costs of marginal power supply to date. For each of the nine U.S. regions of the North American Electricity Reliability Corporation (NERC), they calculate an externality cost per marginal MWh of demand based on the resulting change in generation from each plant in the region and the county and emissions rate of the plant. The result

[15]And, conversely, if the marginal generation costs are quite high, yielding very high profits for producers (but without exercise of any market power), then efficient retail prices should reflect those high short-run marginal costs.

is a marginal externality cost for each NERC region for a representative 24-hour day. So, we are able to distinguish externalities by hour of the day, but not by month, weather conditions, or system demand. Also, the estimates are based on marginal cost of each pollutant independent of the time at which that pollutant is emitted. That is not a problem for GHGs, but it is likely create some error for some local pollutants, such as NO_x. In future versions, we hope to use improved estimates that incorporate additional cost factors.[16]

We do make one adjustment to these estimates to account for line losses. In their regressions of pollution on system load, Holland, Mansur, Muller, and Yates uses for system load data from FERC Form 714, which include transmission and distribution losses. They do not, however, adjust the marginal generation required to deliver one MWh to the end-user for these losses. Thus, we scale up the calculations of pollution associated with a marginal end-use MWh to account for transmission and distribution losses.

The HMMY analysis is based on generation and emissions data from 2010 to 2012, so the match to our analysis for 2015 is not exact. Over the 3 to 5 intervening years, some coal plants have closed, which could lead to lower marginal externality estimates. On the other hand, natural gas prices have declined relative to coal causing coal to be on the margin more frequently, which could lead to higher marginal externality estimates. In future versions, we will incorporate marginal externality analysis based on more recent years.

A. External Marginal Cost Results

In figure 6, we show the average externality cost per kWh. The figure shows the dollar-value externality cost associated with a marginal kWh of demand change in each location. The figure illustrates some coarseness in these data, because the analysis assumes that the same plants are marginal for any incremental demand within a NERC region for a given hour of the day regardless of the location of the incremental demand in the region. Still, the figure demonstrates that externality costs vary widely and are particularly large in the areas where coal-fired power plants are most prevalent. Comparing the scales of figure 5 and figure 6 also indicates that the majority of the social marginal cost in our calculations in most locations is due to externalities, rather than the private marginal cost of generation.

B. Total Social Marginal Cost Results

Figure 7 then aggregates the data in figures 5 and 6 to present the social marginal cost. Though California has among the higher private marginal cost,

[16]In addition, these estimates are based only on weekday data. Weekends are excluded. Because demand is typically higher on weekdays, the bias in our estimates from using weekday-only externality estimates depends on whether marginal supply creates larger externalities in high-demand versus low-demand periods. The sign of this bias likely differs in different regions of the country.

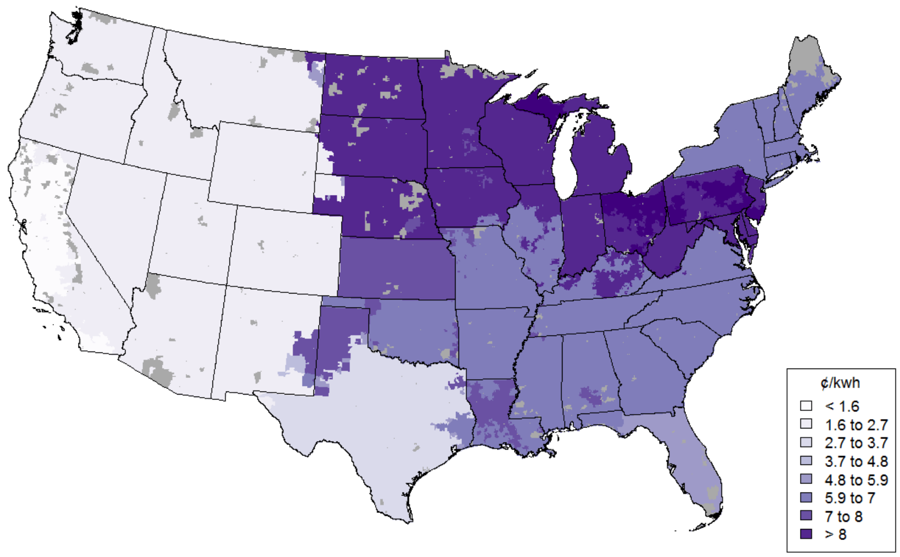


Figure 6: Average External Marginal Cost per kWh

the external marginal cost associated with that generation is much lower than in most of the U.S. causing it to have among the lowest SMCs. In contrast, the Northeast has fairly high PMC and EMC, leading to a high SMC, while the upper Midwest has low PMC, but such high EMC that it also exhibits a very high SMC. Table 5 shows the average quantity-weighted social marginal cost is 9.3 cents per kWh, about two-thirds of which is due to external marginal costs.

V. Mispricing and Deadweight Loss Decomposition

Figure 8 presents the marginal price minus average social marginal cost map. The bluer areas are pricing above average SMC, while the redder areas are pricing below average SMC. Much of the country has fairly light colors, indicating that the static marginal price that residential customers pay is fairly close to average SMC. California and parts of New England are notable for price being well above SMC, while parts of North Dakota and West Virginia exhibit the largest price deviations below SMC.

Figure 8, however, captures only part of the story, because it does not include variation in SMC over time. The static price might reflect the average SMC well, but still create significant inefficiency because the SMC varies substantially hour-to-hour. Figure 9 shows histograms by state of the hourly price minus SMC,

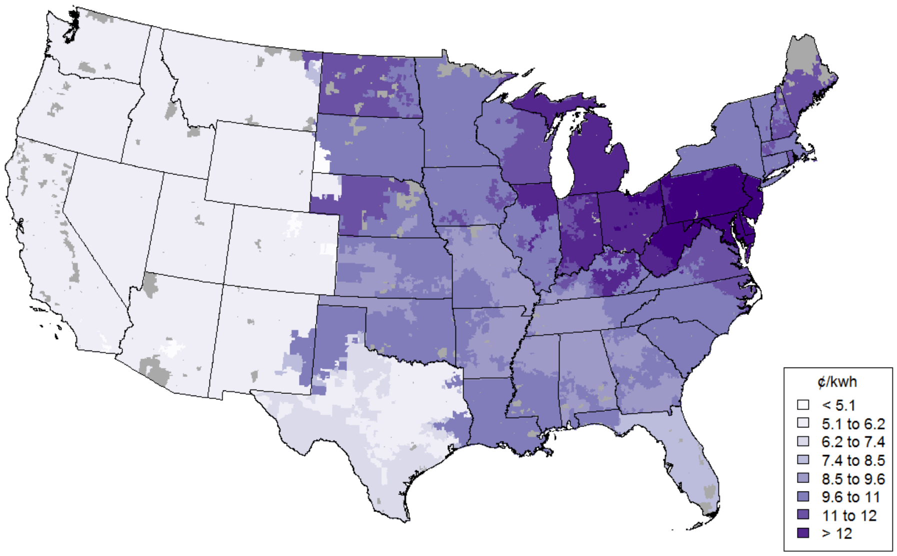


Figure 7: Average Social Marginal Cost per kWh

	Mean	StDv	Min	P10	P90	Max
Private Marginal Cost (¢/kWh)	3.19	0.67	2.17	2.46	4.22	5.32
External Marginal Cost (¢/kWh)	6.67	2.25	1.52	2.44	8.98	9.66
Social Marginal Cost (¢/kWh)	9.86	2.41	4.90	5.63	12.81	14.52
Retail Variable Price - $\overline{\text{SMC}}$ (¢/kWh)	1.06	3.27	-7.10	-2.24	5.15	26.82
Private Marginal Cost (¢/kWh)	3.28	0.67	2.17	2.57	4.35	5.32
External Marginal Cost (¢/kWh)	6.00	2.38	1.52	2.38	8.94	9.66
Social Marginal Cost (¢/kWh)	9.27	2.61	4.90	5.43	12.86	14.52
Retail Variable Price - $\overline{\text{SMC}}$ (¢/kWh)	2.18	3.95	-7.10	-1.67	7.38	26.82

N=2090 utilities. Top panel is unweighted and bottom panel is weighted by sales

Table 5: Summary Statistics of Marginal Costs

illustrating that SMC varies quite widely in some states, while it is much less volatile in others.

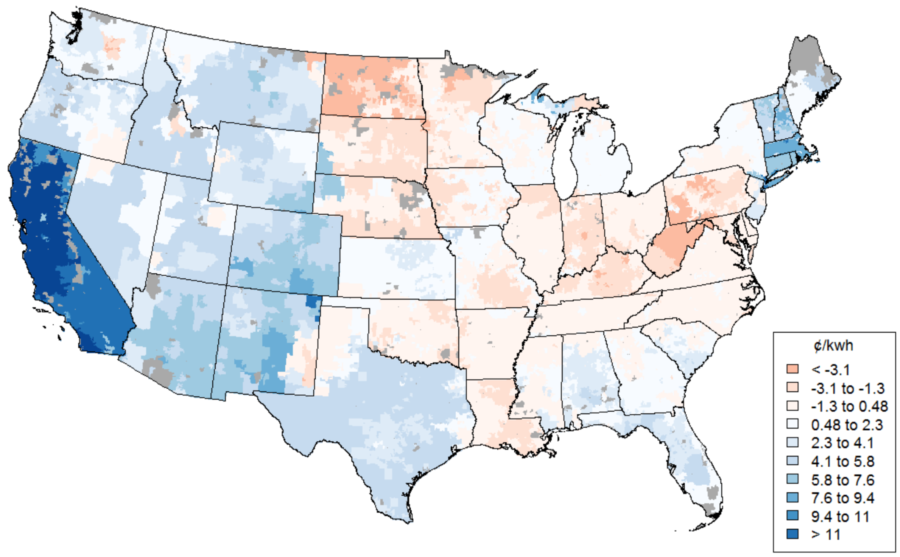


Figure 8: Marginal Price minus Average Social Marginal Cost per kWh

A. Analyzing and Decomposing Deadweight Loss

In order to incorporate the mispricing both from price deviating from average social marginal cost and from charging a static price while the social marginal cost varies temporally, we move to analyzing deadweight loss directly. In the residential electricity market we model here, the seller charges the same price ($\bar{P}$) at all times, but SMC changes hour to hour. In the simplest model of this market, illustrated in figure 10, demand is the same in all hours and is (or can be approximated as) linear. For any hour h,

$$DWL_h = \frac{1}{2}(\bar{P} - SMC) * \frac{(\bar{P} - SMC)}{s} = \frac{1}{2s}(\bar{P} - SMC)^2 \tag{4}$$

where s is the slope of the inverse demand function, $\frac{dP}{dQ}$. So, the total DWL associated with charging a price, $\bar{P}$, is $\sum_h \frac{1}{2s}(\bar{P} - SMC_h)^2$, that is, DWL is proportional to the second uncentered moment of the distribution of $(\bar{P} - SMC)$. The result is the same if demand shifts hour to hour, but always has the same slope.

We can rewrite DWL as

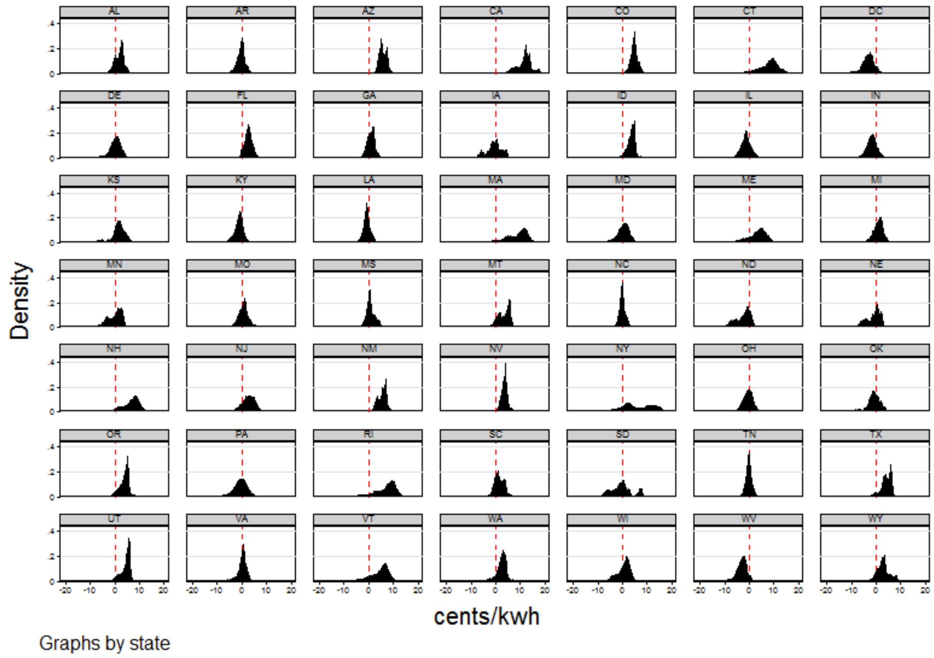


Figure 9: Marginal Price minus Hourly Social Marginal Cost by State

$$
\begin{aligned}
(5) \qquad DWL &= \sum_h \frac{1}{2s}(\bar{P} - SMC_h)^2 \\
&= \frac{1}{2s}[H \cdot (\bar{P} - \overline{SMC})^2 + \sum_h (\overline{SMC} - SMC_h)^2]
\end{aligned}
$$

where H is the total number of hours covered by the DWL calculation. Under the assumption that s is the same for all hours, and would be the same for response to hourly price changes as to a longer-run change in the static price, equation (5) allows us to decompose DWL into the component resulting from price deviating from $\overline{SMC}$ and the component resulting from price failing to vary hour to hour as SMC changes.

Of course, a constant demand slope is not a benign, or even particularly reasonable, assumption, as it implies that the quantity response to a price change is the same regardless of the pre-change quantity. Instead, we adopt the more neutral assumption that all demands exhibits the same elasticity at $\bar{P}$, implying that the slope of inverse demand for hour h and utility i is $s_{hi} = \frac{\hat{s}_i}{Q(\bar{P}_i)}$. That is, $\hat{s}_i$

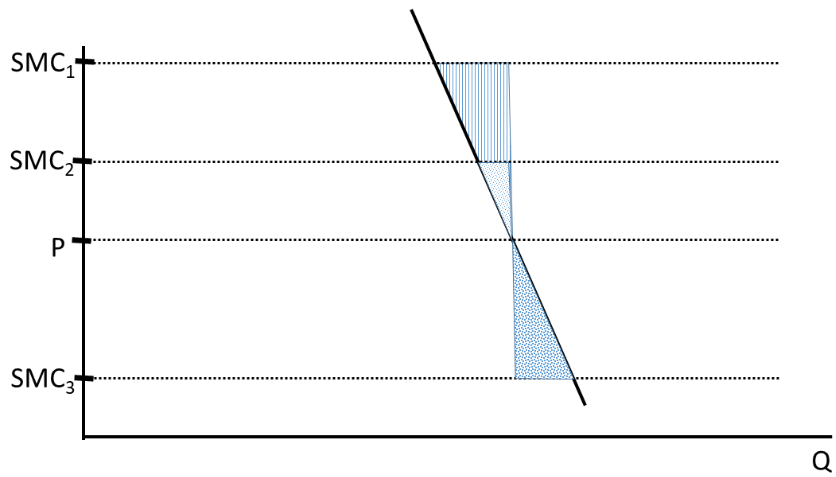


Figure 10: Illustration of Deadweight Loss in Hours with Varying SMC

is a constant for each utility across all hours that is the slope of inverse demand per unit of quantity demanded at the utility's $\bar{P}$. Across utilities, this implies that a utility with twice as many customers would exhibit twice as much quantity response to a given change in price. Across hours, this implies that high-demand hours yield a larger quantity response to a given price change. Thus,

$$(6)\ DWL_{total} = \sum_h \frac{Q_h(\bar{P})}{2\hat{s}}(\bar{P} - SMC_h)^2$$
$$= \frac{1}{2\hat{s}}[\sum_h Q_h \cdot (\bar{P} - \overline{SMC_w})^2 + \sum_h Q_h \cdot (\overline{SMC_w} - SMC_h)^2]$$

where $\overline{SMC_w}$ is the quantity-weighted average of SMC,

$$(7)\qquad \overline{SMC_w} = \frac{\sum_h Q_h \cdot SMC_h}{\sum_h Q_h}$$

We use equation (6) both to compare DWL of pricing across utilities, and to decompose the DWL into the share attributable to setting a constant price at the suboptimal level (given the constraint of charging a constant price) versus the share attributable to failing to adopt dynamic pricing.[17]

[17]Borenstein and Holland (2005) show that the efficient constant price is equal to the quantity-weighted

To evaluate the two components of mispricing – the deviation of average SMC from the static price and the residual volatility of SMC compared to the average SMC – we return to equation (6) and separate these two sources of deadweight loss.

$$DWL_{avg} = \frac{1}{2\hat{s}}[\sum_h Q_h \cdot (\bar{P} - \overline{SMC_w})^2] \tag{8}$$

$$DWL_{resid} = \frac{1}{2\hat{s}}[\sum_h Q_h \cdot (\overline{SMC_w} - SMC_h)^2], \tag{9}$$

where $\hat{s}$ has been defined so that the deadweight loss quantities are per unit of quantity demanded at the utility's $\bar{P}$, specifically assuming a linear demand curve with elasticity -0.2 at the utility's $\bar{P}$.[18]

Importantly, we are assuming, for now, the same price responsiveness to hour-to-hour price variation as to an overall shift in a static price.[19] As of 2018, it seems likely that actual price responsiveness is greater for a change in the static price than in response to hourly price changes. As technology evolves, however, it is quite possible that the ability to automate load shifting between hours could make the elasticity greater for response to hourly price variation.

