BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF OKLAHOMA GAS AND ELECTRIC COMPANY FOR AN ORDER OF THE COMMISSION AUTHORIZING APPLICANT TO MODIFY ITS RATES, CHARGES AND TARIFFS FOR RETAIL ELECTRIC SERVICE IN OKLAHOMA	))))))	CAUSE NO. PUD 201500273

RESPONSIVE TESTIMONY

OF

MARK E. GARRETT

COST OF SERVICE/
RATE DESIGN ISSUES

ON BEHALF
OF

THE ALLIANCE FOR SOLAR CHOICE ("TASC")

March 31, 2016

Responsive Testimony of Mark E. Garrett

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I. WITNESS IDENTIFICATION AND PURPOSE OF TESTIMONY

Q: PLEAS E STATE YOUR NAME AND BUSINESS ADDRESS.

A: My name is Mark Garrett. My business address is 50 Penn Place, Suite 410, 1900 NW Expressway, Oklahoma City, Oklahoma 73118.

Q: WHAT IS YOUR PRESENT OCCUPATION?

A: I am the President of Garrett Group, LLC, a firm specializing in public utility regulation, litigation and consulting services.

Q: PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR PROFESSIONAL EXPERIENCE RELATED TO UTILITY REGULATION?

A: I am an attorney and a certified public accountant. I work as a consultant in the area of public utility regulation. I received my bachelor's degree from the University of Oklahoma and completed postgraduate hours at the University of Texas and Stephen F. Austin State University. I received my juris doctorate degree from Oklahoma City University Law School and was admitted to the Oklahoma Bar in 1997. I am a Certified Public Accountant licensed in the States of Texas and Oklahoma with a background in public accounting, private industry, and utility regulation. In public accounting, as a staff auditor for a firm in Dallas, I primarily audited financial institutions in the State of Texas. In private industry, as controller for a mid-sized ($300 million) corporation in Dallas, I managed the Company's accounting function, including general ledger, accounts payable, financial reporting, audits, tax returns, budgets, projections, and supervision of accounting personnel. In utility regulation, I served as an auditor in the Public Utility Division of the Oklahoma Corporation Commission from 1991 to 1995. In that position, I managed the audits of major gas and electric utility companies in Oklahoma. Since leaving the Commission, I have worked on rate cases and other regulatory proceedings on behalf of various consumers and consumer groups.

Q: HAVE YOUR QUALIFICATIONS BEEN ACCEPTED BY THIS COMMISSION?

A: Yes, they have. A more complete description of my qualifications and a list of the proceedings in which I have been involved are included at the end of my testimony.

Q: ON WHOSE BEHALF ARE YOU APPEARING IN THESE PROCEEDINGS?

A: I am appearing on behalf of The Alliance for Solar Choice ("TASC").

Q: WHO IS TASC?

A: The Alliance for Solar Choice advocates for maintaining successful distributed solar policies nationwide. Founded by the largest rooftop companies in the nation, TASC member companies include Geostellar, Inc., LGCY Power, REPOWER by Solar Universe, SunTime Energy, Sunrun, Lightwave Solar, Palmetto Solar and Demeter Power. These companies are responsible for tens of thousands of solar installations across the country and are engaged at the local, state, and national level.

Q: WHAT IS TASC's INTEREST IN THIS PROCEEDING?

A: TASC's primary interest in this proceeding is to maintain and encourage consumer choice and fair rate setting practices, particularly as it applies to the Company's residential solar customers and those customers who hope to power their homes with solar in the future.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The primary purpose of my testimony is to address, from a ratemaking perspective, the Application of Oklahoma Gas and Electric ("OG&E" or the "Company") to impose distributed generation ("DG") tariff changes in response to 2014 Senate Bill No. 1456 ("S.B. 1456"). My testimony considers the proposed DG tariff changes in light of the pending application in Cause No. 2015-00274. It highlights how OG&E's current application not only fails to remedy the deficiencies TASC identified in Cause No. 2015-00274, but also requests penalties for DG customers that are contrary to S.B. 1456. As I discuss, when the Company uses fresh cost of service data—as opposed to the stale data relied on in Cause No. 2015-00274—it is clear that residential DG customers actually provide a subsidy to non-DG residential customers, and not the other way around. Accordingly, OG&E's proposed demand charge and increased fixed charges for DG customers violate the law. To comply with S.B. 1456, I recommend that the Commission reject those charges and maintain the status quo time-variant rate for DG customers.

My testimony also addresses the broader implications of the Company's residential rate proposals, including substantial increases to customer fixed charges and a residential demand charge. OG&E seeks to impose a default three-part demand-charge rate design on Oklahoma ratepayers. This is an unwise and unprecedented formula that should be rejected.

II. SUMMARY OF RECOMMENDATIONS

Q: PLEASE SUMMARIZE THE SPECIFIC RECOMMENDATIONS YOU MAKE IN YOUR TESTIMONY.

A: I recommend that the Commission reject attempts to impose a discriminatory, mandatory rate structure on residential customers with distributed generation (proposed Schedule R-TOU-kW). The Company's DG proposal is contrary to S.B. 1456 and to standard ratemaking principles for the following reasons:

- The Company fails to consider the costs and benefits of distributed generation to remedy the evidentiary deficiency of its application in Cause No. PUD 2015-00274 and, again, fails to demonstrate that residential customers with distributed generation are being subsidized by other customers within the same class;
- The Company's Cost of Service Study shows that Residential DG customers are providing a subsidy to other residential ratepayers – the opposite of shifting costs to those customers; and
- The proposed R-TOU-kW violates S.B. 1456 because it would raise rates beyond what is necessary to recover the cost of service for residential customers with distributed generation.

I further recommend that the Commission reject the Company's proposal to make drastic rate design changes for residential customers, including those with distributed generation. These changes include the establishment of a three-part rate for standard residential customers, with the unprecedented imposition of a demand charge on these customers, and the doubling of the customer charge. I recommend that these proposed changes be rejected for the following reasons:

- Residential customers are wholly unaccustomed to demand charges, so it is not advisable from a policy perspective to thrust an untested and unprecedented rate experiment on the majority of the Company's residential customers;

- Non-coincident demand charges do not align with cost causation principles and do not reflect the time-specific costs associated with energy consumption;

- Average residential customers generally lack the specialized awareness required to manage demand and cannot readily access the costly equipment necessary to assist in controlling maximum demand;

- Demand charges have the prospect of being punitive and discouraging of beneficial behavior for customers that manage their demand well for 99% of the month, but get hammered for one 15-minute period where usage spikes (perhaps for reasons beyond their control);

- The proposal to double the customer charge inappropriately expands the category of customer-related costs to elements of the distribution grid that vary with the amount of usage, not with the number of customers; and

- The doubling of the customer charge weakens the price signal to conserve electricity.

III. OG&E'S PROPOSAL FOR RESIDENTIAL DG TARIFFS

Q: PLEASE DESCRIBE THE RATE CHANGE THAT OG&E IS PROPOSING FOR ITS RESIDENTIAL CUSTOMERS WITH DG.

A: The Company is essentially maintaining the same punitive proposals put forward recently in Cause No. PUD 2015-00274. Customers that wish to engage in solar net metering must take service under Schedule NEBO-kW in conjunction with a three-part time-of-use rate (Schedule R-TOU-kW). In comparison to currently effective rates for net metering customers, OG&E proposes to more than double the customer charge from

$13 per month to $26.54 per month. In Cause No. PUD 2015-00274, the Company proposed to increase the customer charge to $18 per month for customers on R-TOU-kW. At the time of this testimony, Schedule R-TOU-kW has not been approved, so any changes should be compared to the rates currently in effect.

Q: WHAT IS THE CURRENT TARIFF FOR RESIDENTIAL NET METERING CUSTOMERS?

A: Residential customers with DG engaged in net metering on Schedule NEBO must take service under a time-of-use tariff. For residential customers, that is current standard pricing Schedule R-TOU.

Q: OG&E IS CURRENTLY SEEKING APPROVAL OF THE RESIDENTIAL DG TARIFF IT SOUGHT IN CAUSE NO. PUD 2015-00274. SHOULD THE COMMISSION CONSIDER THE DG TARIFF SOUGHT IN THAT PROCEEDING AS THE CURRENT RATE?

A: No. The R-TOU-kW tariff should not be considered the current tariff for residential net metering customers until or unless the Commission approves the charge as proposed in that cause. Accordingly, the comparison of the proposed changes from existing rates in Company Witnesses' direct testimony is somewhat misleading and underplays the extent of the actual change that would take place if the pending rate proposal in Cause No. 2015-00274 is not approved or not acted upon before the conclusion of this case.[1] At the time of this testimony, it is simply not the case that the Commission has accepted

[1] Direct Testimony of William Wai at p. 27 (Table 14) (December 18, 2015).

demand charges as appropriate for any of the residential customers of any of the electric utilities it regulates.

Q: DID TASC OPPOSE THE IMPOSITION OF R-TOU-KW ON RESIDENTIAL NET METERING CUSTOMERS IN THAT PREVIOUS CASE?

A: Yes.

Q: ON WHAT BASIS DID TASC OPPOSE MAKING R-TOU-KW MANDATORY FOR ALL RESIDENTIAL NET METERING CUSTOMERS?

A: In my testimony on behalf of TASC in that matter, I recommended that the Commission reject the Application on the basis that:

- It is inconsistent with S.B. 1456 because it fails to demonstrate the existence of a subsidy for DG customers and the proposed tariffs are not cost-based.

- From both a technical and policy perspective, it represents single-issue ratemaking, which has been disfavored by this Commission and others nationwide. OG&E's Application would only raise costs on DG customers without correspondingly lowering costs for other customers.

- It contains several rate design flaws, including implementation of demand charges for residential customers. Residential customers are not equipped to respond to demand charges, and implementing demand charges for DG customers is inconsistent with the express language of S.B. 1456.[2]

- It fails to comply with the Commission-led stakeholders' collaborative process that was specifically designed to provide the necessary information for a transparent evaluation of DG rates.

- It makes rate design recommendations for DG customers that are inconsistent

[2] As I noted throughout the proceeding, it is illogical for demand charges to be imposed on distributed generation customers when they are, by statutory definition, customers that are not subject to a demand charge.

with recommendation OG&E has put forward in prior rate cases."[3]

Q: DO THOSE CRITICISMS REMAIN RELEVANT IN THIS CASE?

A: Yes, with the exception that the concerns over single-issue ratemaking do not apply to the currently proposed rate because it is being put forward in a general rate case proceeding. That criticism remains to the validity of any rate proposed in Cause No. 2015-00274, where the charge was sought in isolation, outside of a rate case without any offsetting reductions in rates for other customers where increases in rates to DG customers were contemplated.

The criticisms that the Company failed to demonstrate the existence of a subsidy, failed to adequately address the stakeholders' Master Checklist and would violate S.B. 1456 by causing DG customers to subsidize non-DG customers in the same class remain relevant to the current case.

IV. DEFICIENCIES OF OG&E'S RESIDENTIAL DG TARIFF PROPOSAL

Q: WHAT ARE THE DEFICIENCIES OF OG&E'S PROPOSED DG TARIFF IN THIS CASE?

A: First and most critically, the proposed Residential DG Schedule (R-TOU-kW) is contrary to S.B. 1456. Under that law, the Company must demonstrate the existence of a subsidy in order to trigger the provisions that would allow a special charge or rate structure for DG customers. OG&E fails to produce any evidence of this alleged DG subsidy and does not even attempt to quantify the costs and benefits of DG, as required

[3] Responsive Testimony of Mark E. Garrett in Cause No. PUD 2015-00274 at pp. 4-5 (November 3, 2015).

by the Master Checklist developed by staff and a collaborative stakeholder group. Moreover, the only new, relevant data that they do provide demonstrates that Residential DG customers are actually providing a subsidy *in favor* of other residential customers. The Company's COSS found that residential DG customers, when looked at as a separate class, are subsidizing other residential customers.[4]

OG&E's current residential DG proposal would increase the collection of revenue from residential net metering customers above what it costs to serve those customers. Schedule R-TOU-kW therefore does not comply with S.B. 1456.

Finally, the imposition of a demand charge on residential net metering customers represents a significant policy change for Oklahoma ratepayers. This change should be viewed in light of broader rate design proposals. Such fundamentally unfair shifts in rate structure are likely to create widespread dissatisfaction, confusion and, ultimately, backlash.

Q: YOU SAID THAT ONE DEFICIENCY OF OG&E'S PROPOSED RESIDENTIAL DG RATE (R-TOU-KW) IS THAT THE COMPANY FAILS TO SATISFY THE THRESHOLD REQUIREMENT OF DEMONSTRATING THE EXISTENCE OF A SUBSIDY. PLEASE EXPLAIN WHY THIS IS A THRESHOLD REQUIREMENT.

A: S.B. 1456 provides that, after the effective date of the Act, customers installing DG shall not be subsidized by other customers in the same class that do not have DG. Thus, before

[4] Supplemental Package, Vol. II, W/P Schedule L-1 (showing a higher return on rate base for the residential DG class than any other residential rate schedule) (December 18, 2015).

any action is taken—or before any action is required—there must be a demonstration that a subsidy exists. Demonstration of a subsidy is a prerequisite to taking any rate action on DG customers. I explained this concept in my responsive testimony in Cause No. PUD 2015-00274:

> "OG&E would have to demonstrate that a subsidy exists before the requirements of Title 17 § 156 would take effect, something OG&E has not done... The Company's proposed new tariffs are based on assumptions, and flawed ones at that. OG&E cannot show that its proposed new tariffs are based on actual costs (as required by the statute). In fact, there is no legitimate way to know whether a subsidy actually exits between one set of customers and other customers unless the utility conducts a comprehensive cost of service study contemporaneous with a full revenue requirement review, in other words, in a general rate case. Without a rate case, or at the very least a cost of service study, no cross-subsidization can be proven."[5]

Q: DOES THE COMPANY EXPLAIN WHAT CONSTITUTES A SUBSIDY AS IT RELATES TO RESIDENTIAL NET METERING CUSTOMERS?

A: No. The Company refers to the testimony of Roger Walkingstick in Cause No. PUD 2015-00274 to support its assertion that a cross-subsidy occurs.[6] However, the very definition of what constitutes a "subsidy" was in controversy then, and the matter remains unsettled. The Company's basic argument was that a subsidy is inherent in the retail rate because the embedded fixed costs of the grid are recovered through the volumetric rate in the current residential rate structure. Of course, this merely suggests that subsidization is possible (i.e., there is an opportunity in the tariff), it does nothing to tell the Commission if subsidization is actually occurring. S.B. 1456 requires, at the threshold, a demonstration that subsidization is <u>**actually**</u> occurring before any remedial

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5 Responsive Testimony of Mark E. Garrett in Cause No. PUD 2015-00274 at p. 16 (November 3, 2015).

6 Direct Testimony of Bryan J. Scott at pp.14-15 (December 18, 2015).

action is approved.

The Company also alleged that energy produced by net metering customers is only worth the utility's avoided cost, and that the difference between the retail rate and the avoided cost value of the electricity produced by net metering customers represented a subsidy that flows to net metering customers. This argument lacks merit, as the Company has yet to undertake a good faith effort to understand and quantify the benefits of distributed generation to ratepayers, the grid, and society. Between Cause No. PUD 2015-00274 and this case, the Company has yet to produce any data showing that they have quantified the benefits and costs of net metering. Where independent third parties have undertaken serious cost-benefit analyses, the results illustrate that net metering provides a net financial benefit to all ratepayers.[7]

Moreover, the allegation that net metered customers are paid at retail rates is misleading. The Company does not account for net metered customers' generation as a purchase of electricity and the costs of such "purchases" are not recovered through the Company's fuel adjustment clause. The existence of a subsidy, then, depends on showing that the Company is currently under-recovering from its net metered customers as compared to other customers within the same class. Of course, that view must also consider whether there are other values that DG is contributing to the grid that help lower costs for other customers. OG&E neither defines what constitutes a subsidy, nor shows that it is under-recovering from its net metered customers. In fact, as stated earlier and as I will discuss further below, OG&E's COSS shows that DG customers are

[7] Melissa Whited, Tim Woolf, and Joseph Daniels, *Caught in a Fix: The Problem With Fixed Charges for Electricity* (Synapse Energy Economics, Inc.) ("Synapse Report") at p. 28 (February 9, 2016), Attached as Exhibit MG_2.

providing a subsidy to other non-DG residential ratepayers.

Q: DOES THE COMPANY'S APPLICATION QUANTIFY OR DEMONSTRATE THE ALLEGED SUBSIDY IN THIS APPLICATION?

No. The Company's Application gives very little discussion to the existence of a subsidy and merely assumes that DG customers (or net metered customers) can be treated as a separate rate class or subclass. Thus, the Company not only skips the critical first step of explaining what constitutes a subsidy, but also fails demonstrate that a subsidy exists and presumes that it may impose unique rates on DG customers. As mentioned previously, the Company's COSS actually demonstrates that putting DG customers into a separate class causes those customers to subsidize the general body of residential customers. Schedule L-1 demonstrates that the Company earns a higher rate of return on the Residential DG class than on any other residential schedule.[8]

Table 1. Return on Rate Base for Residential Rate Schedules

	Total Residential Service (Col. 1)	Residential Standard (Col. 2)	Residential TOU (Col. 3)	Residential VPP (Col. 4)	Residential CPP (Col. 5)	Residential DG (Col. 6)
Line 31 (Return on Rate Base)	5.33	5.18	4.89	6.28	6.32	7.23

This figure also fails to account for the contribution the residential DG class makes to the Company through uncompensated excess generation throughout the year. Under the net metering program, any excess generation that is left at the end of the billing period is

[8] *See* W/P Schedule L-1 line 31, column 6.

forfeited to the Company without compensation. As Mr. Walkingstick conceded at the hearing of Cause No. PUD 2015-00274, that uncompensated generation transfers value to other ratepayers:

> "Q. (TASC's Counsel) Understood. And when a customer produces a kilowatt-hour that's eventually not compensated or they don't receive a value for it, the company gets some value out of that; is that correct?
>
> A. (Mr. Walkingstick) I don't think so. I think what occurs is it becomes less of an energy requirement that the customer has to go – or, excuse me, that the company has to go and get from the energy market, the IM. So who receives the benefit from that is less kilowatt-hours are required from the IM, but those additional kilowatt-hours that came into it came in at a zero cost. So the net effect is all the other customers benefited, to some extent, for that uncompensated kilowatt-hours."[9]

In the current application, the Company has not endeavored to put a number on the value of the kWh surrendered to the Company during the test year. In addition to the expected revenues from the residential DG class, this forfeiture of excess kWh represents further contribution of value and shows that residential DG customers are subsidizing other residential customers at an even higher rate than Schedule L-1 reveals.

Having failed to demonstrate that DG customers are subsidized – and in fact proving the opposite – the Company has provided no cost basis to impose a different charge or rate structure on DG customers than it does to other residential customers. Because OG&E's only new evidence shows that DG customers are demonstrably providing a subsidy to other residential customers, their Residential DG proposal must be rejected for failing to satisfy the threshold requirement of S.B. 1456. In other words, because the Company failed to establish the existence of a subsidy, the Residential DG

[9] Transcript of Proceedings in Cause No. PUD No. 2015-00274, December 2, 2015, RDH 29 (line 20) to RDH 30 (line 8).

proposal is plainly discriminatory and violates the intent of S.B. 1456 – to reserve any fee or surcharge on DG customers for circumstances where it is necessary to eliminate a demonstrated subsidy.[10]

Q: PLEASE EXPLAIN HOW THE STAFF'S CHECKLIST IS RELEVANT TO THE DETERMINATION OF A SUBSIDY FOR NET METERING CUSTOMERS?

A: As I discussed in my responsive testimony in Cause No. PUD 2015-00274, Governor Fallin issued Executive Order ("E.O.") 2014-07 on the same day she signed S.B. 1456, directing the Commission to undertake a "transparent evaluation of distributed generation." In the fall of 2014, the Commission held a series of informal stakeholder meetings to discuss the implementation of S.B. 1456 and, as a result of those meetings, the concept of a "Master Checklist" emerged. As I discussed, "the Master Checklist became the compilation of ideas, concepts, and general information provided by interested stakeholders and members of the public, intended to serve as a guide for the Commission in its review of distributive generation tariff application."[11] The final version of the Master Checklist became the compiled list of information that the Company was supposed to include in its application—information that all stakeholders agreed would be necessary to evaluate distributed generation. The Master Checklist is just as relevant with this filing.

The Company's cavalier attitude toward the Master Checklist, and disregard for the investment of Commission and Staff time in developing the list, undermines the

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[10] 17 O.S. § 156.
[11] Responsive Testimony of Mark E. Garrett in Cause No. PUD 2015-00274 at p. 26.

Commission's ability to fairly evaluate any proposal for its consistency with S.B. 1456. With the exception of the examination of Residential DG as a separate class in the new COSS, the Company's Application does nothing to improve the Company's unpersuasive showing in Cause No. PUD 2015-00274.

Q: DOES S.B. 1456 ALLOW A NEW RATE STRUCTURE TO BE IMPOSED ON RESIDENTIAL NET METERING CUSTOMERS IF THAT STRUCTURE RAISES RATES BEYOND THE COST OF SERVICE AND CAUSES THEM TO SUBSIDIZE OTHER CUSTOMERS IN THE CLASS?

A: No. In fact, S.B. 1456 expressly prohibits this result. Even if the Company could satisfy the threshold requirement of demonstrating a subsidy, S.B. 1456 includes a general prohibition against increasing the rates charged or enforcing a surcharge on customers with distributed generation if that measure would collect revenue above and beyond what is required to provide electrical service.[12] Put another way, the law requires a valid diagnosis before any medicine can be administered.

Importantly, the focus of S.B. 1456 is on the elimination of intra-class subsidization. Whether the residential class, as a whole, contributes 100% of its cost of service—as determined in the COSS—is a separate matter and should not be conflated. Because a subsidy can be shown to be flowing from Residential DG customers to all other residential customers, there can be no question that the Residential DG class is already paying more than its relative cost of service. It would be disingenuous and contrary to S.B. 1456 for the Company to claim that the Residential DG class should be

[12] 17 O.S. § 156(B)

held to a different standard from other residential customers when it comes to inter-class subsidization.

Q: IF R-TOU-KW IS INAPPROPRIATE, WHAT RATE SCHEDULE SHOULD NET METERED RESIDENTIAL CUSTOMERS TAKE SERVICE UNDER?

A: Since the Company has not demonstrated the existence of a subsidy in the first place, it is reasonable to maintain the status quo and allow residential customers to take service on the existing time-of-use rate option.

Q. WOULD APPROVAL OF R-TOU-KW NEGATIVELY IMPACT THE ECONOMICS OF RESIDENTIAL CUSTOMERS THAT WISH TO INSTALL DISTRIBUTED GENERATION?

A. Yes. The proposed mandatory schedule for distributed generation customers would erode customers' bill savings and create a disincentive to conserve energy or to go solar. For the reasons I discuss below in Section V (general residential rate design proposal), residential customers are ill-equipped to respond to residential demand charges. A net metering customer, thus, will have far less control over how installing DG can be used to lower their overall bill due to both the imposition of an unprecedented residential demand charge and the doubling of the customer charge. The Company's desire to secure a high revenue stream must be mitigated by longstanding ratemaking principles which do not favor reliance on fixed charges for residential customers.

Q: HAVE YOU UNDERTAKEN AN ANALYSIS OF THE BILL IMPACT OF THE COMPANY'S PROPOSAL FOR RESIDENTIAL NET METERING CUSTOMERS, AS COMPARED TO CURRENTLY EFFECTIVE RATES?

A: Yes. In Exhibit MG-3, I provide a bill analysis to show the impact of requiring a customer currently on R-TOU to shift to the R-TOU-kW being proposed in this case. The existing R-TOU represents the status quo existing for many residential DG customers at the time the Company filed its application in this Cause. Exhibit MG-3 uses the basic bill impact model put forward in discovery by the Company in Cause No. PUD 2015-00274, updated with the charges proposed in this case. A narrative of the adjustments used to adapt this model is given in Exhibit MG-3.

Q: WHAT DOES THE BILL IMPACT ANALYSIS REVEAL?

A: This basic snapshot reveals that a typical DG customer transitioning from the current R-TOU to the proposed R-TOU-kW will see a bill increase of more than 20%, even after adjusting the monthly bill estimate under the proposed R-TOU-kW downward to eliminate the portion of the bill attributable to riders that are not currently in base rates.

Q: ARE THERE EXAMPLES FROM OTHER JURISDICTIONS WHERE INTRODUCTION OF A RESIDENTIAL DEMAND CHARGE HAS NEGATIVELY IMPACTED THE CUSTOMER ECONOMICS OF INSTALLING DISTRIBUTED GENERATION?

A: Yes. In Arizona, in the territory of Salt River Project, utility data shows a 95.5% decrease in installations for the year following the implementation of increased fixed charges and a mandatory demand charge on DG customers. In the calendar year following those rate changes, Arizona lost more than 2,200 solar jobs.[13]

Q: DO YOU HAVE A RECOMMENDATION FOR THE RATE DESIGN FOR CUSTOMERS WITH DISTRIBUTED GENERATION?

A: Yes. I recommend that the Commission maintain the status quo for DG customers – the requirement to take service under a time-of-use tariff – and reject both demand charges and increased fixed charges for any group of residential customers.

V. OG&E'S GENERAL RESIDENTIAL RATE DESIGN PROPOSAL

Q: PLEASE DESCRIBE THE COMPANY'S RATE PROPOSAL FOR RESIDENTIAL CUSTOMERS THAT DO NOT USE DISTRIBUTED GENERATION.

A: The Company is replacing its current Schedule R-1 (seasonally differentiated, inclining block rate) with a three-part rate that features a substantially increased customer charge, an energy charge, and a demand charge based on the maximum 15-minute demand in the billing month. For customers that wish to opt out of the proposed three-part standard residential rate, they can take service under a TOU rate. That said, the proposed TOU rate also carries significant new fees in the form of fixed charges. With this substantial

[13] *See* http://www.thesolarfoundation.org/wp-content/uploads/2016/02/Arizona-Solar-Jobs-Census-2015.pdf.

increase, and reliance on fixed charges for recovery of costs, this rate is not a true alternative that allows customers to take measures to avoid rising electricity bills. Moreover, OG&E has not provided any information on how it will educate customers about their opportunities to opt out of the three part rate. As it now stands, customers are likely to be stuck on a rate they cannot control or understand.

Q: DO THESE RATE PROPOSALS REPRESENT SIGNIFICANT CHANGE FROM THE STATUS QUO RATE DESIGN FOR RESIDENTIAL CUSTOMERS IN OKLAHOMA?

A: Yes. In fact, the proposal to include a default three-part rate structure (i.e., demand-based rate structure) is not only unprecedented in Oklahoma, but also unprecedented in the United States. I am not aware of any other major investor-owned utility that uses a three-part rate design as its default or standard residential rate offering. Moreover, I am not aware of any other utility in the country that forces residential customers to choose between a three-part rate design and a time-variant rate. The mandatory aspect of this—that residential customers would have to be on a time-variant rate or a demand charge rate—is unprecedented and represents the most aggressive push in residential rate design I have seen in the country. Additionally, I am not aware of any utility that has default time-variant rates.

In addition to the proposed structural changes in standard rates for residential customers, the Company's proposal to more than double the fixed customer charge is also troubling. First, the customer-related costs are inflated by including costs that do not truly vary with the number of customers. Second, increasing fixed charges has the effect of lowering the volumetric energy rate, which muddies the price signal for customers and can therefore lead to inefficient use of electricity.

V. A. <u>RESIDENTIAL DEMAND CHARGES</u>

Q: ARE NON-COINCIDENT DEMAND CHARGES FOR RESIDENTIAL CUSTOMERS CONSISTENT WITH THE PRINCIPLE OF COST CAUSATION?

A: No. While it is true that demand charges are common and generally accepted in commercial and industrial rates, residential customers exhibit dramatically different and less consistent usage patterns than commercial and industrial customers. Demand charges can work as an approximation for non-residential causation of capacity costs because non-residential customers' maximum demands are usually coincident with system peak. The same is not true for the diverse residential customer class. Exhibit MG-4, a recent publication from the Regulatory Assistance Project ("RAP"), discusses this issue in detail, noting that among other things with respect to cost causation, "The rough accuracy that exists for using non-coincident peak (NCP) demand charges for large commercial customers is woefully inaccurate for residential customers."[14] For solar distributed generation customers, the disconnect is particularly troubling because a solar customer's non-coincident peak demand is even more likely to occur outside of peak times that drive system capacity needs. For instance, it is more likely to occur on a cooler, cloudy day or later in the evening when the solar system is not operating at full capacity.

[14] Jim Lazar, "*Use Great Caution in Design of Residential Demand Charges*" at p. 15, Attached as Exhibit MG_4

Q. WOULD A TYPICAL RESIDENTIAL CUSTOMER BE ABLE TO RELIABLY MANAGE THEIR ELECTRIC DEMAND IN ORDER TO AVOID HIGH DEMAND CHARGES?

A. No. Adapting to demand charges requires investments in advanced technology that are not feasible for a typical customer because of high cost and lack of availability. The customer would have to couple the advanced technology with significant behavioral adjustments. The behavioral adjustments are possible but difficult, and ineffective unless coupled with the right technology. Accordingly, an affluent and fairly sophisticated customer might have the resources to undertake these measures, but a **typical** customer will not have the luxury of the time, money and attention required to constantly manage their electric demand in order to avoid punitively high demand charges.

Q. PLEASE ELABORATE ON WHY IT WOULD BE DIFFICULT FOR RESIDENTIAL CUSTOMERS TO MITIGATE DEMAND CHARGES WITH BEHAVIORAL ADJUSTMENTS.

A. Managing demand requires a customer to first know and understand what demand is on a conceptual level, how their demand varies, and how each individual load within their residence contributes to that demand. Since OG&E does not currently offer even an opt-in residential demand rate, it is reasonable to conclude that the vast majority of OG&E's customers are totally unfamiliar with this type of rate design, how their energy usage patterns would affect their electricity bills under a demand rate design, and ultimately how to reliably manage their use in order to reduce demand charges.

Even assuming that customer understanding would improve over time, controlling demand under the 15-minute demand charge that OG&E proposes would require constant vigilance and control on the part of all members of a household. Demand charges can be managed by staggering the use of appliances and other household electric loads, but this is far easier said than done. It only takes one instance of lack of attention, or one instance of a compelling need to use a series of appliances at the same time, to result in a high demand charge for the entire month. For instance, a homeowner may need to cook dinner and dry clothes while children are watching television and the refrigerator and the HVAC system happen to cycle on. Many residential electric demands may indeed be flexible much of the time, but times of inflexibility frequently occur.

Q. **WHAT BARRIERS DO YOU SEE TO RELYING ON TECHNOLOGICAL SOLUTIONS TO DEMAND MANAGEMENT FOR RESIDENTIAL CUSTOMERS?**

A. While it is true that technological solutions such as smart appliances, demand controllers, and battery storage are available, the reality is they are not affordable to most customers. Simple, less expensive energy management solutions such as programmable thermostats cannot be relied upon to reduce 15-minute demand with unfailing consistency. Reliable measures such as battery storage or demand controls currently are expensive and not widely available. In practice, a typical residential customer is likely to find it extremely difficult to reliably manage a 15-minute demand charge.

Q. **YOU SAY BEHAVIORAL ADJUSTMENTS FOR THE PURPOSE OF DEMAND MANAGEMENT WOULD BE DIFFICULT FOR RESIDENTIAL CUSTOMERS, BUT WOULD THIS SAME CHALLENGE NOT APPLY TO TIME-OF-USE RATES?**

A. With time-of-use rates, the challenge is more controllable and far more intuitive. A residential customer on a time-of-use rate will indeed accrue higher charges if they are unable to shift energy use to off-peak periods. However, the effect of inflexibility under a time-of-use rate is far less sensitive to unusual or infrequent variations in use because a single instance does not set the charge for an entire month. A time-of-use charge for a month is reflective of a customer's average use during peak periods, and is not affected by past usage during the same billing period. In this respect it allows greater flexibility and provides a consistent incentive to the customer throughout a billing period to shift usage toward periods of less demand. This incentive is consistent with the cost-causation principle that TOU communicates a price signal to customers to consistently and habitually reduce or avoid electricity usage at times when system costs are high.

A demand charge, on the other hand, does not send a customer a price signal that they can consistently and habitually respond to with the effect of reducing system costs. It sets a benchmark that progressively increases throughout the month. That is, once a high demand is hit, the marginal cost of demand throughout the rest of month is zero for all demand below that point. The only incentive for energy conservation is the volumetric energy charge, which itself has been reduced by the addition of the demand rate. In other words, demand charges (and high fixed charges) violate sound rate design policy in that they fail to align with system costs, and tend to dissuade energy efficiency and conservation because they reduce the price signal communicated by volumetric rates.

Q. **ARE DEMAND CHARGES COMMON IN RESIDENTIAL RATE DESIGNS?**

A. No. Dr. Faruqui cites in Exhibit AF-2 that he has identified 18 utilities that offer residential demand rates. Of these, only 10 are investor-owned utilities. There are approximately 170 investor-owned utilities in the United States currently, and several thousand publicly-owned utilities and electric cooperatives. It is also important to emphasize that, as Dr. Faruqui to his credit notes, most of these demand rates require the customer to opt-in to the rate. Thus, not only is customer participation voluntary, the customer has to exercise an affirmative choice prior to being placed on the rate. Of the 18 examples that Dr. Faruqui cites, none are mandatory for most residential customers.

Those with any type of mandatory provision are limited to very large residential customers, and to customers with distributed generation in the case of the Salt River Project and Black Hills Power in Wyoming. In fact, in the case of Westar Energy, the demand rate is not actually available to new customers, and several of the other examples actually contain restrictions that appear to be designed to protect customers. For instance, Otter Tail Power (comprising three of the cited examples) only permits customers with a UL-approved demand controller to enroll in the rate, while Longmont Utilities and Fort Collins Utilities in Colorado limit enrollment to electric heating customers, and in the case of Longmont those with annual energy use of 15,000 kWh or more.

Q. **IS THERE EVIDENCE THAT RESIDENTIAL CUSTOMERS FIND DEMAND RATES ACCEPTABLE OR ATTRACTIVE GENERALLY?**

A. No. The optional demand rate offered by Arizona Public Service, which Dr. Faruqui cites as an example of a residential demand rate with a relatively large subscription base[15] uses a 60-minute interval and is also limited to applying between the hours of noon to 7 PM on non-holiday weekdays. Despite a design that offers somewhat more flexibility to customers, and the fact that Arizona Public Service has offered a residential demand rate since the late 1970's[16], the rate is not well-subscribed. As Dr. Faruqui notes in Exhibit AF-2, Arizona Public Service has more than 1 million residential customers, putting participation in the optional demand rate at around 10% of residential customers. As observed by one of Dr. Faruqui's colleagues at the Brattle Group, apart from the Arizona Public Service rate and one offered by Black Hills Power in South Dakota and Wyoming, enrollments in optional residential demand rates are "well below 1 percent."[17]

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[15] Direct Testimony of Ahmad Faruqui, p. 12, line 13 (December 18, 2015).
[16] Leland Snook and Meghan Grabel. "There and Back Again". *Public Utilities Fortnightly*. November 2015.
[17] Ryan Hledik. "Rediscovering Residential Demand Charges". *The Electricity Journal*. Volume 27, Issue 7, August–September 2014, p. 85.

Q. **HOW WOULD YOU CHARACTERIZE RESIDENTIAL CUSTOMERS' EXPERIENCE AND INTEREST IN MOVING TO DEMAND RATES?**

A. By and large, residential customers lack experience with demand rates because even opt-in rates are rare. But the most relevant fact here is that OG&E's residential customers have zero experience with this type of charge. While OG&E has not performed specific pricing research on customer interest, a good indicator of customer aversion to demand rates are the customers themselves. Over the past several months, it is my understanding that hundreds of Oklahomans who are either OG&E customers or customers of another utility who are likely afraid that "they are next," have submitted public comments in open dockets opposing demand charges. In addition, the lack of participation by residential customers in other jurisdictions is an indication of either a general lack of awareness, knowledge or interest.