Figure 11 presents a map of DWL_{avg}. California is clearly the outlier. Though we saw that much of the Northeast has prices as high as California, the Northeast also has much higher SMC than California. While we have also seen that price is below SMC in much of the center of the country, the gaps to SMC are much smaller than we find in California.

Figure 12 presents DWL_{resid}, the deadweight loss caused by charging a static price when SMC varies. The deadweight loss from SMC variation is most prevalent in the center of the country in the Northeast. Figure 13 presents a county map of the ratio DWL_{avg} to DWL_{total}.

Table 6 presents summary statistics of the components and total deadweight loss per unit demand for the 2,090 utilities in the sample. It also presents the summary statistics for the ratio of DWL_{avg} to DWL_{total}. Whether weighted by sales or unweighted, the mean (and also the median, though it isn't shown) suggests that for most utilities, the largest deadweight loss is due to the failure to implement dynamic pricing, at least under the assumption of equal elasticities

average marginal cost under the condition that demand elasticity is the same in all hours.

[18] $\epsilon = -P/Q * dQ/dP = -P/Qs \iff s = -P/Q\epsilon$. We are calculating s for a unit of quantity demanded ($Q = 1$) at $\bar{P}$ assuming $\epsilon = -0.2$, so $\hat{s} = -\bar{P}/0.2$.

[19] We are also assuming that all other goods in the economy are priced at their social marginal cost including, importantly, substitutes for electricity. That may not be a bad approximation for petroleum products, but natural gas is priced well above social marginal cost to residential customers (Davis and Muehlegger 2010, Borenstein and Davis 2012). Similarly, the welfare change from load shifting is a function of the difference in SMC at the two times and the consumer's difference in willingness to pay for the usage at the two times.

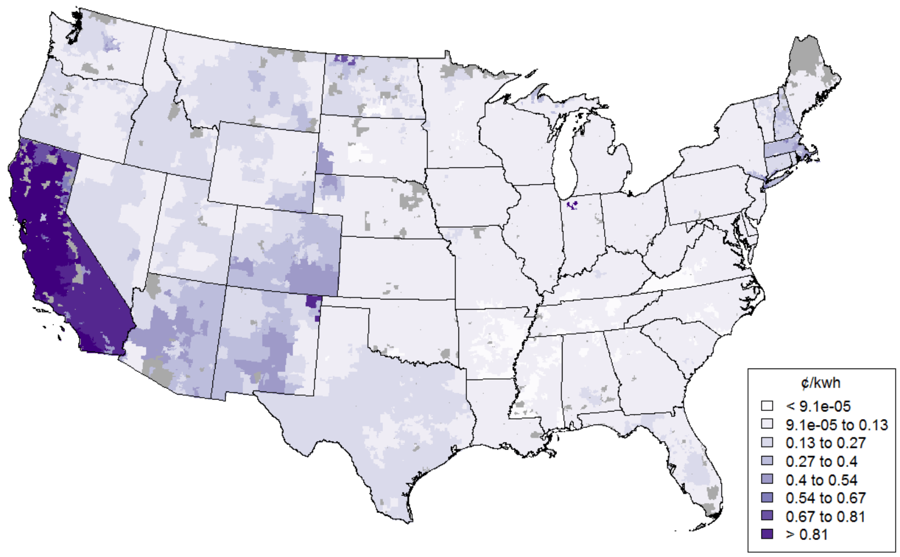


Figure 11: DWL Per Unit Demand Due to Price Differing from Average SMC

	Mean	StDv	Min	P10	P90	Max
DWL_{total} (¢/kWh)	0.22	0.19	0.02	0.08	0.39	2.41
DWL_{avg} (¢/kWh)	0.09	0.17	0.00	0.00	0.25	1.86
DWL_{resid} (¢/kWh)	0.13	0.08	0.01	0.06	0.21	0.81
DWL_{avg}/DWL_{total} (%)	27.29	27.08	0.00	0.52	71.83	97.75
DWL_{total} (¢/kWh)	0.24	0.23	0.02	0.07	0.51	2.41
DWL_{avg} (¢/kWh)	0.14	0.23	0.00	0.00	0.37	1.86
DWL_{resid} (¢/kWh)	0.11	0.06	0.01	0.03	0.19	0.81
DWL_{avg}/DWL_{total} (%)	37.66	32.71	0.00	0.77	88.05	97.75

N=2090 utilities. Top panel is unweighted and bottom panel is weighted by sales

Table 6: Summary Statistics of Deadweight Loss Estimates Per Unit Demand

for all price variation. Still, the utilities whose residential retail pricing generates the largest deadweight loss do so by setting a static price very far above average SMC. Across all 2,090 utilities in the sample, the quantity-weighted mean share of deadweight loss attributable to price differing from average SMC is 38% and the median is 32%. However, 56% of all deadweight loss in the sample results

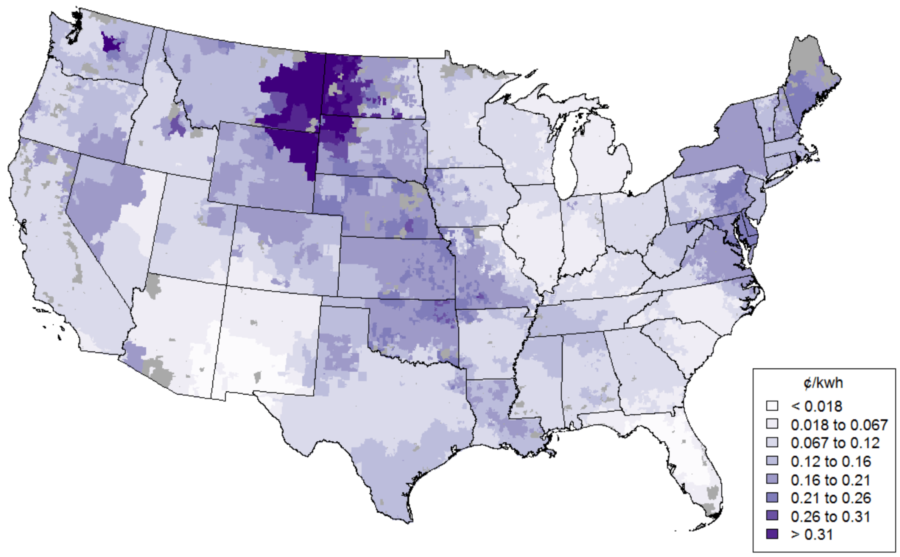


Figure 12: DWL Per Unit Demand Due to Time-Varying SMC and Static Price

from the deviation of price from average SMC, with the remaining 44% due to price not fluctuating with hourly changes in SMC.[20]

VI. Applications and Implications

Having calculated estimates of both the marginal prices and marginal social costs of electricity, we now consider some policy areas where such information ideally would be considered, and the implications of our calculation for the current desirability of such policies. One area where our calculation has potential relevance, but has received limited policy attention in the US, is the application of carbon pricing to the electricity sector. As discussed above, policy debates over the design of carbon pricing policies periodically invoke the Pigouvian ideal of capturing the marginal externality costs of greenhouse gasses in consumer energy prices. Mechanisms such as output-based updating of allowance allocation, and the application of intensity standards, have been criticized on the grounds that they dilute the externality cost faced by consumers ((Holland, Hughes and Knittel 2009, Fowlie 2011)).

However, if marginal prices are already well above social marginal cost, the

[20]The 56% figure is based on aggregation of all deadweight loss across utilities, while the 38% figure is an average share across utilities weighted by the quantity of electricity sold.

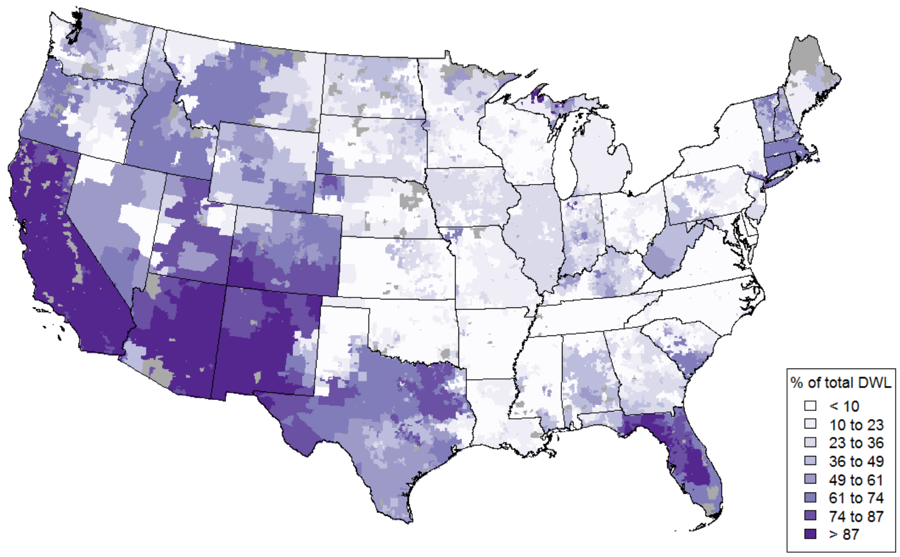


Figure 13: Share of Total DWL Due to Price Differing from Average SMC

additional externality signal only pushes prices further away from first best. It is worth noting that in the United States, carbon pricing - in the form of cap-and-trade - is currently applied to electricity only in California and the northeastern states comprising the Regional Greenhouse Gas Initiative. However, these are the collection of states where we have found average retail prices to be well above social marginal cost.

Still, it is important to recognize that our analysis focuses only on the distorted consumption incentives when residential retail price deviates from social marginal cost. We have not studied commercial and industrial rates, which are more complex, with greater use of time varying pricing and "demand charges" that determine (and distort) customer incentives. More importantly, our analysis does not consider the effect of market mechanisms for greenhouse gases and other pollution externalities on the mix of generation, between coal-fired generation, gas-fired generation, nuclear power, renewable generation and other sources. The efficiency value of pricing emissions at the wholesale level seems likely to be quite significant. Our findings, however, suggest that the argument for passing through those costs to residential rates is much weaker in some parts of the country.

Our findings also have direct implications for two other areas that have received considerable attention in the energy and economics literature: energy efficiency and distributed energy resource policy. We explore each of these in turn. We do not attempt here to perform a detailed calculation of the welfare implications of these policies, but rather present suggestive evidence that efforts in both areas may be significantly geographically misaligned with the benefits they can provide.

A. Energy Efficiency

The subject of energy efficiency in general, and its role in the electricity industry in particular, has been a topic of debate among economists and technologists for decades. Much of the debate has focused on whether these programs deliver the "negawatts" claimed by the utilities that implement them (Joskow and Marron 1992, Auffhammer, Blumstein and Fowlie 2008). Economists have also examined the specific behavioral, regulatory, and market channels that could justify energy efficiency policies (Allcott and Greenstone 2012, Gillingham and Palmer 2014). However, much of the literature on the "efficiency gap" has focused on what Gerarden, Newell and Stavins (2017) call the "private energy-efficiency gap" - the question of whether customers are making individually rational economic choices. They note that the more policy-relevant question of the social energy-efficiency gap hinges on many factors, including the relationship of energy prices to social marginal cost, a question they identify as a "relatively high priority" for further research. Indeed, well-informed consumers who face retail prices that are significantly above social marginal cost are already being given too much incentive to adopt energy efficiency measures. If consumers are able to make privately optimal energy-efficiency decisions, government programs to promote improved energy efficiency would be best aimed at areas where price is below social marginal cost.

Several recent papers have attempted to address aspects of the relationship between energy efficiency programs and the social benefits they provide. Both Novan and Smith (2016) and Boomhower and Davis (2017) examine the impact of energy efficiency programs on the hourly profile of energy use, and compare those impacts to wholesale power costs and environmental impacts.

Using state-level data from the Consortium for Energy Efficiency,[21] we examine per-customer reported expenditures on residential energy efficiency programs.[22] This includes both energy efficiency programs run through utilities and those run through non-utility organizations, which play a significant role in New York, Oregon, Vermont, and parts of California, for instance. Other efficiency measures, such as appliance and building standards, impose costs on firms and consumers that are also not captured in these data. Still the data presented here are strongly reflective of the relative emphasis that different jurisdictions place upon energy efficiency measures. Figure 14 illustrates the regional expenditures per customer of electric utilities on energy efficiency programs. The largest expenditures are focused on the coasts, with particular intensity in California and the northeast.

[21] https://www.cee1.org/annual-industry-reports
[22] Our thanks to Hunt Allcott for suggesting this comparison.

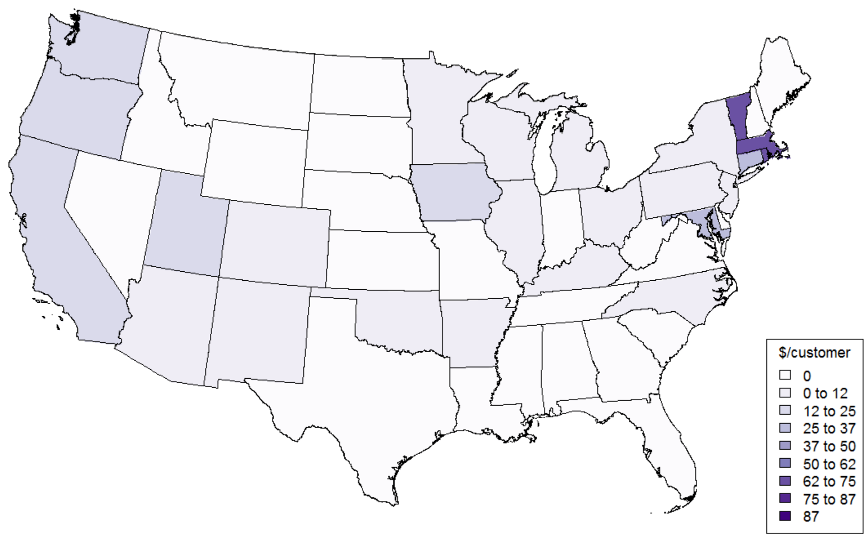


Figure 14: Electric Utility Expenditures on Energy Efficiency Programs

According to our calculations, these are the regions where marginal energy efficiency expenditures provide the least, possible even negative, social value. Clearly, the distribution of spending on energy efficiency within the US is suboptimal at best.

B. Distributed Energy Resources

Another area of energy policy that is directly impacted by the relationship between retail prices and marginal cost is the deployment of small-scale distributed energy resources. Small scale generation resources, currently overwhelming comprised of rooftop solar photovoltaic (PV) installations, are deployed "behind the meter" and generally eligible for "net metering." When a customer's production exceeds consumption, the excess production in one hour is allowed for billing purposes to offset excess demand in other hours. In this way, residential customers with distributed generation can offset the full retail price of electricity, rather than the marginal replacement cost of the energy that is produced. Where retail variable prices substantially exceed the marginal cost, residential solar is considerably more attractive for consumers. In California, Borenstein (2017) calculates that the gap between retail and wholesale marginal electricity prices provides about as large an incentive for residential solar as the 30% federal investment tax credit.

Drawing again from the EIA form 861, we aggregate the capacity of distributed resources that is subject to net metering by utility reporting area. Figure 15 illustrates the capacity of distributed generation (in kW) per customer for the utility systems that report this statistic to the EIA. California, with over 40% of the residential solar capacity in the nation, again dominates this calculation.

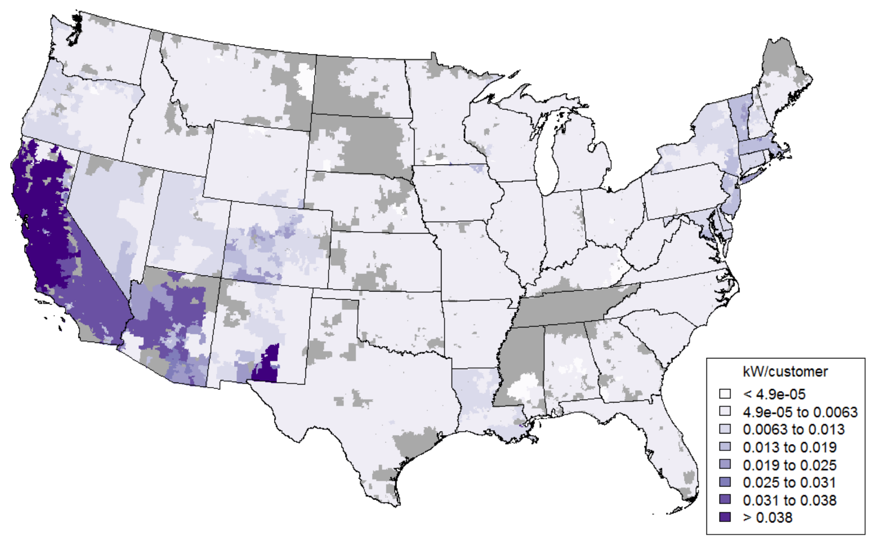


Figure 15: Installed Distributed Generation Capacity Subject to Net Metering

The map reflects the union of at least three sets of attributes: significant solar incentives (*e.g.,* New Jersey), solar potential (desert southwest), and high retail prices. Comparing figure 15 to figure 9, the strong relationship between high retail prices and solar deployment again stands out. A full calculation of the welfare implications of retail tariffs on DG would require a decomposition of rate effects from other incentives, as well as estimates of the relative efficiency of solar deployment in different locations. However, figure 15 does suggest that expenditures on distributed solar are strongly associated with retail price incentives that greatly exceed the social value of distributed generation.