Q. **HAVE RESIDENTIAL DEMAND CHARGES FOUND FAVOR WITH REGULATORY COMMISSIONS IN OTHER STATES?**

A. By and large, no. A number of utilities have proposed to apply demand charges to residential distributed generation customers, but thus far, I am aware of no commission that has approved the broad deployment of a mandatory three-part rate design for residential customers, and only one has approved such a change for residential distributed generation customers. That single example, Black Hills Power in Wyoming, is further distinguished by the fact that it arose only in a stipulated settlement and was not supported by any substantive testimony, cost of service analysis, or an analysis of distributed generation costs and benefits.[18] On the opposing side, the commissions in California, Idaho, and Nevada have rejected demand charges for residential distributed generation customers, and proposals have been withdrawn under settlements in Georgia,[19] Kansas,[20] Montana[21] and South Dakota.[22] Settlements eliminating similar demand charge proposals are awaiting regulatory approval in Montana and Texas.[23]

Q. **WHAT REASONS HAVE OTHER REGULATORY COMMISSIONS GIVEN FOR THE REJECTING RESIDENTIAL DEMAND CHARGES?**

A. The Idaho decision, issued in 2013 in a net metering tariff revision proceeding, rejected a proposal by the Idaho Power Company over concerns that it was inconsistent with the Idaho Energy Plan, would discourage investment in distributed generation, and was more properly considered in a general rate case. [24] The California Public Utilities Commission ("CPUC") has rejected the deployment of residential demand rates on two recent occasions. First, in its investigation of potential changes to residential rate design,

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[18] Wyoming Public Service Commission. Case No. 13788. *In The Matter Of The Application Of Black Hills Power, Inc., For A General Rate Increase Of $2,782,883 Per Annum In Its Retail Electric Service Rates.*
[19] Georgia Public Service Commission. Docket No. 36989. *Georgia Power's 2013 Rate Case.* Order Adopting Settlement Agreement. December 23, 2013.
[20] Kansas Corporation Commission. Docket No. 15-WSEE-115-RTS. *In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company to Make Certain Changes in Their Charges for Electric Service.* Order Approving Stipulation and Agreement. September 24, 2015.
[21] Montana Public Service Commission. Docket No. D2015.6.51. *In the Matter of the Application of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service in the State of Montana.* Order No. 7433f. March 25, 2016.
[22] South Dakota Public Utilities Commission. Docket No. EL14-026. *In the Matter of the Application of Black Hills Power, Inc. for Authority Increase its Electric Rates.* Black Hills withdrew its residential distributed generation demand charge proposal in a revised filing dated April 11, 2014.
[23] Public Utilities Commission of Texas. Case No. 44941. *Application of the El Paso Electric Company to Change Rates.* Settlement Stipulation and Joint Motion. Filed March 29, 2016.
[24] Idaho Public Utilities Commission. Case No. IPC-E-12-27. *In the Matter of Idaho Power Company's Application for Authority to Modify its Net Metering Service and Increase the Generation Capacity Limit.* Order No. 32846. July 3, 2013.

it declined to allow San Diego Gas & Electric to develop a pilot residential demand rate due to concerns over customer understanding and acceptance.[25] The CPUC then rejected demand rate proposals from two utilities (Pacific Gas & Electric and San Diego Gas & Electric) in its net metering successor tariff proceeding, finding that residential DG customers would understand demand charges no better than the residential class as a whole. [26]

Finally, in 2015 the Public Utilities Commission of Nevada ("PUCN") declined to adopt demand rates for residential distributed generation customers, finding that the level of customer acceptance of such a design is unknown and that implementing a demand rate for these customers would require additional ratepayer education.[27]

Q. **IS THERE ANY EVIDENCE THAT DISTRIBUTED GENERATION CUSTOMERS ARE MORE EQUIPPED TO MANAGE ELECTRIC DEMAND THAN THE AVERAGE RESIDENTIAL CUSTOMER?**

A. I am not aware of any study or evidence to this effect, nor apparently is the CPUC despite its multi-year investigation into residential rate design. OG&E has certainly not provided any evidence for consideration in this proceeding. There is a dearth of information on residential customer response to demand rates generally, let alone any

[25] California Public Utilities Commission. Docket No. R.12-06-013. *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*. D.15-07-001. July 13, 2015.

[26] California Public Utilities Commission. Docket No. R.14-07-002. *Order Instituting Rulemaking to Develop a Successor to Existing Net Energy Metering Tariffs Pursuant to Public Utilities Code Section 2827.1, and to Address Other Issues Related to Net Energy Metering.* D.16-01-044. February 5, 2016.

[27] Nevada Public Utilities Commission. Docket No. 15-07041. *Application of Nevada Power Company d/b/a NV Energy for Approval of a Cost of Service Study and Net Metering Tariffs*. Modified Final Order. February 17, 2016. This order also covers a similar application by Sierra Pacific Power in Docket No. 15-07042.

that address distributed generation customers. Dr. Faruqui cites only four such general studies, one from Norway and three others that date from the 1980's.[28] Notably, he does not cite any statistics from these studies or how they are relevant to OG&E's proposal.

Q. DO YOU HAVE ANY RECOMMENDATIONS FOR THE COMMISSION REGARDING OG&E'S RESIDENTIAL DEMAND RATE PROPOSAL?

A. I recommend that the Commission reject the imposition of a default demand rate for residential customers.

V. B. <u>RESIDENTIAL CUSTOMER CHARGE INCREASE</u>

Q: WHAT INCREASE TO THE RESIDENTIAL CUSTOMER CHARGE IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A: The Company is proposing to more than double the monthly fixed charge from $13.00 to $26.54, across all residential schedules.[29]

Q. HOW WOULD THIS CUSTOMER CHARGE COMPARE TO THOSE AUTHORIZED FOR OTHER UTILITIES THROUGHOUT THE COUNTRY?

A. OG&E's proposed charge would be the highest customer charge in the more than 100 investor-owned utilities whose tariffs I reviewed.

[28] Direct Testimony of Ahmad Faruqui, p. 10-11, line 25 on p. 10 to line 5 on p. 11.
[29] Wai Direct, p. 9, Table 1.

Q: WHAT TYPES OF COSTS ARE ORDINARILY INCLUDED IN A MONTHLY CUSTOMER CHARGE OF THIS SORT?

A: Typically, customer charges such as this are intended to collect only costs that vary with the number of customers, rather than costs driven by the volume of electricity consumed.

Q: WHAT TYPES OF COSTS DOES THE COMPANY SEEK TO RECOVER WITH THIS SUBSTANTIALLY LARGER MONTHLY CUSTOMER CHARGE?

A: According to Company Witness Scott, the Company believes the customer charge "should recover metering costs, local distribution facilities, and customer billing and care costs."[30] When asked what is included in the category of "local distribution facilities," as used by Mr. Scott in TASC DR 5-3, the Company responded by attaching a single page from the NARUC manual which states that FERC accounts 369 (Services), 370 (Meters), 371 (Installations on Customer Premises), and 373 (Street Lighting and Signal Systems) are classified as "customer-related" costs.

However, the sentence that is cut off at the top of the excerpted page discusses how these are the non-controversial categories. As the manual notes, the classification of the accounts listed directly above is not as controversial as the classification of some costs as customer-related costs (allocated based on the number of customers) rather than demand-related costs (allocated on the basis of customer demand):

> The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts [e.g., 369, 370, 371, 373] is an important step,

[30] Direct Testimony of Bryan J. Scott at p.4 lines 24-25.

it is not as controversial as the classification of substations, poles, transformers, and conductors."[31]

Q: WHAT "LOCAL DISTRIBUTION COSTS" DOES THE COMPANY CLAIM TO BE "CUSTOMER-RELATED DISTRIBUTION COSTS" THAT VARY WITH THE NUMBER OF CUSTOMERS?

A: Company Witness Smith states that "[c]ustomer-related distribution costs are limited to the costs that vary directly with the number of customers (except for meters and lighting costs which are directly assigned)" and that "[t]hese costs include poles, conductors, underground conduit, service drops, transformers, and associated expenses."[32]

Q: DO YOU AGREE THAT THESE COSTS VARY WITH THE NUMBER OF CUSTOMERS RATHER THAN WITH THE AMOUNT OF ELECTRICITY USED BY CUSTOMERS?

A: No. While costs such as service drops are customer-specific, it does not follow that conductors and transformers vary with the number of customers. Outside of dedicated transformers, line transformers are often shared and evaluated on the anticipated demand of customers using those assets, including consideration of customer diversity. According to the NARUC manual including these costs can be controversial.[33] Continually expanding the category of items that are recoverable in the fixed customer charge serves the utility's desire to increase the certainty of cost recovery.

[31] *Electric Utility Cost Allocation Manual* (NARUC), January 1992, *available at pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD.* (Excerpt attached as Exhibit MG-5).
[32] Direct Testimony of David Smith at p. 16, lines 17 through 22 (December 18, 2015).
[33] *See* Exhibit MG_5.

In Order No. 564437 in Cause No. PUD 200800144, the Commission approved Public Service Company of Oklahoma's ("PSO") request to continue to collect distribution costs on a demand basis. As PSO noted in that case, it "used a demand-only allocator for distribution costs in Accounts 364-368 because the distribution system poles, wires, and conduit contained in those accounts are sized to meet the maximum load demand imposed on the system and the cost of those facilities does not vary directly with the number of customers, unlike distribution costs such as service drops and meters, which are allocated based on the number of customers."[34] OG&E's position on inclusion of these costs in the customer charge is unorthodox in Oklahoma.

Q: DOES THE COMPANY'S TESTIMONY EXPLAIN WHETHER IT IS USING A MINIMUM-SYSTEM APPROACH OR A ZERO-INTERCEPT APPROACH?

A: Yes. Company Witness Smith states that FERC accounts 364-368 "are considered both demand and customer related and are classified based on the zero-intercept methodology as supported by the NARUC Cost Allocation Manual."[35] He further states that "[t]his zero-intercept methodology was approved in Cause No. PUD 200800398 and is consistent with the OG&E's previous rate case."[36]

Q: DID THE COMMISSION'S ORDER IN THAT CAUSE SPECIFICALLY ADDRESS WHETHER THE COMPANY HAD PROPERLY USED THE ZERO-INTERCEPT METHOD TO CLASSIFY CUSTOMER-RELATED COSTS?

[34] Order No. 564437 at p. 34.
[35] Direct Testimony of David Smith at pp. 15-16.
[36] *Id.* at p. 16, lines 2-3.

A: No. The Commission approved a settlement stipulation and did not address the merits of the zero-intercept method directly.

Q: DID THE CUSTOMER CHARGE APPROVED IN CAUSE NO. 2008-00398 RECOVER ALL CUSTOMER-RELATED COSTS THE COMPANY DETERMINED USING THE ZERO-INTERCEPT METHOD?

A: No. The amount of the customer charge approved in the last case was based on a settlement stipulation. The settlement stipulation adopts OG&E's cost of service and allocation methodologies, but does not specifically address whether it properly applied the zero-intercept method to classify certain distribution costs as customer-related.[37] The Commission has not directly addressed whether it is appropriate to incorporate these wires, poles, conduit, transformer and conductor costs as a customer-related cost. This remains an area of controversy and OG&E's proposal to double its customer charge rests on the supposition that the Commission has accepted the inclusion of these types of demand-related costs in a customer-related classification. Clearly, there is no consensus, either in Oklahoma or nationally, in what elements of the distribution system should be classified as customer costs (i.e., those that vary with the number of customers).

Q: DOES INCREASING RECOVERY OF FIXED COSTS, BEYOND THOSE THAT ARE CLEARLY "CUSTOMER-RELATED" COSTS THROUGH A FIXED CHARGE ENCOURAGE CUSTOMERS TO REDUCE ELECTRICITY CONSUMPTION?

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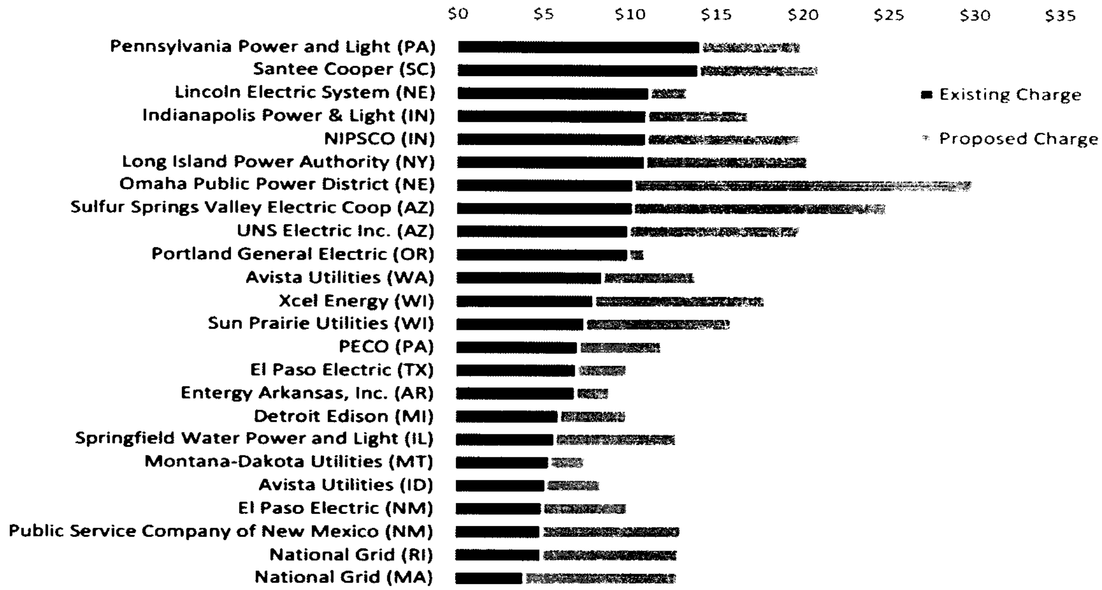
[37] *Joint Stipulation and Settlement Agreement*, Cause No. PUD 2008-00398 (filed July 2, 2009).

A: No, it does the opposite. Increasing the share of fixed costs recovered through a fixed charge means that the share of fixed costs recovered through the energy charge is reduced. This muffles the price signal in volumetric rates that encourages customers to consume less electricity, or to self-generate electricity in lieu of purchasing the next unit from the grid. Thus, increasing reliance on fixed charges to recover fixed costs runs counter to important policy considerations of encouraging customer behaviors that help reduce consumption of electricity and, ultimately, help lessen long-run system costs by reducing the investments needed to provide service to all customers. Regardless of whether the rate structure is flat, tiered, or time-variant, increasing the share of recovery of fixed costs through a fixed customer charge reduces the ability of the energy rate to effectively communicate to customers to reduce their overall (or time-specific) electricity consumption.

Q: IS THERE A GENERAL TREND IN THE UTILITY INDUSTRY TO TRY TO INCREASE RELIANCE ON FIXED MONTHLY CHARGES TO RECOVER FIXED COSTS?

A: Yes, as Figure 1 below, illustrates, a large number of utilities have sought substantial increases to their residential monthly fixed charge in the past two years.

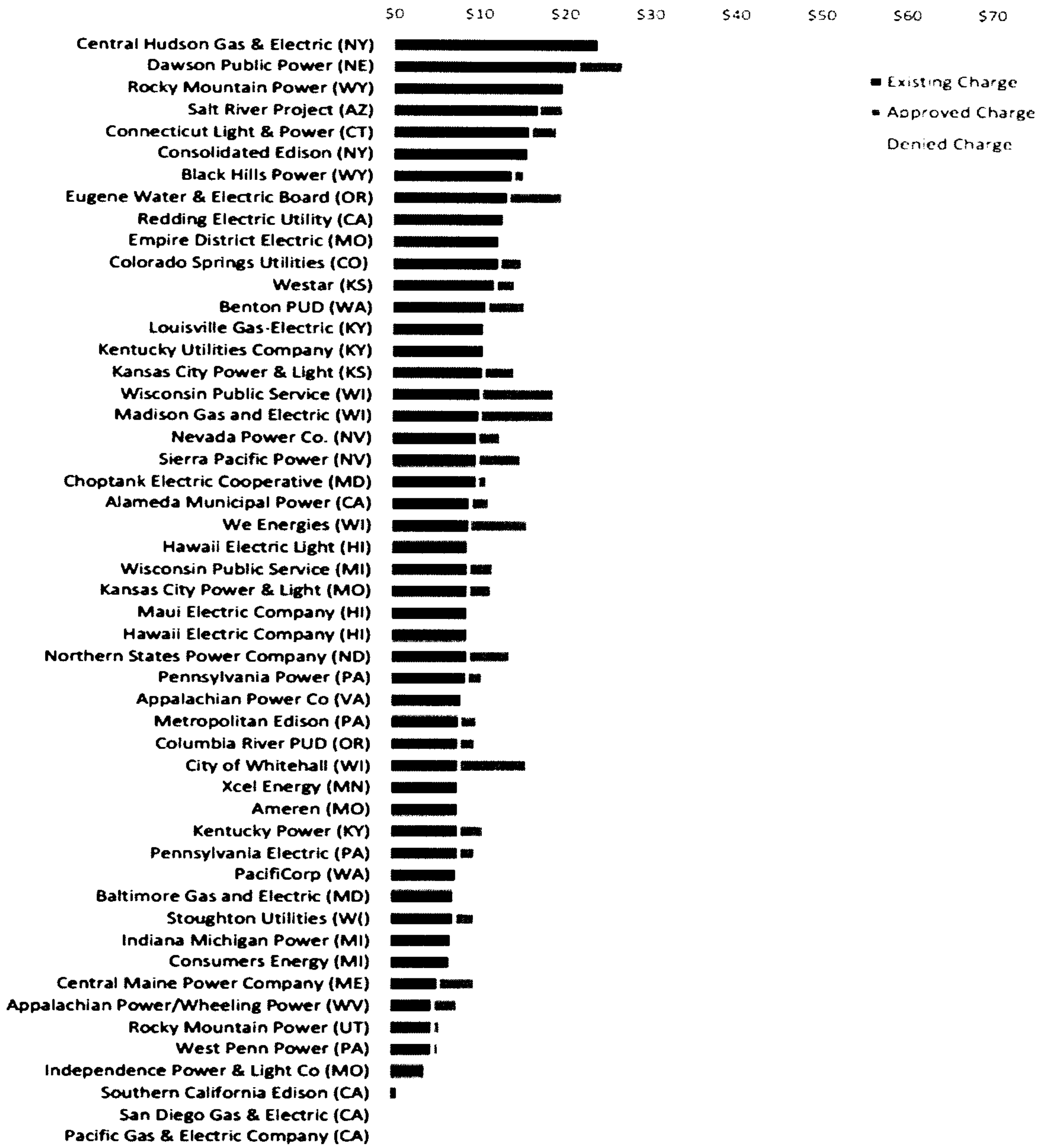
Figure 1. Synapse Report (p.10): Pending proposals for fixed charge increases.



Q: HOW ARE REGULATORS ADDRESSING THESE REQUEST TO DRAMATICALLY INCREASE FIXED MONTHLY CHARGES?

A: Regulators have repeatedly denied or reduced fixed charge increases.

Figure 2. Synapse Report (p.11): Recent decisions regarding fixed charge proposals.



Notably, the National Association of State Utility Consumer Advocates adopted a resolution last summer opposing the increased reliance on customer charges to collect a greater portion of utility fixed costs through this unavoidable charge.[38]

Q: DO YOU HAVE A RECOMMENDATION FOR THE COMMISSION REGARDING THE COMPANY'S PROPOSAL TO DOUBLE THE RESIDENTIAL CUSTOMER FIXED CHARGE?

A: Yes. I recommend that the Commission adhere to the status quo level of the fixed charge, as the Company has not demonstrated the need to increase reliance on fixed charges to adequately recover its fixed costs. Absent a compelling justification for that substantial shift in policy, I would recommend that the Commission err on the side of continuity and maintain the same proportionality of the current fixed customer charge as a percentage of overall costs. The Commission should also ensure that only customer-related costs are being classified in this manner (and collected in this manner), to prevent the gradual creep toward fixed charges for larger and larger portions of the distribution system.

VI. CLASS COST OF SERVICE STUDY AND RESIDENTIAL DG LOAD STUDY

Q: THE "MASTER CHECKLIST" INCLUDES A SUBCATEGORY FOR "SEPARATE CLASS FOR DISTRIBUTED GENERATION (DG) CUSTOMERS." DID THE COMPANY'S CLASS COST OF SERVICE STUDY TREAT DISTRIBUTED GENERATION CUSTOMERS AS THEIR OWN CLASS?

[38] The National Association of State Utility Consumer Advocates Resolution 2015-1, Attached as Exhibit MG_6.

A: Yes. The COSS creates a separate "Residential-DG" class and a "General Service-DG" class for purposes of the analysis.

Q: DOES THE COMPANY'S CLASS COST OF SERVICE STUDY REVEAL ANY INFORMATION RELEVANT TO THE CONSIDERATION OF WHETHER A SEPARATE CHARGE OR RATE IS JUSTIFIED?

A: Yes. The COSS reveals that residential DG customers, on a unit basis, are less costly to serve than other residential customers. Table 2 compiles the unit cost analyses in Schedule L-8.1, 8.2 and 8.3 to give a comparative look at the unit costs associated with the various residential schedules.

Table 2. Comparative Residential Unit Cost Per Customer/Month[39]

	Res-DG	Res-Std	Res-TOU	Res-VPP	Res-CPP
Customer Component	$24.54	$28.64	$26.07	$27.20	$24.57
Energy Component	$0.35	$0.37	$0.45	$0.42	$0.39
Demand-Production	$17.65	$35.19	$38.17	$26.44	$29.71
Demand-Transmission	$5.20	$9.78	$10.69	$7.60	$8.40
Demand-Distribution	$11.03	$13.08	$13.19	$14.37	$11.89
Total	$58.77	$87.06	$88.57	$76.03	$74.96

Q: WHAT APPEARS TO DRIVE THE SIGNIFICANTLY LOWER UNIT COSTS FOR RESIDENTIAL DG CUSTOMERS?

[39] Derived from W/P L-8.1 – 8.3.

A: The categories where Residential DG is significantly less expensive on a unit basis are those where costs are allocated to the class based on the 4 CP allocators (i.e., production and transmission demand). This suggests that the residential customers with DG have significantly smaller contributions to system peaks than other residential customers.

Looking to W/P Schedule L-13, at page 10, Residential DG's percentage share of total residential class contribution to system peak demand is significantly lower in the months from June to September than its percentage share of contribution to system peak demand for the other months. In fact, Residential DG cuts its averaged share of the residential contribution to system peak in half in the 4 CP months when compared to the average over the non-4 CP months.

Table 3. Residential DG Share of Residential Contribution to Peak in Test Year.[40]

	Res-DG	Res-Std	Res-TOU	Res-VPP	Res-CPP
Avg. Share of Residential Contribution to System Peak Demand (Oct.-May)	0.036%	83.198%	0.569%	16.075%	0.123%
Avg. Share of Residential Contribution to System Peak Demand (June-Sept.)	0.018%	86.986%	0.573%	12.308%	0.114%

Q: IS THE FACT THAT RESIDENTIAL DG CUSTOMERS CONTRIBUTE LESS TO SYSTEM PEAK RELEVANT FOR CONSIDERATION OF THE CHECKLIST?

A: Yes, the purpose of the checklist was to give the Commission sufficient information to determine the threshold question of whether a subsidy is occurring **within** the residential

[40] Derived from W/P Schedule L-13.

class. The fact that residential DG customers are significantly less costly to serve, when analyzed as a separate class, is an important indicator that they are creating system benefits. Thus, the Staff and stakeholders had considerable foresight in requiring a COSS that looks at residential DG as a separate class, as that information has proven to be quite revealing.

Q: DOES THE FACT THAT RESIDENTIAL DG CUSTOMERS ARE LESS COSTLY TO SERVE REQUIRE THEM TO BE TREATED AS A SEPARATE CLASS FOR RATEMAKING PURPOSES?

A: No. The Master Checklist called for a COSS to look at the cost to serve residential DG as a separate class as an analytical exercise to determine if a subsidy is occurring in favor of DG customers at the expense of the general body of residential ratepayers. Neither S.B. 1456 nor the Master Checklist presupposes or suggests that residential DG customers should be a separate class.

Q: WOULD THE CURRENT R-TOU CLASS BENEFIT FROM RETAINING DG CUSTOMERS ON THAT SCHEDULE?

A: Yes. Because Residential DG customers have a lower contribution to the 4 CPs than all other residential schedules, it would follow that they would help lower the contributions to system peak for R-TOU customers if they remained on that schedule.

Q: DOES THE COMPANY PROVIDE ANY JUSTIFICATION FOR TREATING RESIDENTIAL DG CUSTOMERS AS A SEPARATE CLASS FOR RATEMAKING PURPOSES?

A: No. Although the new COSS presents vital new information about residential DG customers, the Company's testimony lacks discussion of the impact of the COSS results for the Residential DG class on the legal requirements of S.B. 1456. Given the fact that the Commission has yet to approve the Company's proposal in Cause No. 2015-00274, this lack of discussion is perplexing, and perhaps indicates the Company did not want to focus attention on the fact that its COSS shows DG customers actually subsidize other residential customers.

Q: WHAT IS THE RELEVANCE OF THE CLASS COST OF SERVICE STUDY RESULTS FOR THE RESIDENTIAL DG CLASS TO THE LEGAL REQUIREMENTS OF S.B. 1456?

A: First, the COSS shows that Residential DG customers are not being subsidized. Instead, they are providing a subsidy to other residential customers, as they provide the highest rate of return on rate base of all of the residential classes. Second, the results of OG&E's COSS demonstrate that the Company's effort in Cause No. PUD 2015-00274, using an outdated COSS, was wholly inadequate to demonstrate that DG customers are subsidized. With the knowledge that residential DG customers are providing substantial peak reduction benefits to the grid — and to other customers in the class by reducing allocations to the class—the results of the current COSS suggest that residential DG customers are actually paying in excess of their cost of service. In Cause No. PUD 2015-00274, it would have been impossible for the Company to provide this picture, as they lacked load data on residential DG customers.[41]

Q: DID THE COMPANY HAVE A LOAD STUDY IN SUPPORT OF ITS CLASS COST OF SERVICE STUDY?

A: Yes. In response to TASC Data Request 6-2, the Company provided an explanation of this study and provided a spreadsheet showing the 8760 data for the Residential DG class and General Service-DG class.

Q: PLEASE GENERALLY DESCRIBE THE APPROACH THE COMPANY TOOK TO CREATE A DG LOAD PROFILE.

A: As described by the Company in its response to TASC DR 6-2, the Company started with the mean-per-unit ("MPU") load shape and then performed several adjustments to end up with a net profile. To account for the fact that residential net metering customers are capable of both receiving and supplying kWh over the course of a 60-minute period, the Company created a calculation that nets the "net flowing in" and the "net flowing out" over that period. However, the Company states that if the outflow in an hour exceeds the inflow, the negative reading would be changed to zero.[42]

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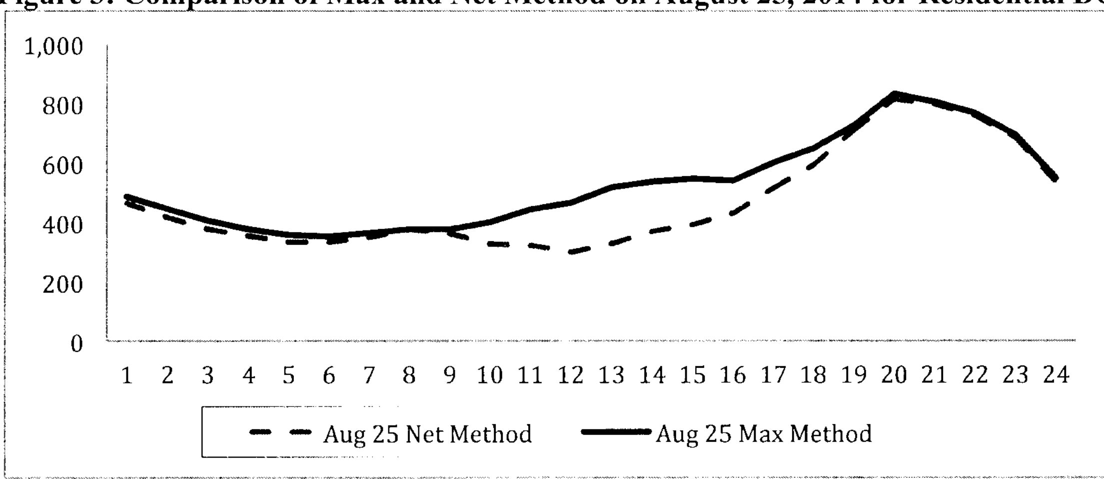
[41] Transcript of Proceedings in Cause No. PUD No. 2015-00274, December 2, 2015, RDH 10

[42] *See* TASC Data Request to OG&E 6-2 (Response Provided by Bryan Scott on March 22, 2016), attached as Exhibit MG-7.

Q: DO YOU AGREE WITH THE COMPANY THAT IT IS PROPER TO SUBTRACT THE "NET FLOWING OUT" FROM THE "NET FLOWING IN" TO DETERMINE THE FINAL MPU LOAD SHAPE FOR DG CUSTOMERS?

A: Yes. It is reasonable to treat electricity that is exported by a customer as a load reduction in the measured period. A customer's electricity export is consumed by nearby load and represents a quantity of electricity that the Company was not called upon to generate and is rightly assigned to DG customers. The net load method reflects capacity value over the hour period, so it is appropriate to count "net flowing out" as reducing the load profile of the residential customer. Figure 3 shows the impact of the net load method.

Figure 3: Comparison of Max and Net Method on August 25, 2014 for Residential DG.[43]



As shown in Figure 3, the "Net" method recognizes DG customers' reduction of contribution to system peak. With the Company's system peak demand occurring during the test year on August 25, 2014 at 1600 hours, the dotted line shows an approximate

[43] Derived from data in TASC 6-2_Att.

20% reduction from what the residential DG customers' demand would have been at coincident peak under the Max Method (solid line). It is important to note that even with the Max method, a customer is likely consuming onsite solar behind the meter, significantly reducing load at times of system peak. Accordingly, the net method is an appropriate means of reflecting the fact that exports to the grid have value and help to offset the transmission and production costs allocated by 4 CP.

Q: DO YOU AGREE THAT IT IS PROPER TO REPLACE ANY NEGATIVE NET FLOW IN ANY HOUR WITH A ZERO?

A: No. This suggests that any capacity value the Company is recognizing for exported kWh is being limited arbitrarily and that some portion (potentially large) of customer generation is being ignored and not valued. Even if it were proper to assign a zero for load research purposes, the ability of exported electricity to reduce demand on the grid is a benefit that should be quantified and carefully considered when determining whether subsidization is occurring. While typical customer demand can never be below zero, this framing ignores the benefit of solar exports to the grid. The load research for DG, in this regard, does not give a full picture of the benefit of all exported electricity to the grid, including the ability of those exports to reduce line losses for electricity delivered to other nearby customers.

Q: DOES THE DG LOAD STUDY SUGGEST THAT DG CUSTOMERS ARE HELPING REDUCE PEAK DEMAND BY REDUCING CUSTOMER CONTRIBUTION TO PEAKS AT TIMES OF SYSTEM PEAK?

A: Yes. For four of the highest demand months (June, July, August, September), the system peak occurs at 1600 hours, a time where solar production is still quite significant. Using the average production profile for the months of June through September from the publicly available tool PV Watts, it appears that solar would likely be contributing an average range of 20 to 50% of its highest hourly output at the times of system peak.

Table 4. Average Solar Production Profile for a 5 kW PV System in Oklahoma City Using Standard Assumptions on NREL's PV Watt Production.[44]

hour	June	July	August	September
5	0.04	0.02	0.00	0.00
6	0.27	0.19	0.13	0.07
7	0.88	0.81	0.70	0.57
8	1.60	1.57	1.52	1.37
9	2.23	2.20	2.22	2.03
10	2.65	2.75	2.70	2.49
11	3.04	2.94	2.91	2.81
12	3.14	3.11	3.12	2.89
13	2.95	3.11	3.02	2.80
14	2.69	2.77	2.70	2.43
15	2.26	2.34	2.27	1.90
16	1.60	1.77	1.58	1.25
17	0.87	0.98	0.81	0.47
18	0.28	0.29	0.17	0.05
19	0.04	0.04	0.01	0.00

Thus, solar is providing significant peak reduction, regardless of whether solar peak output is perfectly correlated with system peak. This is just one example of the types of

[44] Data derived from PV Watts, the solar free online solar calculation tool published by the National Renewable Energy Laboratory, *available at* http://pvwatts.nrel.gov/. The average solar production profile for August was based on a 5 kW fixed PV system using default inputs on tilt and azimuth.

benefits that the Company's application should have explored in reference to the Master Checklist.

Q: WITH THE COST OF SERVICE STUDY SHOWING THAT THERE IS NO SUBSIDIZATION OCCURING, AND WITH S.B. 1456 BARRING AN ADDITIONAL FEE OR SUCHARGE, SHOULD THE COMPANY STILL BE REQUIRED TO FULFILL THE MASTER CHECKLIST?

A: Yes. Even if the Company withdraws its DG proposals from this case, it is important to understand and capture the cost saving benefits that customer-side DG can create. If the Company ignores the benefits created by customer's own private investment, then it might also ignore other cost saving opportunities, particularly where it relates to opportunities to defer or avoid distribution, transmission or generation capacity. The Company's COSS suggests that it is in ratepayers' interests for DG customers to be encouraged to make investments in these beneficial technologies. Keeping DG customers within the classes they belong, and not segregating and punishing them with draconian rate designs, will produce savings that spread among other customers in the class, and across the system as a whole.

VII. CONCLUSION

Q: DOES THIS CONCLUDE Y OUR TESTIMONY?

A: Yes, it does.

Exhibit MG_1

EXHIBIT MG-1

MARK E. GARRETT

CONTACT INFORMATION:

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EDUCATION:

Juris Doctor Degree, With Honors, Oklahoma City University Law School, 1997
Post Graduate Hours in Accounting, Finance and Economics, 1984-85:
University of Texas at Arlington; University of Texas at Pan American; Stephen F. Austin State University
Bachelor of Arts Degree, University of Oklahoma, 1978

CREDENTIALS:

Member Oklahoma Bar Association, 1997, License No. 017629
Certified Public Accountant in Oklahoma, 1992, Certificate No. 11707-R
Certified Public Accountant in Texas, 1986, Certificate No. 48514

WORK HISTORY:

GARRETT GROUP, LLC - REGULATORY CONSULTING PRACTICE (1996 - Present) Participates as a consultant and expert witness in electric utility, natural gas distribution company, and natural gas pipeline matters before regulatory agencies making recommendations related to cost-based rates. Reviews management decisions of regulated utility companies for reasonableness from a ratemaking perspective especially regarding the reasonableness of prices paid for natural gas supplies and transportation, coal supplies and transportation, purchased power and renewable energy projects. Participates in gas gathering, gas transportation, gas contract and royalty valuation disputes to determine pricing and damage calculations and to make recommendations concerning the reasonableness of charges to royalty and working interest owners and other interested parties. Participates in regulatory proceedings to restructure the electric and natural gas utility industries. Participates as an Instructor at NMSU Center for Public Utilities and as a Speaker at NARUC Staff Subcommittee on Accounting and Finance.

OKLAHOMA CORPORATION COMMISSION - Coordinator of Accounting and Financial Analysis (1991 - 1994) Planned and supervised the audits of major public utility companies doing business Oklahoma for the purpose of determining revenue requirements. Presented both oral and written testimony as an expert witness for Staff in defense of numerous accounting and financial recommendations related to cost-of-service based rates. Audit work and testimony covered all areas of rate base and operating expense. Supervised, trained and reviewed the audit work of numerous Staff CPAs and auditors. Promoted from Supervisor of Audits to Coordinator in 1992.

FREEDOM FINANCIAL CORPORATION - Controller (1987 - 1990) Responsible for all financial reporting including monthly and annual financial statements, cash flow statements, budget reports, long-term financial planning, tax planning and personnel development. Managed the General Ledger and Accounts Payable departments and supervised a staff of seven CPAs and accountants. Reviewed all subsidiary state and federal tax returns and facilitated the annual independent financial audit and all state or federal tax audits. Received promotion from Assistant Controller in September 1988.