The deployment of distributed energy resources, and the resulting reduction in metered consumption, or "load defection" is a growing threat to the finances of distribution utilities who have been recovering capital cost though volumetric rates. Critics of small-scale DG have pointed to net-metering policies as a target for changes to rectify the situation, but net-metering policies lose their relevance if the marginal retail rate reflect social marginal cost. Recognizing this fact, utilities are increasingly seeking to adjust their rate structures to increase monthly fixed charges and reduce their volumetric prices. While not a panacea (Borenstein 2016) a shift toward larger fixed fees, particularly in states like California where they are modest to non-existent, would partially insulate utilities from the loss of customer load and reduce the marginal private reward of solar deployment for customers.

Consideration of distributed generation also raises questions of their potential impact on distribution losses and other costs associated with distribution networks, such as voltage support. As discussed above, marginal distribution losses can be significant, reaching over 20% at times, which DG could mitigate or exacerbate depending on location and timing of production. More generally, the degree to which optimized location and control of distributed resources could change the cost of distribution remains an important area of research. Collection of distribution-level data with higher temporal and locational resolution could help address these questions.

VII. Conclusion

Most policy recommendations from economists for responding to the challenge of climate change revolve around "getting the prices right." But in electricity, the prices are wrong for many reasons beyond greenhouse gas emissions. In this paper, we have sought to present a first analysis of the direction and degree of mispricing in residential electricity.

We find that with the current generation capacity and remuneration mechanisms for generation, the short-run private marginal cost was quite low in 2015, averaging around 3 cents per kWh, which is below most estimates of the long-run average cost that generation must cover to support new investment. Estimates of the average externalities associated with generation are approximately twice the level of private marginal costs. We show that distribution-level marginal line losses significantly increase both of these costs, by more than 9% on average. Accounting for private and external marginal costs, and adjusting for distribution line losses, we find large variation in full societal marginal cost from a (sales-weighted) 10th percentile of 5.4 cents per kWh to a 90th percentile of 12.9 cents per kWh.

Somewhat surprisingly, we find that across the country about 36% of residential sales at a time-invariant marginal electricity price are below the utility's average social marginal cost of providing electricity. But we find wide variation, with prices well above average SMC in California and the Northeast, and below in much of the Midwest and the South.

That comparison, however, captures only part of the inefficiency, because social marginal cost varies hour to hour while price does not for nearly all residential customers. We show that the full inefficiency can be decomposed into a component due to the gap between price and average social marginal cost and a component due to static pricing when SMC varies. Under the strong assumption that the elasticity of residential demand is the same for these two types of price variation, we show that for most utilities more of the deadweight loss is due to failure to capture volatile SMC. Nonetheless, the largest DWL results from a small number of utilities, mostly in California, setting prices well above average SMC.

Our findings have implications not just for standard deadweight loss analysis of consumption, but also for common related policies on residential energy efficiency and distributed generation. Many states have aggressive programs to encourage such investments, but if prices already exceed social marginal cost, the value of additional investments beyond those that well-informed individuals would already choose to make is open to question. It is perhaps not politically surprising, but nonetheless economically concerning, that we find these programs are most prevalent in areas where retail prices are already substantially above social marginal cost.

VIII. Appendix

IX. Appendix

The data used in this analysis come from a diverse range of sources. The construction of the data necessary for this analysis can be divided into the following categories:

- The annual sales of electricity to residential customers
- The marginal retail price paid by residential customers
- The location of residential customers as determined by utility service territories
- The private marginal costs of serving electricity demand
- The external marginal costs of serving electricity demand
- The hourly load shapes to distribute annual residential demand throughout the year
- The losses associated with distributing electricity from the transmission grid to residential customers

Each of these categories is covered by a section below.

A. Residential Electricity Sales

The starting point for this analysis was the Form EIA-861 survey published by the US Energy Information Administration (EIA) (Energy Information Administration 2015*a*). This survey collects a range of valuable annual data on every electric utility in the US. Of primary interest for this work was the dataset on "Sales to Ultimate Customers" which contains annual data on kilowatt-hour sales of electricity, numbers of customers and retail revenues. These data are broken down by state, so there can be multiple entries for a single utility if it has customers in multiple states. These data are also broken down by customer class, such that the sales, revenues and customer numbers are reported separately for residential, commercial and industrial customer types.[23] There is also some other key information available through the EIA-861 including data on the ownership structure of a utility (*e.g.,* Investor Owned, Municipal, Cooperative, etc.); the various regulatory regimes each utility belongs to (*e.g.,* reliability regions or balancing authorities); the counties that are part of a given utility's service territory; and operational data such as the peak load in each utility's service territory, numbers of distribution circuits and line losses.

[23] Strictly speaking a Transportation customer class is also included, although during our analysis period this represents a negligible volume and so is largely ignored.

The analysis here is focused on residential customers, so all information on industrial and commercial customers was dropped. Only utility-state pairs serving at least some residential customers were retained. The analysis here also focuses on the continental 48 states and the District of Columbia because the necessary private and external marginal cost data are not available for Hawaii, Alaska or the US territories. We also opted to drop the very small number of utilities that were classed as "Behind the Meter" as we are interested in comparing residential customers recieving a standard electricity service throughout the US.

Finally, the data were reformatted to appropriately deal with the different ways that residential customers receive their electricity. Roughly 85% of customers still receive their electricity through a vertically integrated utility that provides "bundled" service. This means the utility that is procuring the electricity that customers consume is also the company that owns and operates the distribution network that delivers the electricity to customers homes. However, in some states the electricity sector has been restructured such that customers can choose their electricity provider. In this case the service has been "unbundled" such that one company provides the electricity procurement service (*i.e.,* the "energy" service) and another company distributes the electricity to the customer (*i.e.,* the "delivery" service). The utility providing the energy service is subject to competition from other providers, and will be referred to here as the "retail choice provider". The utility providing the delivery service continues to be a public or regulated monopoly and will be referred to hear as the "local distribution company". Various states take different approaches to handling which of these two entities is in charge of the other aspects of electricity service, such as billing and customer service. Roughly 15% of customers recieve their electricity this way, and a large number of these customers are concentrated in a few states such as Texas, Ohio, Pennsylvannia and New Jersey. To ensure these customers can be correctly incorporated into the analysis, the data were reformatted such that each entry had a "delivery" utility and an "energy" utility. For vertically integrated utilities providing "bundled" service these two entries were the same. For customers recieving "unbundled" electricity service these two entries would necessarily differ. Unfortunately, the EIA-861 data do not include information on how a given retail choice provider's customers and sales are divided among the various local distribution companies that are providing delivery-only service in a given state. As such, new entries were created for all possible state-by-state combinations of retail choice providers and local distribution companies. The sales and customer numbers were then allocated proportionally. In the limited cases where we had prior knowledge about the operations of a retail provider this was included before any proportional allocation.[24] Where there were discrepencies between the

[24]For example, Marin Clean Energy is effectively a retail choice provider in California and there are three local distribution companies that provide delivery service in the state: Southern California Edison, San Diego Gas & Electric and Pacific Gas & Electric. However, Marin Clean Energy's operations are limited to Marin County and nearby counties and so delivery service is only provided to its customers by Pacific Gas & Electric.

state totals for energy-only and delivery-only customer numbers and sales the convention was adopted that the energy service totals were correct and the delivery service totals were re-scaled accordingly. In general any discrepencies were relatively small and likely due to errors in reporting.

One final wrinkle in completing this reformatting was the approach taken to reporting in the EIA-861 by utilities in Texas. Unfortunately, the Texas utilties do not break out their reporting between "energy" and "delivery" service. Instead, the retail choice provider reports the sales, customer numbers and revenues as if they were providing a complete "bundled" service. This also means that the six local distribution companies that offer delivery services to the retail choice providers in Texas do not report any information in this part of the survey.[25] To remedy this and make the data for Texas consistent with the other retail choice states, additional data were collected from the Texas Public Utilities Commission on the residential customer numbers, sales and revenues for these six missing local distribution utilities (Public Utility Commission of Texas 2017*b*). These data were then matched with the retail choice providers using the same proportional allocation process used for the other retail choice states.

B. Residential Marginal Retail Prices

Once the EIA-861 data had been collected and reformatted, it was then straightforward to calculate the annual average retail price paid by every residential customer. To do this, total revenues were divided by total kWh sales to get the average cents per kWh price. However, this is almost certainly not a good reflection of the marginal retail price faced by each customer for three reasons. First, electricity tariffs are usually designed as two part tariffs, with a fixed monthly charge and a variable per-kWh charge. Because fixed charges are so prevalent and can comprise a substantial portion of customers' bills, simply using the average price would overstate the marginal rate customers actually face. Second, for many utilities, there is variation in the variable per-kWh price customers pay even after accounting for fixed charges. To name some of the most common instances, the per-kWh price a customer pays can vary depending on the amount that a customer consumes (i.e. tiered rates where prices increase or decrease in discrete blocks of cumulative consumption), the time of day (*i.e.,* "time-of-use" or "dynamic" pricing), or the time of year (*i.e.,* seasonal pricing where winter and summer rates differ). Third, the structure of retail tariffs themselves are also not static over time and are updated as utilities' new regulatory cases are approved, as changes in certain costs are automatically passed through to customers or as retail choice providers alter their tariffs in an effort to win new customers.

To deal with fixed charges, we have collected information on the retail tariffs actually offered by utilities and extracted the monthly fixed charges. Our main

[25]These six utilities are Oncor Electric Delivery Company LLC, CenterPoint Energy, AEP Texas Central Company, AEP Texas North Company, Texas-New Mexico Power Company and Sharyland Utilities LP.

source for this information is the National Renewable Energy Laboratory's Utility Rate Database (URDB) (National Renewable Energy Laboratory 2017*b*). This is an open-access repository for rate structure information for utilities operating in the US. The fixed charges for residential tariffs active during our analysis period were extracted, and the utility names were cleared up so that their corresponding identifiers and states matched those in the EIA-861 data. At the time of writing, the URDB only contained tariffs for utilities providing "bundled" service. This presented us with a similar challenge to the EIA-861 data in dealing with the roughly 15% of customers subject to retail choice. To resolve this, we manually collected additional fixed charge information for the largest retail choice providers in the states with substantial numbers of retail choice customers (Public Utility Commission of Texas 2017*a*).[26] Once we had finished collecting all the necessary data on fixed charges we found that it was almost always the case that a given utility operating in a given state had many different tariffs. The average fixed charge paid by a given utility's customers must therefore be some weighted average of the fixed charges in each of these tariffs, with the weights determined by the number of customers on each tariff. Unfortunately we know of no comprehensive data source that could give us this breakdown of customers by tariff. As such we summarized the fixed charges in these tariffs by identifying the standard tariffs that were most likely to have many customers on them, as compared to the more niche non-standard tariffs that few customers were likely to be on. We did this by searching for keywords in the names of the tariffs. Tariffs containing words like "vehicle", "solar", "medical" or "three-phase" were identified as non-standard. This tended to leave us with a set of more standard tariffs with names containing words like "default", "residential" and "general". Full details of the keywords used can be found in the accompanying code. Once these standard tariffs had been identified, we took the median, giving us a single estimate of the residential fixed charge for each utility-state pair. We considered other approaches to combining these (e.g. mean or mode), but this did not significantly affect our results. It was also often the case that utilities had similar or identical fixed charges on many or all of their tariffs. Once this exercise was complete, these rates were matched with the utility-state pairs in our reformatted version of the EIA-861 data. At this point it was now possible to estimate the second part of the two part tariff - namely the average variable per kWh price. To do this the fixed charge was multiplied by the number of customers to get fixed revenues, these were subtracted from total revenues to get variable revenues, and these were then divided by total kWh sales to get the average variable cents per kWh price.

The second issue in identifying the marginal retail price was dealing with the fact that utility tariffs often do not contain just a single flat per-kWh variable price. This could mean that the average variable per kWh price calculated using

[26] In collecting these data we sought to capture whether the fixed charges offered by a given retail choice provider varied depending on the local distribution company whose service territory their customer was located in. In general though we found very little evidence of utilities having much variation in their fixed charges for this reason.

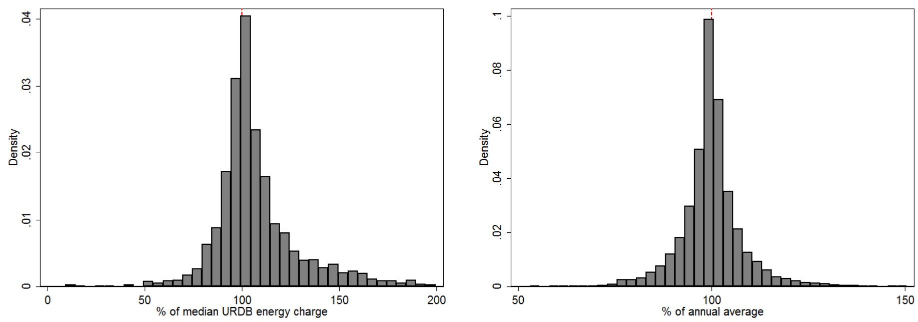
the fixed charge information described above does not reflect the actual marginal price paid by customers. The URDB does in fact contain some information on the structure of the per kWh prices in each tariff (e.g. tier sizes and prices for increasing- or decreasing-block rates, or peak vs off-peak rates and timings for time-of-use pricing). However, these data are necessarily complex, and they are less complete than the fixed charge information we had already extracted. As already noted, these data also don't cover retail choice providers and so significant additional manual collection would be required to make these data complete. Furthermore, to properly use this information we would need to know both how many customers are on each tariff and the consumption patterns of the customers on each tariff. As was noted before, we know of no comprehensive source of these data, and to the extent that these data are held by individual utilities it is almost certainly confidential.

Thus, we have opted here to conduct the analysis assuming utilities charge a single flat variable per kWh price. While this is obviously not strictly true, we believe it is not an unreasonable assumption for the purposes of our analysis. To investigate this, we conducted the following robustness checks. First, we compared our derived estimates of average variable per-kWh prices with the $/kWh energy charges recorded in the URDB. Where rates had multiple energy charges (e.g. for tiered or time-varying rates) we conducted our comparison against the median. Figure 16a indicates that our estimates do broadly match up with the rates recorded in the URDB. Second, to look at the issue of variation in prices due to seasonal factors or tiered rate structures we calculated monthly estimates of the variable per kWh rate. To do this we used the EIA-861M survey which is a monthly version of the annual EIA-861 survey that covers a sample of the complete population of utilities (Energy Information Administration 2015*b*).[27] Figure 16b indicates that the vast majority of customers rates do not vary substantially month-to-month. Third, to look at the issue of hourly variation in prices during the day we examined evidence from the "Demand Response" and "Dynamic Pricing" sections of the EIA-861 survey. These sections provide data on the numbers of customers participating in demand response programs or subject to some form of dynamic pricing tariff. We find that 4.2% of residential customers in the US are on tariffs with time-varying prices. This includes time-of-use, real time, variable peak and critical peak tariffs. Demand response programs are also limited in scope with 5.4% of customers enrolled in a demand response program in 2015. There is also likely substantial overlap in the customers exposed to these two forms of price variability. Roughly three quarters of the customers on tariffs with time-varying prices or in demand response programs are served by the same set of 96 utilities.

A closely related issue for many utilities is that a share of customers are on low-income rates, which in many cases are lower marginal rates than the stan-

[27]In 2015 the EIA-861M contained information on utilities accounting for 67% of residential customers and sales.

dard tariff. Our analysis captures the average variable payment (assuming that we have correctly characterized the fixed charges), but it is possible that some customers pay a higher marginal rate and others pay a lower marginal rate. We are not able to capture such variation in marginal rates across customers. It is straightforward, however, to show that if that is the this case our analysis understates the deadweight loss associated with marginal rates deviating from average SRSMC.



(a) Correspondence between estimated variable prices and median URDB energy charges

(b) Variability in monthly variable per kWh retail prices relative to the annual average

Figure 16: Robustness of use of flat variable charge

The third and final issue in identifying the marginal retail price was dealing with the fact that utility tariffs can change and be updated over time. This is probably the least concerning of the three issues, in large part because the cost drivers and regulatory arrangements in the electricity sector mean that changes to residential retail tariffs tend to occur in a slow and incremental manner. Nonetheless, we are collecting data for multiple years in order to examine the robustness of our findings over time.

C. Utility Service Territories

To match up our data on retail rates with information on social marginal costs, we had to represent the spatial distribution of residential customers. For this we used information on the service territories of the local distribution companies that distribute electricity to end consumers.

Our main source for this was a lookup file provided as part of the URDB (National Renewable Energy Laboratory 2017*a*). This provides a list of ZIP Codes served by each local distribution company. These lookups were created using a proprietary set of shapefiles detailing the actual service territories of major electric utilities, which were converted to a list of ZIP Codes falling within those service territories. Unfortunately the ZIP Code lookups did not cover all the utilities in our dataset. To fill in any gaps we relied on the "Service Territory" section in the EIA-861 survey. This provides a list of counties served by each local distribution company. For consistency these were converted to ZIP Code lookups by assuming any local distribution company serving a given county also served all the ZIP Codes in that county. Our spatial data on US ZIP Codes was downloaded from Environmental Systems Research Institute and included polygons for 30,105 ZIP Code areas, and central coordinates for the full universe of 40,552 ZIP Codes (Environmental Systems Research Institute 2017).[28] These data were used as they were more comprehensive than the Zip Code Tabulation Area data available from the US Census Bureau.