SHELBY, RUCKSDASHEL & JONES, CPAs - Auditor (1986 - 1987) Audited the financial statements of businesses in the state of Texas, with an emphasis in financial institutions.

Previous Experience Related to Cost-of-Service, Rate Design, Pricing and Energy-Related Issues

1. **Texas Gas Service, 2016 (Docket No. 10488)** – Participating as an expert witness on behalf of South Jefferson County Service Area ("SJCSA") before the Texas Railroad Commission in TGS's General Rate Case application, sponsoring testimony to address the utility's overall revenue requirement and various rate design proposals.

2. **Oklahoma Gas and Electric Company, 2016 (Cause No. PUD 201500273)** – Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC") and Oklahoma Energy Results, LLC ("OER") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring testimony to address the utility's overall revenue requirement and rate design proposals.

3. **Oklahoma Gas and Electric Company, 2016 (Cause No. PUD 201500273)** – Participating as an expert witness on behalf of The Alliance for Solar Choice ("TASC") before the Oklahoma Corporation Commission in OG&E's General Rate Case application. Sponsoring rate design testimony to address the utility's proposed new rates for distributed generation customers.

4. **Anchorage Municipal Light and Power, 2016 (Docket No. U-13-097)** – Participating as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on rates and tariffs proposed for customer-owned combined heat and power plant generation.

5. **Oklahoma Natural Gas Company, 2015 (Cause No. PUD 201500213)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission in ONG's General Rate Case application. Sponsored testimony to address the utility's overall revenue requirement and rate design proposals.

6. **Oklahoma Gas & Electric Company, 2015 (Cause No. PUD 201500274)** – Participated as an expert witness on behalf of The Alliance for Solar Choice ("TASC") before the Oklahoma Corporation Commission to address OG&E's proposed Distributed Generation ("DG") rates for solar DG customers.

7. **Nevada Power Company, 2015** (Docket No. 15-07004) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG")[1] before the Nevada PUC. Sponsoring written and oral testimony in NPC's 2015 Integrated Resource Plan to provide analysis of the On Line transmission line allocation, the Siverhawk plant acquisition, and the Griffith contract termination.

8. **Oklahoma Gas & Electric Company, 2015 (Docket No. 15-034-U)** – Participated as an expert witness on behalf of the Arkansas River Valley Energy Consumers ("ARVEC")[2] before the Arkansas Public Service Commission in OG&E's Act 310 application to implement a rider to recover environmental compliance costs.

9. **MGM Resorts, LLC, 2015** (Docket No. 15-05017) – Participating as an expert witness on behalf of the MGM Resorts, LLC before the Nevada PUC. Sponsoring written and oral testimony in MGM's application to purchase energy and capacity from a provider other than Nevada Power.

[1] The Southern Nevada Hotel Group is comprised of Boyd Gaming, Caesars Entertainment, MGM Resorts, Station Casinos, Venetian Casino Resort, and Wynn Las Vegas.
[2] ARVEC is an association of industrial manufacturing facilities in northwest Arkansas.

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10. **Entergy Arkansas, 2015 (Docket No. 15-015-U)** – Participating as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

11. **Public Service Company of Oklahoma, 2015 (Cause No. PUD 201500208)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

12. **Nevada Power Company, 2014** (Docket No. 14-05003) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored written and oral testimony in NPC environmental compliance case, called the Emissions Reduction and Capacity Replacement case. The main focus of our testimony was our recommendation to eliminate the $438M Moapa solar project from the compliance plan.

13. **Nevada Power Company, 2014** (Docket No. 14-05004) – Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC to sponsor written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

14. **Oklahoma Gas and Electric Co., 2014 (Cause No. PUD 201400229)** – Participating as an expert witness on behalf of Oklahoma Industrial Energy Consumers ("OIEC")[3] in OG&E's Environmental Compliance and Mustang Modernization Plan before the Oklahoma Corporation Commission to provide testimony addressing the economics and rate impacts of the plan.

15. **Sourcegas Arkansas, Inc., 2014 (Docket No. 13-079-U)** Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG"), an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in SGA's general rate case to provide testimony on various revenue requirement issues.

16. **Anchorage Municipal Light and Power, 2014 (Docket No. U-13-184)** – Participating as an expert witness before the Alaska Regulatory Utility Commission on behalf of Providence Health and Services to provide testimony on various revenue requirement and cost of service issues.

17. **Public Service Company of Oklahoma, 2014 (Cause No. PUD 201300217)** – Participating as an expert witness on behalf of OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

18. **Entergy Texas Inc., 2013 (PUC Docket No. 41791)** – Participating as an expert witness on behalf of the Cities[4] in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

19. **MidAmerican/NV Energy Merger, 2013 (Docket No. 13-07021)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored testimony to address various issues raised in the proposed acquisition of NV Energy by MidAmerican

[3] OIEC is an association of approximately 25 large commercial and industrial customers in Oklahoma.
[4] The Cities include Beaumont, Conroe, Groves, Houston, Huntsville, Orange, Navasota, Nederland, Pine Forest, Pinehurst, Port Arthur, Port Neches, Rose City, Shenandoah, Silsbee, Sour Lake, Vidor, and West Orange.

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Energy Holdings Company, including capital structure and acquisition premium recovery issues.

20. **Entergy Arkansas, 2013 (Docket No. 13-028-U)** – Participated as an expert witness on behalf of the Hospital and Higher Education Group ("HHEG") an intervener group that includes the University of Arkansas and several hospitals before the Arkansas PSC in Entergy's general rate case to provide testimony on various revenue requirement issues.

21. **Sierra Pacific Power Company, 2013 (Docket No. 13-06002)** – Participated as an expert witness on behalf of the Northern Nevada Utility Customers[5] before the Nevada PUC in SPPC's general rate case proceeding to provide testimony on various cost of service and revenue requirement issues. Sponsored written and oral testimony in the depreciation phase, the revenue requirement phase and the rate design phase of these proceedings.

22. **Gulf Power Company, 2013 (Docket No. 130140-EI)** – Participated as an expert witness on behalf of the Office of Public Counsel before the Florida Commission in Gulf Power's general rate case proceeding to provide testimony on various revenue requirement issues.

23. **Public Service Company of Oklahoma, 2013 (Cause No. PUD 201200054)** – Participating as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission ("OCC") to provide testimony in PSO's application seeking Commission approval of its settlement agreement with EPA.

24. **Southwestern Electric Power Company, 2012 (PUC Docket No. 40443)** – Participated as an expert witness on behalf of Cities Advocating Reasonable Deregulation ("CARD Cities") before the Texas Public Utility Commission in SWEPCO's general rate case proceeding to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

25. **Doyon Utilities, 2012 Alaska Rate Case** (Docket No. TA7-717) – Participated as an expert witness consultant on behalf of the Department of Defense to provide expert testimony in twelve rate case reviews for the utility systems of Fort Wainwright, Fort Greely and Joint Base Elmendorf-Richardson before the Regulatory Commission of Alaska.

26. **University of Oklahoma, 2012** – Participated as an expert witness on behalf of the University of Oklahoma to provide expert testimony on various revenue requirement issues in the University's general rate case with the Corix Group, which provides utility services to the University.

27. **Public Service Company of Oklahoma, 2012 (Cause No. PUD 201200079)** – Participated as an expert witness on behalf of the OIEC before the Oklahoma Corporation Commission to provide expert testimony addressing the utility's request to earn additional compensation on a 510MW purchased power agreement with Exelon

28. **Centerpoint Energy Texas Gas, 2012 (Docket No.** GUD 10182) – Participated as an expert witness on behalf of the Steering Committee of Cities before the Texas Railroad Commission to provide expert testimony on various revenue requirement issues.

29. **Entergy Texas Inc., 2012 (PUC Docket No. 39896)** – Participated as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

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[5] The Northern Nevada Utility Consumers is a group of large commercial and industrial customers in the SPPC service territory.

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30. **Oklahoma Natural Gas Company, 2012 (Cause No. PUD 2012-029)** – Participating as an expert witness on behalf of the OIEC before the OCC in ONG's Performance Based Rate ("PBR") application seeking Commission approval of a requested rate increase based upon formula results for 2011.

31. **University of Oklahoma, 2012** – Assisted the University of Oklahoma with an audit of the costs associated with its six utility operations and its contract with the Corix Group to provide utility services to the university.

32. **Oklahoma Gas and Electric Company, 2012 (Cause No. PUD 2011-186)** – Participating as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking Commission approval of a special contract with Oklahoma State University and a wind energy purchase agreement in connection therewith.

33. **Empire Electric Company, 2011, (Cause No. PUD 11-082)** – Participated as an expert witness on behalf of Enbridge before the OCC in Empire's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

34. **Nevada Power Company, 2011, (Docket No. 11-04010)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC. Sponsored written and oral testimony to address proposed changes to the Company's customer deposit rules.

35. **Nevada Power Company, 2011, (Docket No. 11-06006)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

36. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2011-106)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking rider recovery of third party SPP transmission costs and fees.

37. **Oklahoma Gas and Electric Company, 2011 (Cause No. PUD 2011-087) –** Participating as an expert witness on behalf of OIEC before the OCC in OG&E's rate case to provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

38. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-109-U)** – Participated as an expert witness on behalf of Gerdau Macsteel before the Arkansas Public Service Commission in OG&E's application to recover Smart Grid costs to make recommendations regarding the allocation of the Smart Grid costs.

39. **Oklahoma Gas & Electric Company, 2011 (Cause No. PUD 2011-027)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking to include retire medical expense in the Company's pension tracker mechanism.

40. **Public Service Company of Oklahoma, 2011 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of OIEC before the Oklahoma Corporation Commission in AEP/PSO's application to recover ice storm O&M expenses through a regulatory asset/rider mechanism to address tax impact and return issues in the proposed rider.

41. **Public Service Company of Colorado, 2011 (Docket No. 10AL-908E) –** Participated as an expert

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witness on behalf of the Colorado Retail Council ("CRC") before the Colorado Public Utilities Commission providing written and live testimony to address PSCo's proposed Environmental Tariff.

42. **Oklahoma Gas & Electric Company, 2011 (Docket No. 10-067-U)** – Participated as an expert witness on behalf of the Northwest Arkansas Industrial Energy Consumers ("NWIEC")[6] before the Arkansas Public Service Commission in OG&E's general rate case application to provide testimony on various revenue requirement, cost of service and rate design issues.

43. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-146)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking rider recovery of third party SPP transmission costs and SPP administration fees.

44. **Massachusetts Electric Co. & Nantucket Electric Co. d/b/a National Grid, 2010 (Docket No. DPU 10-54)** – Participated as an expert witness providing both written and live testimony before the Massachusetts Department of Public Utilities on behalf of the Associated Industries of Massachusetts ("AIM") to address the Company's proposed participation in the 438MW Cape Wind project in Nantucket Sound.

45. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-50)** – Participated as an expert witness on behalf of the OIEC before the OCC in AEP/PSO's general rate case application to provide testimony on various cost-of-service issues and on the utility's overall revenue requirement and rate design proposals.

46. **Texas-New Mexico Power Co., 2010 (Docket 38480)** – Participating as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

47. **Southwestern Public Service Co., 2010 (PUCT Docket No. 38147)** – Participating as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application to provide testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsor the AXM Accounting Exhibits.

48. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-37)** – Participating as an expert witness on behalf of OIEC before the OCC to address the preapproval and ratemaking treatment of OG&E's 220MW self-build wind project.

49. **Oklahoma Gas & Electric Company, 2010 (Cause No. PUD 2010-29)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking pre-approval of deployment of smart-grid technology and rider-recovery of the associated costs. Sponsored written testimony to address smart-grid deployment and time-differentiated fuel rates.

50. **Public Service Company of Oklahoma, 2010 (Cause No. PUD 2010-01)** – Participated as an expert witness on behalf of the OIEC before the OCC in the Company's proposed Green Energy Choice Tariff. Sponsored testimony to address the pricing and ratemaking treatment of the Company's proposed wind subscription tariff.

51. **Nevada Power Company, 2010 (Docket No. 10-02009)** – Participated as an expert witness on behalf of the Southern Nevada Hotel Group ("SNHG") before the Nevada PUC to provide testimony in NPC's Internal Resource Plan to address the ratemaking treatment of the proposed ON Line

[6] NWIEC is an association of industrial manufacturing facilities in northwest Arkansas.

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transmission line.

52. **Entergy Texas Inc., 2010 (PUC Docket No. 37744)** – Participating as an expert witness on behalf of the Cities in ETI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

53. **El Paso Electric Company, 2010 (PUC Docket No. 37690)** – Participated as an expert witness on behalf of the City of El Paso in the EPI general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

54. **Public Service Company of Oklahoma, 2009 (Cause No. 09-196)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application for approval of DSM programs and cost recovery. Sponsored testimony to address program costs, lost revenue recovery, cost allocations and incentives.

55. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 09-230 and 09-231)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

56. **Oklahoma Gas and Electric Company, 2009 (Cause No. PUD 08-398)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E's rate case. Provided testimony in both the revenue requirement and rate design phases of the proceedings to establish prospective cost-of-service based rates for the power company.

57. **Nevada Power Company, 2009, (Docket No. 08-12002)** - Participated as an expert witness on behalf of the Southern Nevada Hotel Group before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

58. **Public Service Company of Oklahoma, 2009 (Cause No. 09-031)** – Participated as an expert witness on behalf of OIEC before the OCC in PSO's application to add wind resources from two purchased power contracts. Sponsored written testimony to address the proper ratemaking treatment of the contract costs and the renewable energy certificates.

59. **Oklahoma Natural Gas Co., 2009 (Cause No. PUD 08-348)** – Participated as an expert witness on witness on behalf of the OIEC before the OCC in ONG's application to establish a Performance Based Rate tariff. Sponsored both written and oral testimony to address the merits of the utility's proposed PBR.

60. **Rocky Mountain Power, 2009 (Docket No. 08-035-38)** – Participated as an expert witness on behalf of the Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

61. **Texas-New Mexico Power Co., 2008 (Docket 36025)** – Participating as an expert witness on behalf of the Alliance of Texas Municipalities ("ATM") before the Texas PUC in TMNP's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

62. **Public Service Company of Oklahoma, 2008 (Cause No. 08-144)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address revenue requirement and rate design issues to establish prospective cost-of-service based rates.

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63. **Public Service Company of Oklahoma, 2008 (Cause No. 08-150)** – Participated as an expert witness on behalf of the OIEC before the OCC to address PSO's calculation of its Fuel Clause Adjustment for 2008.

64. **Oklahoma Gas and Electric Company, 2008 (Cause No. PUD 08-059)** – Participated as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

65. **Entergy Gulf States, 2008 (PUC Docket No. 34800, SOAH Docket No. 473-08-0334)** – Participated as an expert witness on behalf of the Cities in EGSI's general rate case to provide testimony on various cost of service issues and on the utility's overall revenue requirement.

66. **Public Service Company of Oklahoma, 2008 (Cause No. 07-465)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application to recover the pre-construction costs of the cancelled Red Rock coal generation facility.

67. **Oklahoma Gas and Electric Company, 2008 (Cause No. 07-447)** – Participating as an expert witness on behalf of the OIEC before the OCC in OG&E's application seeking authorization to recover the pre-construction costs of the cancelled Red Rock coal generation facility using proceeds from sales of excess SO_2 allowances.

68. **Rocky Mountain Power, 2008 (Docket No. 07-035-93)** – Participating as an expert witness on behalf of Division of Public Utilities (Staff) in PacifiCorp's general rate case to provide testimony on various revenue requirement issues.

69. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-449)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking authorization of its Demand Side Management ("DSM") programs and the establishment of a DSM Rider to recover program costs, lost revenues and utility incentives.

70. **Public Service Company of Oklahoma, 2008 (Cause No. PUD 07-397)** – Participated as an expert witness on behalf of OIEC before the OCC in PSO's application seeking authorization to defer storm damage costs in a regulatory asset account and to recover the costs using the proceeds from sales of excess SO_2 allowances.

71. **Oklahoma Gas & Electric Co., 2007 (Cause No. PUD 07-012)** – Participated as an expert witness on behalf of OIEC before the OCC in OG&E's application seeking pre-approval to construct the Red Rock coal plant to address the Company's proposed rider recovery mechanism.

72. **Oklahoma Natural Gas Co., 2007 (Cause No. PUD 07-335)** – Participated as an expert witness on behalf of the OIEC before the OCC in ONG's application proposing alternative cost recovery for the Company's ongoing capital expenditures through the proposed Capital Investment Mechanism Rider ("CIM Rider"). Sponsored testimony to address ONG's proposal.

73. **Public Service Company of Oklahoma, 2007 (Cause No. PUD 06-030)** – Participated as an expert witness on behalf of the OIEC before the OCC in PSO's application seeking a used and useful determination for its planned addition of the Red Rock coal plant to address the Company's use of debt equivalency in the competitive bidding process for new resources.

74. **Public Service Company of Oklahoma, 2006 (Cause No. PUD 06-285)** – Participated as an expert

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witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

75. **Nevada Power Company, 2007, (Docket No. 07-01022)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

76. **Nevada Power Company, 2006, (Docket No. 06-11022)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

77. **Southwestern Public Service Co., 2006 (PUCT Docket No. 37766)** – Participated as an expert witness on behalf of the Alliance of Xcel Municipalities ("AXM") in the SPS general rate case application. Provided testimony before the Texas Public Utility Commission regarding rate base and operating expense issues and sponsored the Accounting Exhibits on behalf of AXM.

78. **Atmos Energy Corp., Mid-Tex Division, 2006 (Texas GUD 9676)** – Participated as an expert witness in the Atmos Mid-Tex general rate case application on behalf of the Atmos Texas Municipalities ("ATM"). Provided written and oral testimony before the Railroad Commission of Texas regarding the revenue requirements of Mid-Tex including various rate base, operating expense, depreciation and tax issues. Sponsored the Accounting Exhibits for ATM.

79. **Nevada Power Company, 2006 (Docket No. 06-06007)** – Participated as an expert witness on behalf of the MGM MIRAGE in the Sinatra Substation Electric Line Extension and Service Contract case. Provided both written and oral testimony before the Nevada Public Utility Commission to provide the Commission with information as to why the application is consistent with the line extension requirements of Rule 9 and why the cost recovery proposals set forth in the application provide a least cost approach to adding necessary new capacity in the Las Vegas strip area.

80. **Public Service Co. of Oklahoma, 2006 (Cause No. PUD 05-00516)** - Participated as an expert witness on behalf of the OIEC to review PSO's application for a "used and useful" determination of its proposed peaking facility.

81. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 06-00041)** – Participated as an expert witness on behalf of the OIEC in OG&E's application to propose an incentive sharing mechanism for SO_2 allowance proceeds.

82. **Chermac Energy Corporation, 2006 (Cause No. PUD 05-00059 and 05-00177)** – Participated as an expert witness on behalf of the OIEC in Chermac's PURPA application. Sponsored written responsive and rebuttal testimony to address various rate design issues arising under the application.

83. **Oklahoma Gas and Electric Co., 2006 (Cause No. PUD 05-00140)** – Participated as an expert witness on behalf of the OIEC in OG&E's 2003 an 2004 Fuel Clause reviews. Sponsored written testimony to address the purchasing practices of the Company, it transactions with affiliates, and the prices paid for natural gas, coal and purchased power.

84. **Nevada Power Company, 2006, (Docket No. 06-01016)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written testimony in NPC's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

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85. **Oklahoma Gas and Electric Co., 2005 (Cause No. PUD 05-151)** – Participated as an expert witness on behalf of the OIEC in OG&E's general rate case application. Sponsored both written and oral testimony before the OCC to address various revenue requirement and rate design issues for the purpose of setting prospective cost-of-service based rates.

86. **Oklahoma Natural Gas Co., 2005 (Cause No. PUD 04-610)** – Participated as an expert witness on behalf of the Attorney General of Oklahoma. Sponsored written and oral testimony to address numerous rate base, operating expense and depreciation issues for the purpose of setting prospective cost-of-service based rates.

87. **CenterPoint Energy Arkla, 2004 (Cause No. PUD 04-0187)** – Participating as an expert witness on behalf of the Attorney General of Oklahoma: Sponsored written testimony to provide the OCC with analysis from an accounting and ratemaking perspective of the Co.'s proposed change in depreciation rates from an Average Life Group to an Equal Life Group methodology. Addressed the Co.'s proposed increase in depreciation rates associated with increased negative salvage value calculations.

88. **Public Service Co. of Oklahoma, 2004 (Cause No. PUD 02-0754)** – Participated as an expert witness on behalf of the OIEC. Sponsored written testimony (1) making adjustments to PSO's requested recovery of an ICR programming error, (2) correcting errors in the allocation of trading margins on off-system sales of electricity from AEP East to West and among the AEP West utilities and (3) recommending an annual rather than a quarterly change in the FAC rates.

89. **PowerSmith Cogeneration Project, 2004 (Cause No. PUD 03-0564)** - Participated as an expert witness on behalf of the OIEC to provide the OCC with direction in setting an avoided cost for the PowerSmith Cogeneration project under PURPA requirements. Provided both written and oral testimony on the provisions of the proposed contract under PURPA:

90. **Electric Utility Rules for Affiliate Transactions, 2004 (Cause No. RM 03-0003)** – Participated as a consultant on behalf of the OIEC to draft comments to assist the OCC in developing rules for affiliate transactions. Assisted in drafting the proposed rules. Successful in having the Lower of Cost or Market rule adopted for affiliate transactions in Oklahoma.

91. **Nevada Power Company, 2003, (Docket No. 03-10001)** - Participated as an expert witness on behalf of the MGM MIRAGE properties before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

92. **Nevada Power Company, 2003, (Docket No. 03-11019)** - Participated as an expert witness on behalf of the MGM MIRAGE before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power.

93. **Public Service Company of Oklahoma, 2003 (Cause No. PUD 03-0076)** – Participating as an expert witness on behalf of the OIEC before the OCC in PSO's general rate case application to address various revenue requirement and rate design issues to establish prospective cost-of-service based rates.

94. **Oklahoma Gas & Electric Co., 2003 (Cause No. PUD 03-0226)** – Participated as an expert witness on behalf of the OIEC. Provided both written and oral testimony before the OCC to determine the appropriate level to include in rates for natural gas transportation and storage services acquired from an affiliated company.

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95. **Nevada Power Company, 2003 (Docket No. 02-5003-5007)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony to calculate the appropriate exit fee in MGM Mirage's 661 Application to leave the system.

96. **McCarthy Family Farms, 2003** – Participated as a consultant to assist McCarthy Family Farms in converting a biomass and biosolids composting process into a renewable energy power producing business in California.

97. **Bice v. Petro Hunt, 2003 (ND, Supreme Court No. 20030306)** - Participated as an expert witness in a class certification proceeding to provide cost-of-service calculations for royalty valuation deductions for natural gas gathering, dehydration, compression, treatment and processing fees in North Dakota.

98. **Nevada Power Company, 2003 (Docket No. 03-11019)** - Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power. Provided written and oral testimony on the reasonableness of the cost allocations to the utility's various customer classes.

99. **Wind River Reservation, 2003 (Fed. Claims Ct. No. 458-79L, 459-79L)** – Participated as a consulting expert on behalf of the Shoshone and Arapaho Tribes to provide cost-of-service calculations for royalty valuation deductions for gathering, dehydration, treatment and compression of natural gas and the reasonableness of deductions for gas transportation.

100. **Oklahoma Gas & Electric Co., 2002 (Cause No. PUD 01-0455)** – Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored written and oral testimony on numerous revenue requirement issues including rate base, operating expense and rate design issues to establish prospective cost-of-service based rates.

101. **Nevada Power Company, 2002 (Docket No. 02-11021)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power and to make recommendations with respect to rate design.

102. **Nevada Power Company, 2002 (Docket No. 01-11029)** - Participated as a consulting expert on behalf of the MGM Mirage before the Nevada PUC in Nevada Power Company's deferred energy docket to determine the level of prudent company expenditures for fuel and purchased power included in the Company's $928 million deferred energy balances.

103. **Nevada Power Company, 2002 (Docket No. 01-10001)** - Participated as an expert witness on behalf of the MGM Mirage before the Nevada PUC. Sponsored written and oral testimony in both the revenue requirement phase and the rate design phase of the proceedings to establish prospective cost-of-service based rates for the power company.

104. **Chesapeake v. Kinder Morgan, 2001 (CIV-00-397L)** - Participated as an expert witness on behalf of Chesapeake Energy in a gas gathering dispute. Sponsored testimony to calculate and support a reasonable rate on the gas gathering system. Performed necessary calculations to determine appropriate levels of operating expense, depreciation and cost of capital to include in a reasonable gathering charge and developed an appropriate rate design to recover these costs.

105. **Southern Union Gas Company, 2001** - Participated as a consultant to the City of El Paso in its review of SUG's gas purchasing practices, gas storage position, and potential use of financial hedging

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instruments and ratemaking incentives to devise strategies to help shelter customers from the risk of high commodity price spikes during the winter months.

106. **Nevada Power Company, 2001** - Participated as an expert witness on behalf of the MGM-Mirage, Park Place and Mandalay Bay Group before the Nevada Public Utility Commission to review NPC's Comprehensive Energy Plan (CEP) for the State of Nevada and make recommendations regarding the appropriate level of additional costs to include in rates for the Company's prospective power costs associated with natural gas and gas transportation, coal and coal transportation and purchased power.

107. **Bridenstine v. Kaiser-Francis Oil Co. et al., 2001 (CJ-95-54)** - Participated as an expert witness on behalf of royalty owner plaintiffs in a valuation dispute regarding gathering, dehydration, metering, compression, and marketing costs. Provided cost-of-service calculations to determine the reasonableness of the gathering rate charged to the royalty interest. Also provided calculations as to the average price available in the field based upon a study of royalty payments received on other wells in the area.

108. **Klatt v. Hunt et al., 2000 (ND)** - Participated as an expert witness and filed report in United States District Court for the District of North Dakota in a natural gas gathering contract dispute to calculate charges and allocations for processing, sour gas compression, treatment, overhead, depreciation expense, use of residue gas, purchase price allocations, and risk capital.

109. **Oklahoma Gas and Electric Co., 2000 (Cause No. PUD 00-0020)** - Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Generation Efficiency Performance Rider (GEPR). Provided a list of criteria with which to measure a utility's proposal for alternative ratemaking. Recommended modifications to the Company's proposed GEPR to bring it within the boundaries of an acceptable alternative ratemaking formula.

110. **Oklahoma Gas and Electric Co., 1999** - Participated as an expert witness on behalf of the OIEC before the OCC. Sponsored testimony on OG&E's proposed Performance Based Ratemaking (PBR) proposal including analysis of the Company's regulated return on equity, fluctuations in the capital investment and operating expense accounts of the Company and the impact that various rate base, operating expense and cost of capital adjustments would have on the Company's proposal.

111. **Nevada Power Company, 1999 (Docket No. 99-7035)** - Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony addressing the appropriate ratemaking treatment of the Company's deferred energy balances, prospective power costs for natural gas, coal and purchased power and deferred capacity payments for purchased power.

112. **Nevada Power Company, 1999 (Docket No. 99-4005)** - Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to unbundle the utility services of the NPC and to establish the appropriate cost-of-service allocations and rate design for the utility in Nevada's new competitive electric utility industry.

113. **Nevada Power Company, 1999 (Docket No. 99-4005)** - Participated as an expert witness on behalf of the Mirage, Park Place and Mandalay Bay Group before the Nevada PUC. Sponsored written and oral testimony to establish the cost-of-service revenue requirement of the Company.

114. **Nevada Power/Sierra Pacific Merger, 1998 (Docket No. 98-7023)** - Participated as an expert witness on behalf of the Mirage and MGM Grand before the Nevada PUC. Sponsored written and oral testimony to establish (1) appropriate conditions on the merger (2) the proper sequence of regulatory events to unbundle utility services and deregulate the electric utility industry in Nevada (3)

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the proper accounting treatment of the acquisition premium and the gain on divestiture of generation assets. The recommendations regarding conditions on the merger, the sequence of regulatory events to unbundle and deregulate, and the accounting treatment of the acquisition premium were specifically adopted in the Commission's final order.

115. **Oklahoma Natural Gas Company, 1998 (Cause No. PUD 98-0177)** - Participated as an expert witness in ONG's unbundling proceedings before the OCC. Sponsored written and oral testimony on behalf of Transok, LLC to establish the cost of ONG's unbundled upstream gas services. Substantially all of the cost-of-service recommendations to unbundle ONG's gas services were adopted in the Commission's interim order.

116. **Public Service Company of Oklahoma, 1997 (Cause No. PUD 96-0214)** - Audited both rate base investment and operating revenue and expense to determine the Company's revenue requirement and cost-of-service. Sponsored written testimony before the OCC on behalf of the OIEC.

117. **Oklahoma Natural Gas /Western Resources Merger, 1997 (Cause No. PUD 97-0106)** - Sponsored testimony on behalf of the OIEC regarding the appropriate accounting treatment of acquisition premiums resulting from the purchase of regulated assets.

118. **Oklahoma Gas and Electric Co., 1996 (Cause No. PUD 96-0116)** - Audited both rate base investment and operating income. Sponsored testimony on behalf of the OIEC for the purpose of determining the Company's revenue requirement and cost-of-service allocations.

119. **Oklahoma Corporation Commission, 1996** - Provided technical assistance to Commissioner Anthony's office in analyzing gas contracts and related legal proceedings involving ONG and certain of its gas supply contracts. Assignment included comparison of pricing terms of subject gas contracts to portfolio of gas contracts and other data obtained through annual fuel audits analyzing ONG's gas purchasing practices.

120. **Tenkiller Water Company, 1996** - Provided technical assistance to the Attorney General of Oklahoma in his review of the Company's regulated cost-of-service for the purpose of setting prospective utility rates.

121. **Arkansas Oklahoma Gas Company, 1995 (Cause No. PUD 95-0134)** - Sponsored written and oral testimony before the OCC on behalf of the Attorney General of Oklahoma regarding the price of natural gas on AOG's system and the impact of AOG's proposed cost of gas allocations and gas transportation rates and tariffs on AOG's various customer classes.

122. **Enogex, Inc., 1995 (FERC 95-10-000)** - Analyzed Enogex's application before the FERC to increase gas transportation rates for the Oklahoma Independent Petroleum Association and made recommendations regarding revenue requirement, cost-of-service and rate design on behalf of independent producers and shippers.

123. **Oklahoma Natural Gas Company, 1995 (Cause No. PUD 94-0477)** - Analyzed a portfolio of ONG's gas purchase contracts in the Company's Payment-In-Kind (PIC) gas purchase program and made recommendations to the OCC Staff on behalf of Terra Nitrogen, Inc. regarding the inappropriate profits made by ONG on the sale of the gas commodity through the PIC program pricing formula. Also analyzed the price of gas on ONG's system, ONG's cost-of-service based rates, and certain class cross-subsidizations in ONG's existing rate design.

124. **Arkansas Louisiana Gas Company, 1994 (Cause No. PUD 94-0354)** - Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of the other auditors on

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the case. Sponsored cost-of-service testimony on cash working capital and developed policy recommendations on post test year adjustments.

125. **Empire District Electric Company, 1994 (Cause No. PUD 94-0343) -** Planned and supervised the rate case audit for the OCC Staff and reviewed the workpapers and testimony of other auditors. Sponsored cost-of-service testimony on rate base investment areas including cash working capital.

126. **Oklahoma Natural Gas Company, 1992 through 1993 (Cause No. PUD 92-1190) -** Planned and supervised the rate case audit of ONG for the OCC Staff. Reviewed all workpapers and testimony of the other auditors on the case. Sponsored written and oral testimony on numerous cost-of-service adjustments. Analyzed ONG's gas supply contracts under the Company's PIC program.

127. **Oklahoma Gas and Electric Company, 1991 through 1992 (Cause No. PUD 91-1055)** - Audited the rate base, operating revenue and operating expense accounts of OG&E on behalf of the OCC Staff. Sponsored written and oral testimony on numerous revenue requirement adjustments to establish the appropriate level of costs to include for the purpose of setting prospective rates.

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Exhibit MG_2

Caught in a Fix

The Problem with Fixed Charges for Electricity

Prepared for Consumers Union

February 9, 2016

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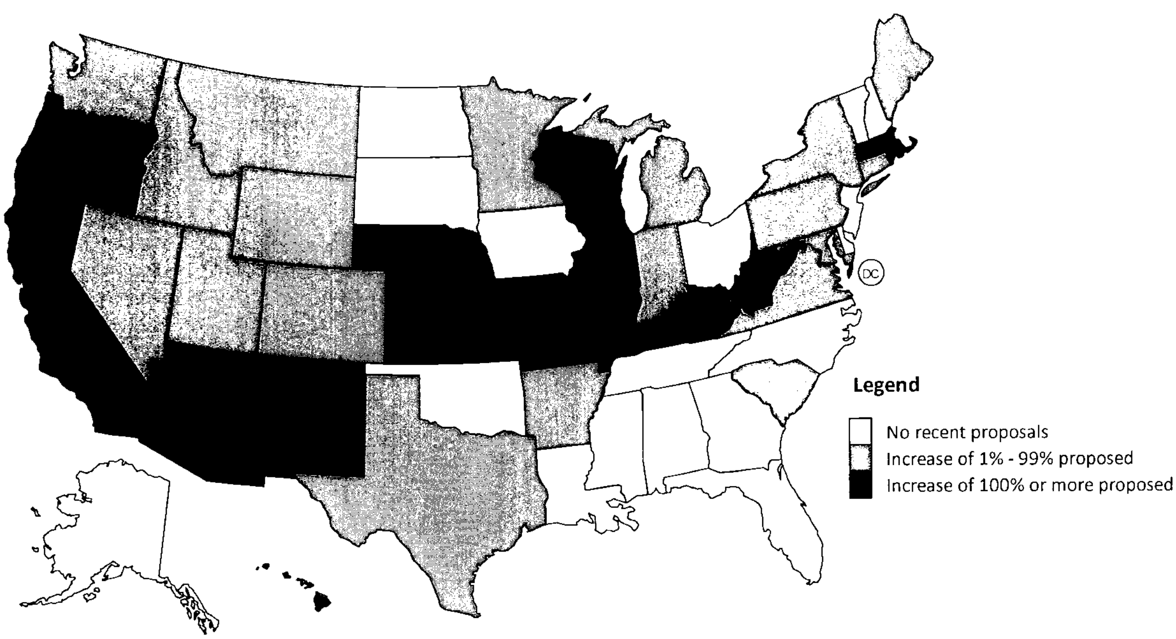
CONTENTS

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]

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.

"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."

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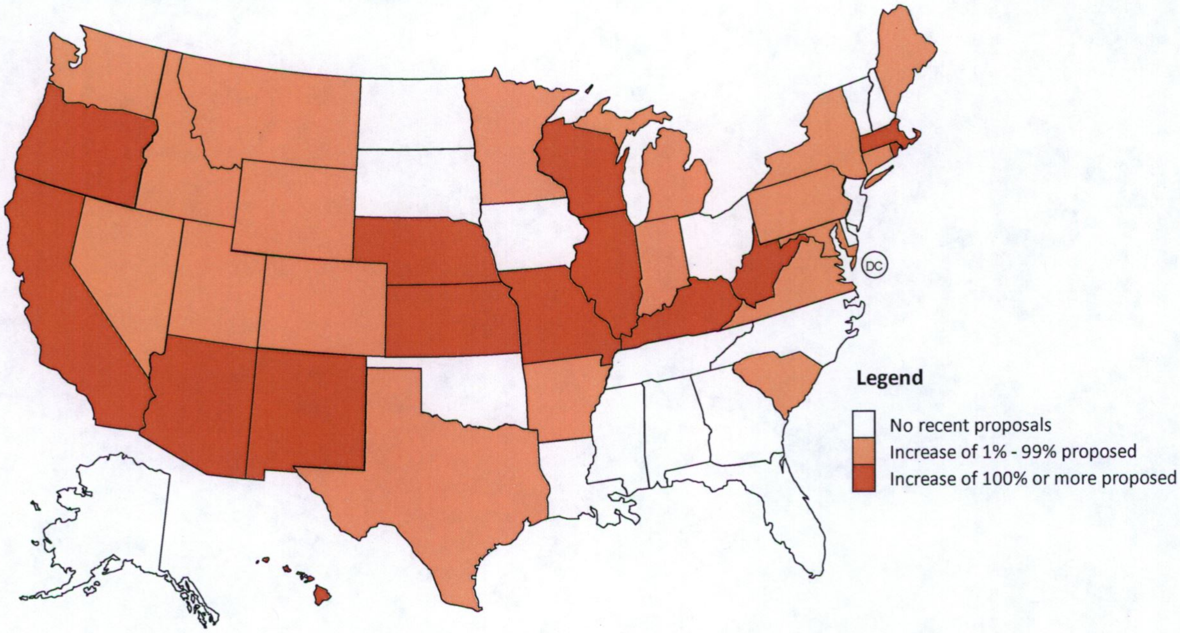
[2] Written comment of John Dupell, Docket 14-05-06, filed May 30, 2014

[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.