To increase the accuracy of our geographic allocation of residential customers within a given service territory we also collected data on population counts by ZIP Code. The vast majority of these data were from the ESRI spatial data we downloaded, as this also included estimates of population for each ZIP Code based on ESRI's analysis of US Census Bureau data. However, there were a few ZIP Codes where the population data were missing but where we were confident that people lived. To remedy this, county-level population data were downloaded from the US Census Bureau, along with spatial data on US counties and a set of lookups from counties to ZIP Codes (US Census 2017*a*, US Census 2017*b*, US Census 2017*c*). The ZIP Codes with missing data were then assumed to have a population density equivalent to the county they belonged to. Missing ZIP Code population counts were then calculated as the county-level population density multiplied by the ZIP Code area.

It is important to emphasize that the matching of utility service territories to ZIP Codes, or counties, affects only the construction of the maps shown in the results. It does not affect any of the summary statistics by utility, or the calculations of deadweight loss and its decomposition.

D. Private Marginal Costs

The primary source of the data for calculating private marginal costs was the price information provided by the seven major US Independent System Operators (ISOs).[29] These are Electric Reliability Corporation Texas (ERCOT), the New England ISO (ISO-NE), the New York ISO (NYISO), the California ISO (CAISO), the Southwestern Power Pool (SPP), the Midcontinent ISO (MISO) and the PJM Interconnection (PJM). Each of these manages the operation of the electricity transmission grid over a large geographic area, most encompassing multiple states. These organizations calculate wholesale locational marginal prices (LMPs) for major locations in their covered territories, reflecting the value

[28]The latter is larger because it includes ZIP Codes that have no associated area such as post office box ZIP Codes and single site ZIP Codes (e.g. government, building, or large volume customer).

[29]Strictly speaking some of these, such as PJM, are classed as Regional Transmission Organizations (RTOs) but for the purpose of this paper the distinction is largely immaterial and so we refer to all as ISOs.

of electricity supplied at different points in the power grid. Each ISO has LMPs for thousands of pricing nodes within their system, such that across all seven ISOs there are in excess of 30,000 nodes with hourly price data available.[30] We did not consider it necessary to utilize data from all these nodes in our analysis. This was in part because prices at nodes located very close to one another are usually very highly correlated, and so selecting a smaller number should still allow us to create a sufficiently robust picture of the main spatial and temporal variation. In light of this we selected a total of 157 key LMPs. All of these were aggregated "zonal" LMPs that represent averages of many individual nodal prices. In selecting these we were also mindful that different nodes can refer to a range of important locations in the power grid, such as power stations, load substations or major interconnection points with neighboring systems. Wherever possible our selection focused on zones that were aggregates of load nodes or were used by regulators in their determinations of utilities' wholesale costs for supplying their customers. This clearly fits with our interest in finding the marginal cost of serving residential customer demand. These data were downloaded from SNL Financial (SNL Financial 2017*b*). This is a proprietary source of financial data and market intelligence and includes a convenient centralised database of LMP data from all seven ISOs.[31] All data were converted to Eastern Standard Time (EST) for consistency.

These seven ISOs cover large parts of the US. However, their coverage is not complete and they are most notably absent from the most of the Southeastern U.S. To remedy this and provide a secondary source of corroborating data we also used data from the Federal Energy Regulatory Commission's Form-714 survey (Federal Energy Regulatory Commission 2017). This survey collects data from electric utility balancing authorities (or control areas) in the United States. The seven ISOs are also classed as balancing authorities and so their aggregate system-wide data appear in the FERC-714 data. Importantly though, balancing authorities also include approximately 200 additional utilities and regulatory entities that undertake a similar electricity system operation role. This includes major utilities in the Southeastern U.S. The FERC-714 data used are the hourly system lambda data. Here respondents are supposed to report hourly values of the incremental cost of energy in their system. In principal this seems ideal. In practice, a check of the data reported by the ISOs shows that ISOs simply report LMPs as the system lambdas at various locations. Unfortunately, visual inspection of the system lambda data provided by the other balancing authorities reveals a range of suspect data, including respondents providing no data, respondents providing all zeros, respondents providing data that remain unchanged over long periods, and respondents providing data that differ substantially from LMPs at nodes in nearby ISOs. To deal with these weaknesses in the system lambda data, each

[30]Often pricing data are available at even finer temporal resolutions (*e.g.,* 15 minute) but for this analysis we have used hourly data as they are consistently available across all seven ISOs.

[31]It should be noted that these data are freely available directly from each ISO. We have opted to utilize SNL Financial's database purely due to ease of accessing and compiling the data.

series was individually inspected to determine if it was sufficiently robust to be included. This left just 19 balancing authorities (besides the seven ISOs) with reliable system lambda data. Fortunately this still included a number of balancing authorities in Southeastern states such as Florida and Alabama. As with the ISO data, all series were converted to EST for consistency. Unfortunately the quality of the reporting of time zones was also not perfect such that it is not always clear whether data are reported in standard time or daylight savings time. In some cases respondents even left the time zone section blank. Where possible we sought to identify the reporting time zone by visual inspection. Beyond that, we assumed that respondents reported their time zone in a manner consistent with the requirements set out in the survey instructions.[32] Lastly, the system lambda data do not account for transmission losses, while LMP data implicitly do. To remedy this all system lambda prices were increased by an assumed transmission loss rate of 2%.

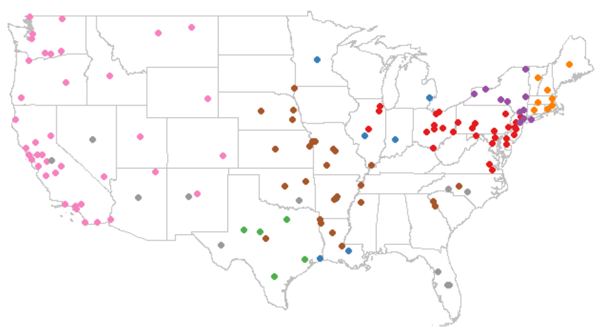


Figure 17: Locations of ISO zonal price points and Balancing Authority area system lambdas in 2015

Once the ISO and balancing authority data had been collected, we next sought to use these data to calculate hourly ZIP Code level estimates of the marginal private costs of supplying electricity. We chose to do this at the ZIP Code level because our intention is to combine these outputs with the EIA-861 data described

[32] "The hourly lambda data calculations for each day is based on the respondent observing *standard time* for its respective time zone for the entire year even though it may have observed *daylight savings time* for part of the year. Respondents must denote in column (b) the actual time zone observed for each day (e.g., EST, EDT, CST, CDT, etc.)."

earlier, and as mentioned in the previous section, our representation of utility service territories is based on ZIP Codes. To begin this process of creating ZIP Code-level prices we first had to determine where each ISO zone or balancing authority area was located. Unfortunately, we were unable to get access to the necessary spatial polygon data files detailing the areas covered by the ISO zones. Instead SNL Financial were able to provide us with a list of coordinates they use to represent the location of each ISO node, including the zonal nodes we had chosen for this analysis (SNL Financial 2017*a*). Strictly speaking, the ISO zonal nodes are themselves representing many individual nodes, but for our purposes the central coordinates of these zones are likely sufficient. For consistency we also represented the locations of the FERC-714 balancing authorities using the central coordinates of their respective network areas. These coordinates were calculated using the polygon centroid from spatial data on electricity balancing authorities downloaded from the Homeland Infrastructure Foundation-Level Data website, which is part of the US Department of Homeland Security (Department of Homeland Security 2017*a*). These spatial coordinates can be seen in Figure 17.[33] Once these had been collected we calculated the distance to each ZIP Code centroid using the geodesic on a WGS84 ellipsoid. The price for each ZIP Code was then calculated as the inverse distance-weighted average of the prices at the three closest price nodes.

Average wholesale electricity costs are made up of energy costs, capacity costs, ancillary services costs and other uplift payments. Our use of LMP and system lambda data captures the energy cost component. Table 4 shows the relative contributions of each of these four categories across the seven ISOs (Electric Reliability Council of Texas 2015, California Independent System Operator 2016, Independent System Operator New England 2016, Midwest Independent System Operator 2015, New York Independent System Operator 2016, PJM Interconnection 2016, Southwest Power Pool 2016).[34]

The end product of the private marginal cost data collection process was a dataset of hourly estimates for each US ZIP Code. These data were then merged with the reformatted retail rates data using the information on the ZIP Codes served by each local distribution company. Where a utility served multiple ZIP Codes in a given state, the hourly price assigned to that utility was an average of each of the ZIP Code prices, weighted by the total population of each ZIP Code.

[33]The figure depicts selected price points for ISO-NE (orange), NYISO (purple), PJM (red), MISO (blue), SPP (brown), ERCOT (green), CAISO (pink) and FERC planning areas (grey).

[34]These values are taken from the annual reports of each ISO. The one exception to this is capacity costs in the CAISO. Capacity payments in California are primarily agreed through bilateral contracts overseen by the CPUC's Resource Adequacy program, and so do not show up as capacity costs levied by the ISO. To account for this we have calculated capacity costs using data from the CPUC's Resource Adequacy Report (California Public Utilities Commission 2015). This yields an additional capacity cost of approximately $4/MWh, or approximately 9% of total wholesale costs.

E. External Marginal Costs

The data on external marginal costs are from Holland, Mansur, Muller, and Yates (2016). They contain the environmental externality costs in \$/MWh from four pollutants associated with the generation and supply of electricity: particulate matter (PM), nitrogen oxides (NO_x), sulphur dioxide (SO_2) and carbon dioxide (CO_2). The data provide estimates for each hour of the day, for weekdays. Weekends are excluded. Unfortunately, there is no temporal variation in these data capturing how these costs might vary across different seasons, months, days of the year or load. These data also don't indicate how external costs may vary in response to other factors, such as weather, time or day of week. The spatial resolution of these data are also relatively coarse. Observations are available for nine different regions of the US. These correspond to the eight reliability regions of the North American Electric Reliability Coorporation (NERC), with the exception of the Western Interconnection region which they split into a California region and a non-California region. These data were merged with the reformatted retail rates data using information in the EIA-861 survey on the NERC region that each local distribution utility belongs to.[35]

Lastly, we make a small set of adjustments to the (Holland et al. 2016) data to avoid double counting. This can arise where the private marginal costs data already incorporates some portion of external marginal costs due to environmental policies that put a price on externalities. The two main instances of this that are relevant here are California's Cap and Trade Program and the Regional Greenhouse Gas Initiative (RGGI) that covers nine states in the north-eastern US. The (Holland et al. 2016) estimates were created using a social cost of carbon of \$40/ton of CO2. The California and RGGI carbon prices in 2015 averaged \$12.70/ton and \$6.00/ton respectively. We therefore multiply the \$/kWh external damages by $(\$40 - \$12.70)/\$40 = 68\%$ for the state of California and by $(\$40 - \$6.00)/\$40 = 85\%$ for the states that participate in the RGGI.[36]

F. Hourly Load Shapes

Residential customer demand for electricity is not constant, nor is the deviation between residential retail price and the social marginal costs of supplying electricity. In fact, it is likely the case that these will sometimes be strongly correlated (*e.g.,* periods of peak wholesale electricity prices tend to coincide with peak residential electricity demand). It is therefore important to be able to determine how annual residential sales are distributed across the hours in our analysis period. The ideal dataset for this would likely be some form of hourly metered consumption data for the universe of residential households in the US. Clearly

[35]The exception here was the California and non-California regions that the Western Interconnection was divided into. Here the data were matched by the combination of both NERC region and state identifiers.

[36]These are Conneticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont.

such a dataset does not exist - customers' meter data are confidential and held by their individual utility, and many residential households still do not even have meters that can record this information at an hourly frequency. To tackle this challenge our preferred approach involved using hourly load data from a selection of ISO zonal nodes and planning areas. These data were used to represent the shape of hourly residential load profiles at the ZIP Code level up to a scale factor, and then once again we used our dataset of ZIP Code service territory lookups to match these up to utilities.

To do this, we again used the ISO zonal data from SNL Financial (SNL Financial 2017*b*). Unlike pricing nodes, load is only available for a limited number of zonal nodes, and is not available for the many thousands of individual load nodes where LMPs are calculated. Fortunately many of these are the same nodes that we already chose to use in our selection of LMPs. In total this gave us load data for 66 ISO zonal nodes. The FERC-714 survey was then used to supplement this with additional hourly load data for planning areas. These planning areas have a regulatory responsibility to ensure resources are available to meet customer load and there is often considerable overlap with the balancing authorities used earlier for the system lambda data. The coverage and quality of the planning area load data is much better than for the balancing authority system lambda data, resulting in 122 planning areas with usable load data. For both sets of data the same time zone conversions were applied so that all data was in EST. All series were then normalized to hourly shares of annual load by dividing each hour by the annual total for that ISO zone or planning area.[37] On average this would mean the load share in a single hour should be 1/8760, or 0.0114%. Above average hours (*e.g.,* 6pm on weekdays) should be above this and below average hours (*e.g.,* 3am on weekends) should be below this. Normalizing the data in this way helped account for the fact that ISOs and planning areas differ massively in size (as measured by total load) and is also consistent with our intended use of these data to apportion annual kWh sales across each hour of the year. As with the private marginal cost data, these shares of annual load needed to be assigned to the utility-state entries in our reformatted retail rates dataset. We employ the same approach as for the private marginal costs analysis. This involves assigning each ISO zone or planning area series to a central coordinate (SNL Financial 2017*a*, Department of Homeland Security 2017*b*). These spatial coordinates can be seen in Figure 18.[38] We then calculated load shares for each ZIP Code using the inverse distance-weighted averages of the three nearest load points.

The end product of the residential load profile data collection process was a

[37]There were some series with data missing for some hours of the year. If an ISO zone or FERC balancing authority had more than 10% of the hours in a year missing, shares were not calculated and that series was dropped. The concern here was that shares calculated using a subset of the hours in the year may not produce accurate shares if the hours for which there were missing data were not representative of all hours. This only led to data for 3 planning areas being dropped.

[38]The figure depicts selected price points for ISO-NE (orange), NYISO (purple), PJM (red), MISO (blue), SPP (brown), ERCOT (green), CAISO (pink) and FERC planning areas (grey)

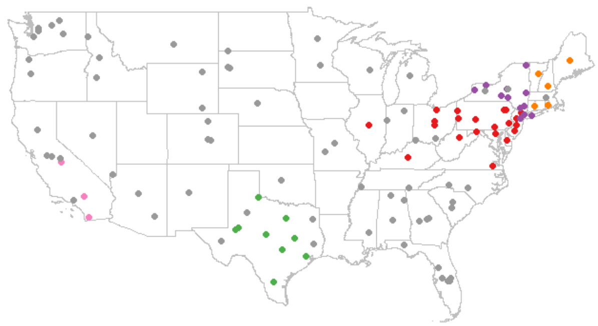


Figure 18: Locations of ISO load zones and load Planning Areas in 2015

dataset of estimates of hourly shares of annual residential electricity demand for each US ZIP Code. These data were then merged with the reformatted retail rates data using the information on the ZIP Codes served by each local distribution company. Where a utility served multiple ZIP Codes in a given state, we again weighted the ZIP Code values for the load shares by the total population of each ZIP Code. A final adjustment was made to ensure that each of the newly created series correctly summed to one over the year.

It is important to note that our preferred approach of using system load profiles as a proxy for residential load profiles has a clear drawback in that it likely underestimates the peakiness of residential load. This is because system load is made up of all demand for electricity from residential, commercial and industrial customers. Differences in the load profiles of residential versus commercial and industrial customers mean that the combination of these three customer classes tends to lead to a smoother total system load profile. It is true that residential customers make up the largest customer class, accounting for over 37% of all kWh sales in 2015, and so are an important driver of total system load. Even so, where commercial and industrial customers have significantly different load profiles to residential customers and where they make up a significant portion of total load, our hourly allocation of residential load will almost certainly be biased towards less volatility.

To test the robustness of using these system load profiles as a proxy for residential load profiles, we conducted a sensitivity analysis using an alternative source of residential load profile data. For this, we collected modelled residential load profiles produced by NREL (National Renewable Energy Laboratory 2013).

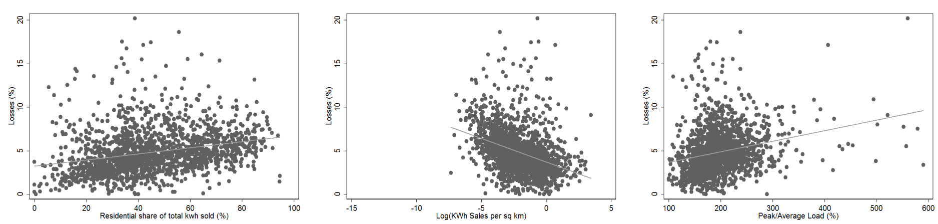
This dataset uses an engineering model to estimate hourly residential electricity demand profiles for a set of representative residential households at different locations throughout the US. To construct the dataset NREL classified the US into five climate zones and made assumptions about building characteristics that varied by climate zone (*e.g.,* source of space heating, presence of air conditioning, square footage, construction materials etc.). NREL also made additional assumptions about operational conditions, such as occupancy rates and weather. An hourly weather profile was used based on NREL's "typical meteorological year" (TMY3) dataset. This provides hourly averages for a range of weather variables (*e.g.,* temperature, humidity, precipitation etc.) based on up to 30 years of historical data from 1976 to 2005. The engineering model then takes these assumptions and weather data and estimates a residential electricity demand profile at over 1,400 TMY3 locations throughout the US (National Renewable Energy Laboratory 2008). The clear advantage of the NREL dataset is that it is a more explicit measure of fluctuations in *residential* load, rather than system load. The main disadvantages are twofold. First, the dataset is comprised of estimates of residential load based on a 2008 engineering model that necessarily makes strong assumptions about building performance, customer behavior and the nature of the housing stock. As such this may be a poor proxy for the performance of the actual housing stock in our analysis period. Second, the dataset is produced using averaged weather data from well before our chosen period of analysis. As such the weather profile used may differ substantially from the actual weather that prevailed during our analysis period.