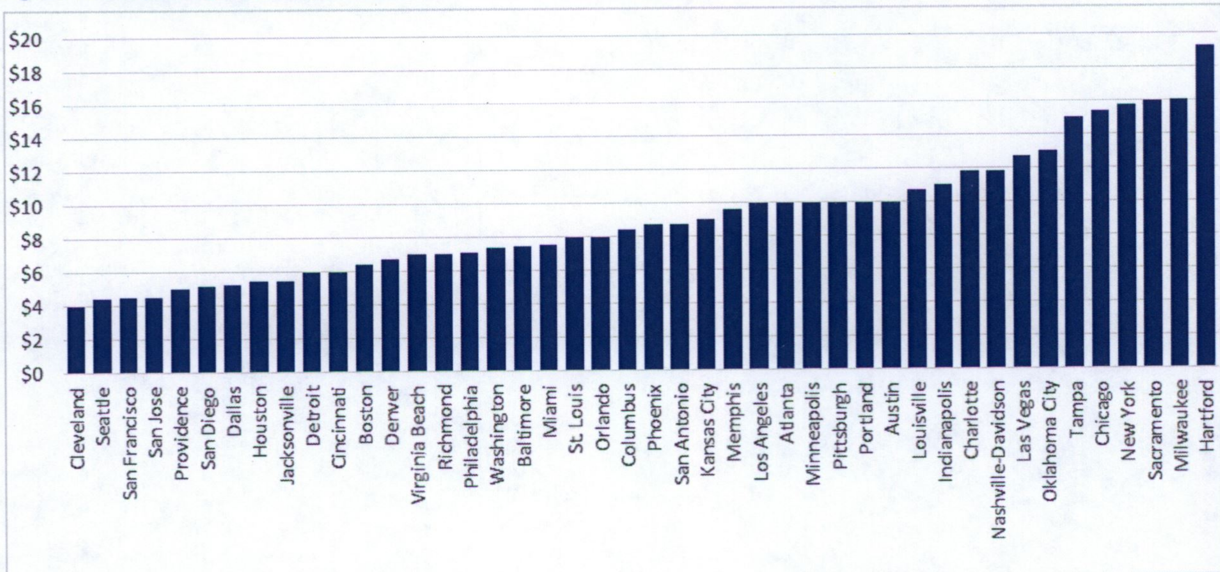
[5] Senate Bill No. 1502, June Special Session, Public Act No. 15-5, "An Act Implementing Provisions of the State Budget for The Biennium Ending June 30, 2017, Concerning General Government, Education, Health and Human Services and Bonds of the State."

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.

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

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

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

Other recent examples include:

- The Hawaiian Electric Companies' proposal to increase the customer charge from $9.00 to $55.00 per month (an increase of $552 per year) for full-service residential customers, and $71.00 per month for new distributed generation customers (an increase of $744 per year);[9]

- Kansas City Power and Light's proposal to increase residential customer charges 178 percent in Missouri, from $9.00 to $25.00 per month (an increase of $192 per year);[10] and

- Pennsylvania Power and Light's March 2015 proposal to increase the residential customer charge from approximately $14.00 to approximately $20.00 per month (an increase of more than $70 per year).[11]

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

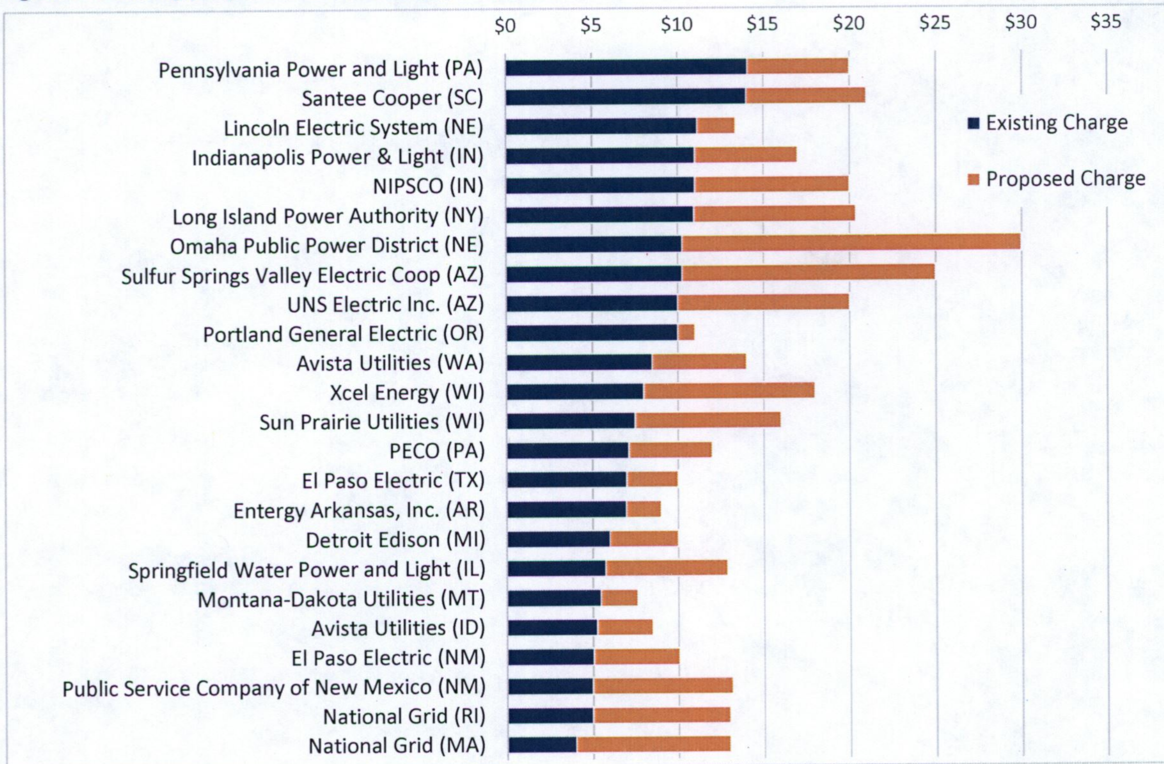
[8] Ultimately the commission approved a fixed charge of $19.25, below the utility's request, but among the highest in the country.

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

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

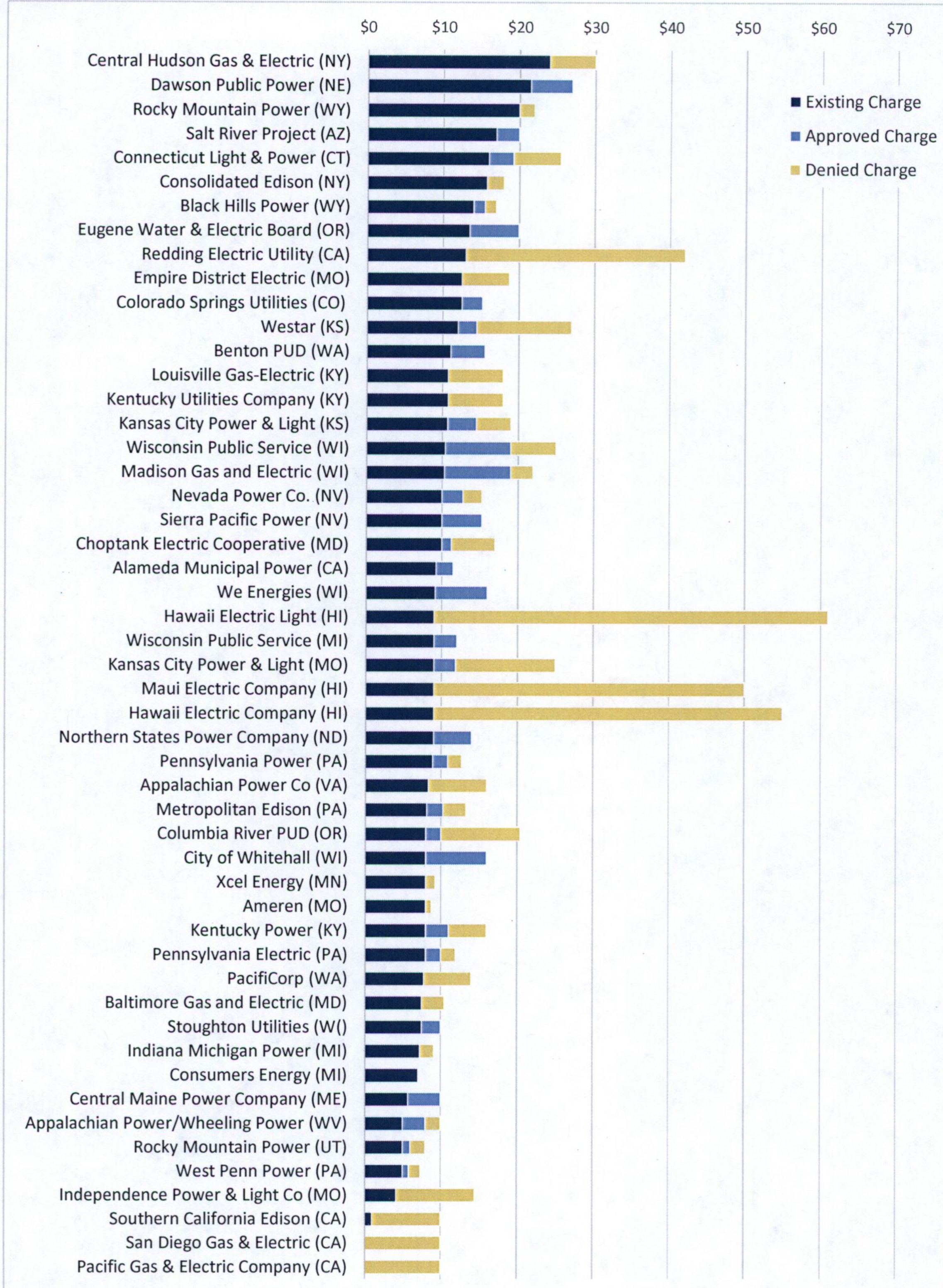
[11] PPL Witness Scott R. Koch, Exhibit SRK 1, Supplement No. 179 to Tariff – Electric Pa. P.U.C. No. 201, Docket No. R-2015-2469275, March 31, 2015, at http://www.puc.state.pa.us/pcdocs/1350814.pdf.

Figure 3. Pending proposals for fixed charge increases



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.

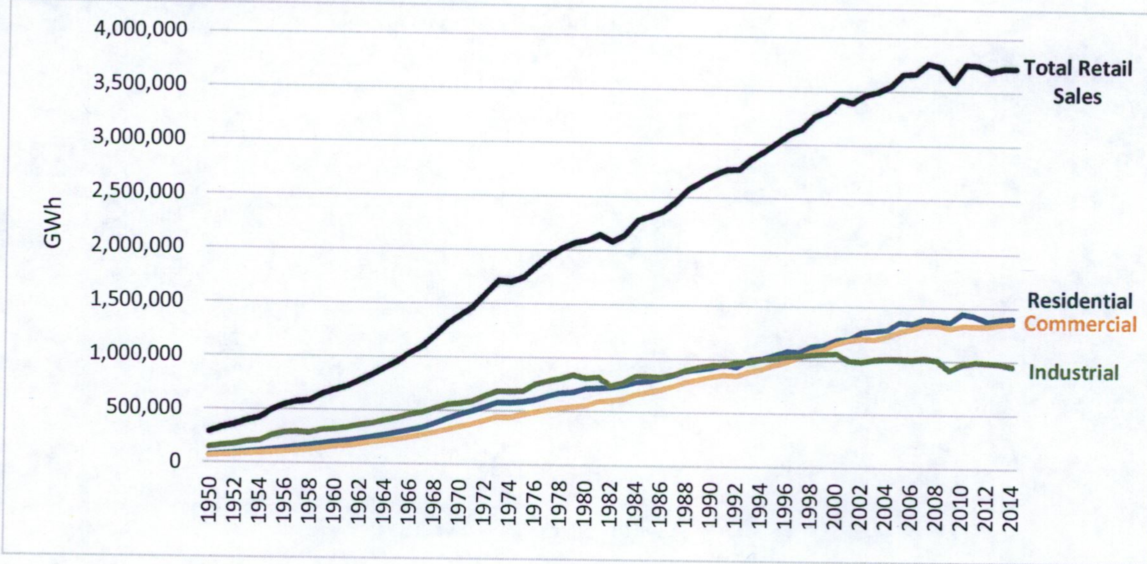
Rates are typically composed of some combination of the following three types of charges:

- 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]

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

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

3. How Fixed Charges Harm Customers

Reduced Customer Control

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

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

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

Low-Usage Customers Hit Hardest

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

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

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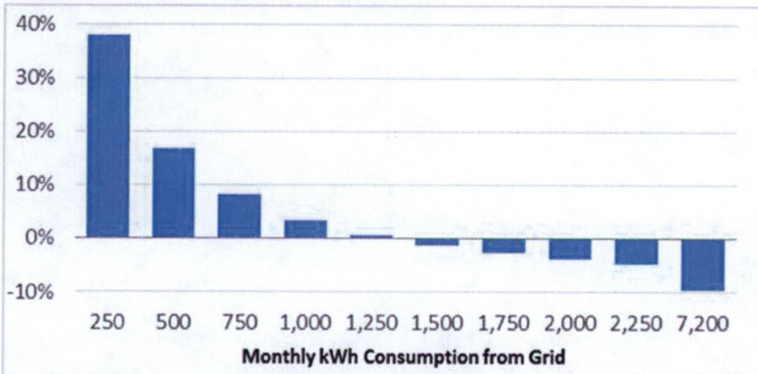
[15] Phil Carson, "Connecticut Light & Power Engages Customers," *Intelligent Utility*, July 1, 2011, http://www.intelligentutility.net/article/11/06/connecticut-light-power-engages-customers?quicktabs_4=2&quicktabs_11=1&quicktabs_6=1.

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

Figure 6. Increase in average monthly bill

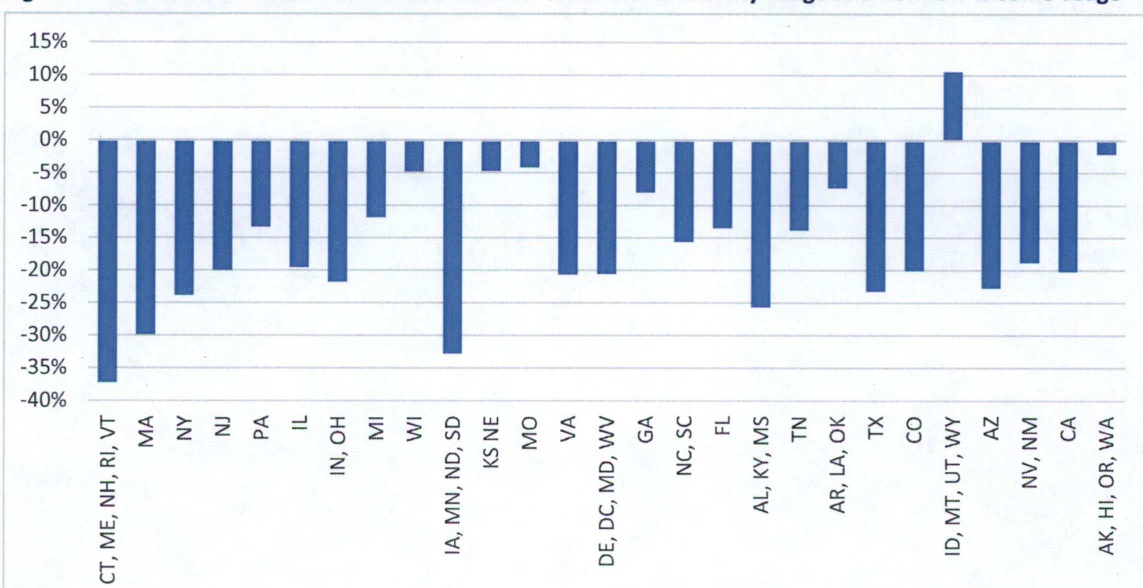


Analysis based on increasing the fixed charge from $9/month to $25/month, with a corresponding decrease in the $/kWh charge.