To conduct our sensitivity analysis we carried out the same processing steps described earlier to get a second set of estimates of residential load profiles for each US ZIP Code, in this case based on the NREL simulation data. To assess the actual performance of the load profiles based on the NREL dataset relative to our load profiles based on observed system load we compared both approaches against the very few datasets of actual metered residential load we were able to find. In general we found that the load profiles based on system load understated the peakiness of residential load and the load profiles based on the NREL modelling data overstated the peakiness of residential load. We also found some limited evidence that the profiles based on system load were more strongly correlated with the actual residential load data. Finally, we conducted the entire analysis using both approaches to estimating the residential load profile to see how this would move the results. We found that the choice of residential load profile had a very small impact on the final results (*e.g.,* on the extent of estimated deadweight loss) and so throughout we have opted to use the approach based on system load.

G. Distribution Losses

Our estimation of private and external marginal costs gives the marginal cost of electricity delivered in the high-voltage transmission system. However, our analysis is concerned with the marginal costs of serving residential customers.

It is therefore important that we account for losses incurred as power is carried through the low-voltage distribution system to residential households. We estimate average annual residential distribution losses for each local distribution company using data in the EIA-861 survey. Unfortunately, the only data on losses that are available report total losses for a given utility across all types of customers (*i.e.,* residential, commercial and industrial). This is problematic because losses to residential customers are likely higher than for any other customer type. This is because residential customers are located at the furthest ends of the distribution network at the lowest voltage levels. Industrial customers, on the other hand, likely have the lowest losses because they are connected to more centralized portions of the distribution network at higher voltage levels. Sometimes industrial customers are even connected directly to the transmission network and so incur zero distribution losses. A second issue with these data on total losses is that they are not exclusively distribution system losses; some utilities own and operate both transmission and distribution system infrastructure, and so their reported losses cover both these parts of the power grid.



(a) Losses by residential share of sales (b) Losses by density of load (kWh per sq km of service territory) (c) Losses by ratio of peak to average load

Figure 19: Key Predictors of Losses

To address these shortcomings, we estimate average annual residential distribution losses. We compile data on the following variables for each local distribution company, i: total losses in kWh, L_i; total sales in kWh, Q_i, sales for residential customers in kWh, $Qres_i$, commercial customers, $Qcom_i$, and industrial customers, $Qind_i$; the density of customer load, D_i, as measured by the log of total kWh sales divided by the service territory area in square kilometers; the share of distribution circuits with voltage optimization, $VoltOpt_i$; the coefficient of variation for the hourly load profile, $CVsales_i$; and another measure of volatility, the ratio of peak load to average load, P_i.[39] We also created dummies for each state, $State_{si}$, utility type, $UtilityType_{ui}$, and a dummy variable representing whether the utility is involved in electricity transmission, $Transmission_i$.[40]

[39] The log of the density of kWh sales was used as it provided a much better fit.

[40] All utilities in our sample were involved in distribution. We also chose to aggregate the State,

Table 7 presents summary statistics on these variables.

	Mean	StDv	Min	Max	N
Avg. Proportion Total Losses	0.05	0.03	0.00	0.20	1697
Share of Sales (Residential)	0.46	0.21	0.00	1.00	1933
Share of Sales (Commercial)	0.30	0.17	0.00	1.00	1933
Share of Sales (Industrial)	0.24	0.23	0.00	1.00	1933
Log(Sales per sq. km)	-2.29	2.02	-12.66	3.43	1932
Share of Circuits w. Volt. Optim.	0.23	0.39	0.00	1.00	1921
Ratio of Peak to Average Load	1.98	0.51	1.00	5.90	1732
Coef. of Variation for Load	0.20	0.04	0.12	0.35	1931
Transmission	0.13	0.34	0.00	1.00	1758

1669 out of 1933 utilies with complete information

Table 7: Summary Statistics of Variables in the Distribution Losses Regression

Using this data we estimated the following regression. We clustered standard errors by state:

$$
\begin{aligned}
Lavg_i &= \alpha_0 + \alpha_1 Qres_i/Qtot_i + \alpha_2 Qcom_i/Qtot_i + \alpha_3 Density_i \\
&+ \alpha_4 VoltOpt_i + \alpha_5 (Qpeak/Qavg_i) \\
&+ \alpha_6 CVsales_i + \alpha_7 Qtot_i Transmission_i \\
&+ \sum_{u=1}^{U} \gamma_u UtilityType_{ui} + \sum_{s=1}^{S} \beta_s State_{si} + \epsilon_i
\end{aligned}
$$

We then generated predicted values from this regression. However, in order for these predictions to be for annual *distribution* losses for *residential* customers, we generate our predicted values after altering the underlying dataset such that each utility's load is 100% residential and that each utility is only engaged in distribution. This meant setting the commercial and industrial shares to zero and the transmission dummy to zero. The result was a set of predictions of average annual distribution losses for residential customers for each local distribution company. The vast majority of our estimates fall between 4% and 8%, as can be seen in the histogram below.

Once we had estimates for average annual distribution losses for residential customers, the final step was to convert these to marginal losses and account

Federal and Political Subdivision utility types into a single "Other Public" category as some of these classifications only contained a very small number of observations. The Retail Power Marketer utility type was also not relevant for this analysis because we are focused on local distribution companies. This left us with four utility type categories for our distribution losses analysis: Investor Owned, Cooperative, Municipal, Other Public.

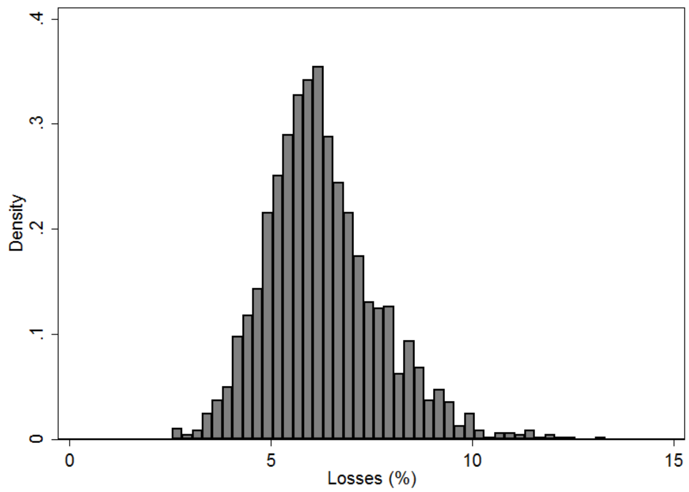


Figure 20: Histogram of Predicted Average Residential Distribution Losses

for how losses vary throughout the year. As explained in the paper, we use the common characterization that 25% of losses are independent of flow on the line – and therefore not associated with any marginal losses from increased consumption – and the engineering result that the other 75% resistive losses increase with the square of flow on the line.[41]

We adapt the approach taken in Borenstein (2008) and assume that utility i's losses in each hour are:

$$L_{it} = \alpha_{i1} + \alpha_{i2} Q_{it}^2 \tag{10}$$

We have already estimated average annual losses for each local distribution company, which we call γ_i. Because the α terms are constant across all hours we can convert the equation to annual sums and substiute for L_{it}. If we also assume that the static no-load losses, as represented by the α_{i1} term, constitute a quarter of a utility's total losses, we can then solve for α_2 for each local distribution company.

$$\sum_{t=1}^{T} L_{it} = \gamma_i \sum_{t=1}^{T} Q_{it} = \alpha_{i1} + \alpha_{i2} \sum_{t=1}^{T} Q_{it}^2 \iff \alpha_{i2} = (1-0.25)\gamma_i \frac{\sum_{t=1}^{T} Q_{it}}{\sum_{t=1}^{T} Q_{it}^2} \tag{11}$$

[41]See Lazar and Baldwin (1997) and Southern California Edison's methodology for calculating Distribution Loss Factors, as set out in filings to the California Public Utilities Commission (California Public Utilities Commission 1997).

Finally, our interest is in marginal losses so we take the derivative of our original losses expression such that:

$$\frac{dL_{it}}{dQ_{it}} = 2\alpha_{i2}Q_{it} \tag{12}$$

Thus, equation (12) produces our estimate of marginal line losses as a fraction of energy that enters the distribution system of utility i in hour t. For each hour, private and external marginal costs were then scaled up by $\frac{1}{1-dL_{it}/dQ_{it}}$ to give our complete estimate of the social marginal cost of residential electricity consumption.

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Use Great Caution in Design of Residential Demand Charges

Jim Lazar

For decades, electricity prices for larger commercial and industrial customers have included demand charges, which recover a portion of the revenue requirement based on the customer's highest usage during the month. Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Data being collected through smart meters allows utilities to consider expanding the use of demand charges to residential consumers.

Great caution should be applied when considering the use of demand charges, particularly for smaller commercial and residential users. Severe cost shifting may occur. Time-varying energy charges result in more equitable cost allocation, reduce bill volatility, and improve customer understanding. The caution applied should address the following key issues in most demand-charge rate designs:

- *Diversity:* Different customers use capacity at different times of the day, and these customers should share the cost of this capacity.
- *Impact on Low-Use Customers:* Most demand-charge rate designs have the effect of increasing bills to low-use customers, including the vast majority of low-income customers.
- *Multifamily Dwellings:* The utility never serves individual customer demands in apartment buildings, only the combined demand of many customers at the transformer bank.
- *Time Variation:* If demand charges are not focused on the key peak hours of system usage, they send the wrong price signal to customers.

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In the recent Regulatory Assistance Project (RAP) publication *Smart Rate Design for a Smart Future,*[1] we looked at many attributes of rate design for residential and small commercial consumers. We identified three key principles for 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 power supply and grid services based on how much these customers use and when they use it.
- Customers supplying power to the grid should receive full and fair compensation—no more and no less.

Applying these principles results in an illustrative rate design that constructively applies costing principles in a manner that consumers can understand and respond to. **Exhibit 1** shows the illustrative rate design, including a customer charge for customer-specific billing costs and a demand charge for customer-specific transformer capacity costs. The exhibit also includes a time-varying energy price to recover distribution

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Exhibit 1. Illustrative Rate Design

Illustrative Residential Rate Design		
Rate Element	**Based On the Cost Of**	**Illustrative Rate**
Customer Charge	Service Drop, Billing, and Collection Only	$4.00/month
Transformer Charge	Final Line Transformer	$1/kVA/month
Off-Peak Energy	Baseload Resources + Transmission and Distribution	$.07/kWh
Mid-Peak Energy	Baseload + Intermediate Resources + T&D	$.09/kWh
On-Peak Energy	Baseload, Intermediate, and Peaking Resources + T&D	$.14/kWh
Critical Peak Energy (or PTR)	Demand Response Resources	$.74/kWh

Source: Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://raponline.org/document/download/id/7680.

system capacity costs and power supply costs designed to align prices with long-run marginal costs.

Customers can and will respond to rate design. We need to make sure that their actions actually serve to maximize their value and minimize long-run electric system costs. The illustrative rate is clearly directed toward these ends.

DEMAND CHARGES HAVE ALWAYS BEEN ONLY AN APPROXIMATION

Demand charges are imposed based on a customer's demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month. Demand charges are sometimes coupled with a "ratchet" provision that charges the customer on the basis of the highest measured demand over the previous 12-month period or other multi-billing-period span of time.

Demand charges are imposed based on a customer's demand for electricity, typically measured by the highest one-hour (or 15-minute) usage during a month.

Exhibit 2 is a typical medium commercial rate design. It includes a demand component.

Utilities often justified demand charges on the basis of two arguments. First, they were

Exhibit 2. Illustrative Demand Charge Rate

Basic Tariff For Large Commercial Customer	
Rate Element	**Price**
Customer Charge $/month	$20.00
Demand Charge $/kW/month	$10.00
Energy Charge $/kWh	$0.08

Key Terms for Demand Charges

CP: coincident peak demand: the customer's usage at the time of the system peak demand.

NCP: non-coincident peak demand: the customer's highest usage during the month, whenever it occurs.

Diversity: the difference between the sum of customer NCP and the system CP demands.

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asserted as a "fairness" rate that assured that all customers paid some share of the utilities' system capacity costs. Second, especially when coupled with ratchets, they had the effect of stabilizing revenues.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak.

But demand charges are a shortcut, measuring each customer's individual highest usage during a month, regardless of whether the usage was coincident with the system peak. The customer's individual peak was used as a proxy for that customer's contribution to system capacity costs. Demand charges were implemented in this way even though customers' individual demands did not coincide with the peak system demand, or more accurately, with the coincident peak for the individual components of the system involved, each of which may have peaks different from the system peak. This was always a "second-best" approach. It is roughly accurate for large commercial customers, because their highest usage *usually* (but not always) coincided with the system peak.

Residential consumers have much more diversity in their usage, with individual customer maximum demands seldom coinciding with the system peak. The rough accuracy that exists for using non-coincident peak (NCP) demand charges for large commercial customers is woefully inaccurate for residential consumers. But coincident-peak (CP) demand charges have other shortcomings, leaving some customers with more than their share of costs and others with none at all, as shown in **Exhibit 3**.

With data from smart meters, utility regulators can be more targeted in how costs are recovered, focusing on well-defined peak and off-peak periods of the month, not just a single hour of usage.

Today, with data from smart meters, utility regulators can be more targeted in how costs are recovered, focusing on well-defined peak and off-peak periods of the month, not just a single hour

Exhibit 3. Garfield and Lovejoy Criteria and Alternative Rate Forms

Garfield and Lovejoy Criteria	CP Demand Charge	NCP Demand Charge	TOU Energy Charge
All customers should contribute to the recovery of capacity costs.	N	Y	Y
The longer the period of time that customers pre-empt the use of capacity, the more they should pay for the use of that capacity.	N	N	Y
Any service making exclusive use of capacity should be assigned 100% of the relevant cost.	Y	N	Y
The allocation of capacity costs should change gradually with changes in the pattern of usage.	N	N	Y
Allocation of costs to one class should not be affected by how remaining costs are allocated to other classes.	N	N	Y
More demand costs should be allocated to usage on-peak than off-peak.	Y	N	Y
Interruptible service should be allocated less capacity costs, but still contribute something.	Y	N	Y

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of usage. This more precise usage data makes demand charges a largely antiquated approach for all customer classes—and particularly inappropriate for residential consumers.

DIVERSE USER PATTERNS VARY GREATLY

Residential customers use system capacity at different times of the day and year. Some people are early-risers, and others stay up late at night. Some shower in the morning, and some in the evening. Some have electric heat, and others have air conditioning.

This variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs. Demand charges are not very useful for this purpose.

A half-century ago, Garfield and Lovejoy discussed how system capacity costs should be reflected in rates.[2] Their observations, summarized in Exhibit 3, are as relevant today as when they were published. We compare the performance of three rate-design approaches to these criteria.

Variability results in great diversity in usage. It is important to anticipate and recognize this diversity in choosing the method for recovery of system capacity costs.

Following this guidance, capacity costs need to be recovered in every hour, with a concentration of these charges in system peak hours. The illustrative rate design in Exhibit 1 does this effectively. The typical commercial rate design in Exhibit 2, loading system capacity costs to an NCP demand charge, does not, because it recognizes only one hour of customer-specific demand.

Churches and stadiums illustrate this problem with demand charges. Churches have peak demands on days of worship—most often Wednesday nights and Sunday mornings, and stadium lights are used only a few hours per month, in the evening hours in the fall and winter. None of this usage is during typical peak periods.

Applying demand charges to recover system capacity costs based on non-coincident peak demand to churches and stadiums has long been recognized as inappropriate. Such charges have the effect of imposing system capacity costs on customers whose usage patterns contribute little, if anything, to the capacity design criteria of an electric utility system at the same rate as customers using that capacity during peak periods. The same problem applies for residential consumers.

On a typical distribution system, multiple residential consumers share a line transformer, and hundreds or thousands share a distribution feeder. The individual non-coincident demands of individual customers are not a basis for the sizing of the distribution feeder; only the combined demands influence this cost. Even at the transformer level, some level of diversity is assumed in determining whether to install a 25-kilovolt-amp or 50-kilovolt-amp transformer to serve a localized group of perhaps a dozen customers.

Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month.

Demand charges applied on NCP ignore this diversity, charging a customer using power for one off-peak hour per month the same as another customer using power continuously for every hour of the month. Some customers (think of a doughnut shop and nightclub) use capacity only in the morning or evening, and can share capacity, while others (think of a 24-hour mini-mart) use capacity continuously and preempt this capacity from use by others. Modern rate design needs to distinguish between different characteristics in the usage of capacity and ensure all customers make an appropriate contribution to system capacity costs.

Time-varying rates do this very well, while simple CP and NCP demand charges do not.

IMPACT ON LOW-USE CUSTOMERS

Individual residences have very low individual customer load factors but quite average collective usage patterns.

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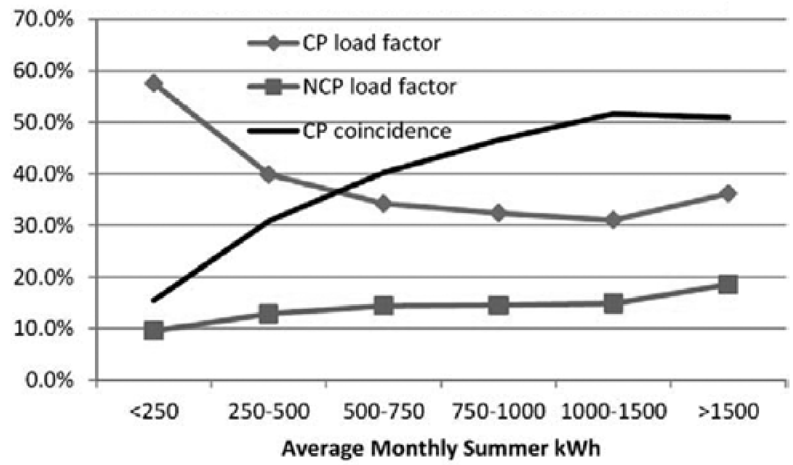
Exhibit 4. Load Factors



Source: Marcus, B. (2015, June). Presentation at Western Conference of Public Service Commissioners, Phoenix, AZ.

Exhibit 4 shows data from Southern California Edison Company. As is evident, while the individual customer load factors of small-use residential customers are only about 10 percent, their group coincident peak load factor is more like 60 percent, quite close to an overall system load factor. A demand charge based on NCP demand greatly overcharges these customers. Meanwhile, the high-use residential customers, who have more peak-oriented loads, would be undercharged with a simple NCP demand charge based on overall residential usage.

The evidence is that the effect is to shift costs to smaller-use customers.

Rate analysts have examined the impact of demand-charge rate designs on residential customers. The evidence is that the effect is to shift costs to smaller-use customers, with about 70 percent of small-use residential customers experiencing bill increases, and about 70 percent of large-use residential customers experiencing bill decreases, even before any shifting of load.[3]

APARTMENT DIVERSITY

About 30 percent of American households live in some sort of multifamily dwelling. Apartments generally have the lowest cost of service of any residential customer group, because the utility provides service to many customers at a single point of delivery through a transformer bank sized to their combined loads. Because the sum of individual customer NCP demand greatly exceeds the combined group demand the utility serves, and by a greater margin than for other customer subclasses, NCP demand charges shift costs inappropriately to these multifamily customers.

About 30 percent of American households live in some sort of multifamily dwelling.

Low-income consumers are more likely to reside in apartments, and nationally, low-income household usage is about 70 percent of average household usage.[4] Therefore, imposing NCP demand charges on residential consumers, without separate treatment of apartments, would have a serious adverse impact on these customers, many of whom are

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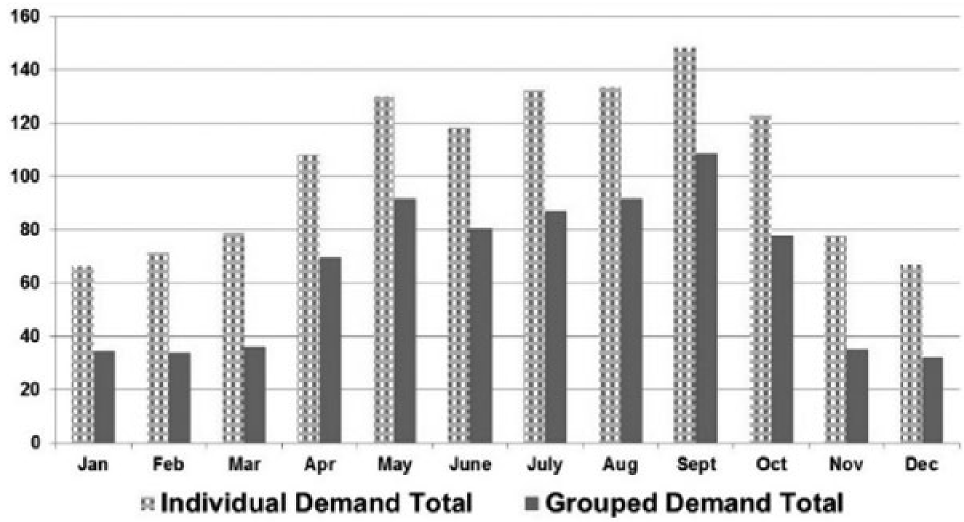
Exhibit 5. Individual and Group Peaks for a 26-Unit Apartment Building



Source: Author, from data supplied by Los Angeles–area municipal utility.

low-income households and often strain to pay their electric bills.

Exhibit 5 shows the sum of individual customer monthly non-coincident peaks for a 26-unit apartment complex in the Los Angeles area, and the monthly group peaks of these customers actually seen by the utility at the transformer bank serving the complex. The exhibit shows that billing customers on the basis of non-coincident peak demand would dramatically overstate the group responsibility for system capacity costs.

TIME-VARYING COST RECOVERY

As expressed by Garfield and Lovejoy, the optimal way to recover system capacity costs is through a time-varying rate design. This can be as simple as a higher charge for usage during on-peak hours than off-peak hours, or it can be a fully dynamic hourly time-varying energy rate. What is clear is that a single demand charge, applied to a single one-hour NCP or CP measure of demand, is unfair to those customers whose usage patterns allow the shared use of system capacity.

Some utilities have implemented time-varying demand charges. California investor-owned utilities impose NCP demand charges for distribution costs, and CP demand charges for generation and transmission capacity on larger commercial consumers. More recently, some utilities have imposed demand charges on smaller customers based on summer on-peak-hour demands only. All of these reflect gradual movement toward equitable recovery of system capacity costs, but full time-of-use (TOU) energy pricing is more effective, more cost-based, more equitable, and more understandable.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month.

Today, with interval data from smart meters, we can easily collect data on the actual usage during each hour of the month. Usage during peak periods can be assigned the costs of peaking power supply resources and seldom-used distribution system capacity costs installed for peak hours. Usage during other hours can be assigned the cost of baseload resources and the basic distribution infrastructure needed to deliver that power.

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The pricing can be as granular as the analyst chooses and the regulator approves—but a key element of rate design is simplicity. For that reason, most analysts shy away from rate design with more than three time periods and a few rate elements.

The illustrative rate design in Exhibit 1 shows a three-period TOU plus critical peak price for both power supply and distribution capacity cost recovery, a customer charge for billing costs, and a demand charge to recover the cost of the final line transformer. It may be as complex a rate design as most residential consumers will reliably understand.

TRANSITIONING TO A TOU RATE DESIGN

Many customer groups are apprehensive about time-varying utility rates, because some consumers will receive higher bills and may not be able easily to change their usage patterns. This same concern would apply to implementation of a demand-charge rate design, but because that produces a less desirable result, we do not consider it a meaningful option. There are the following tools that can be used for a transition:

- *Shadow billing:* Provide consumers with *both* the current rate design and the proposed TOU rate design calculated on the bill prior to rollout.
- *Load control:* Prior to implementing a TOU rate, assist customers to install controls on their major appliances to ensure against inadvertent usage during on-peak periods.
- *Customer-selected TOU periods:* The Salt River Project in Arizona has had excellent success allowing customers to choose a three-hour "on-peak" period out of a four-hour system peak period.[5]

COMMON ERRORS IN DEMAND-CHARGE DESIGN

Common errors include the following:

- *Upstream Distribution Costs:* Any capacity costs upstream of the point of customer connection can be accurately assigned to usage and recovered in time-varying prices.
- *Using NCP Demand:* NCP demand is not relevant to any system design or investment criteria above the final line transformer, and only there if the transformer serves just a single customer.
- *Accounting for Diversity:* Diversity is greatest among small-use customers and needs to be fully accounted for.
- *Apartments:* Apartments have the lowest cost of service of any residential customer group, the highest diversity, and suffer the most when a single rate design is applied to all residential customers.

GUIDANCE FOR COST-BASED DEMAND CHARGES

The following guidelines can be used;

- Limit any demand charges to customer-specific capacity.
- Fully recognize customer load diversity in rate design.
- Demand charges upstream of the customer connection, if any, should apply only to the customer's contribution to system coincident peak demand.
- Compute any demand charges on a multi-hour basis to avoid bill volatility.

Modern metering and data systems make it possible to increase greatly the accuracy, and therefore the fairness, of cost allocation among a diverse customer base. Legacy concepts, such as demand charges, especially those based on NCP demand, prevent the implementation of these improvements and should be eliminated. Time-varying cost assignment is preferred, so that these new technologies can deliver their full value to customers and utilities alike.

NOTES

1. Lazar, J., & Gonzalez, W. (2015). *Smart rate design for a smart future.* Montpelier, VT: Regulatory Assistance Project. Retrieved from http://raponline.org/document/download/id/7680.
2. Garfield, P. J., & Lovejoy, W. F. (1964). *Public utility economics*. Englewood Cliffs, NJ: Prentice Hall; pp. 163–164.
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Caught in a Fix

The Problem with Fixed Charges for Electricity

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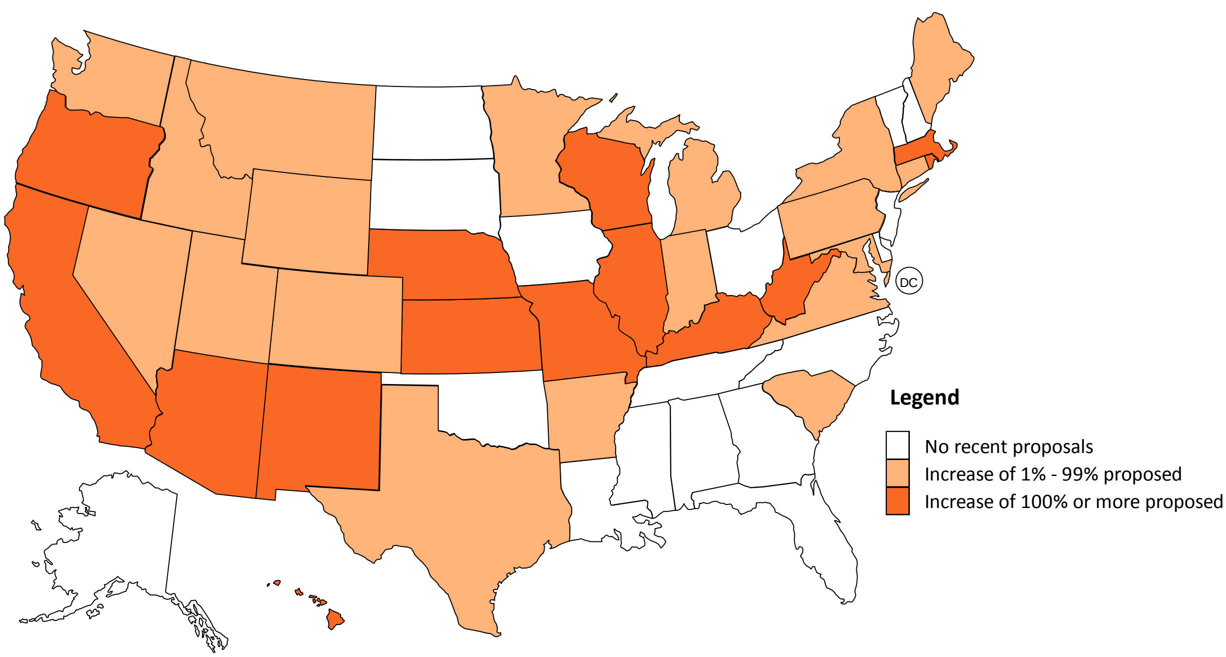
CONTENTS

EXECUTIVE SUMMARY

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

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

Figure ES 1. Recent proposals and decisions regarding fixed charges



Source: See Appendix B

Fixed Charges Harm Customers

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

Low-Usage Customers Hit Hardest. Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised. There are many reasons a customer might have low energy usage: they may be very conscientious to avoid wasting energy; they may simply be located in apartments or dense housing units that require less energy; they may have small families or live alone; or they may have energy-efficient appliances or solar panels.

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

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

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

Common Myths Supporting Fixed Charges

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

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

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

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

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

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

Recent Commission Decisions on Fixed Charges

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

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

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

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

Alternatives to Fixed Charges

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

1. INTRODUCTION

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

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

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

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

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

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

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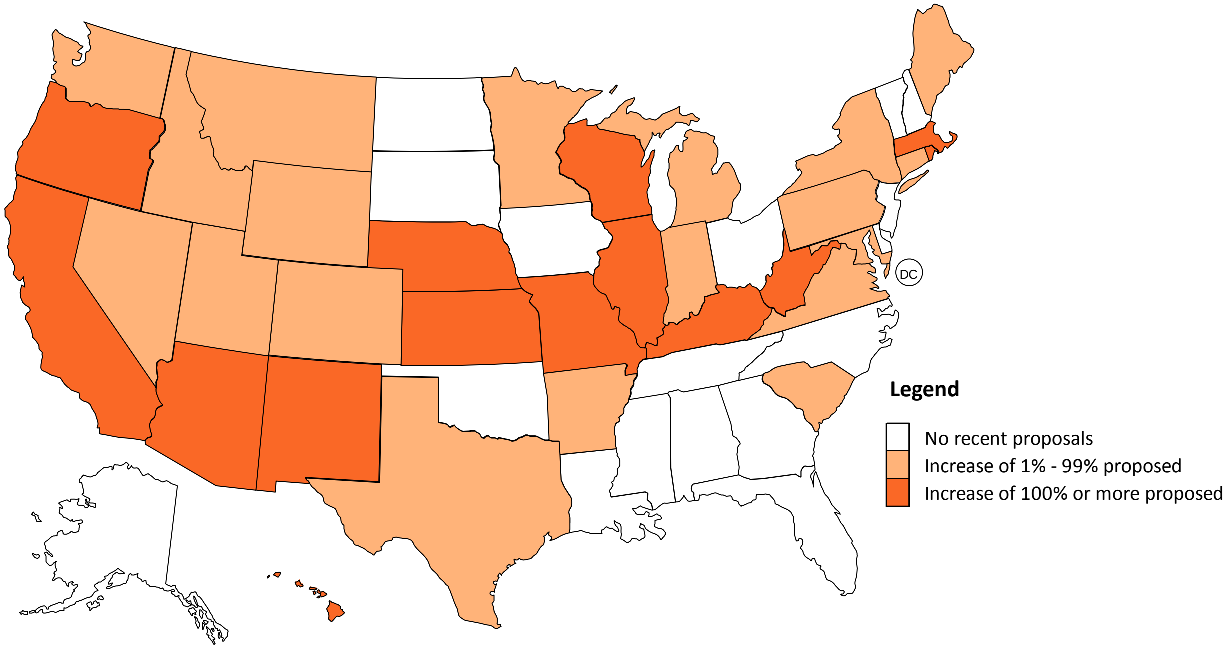
[2] Written comment of John Dupell, Docket 14-05-06, filed May 30, 2014

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

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

Figure 1. Recent proposals and decisions regarding fixed charges



Source: See Appendix B

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

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

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

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

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

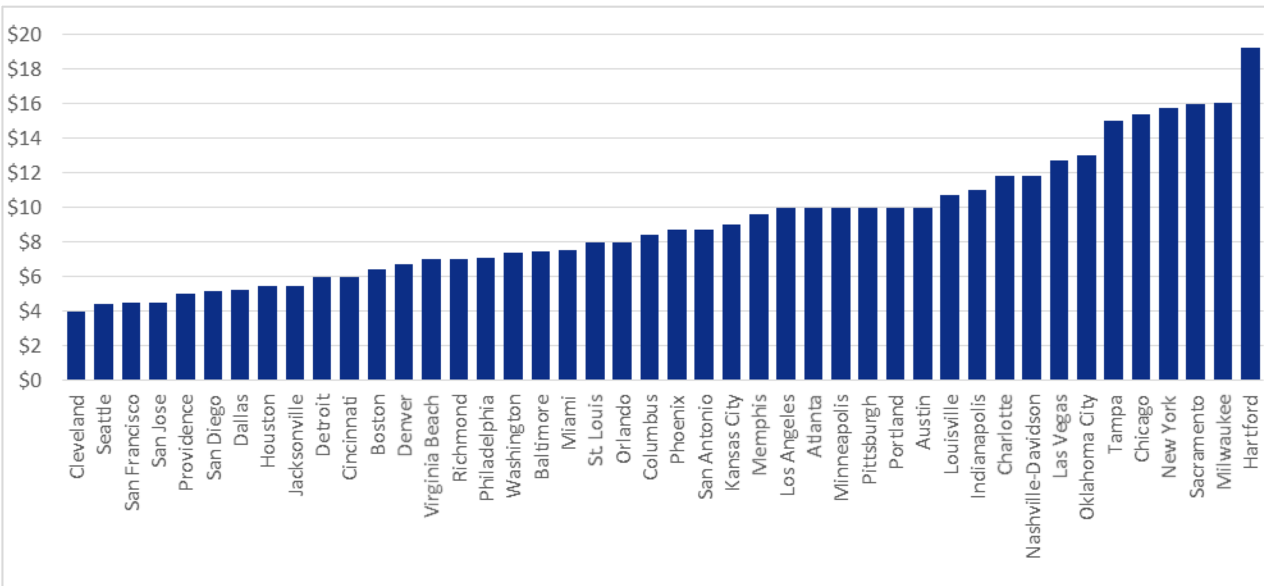
[5] Senate Bill No. 1502, June Special Session, Public Act No. 15-5, "An Act Implementing Provisions of the State Budget for The Biennium Ending June 30, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State."

2. Troubling Trends Toward Higher Fixed Charges

What's Happening to Electric Rates?

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

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



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

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

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

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

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

Other recent examples include:

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

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

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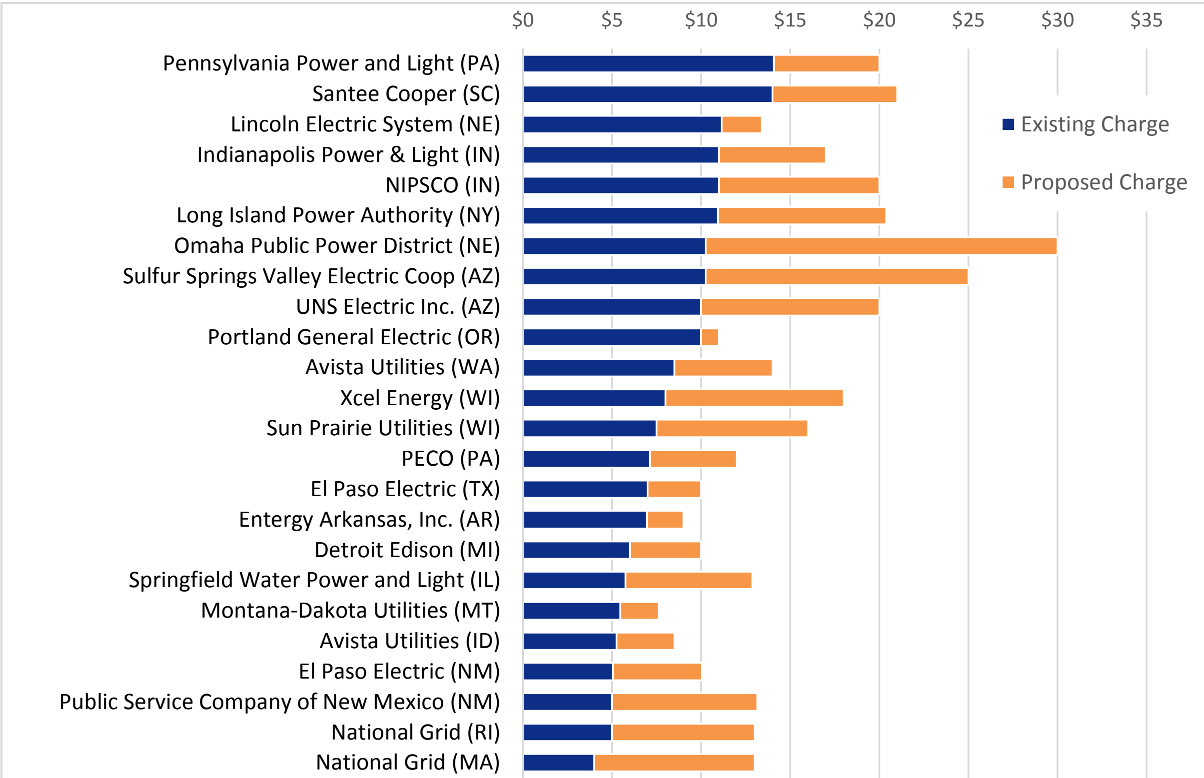
[8] Ultimately the commission approved a fixed charge of $19.25, below the utility's request, but among the highest in the country.

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

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

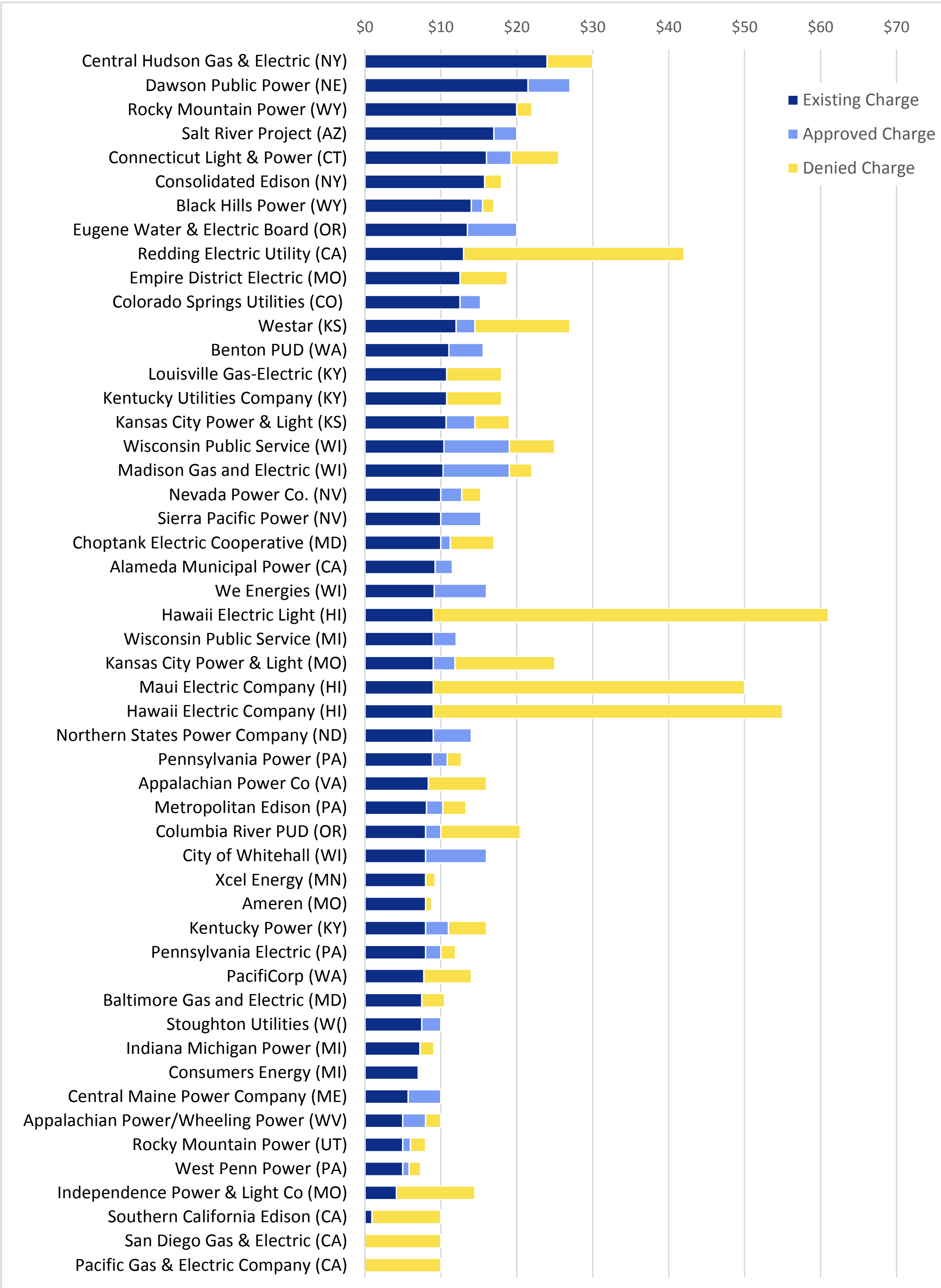
[11] PPL Witness Scott R. Koch, Exhibit SRK 1, Supplement No. 179 to Tariff – Electric Pa. P.U.C. No. 201, Docket No. R-2015-2469275, March 31, 2015, at http://www.puc.state.pa.us/pcdocs/1350814.pdf.

Figure 3. Pending proposals for fixed charge increases



Source: See Appendix B

Figure 4. Recent decisions regarding fixed charge proposals



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

What is Behind the Trend Toward Higher Fixed Charges?

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

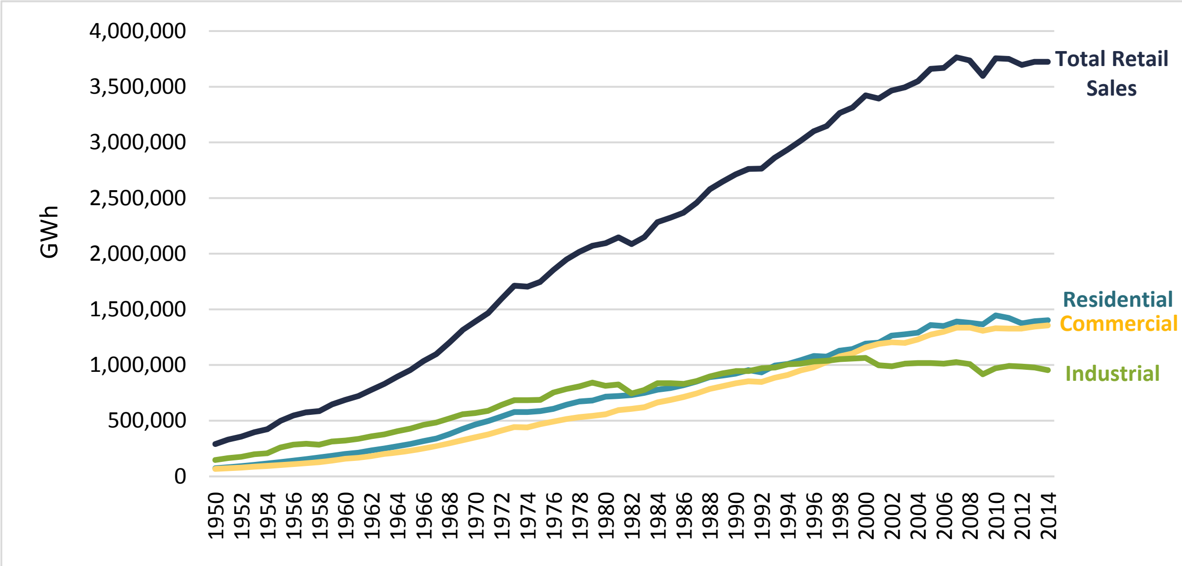
Rates are typically composed of some combination of the following three types of charges:

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

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

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

Figure 5. Retail electricity sales by sector



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

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

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

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

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

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

3. How Fixed Charges Harm Customers

Reduced Customer Control

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

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

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

Low-Usage Customers Hit Hardest

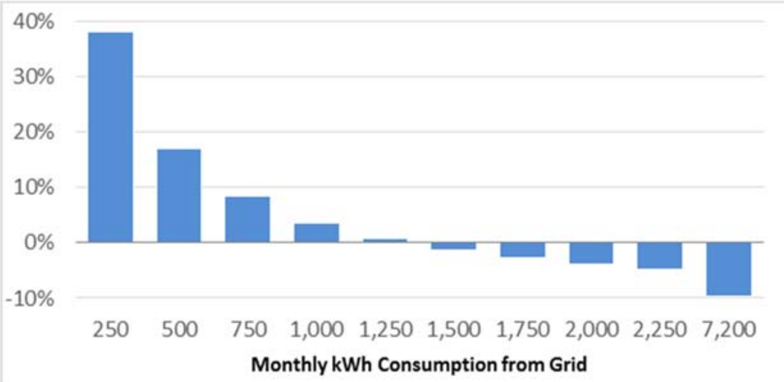
Customers who use less energy than average will experience the greatest percentage jump in their electric bills when the fixed charge is raised, since bills will then be based less on usage and more on a flat-fee structure. There are many reasons why a customer might have low energy usage. Low-usage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

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

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

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

Figure 6. Increase in average monthly bill

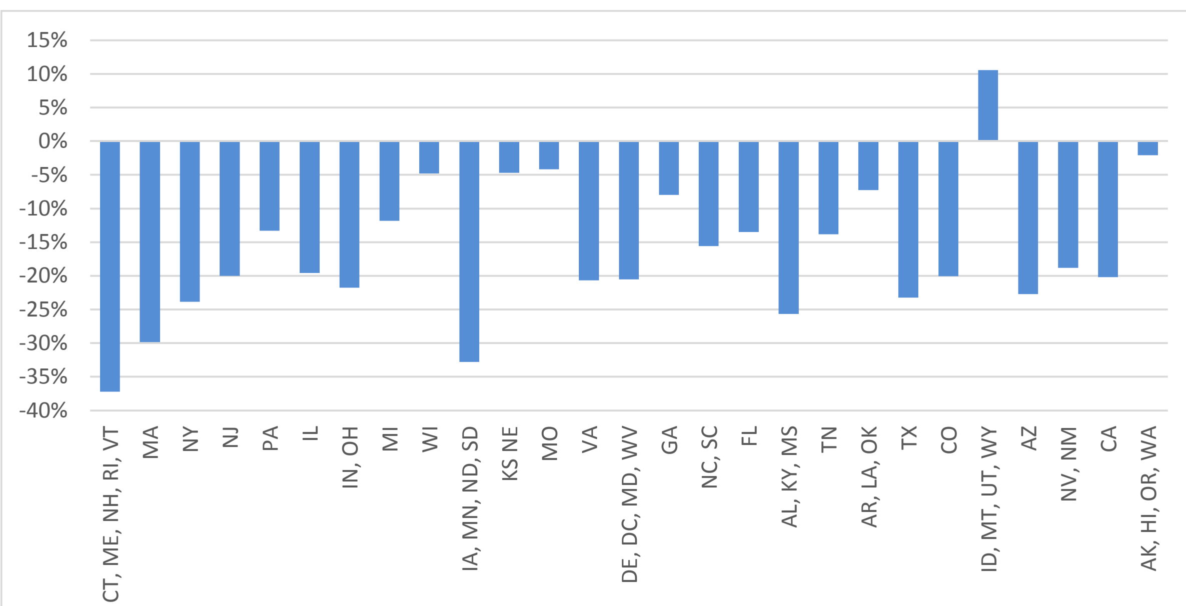


Analysis based on increasing the fixed charge from $9/month to $25/month, with a corresponding decrease in the $/kWh charge.

Disproportionate Impacts on Low-Income Customers

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

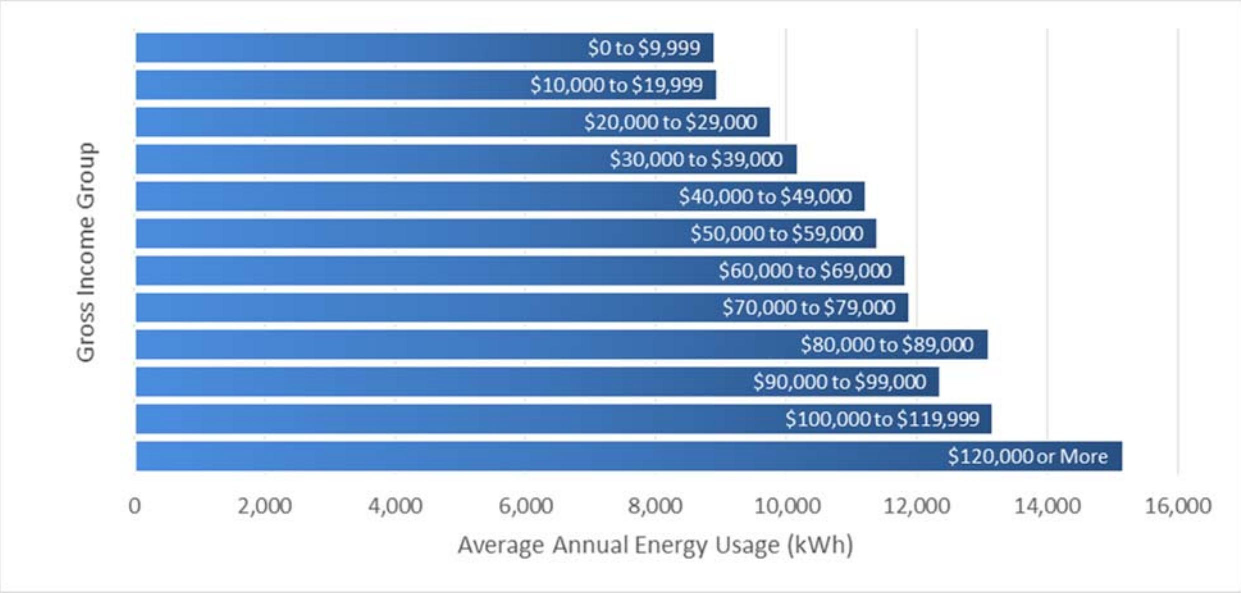
Figure 7. Difference between low-income median residential electricity usage and non-low-income usage



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

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

Figure 8. Nationwide average annual energy usage by income group



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

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

Reduced Incentives for Energy Efficiency and Distributed Generation

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

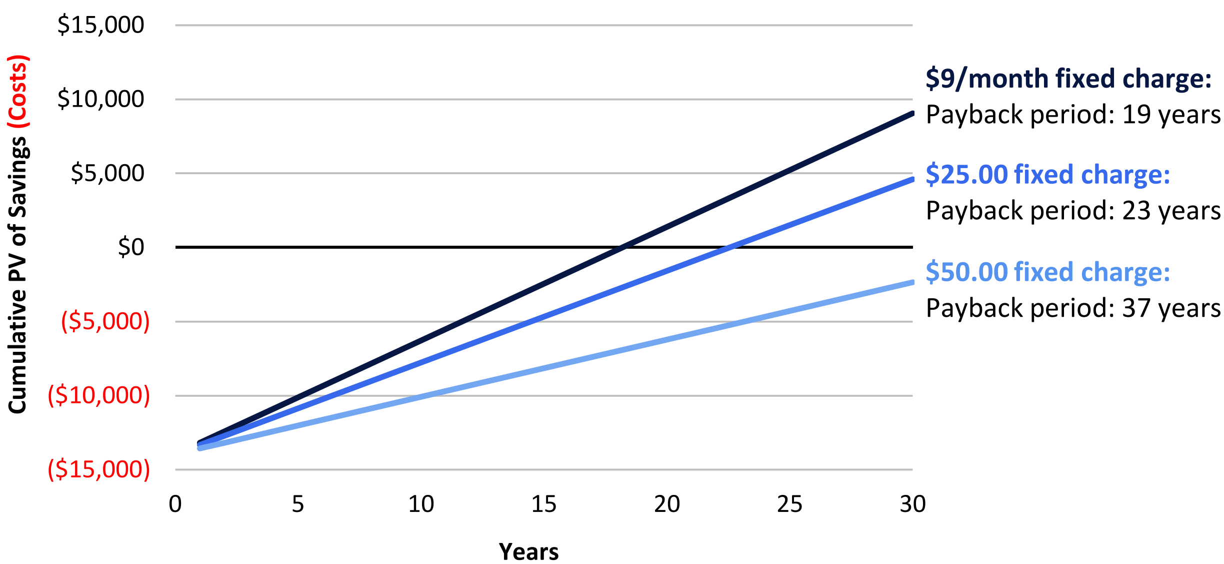
[17] Annie Gilleo et al., "The 2014 State Energy Efficiency Scorecard" (American Council for an Energy Efficient Economy, October 2014).

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

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

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

Figure 9. Rooftop solar payback period under various customer charges



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

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

Increased Electricity System Costs

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

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

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

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

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

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

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

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

4. RATE DESIGN FUNDAMENTALS

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

Guiding Principles

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

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

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

Cost-of-Service Studies

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

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

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

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

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

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

Rate Design Basics

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

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

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

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

5. Common Arguments Supporting Higher Fixed Charges

"Most Utility Costs Are Fixed"

Argument

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

Response

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

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

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

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

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

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

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

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

"Fixed Costs Are Unavoidable"

Argument

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

Response

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

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

"The Fixed Charge Should Recover Distribution Costs"

Argument

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

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

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

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

Response

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

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

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

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

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

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

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

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

Argument

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

Response

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

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

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

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

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

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

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

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

Argument

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

Response

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

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

Argument

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

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

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

Response

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

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

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

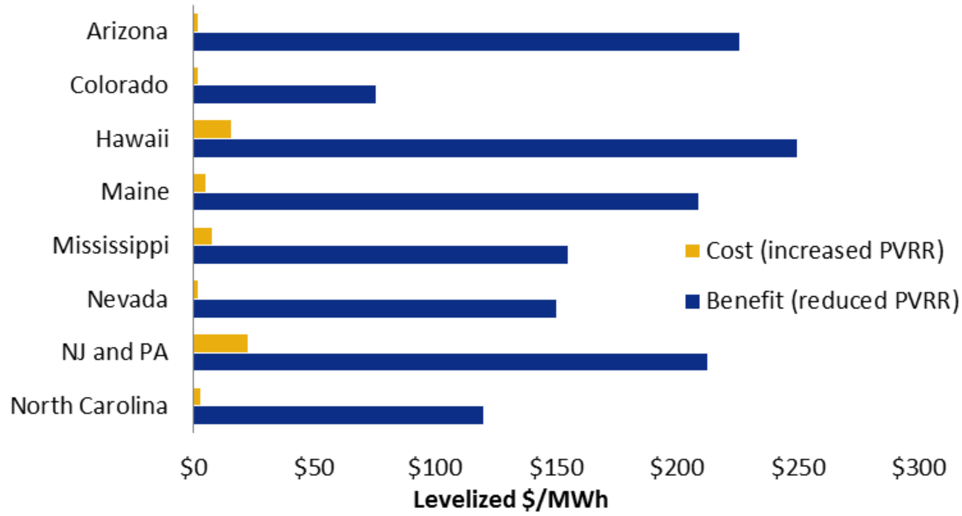
The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may even eliminate, any cost-shifting that might occur.

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

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

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

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



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

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

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

- The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may possibly even eliminate, any cost-shifting that might occur between distributed generation host customers and other customers.[31]

- When arguments about cost-shifting from distributed generation resources are used to justify increased fixed charges, it is important to assess and consider the likely magnitude of cost-shifting in light of the benefits offered by distributed generation. It is quite possible that any cost-shifting is *de minimis*, or non-existent.

- The net benefits of distributed generation should be considered as an important factor in making rate design decisions. Rate designs should be structured to encourage the

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

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

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

6. Recent Commission Decisions on Fixed Charges

Commission Decisions Rejecting Fixed Charges

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

Customer Control

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

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

Energy Efficiency, Affordability, and Other Policy Goals

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Commission Decisions Approving Higher Fixed Charges

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

Fixed Charges and Recovery of Distribution System Costs

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

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

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

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

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

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

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

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

Demand Costs Not Appropriate for Energy Charge

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

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

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

Settlements

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

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

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

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

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

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

7. ALTERNATIVES TO FIXED CHARGES

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

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

Rate Design Options

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

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

Status Quo

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

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

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

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

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

Minimum Bills

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

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

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

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

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

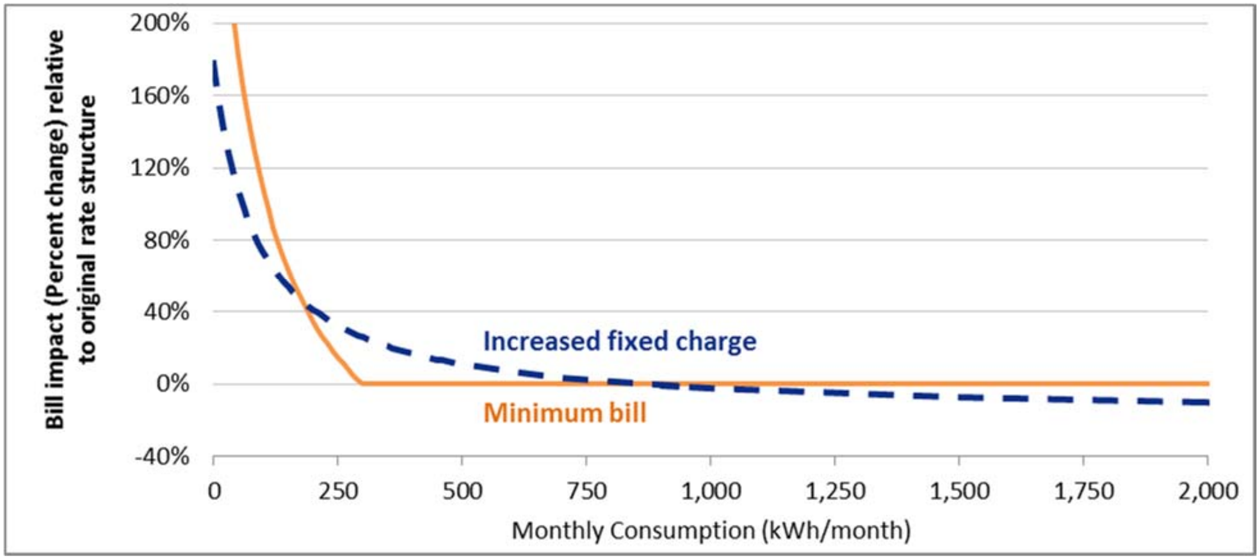
Under the minimum bill option, only customers with usage less than 280 kWh per month (approximately 5 percent of customers at a representative Midwestern utility) would see a change in their bills, and most of these customers would see an increase in their monthly bill of less than $10.

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

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

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

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



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

Time-of-Use Rates

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

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

1. Encouraging ratepayers to reduce their bills by shifting usage from peak periods to off-peak periods, thereby better aligning the consumption of electricity with the value a customer places on it;
2. Avoiding capacity investments and reducing generation from the most expensive peaking plants; and

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

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

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

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

Value of Solar Tariffs

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

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

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

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

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

Demand Charges

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

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

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

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

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

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

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

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

8. CONCLUSIONS

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

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

APPENDIX A – BONBRIGHT'S PRINCIPLES OF RATE DESIGN

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

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

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

APPENDIX B – RECENT PROCEEDINGS ADDRESSING FIXED CHARGES

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

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

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

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

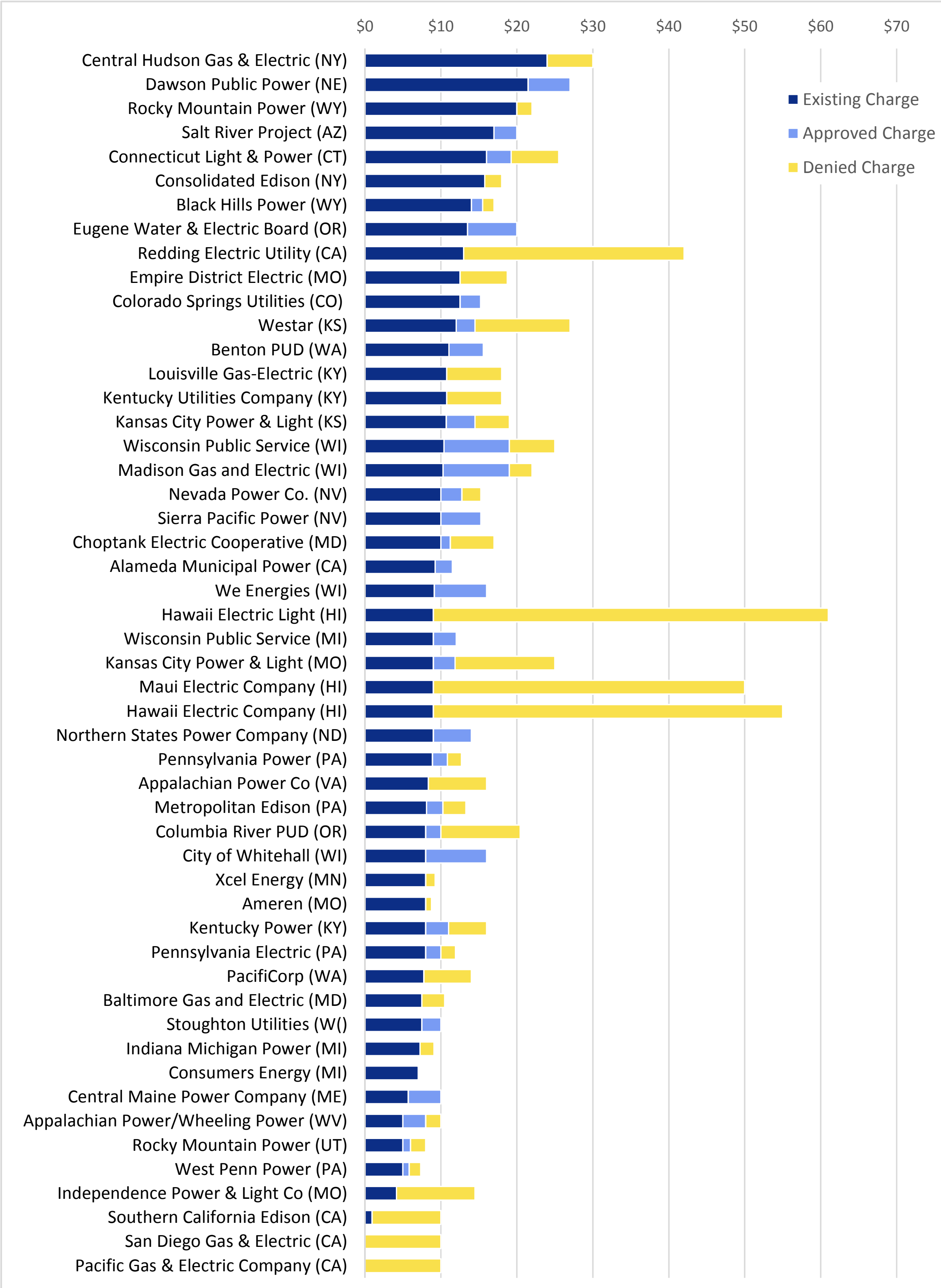
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

Table 2. Pending dockets and proposals to increase fixed charges

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

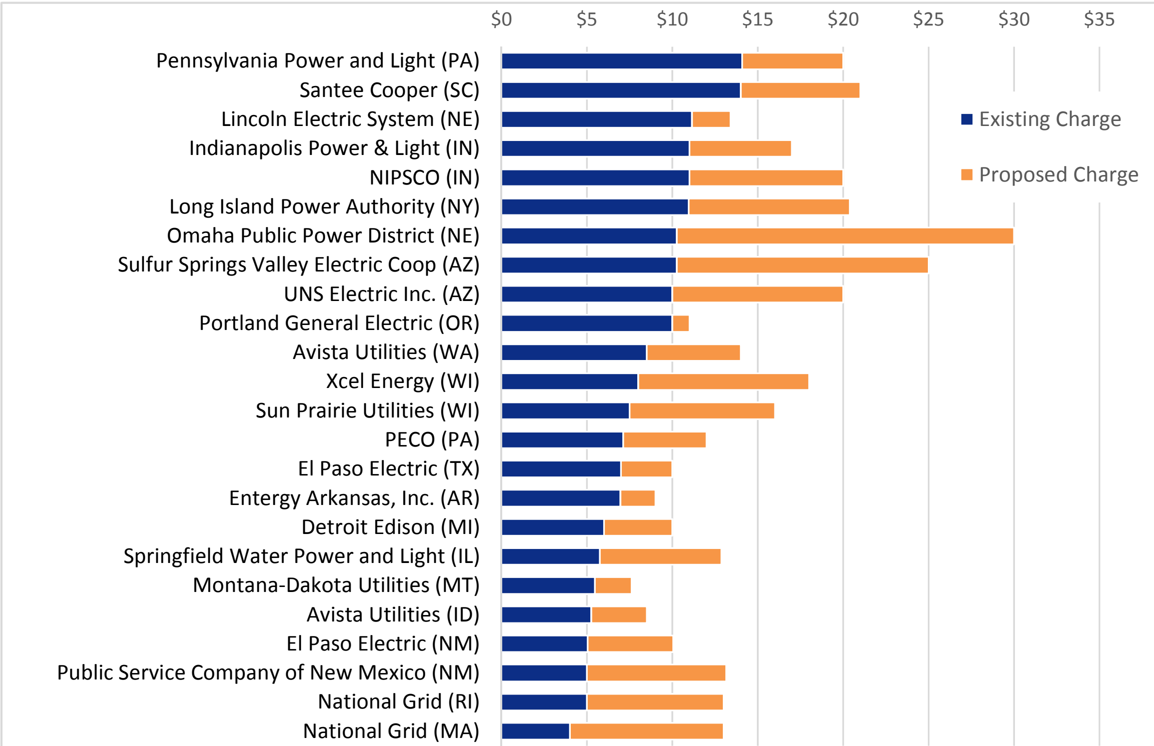
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

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



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

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

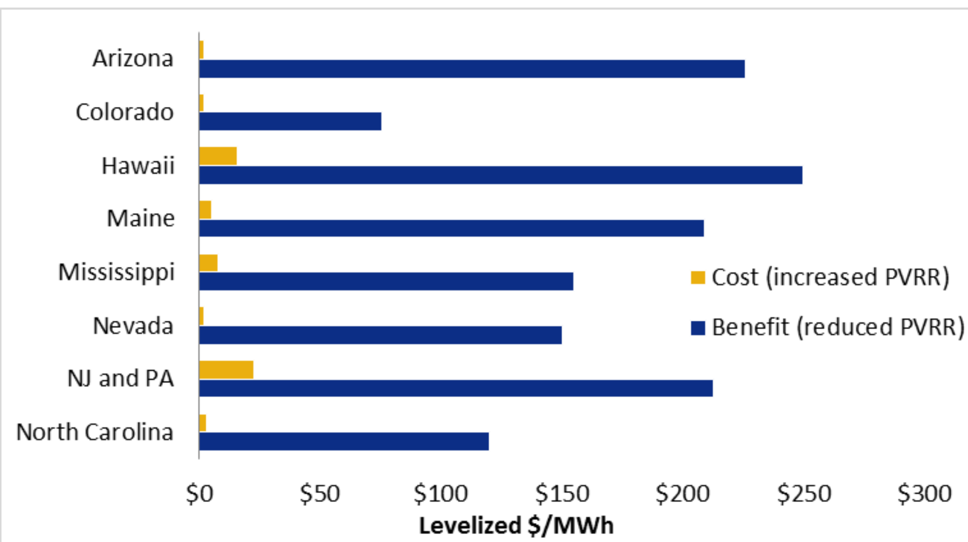


Appendix C – Net Metering Impacts on Utility Costs

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

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

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



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

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

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

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

Source: Synapse Energy Economics, 2015.

Arizona

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

Colorado

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

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

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

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

Hawaii

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

Maine

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

Mississippi

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

Nevada

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

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

[52] Ibid. Page 50, Figure 23.

[53] Ibid. Page 47, Figure 20.

[54] Ibid. Page 43, Figure 17.

[55] Ibid. Pages 55 and 56.

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

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

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

New Jersey and Pennsylvania

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

North Carolina

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

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

[59] Ibid. Page 61.

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

GLOSSARY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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