Disproportionate Impacts on Low-Income Customers

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

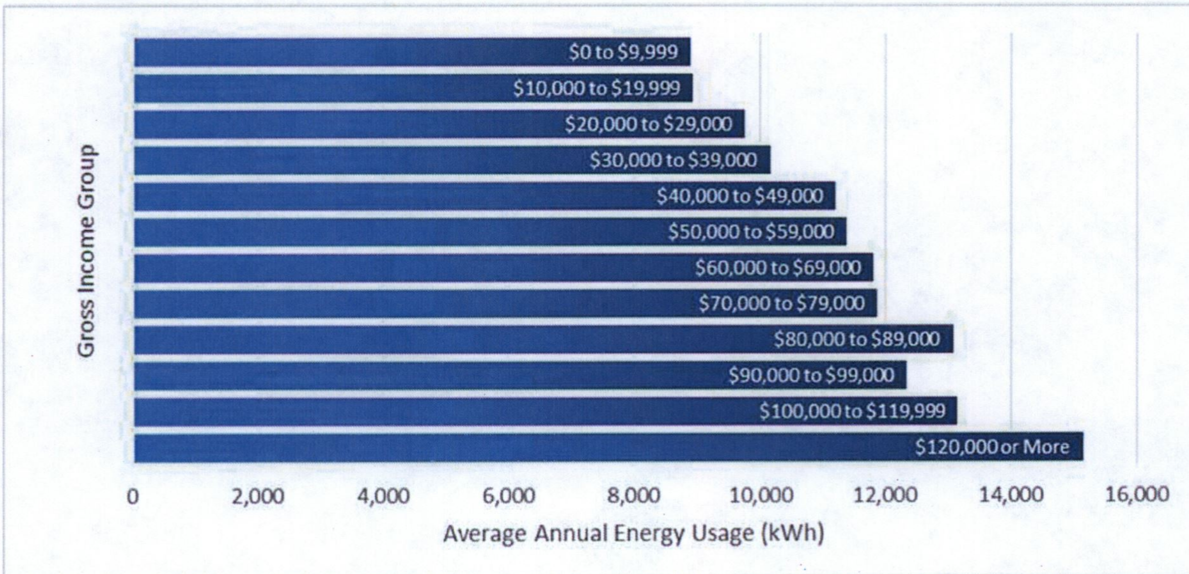
Figure 7. Difference between low-income median residential electricity usage and non-low-income usage



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

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

Figure 8. Nationwide average annual energy usage by income group



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

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

Reduced Incentives for Energy Efficiency and Distributed Generation

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

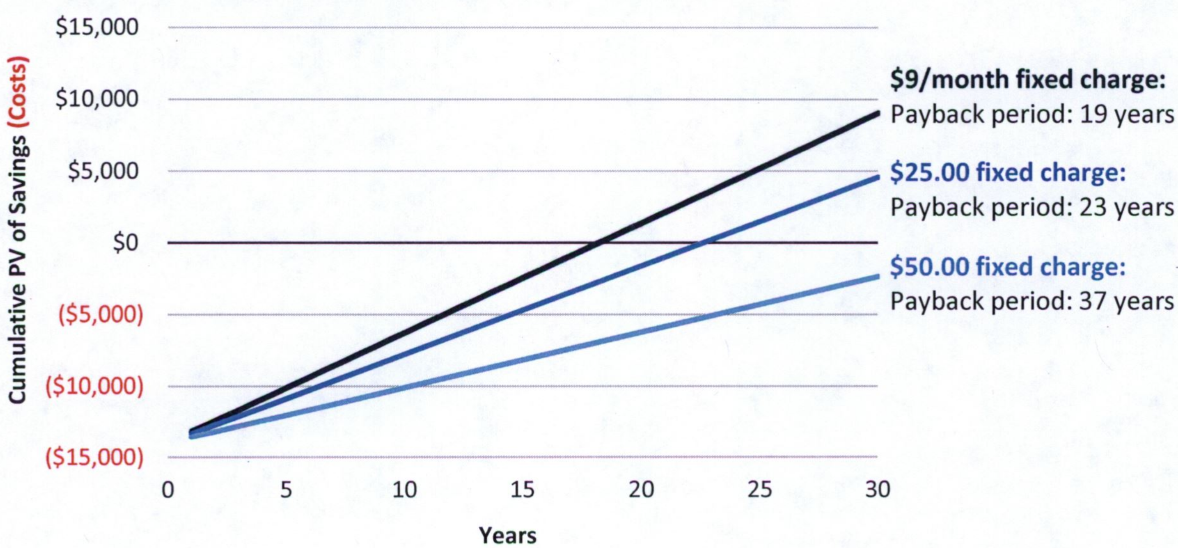
[17] Annie Gilleo et al., "The 2014 State Energy Efficiency Scorecard" (American Council for an Energy Efficient Economy, October 2014).

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

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

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

Figure 9. Rooftop solar payback period under various customer charges



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

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

Increased Electricity System Costs

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

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

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

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

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

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

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

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

4. Rate Design Fundamentals

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

Guiding Principles

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

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

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

Cost-of-Service Studies

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

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

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

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

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

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

Rate Design Basics

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

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

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

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

5. Common Arguments Supporting Higher Fixed Charges

"Most Utility Costs Are Fixed"

Argument

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

Response

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

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

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

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

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

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

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

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

"Fixed Costs Are Unavoidable"

<u>Argument</u>

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

<u>Response</u>

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

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

"The Fixed Charge Should Recover Distribution Costs"

<u>Argument</u>

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

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

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

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

Response

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

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

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

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

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

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

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

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

Argument

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

Response

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

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

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

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

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

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

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

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

Argument

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

Response

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

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

Argument

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

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

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

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.

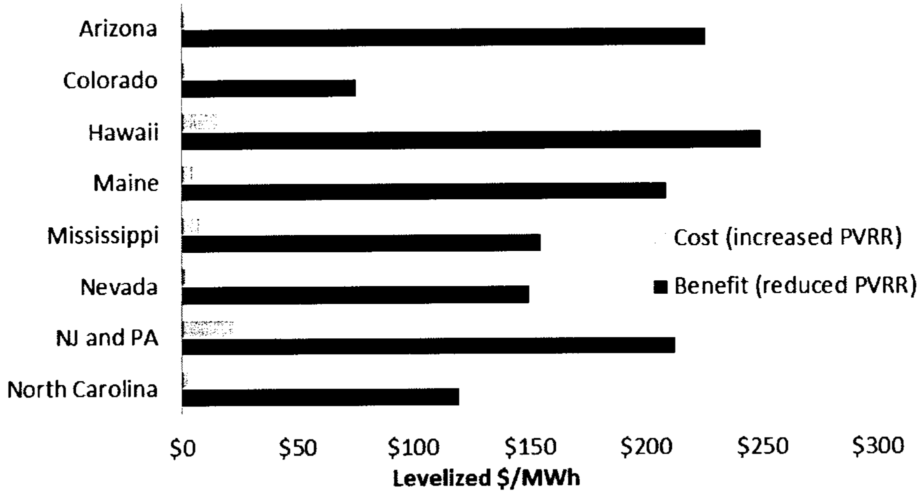
The benefits of distributed generation, in terms of reduced revenue requirements, will significantly reduce, and may even eliminate, any cost-shifting that might occur.

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

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

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

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

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

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

Demand Costs Not Appropriate for Energy Charge

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

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

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

Settlements

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

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

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

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

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

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

7. ALTERNATIVES TO FIXED CHARGES

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

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

Rate Design Options

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

[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.

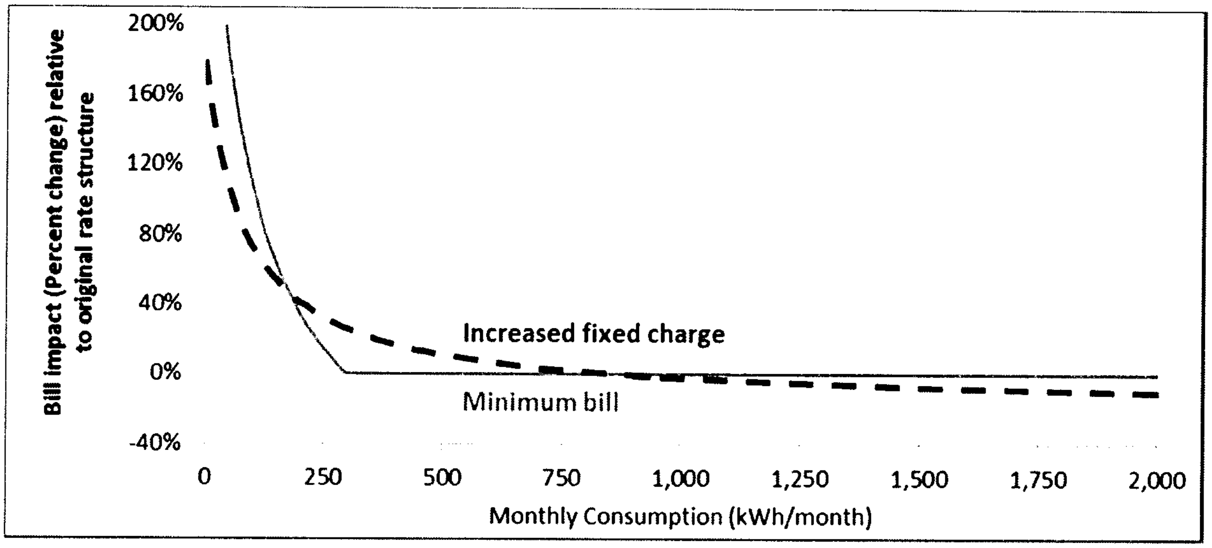
Under the minimum bill option, only customers with usage less than 280 kWh per month (approximately 5 percent of customers at a representative Midwestern utility) would see a change in their bills, and most of these customers would see an increase in their monthly bill of less than $10.

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

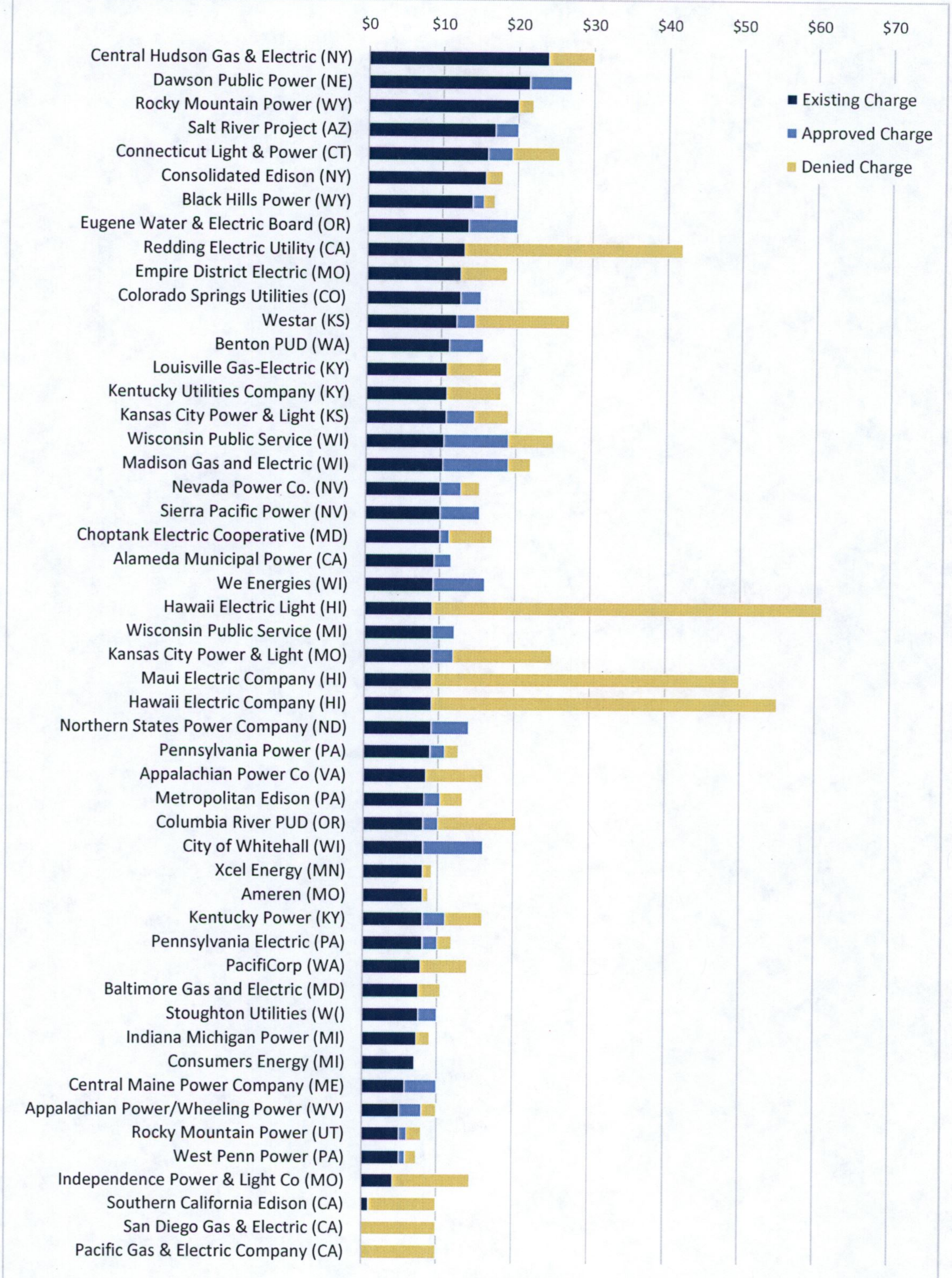
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

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		

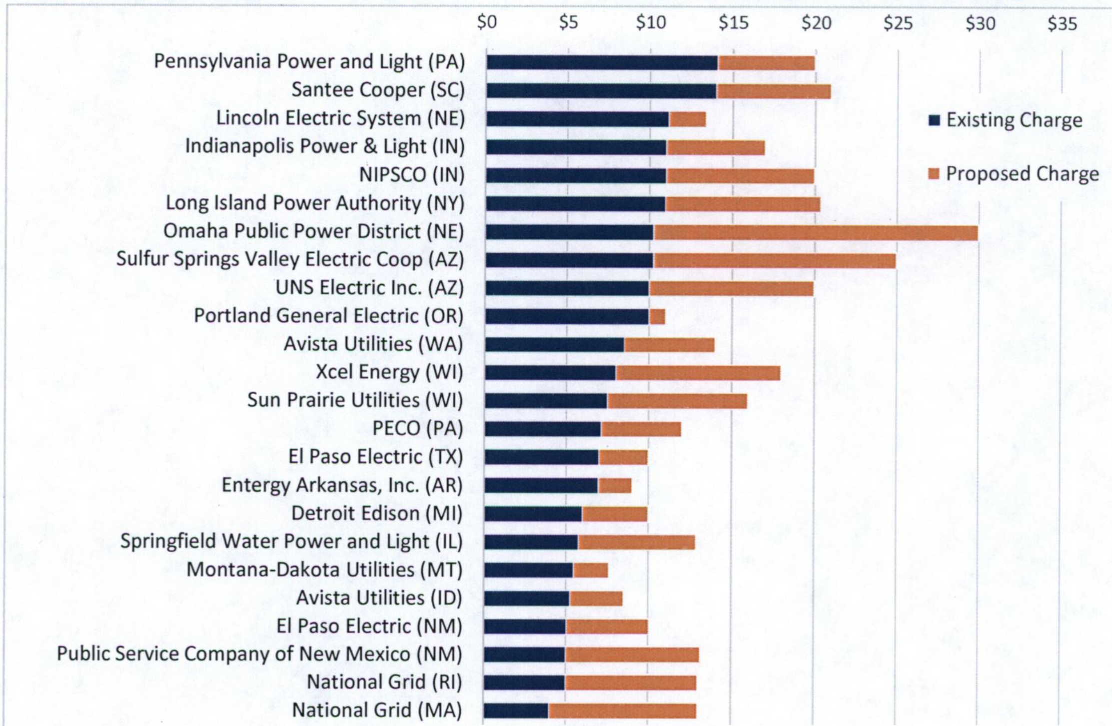
Source: Research as of December 1, 2015. List is not meant to be considered exhaustive.

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

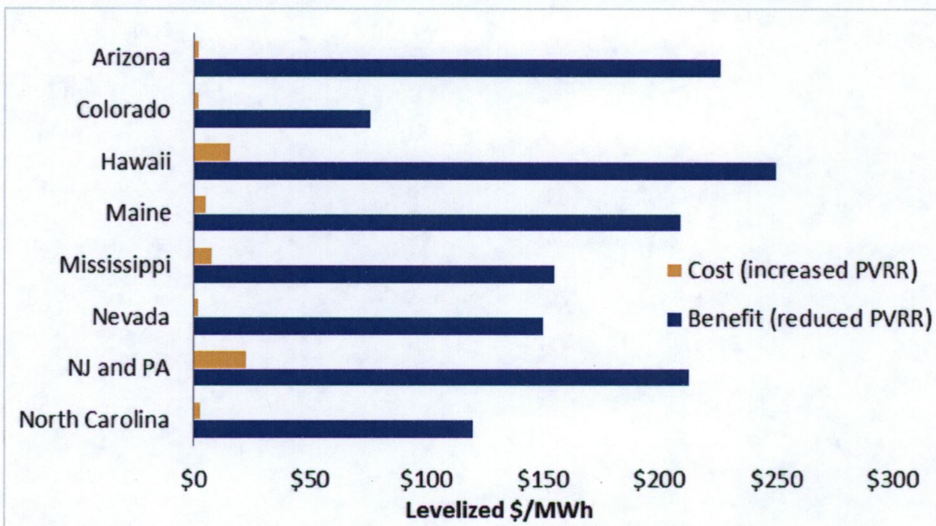


Appendix C – Net Metering Impacts on Utility Costs

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.

[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.

Exhibit MG_3

Exhibit MG_3

Residential NEBO Customers Without Adjustment for Riders Now in Base Rates & Current FCA

	Under Current R-TOU Tariff	Under Proposed R-TOU-kW Tariff	Change	
			$	%
Monthly Impact - Average Bill	$81.94	$104.92	$22.98	28.0%

Residential NEBO Customers Adjusted for Riders Proposed to be Placed in Base Rates

	Under Current R-TOU Tariff	Under Proposed R-TOU-kW Tariff	Change	
			$	%
Monthly Impact - Average Bill	$81.94	$98.39	$16.45	20.1%

The second R-TOU-kW rate estimate incorporates an subtraction of riders being folded into base rates in current GRC application. This was done to make the estimate for proposed R-TOU-kW, which includes these riders in base rates, comparable to the current R-TOU tariff. Riders other than the current FCA that were not incorporated into base rates are excluded from all calculations The new additions into the FCA were not included because they would affect the current and proposed rates equally on a monetary basis.

Exhibit MG_3

Modeling Description

Two different bill impact models were created. The first is based on actual residential DG customer billing data from roughly 200 existing residential DG customers. The second uses average residential customer data for the residential class as a whole and a reference PV system. Both data sets were provided by OG&E in PUD 201500274. The different models return different results because existing DG customers each have unique usage patterns and a unique DG production profile that differ from the average residential customer and the reference PV system. In other words, one is hypothetical, while the other reflects more granular data on the average DG customer.

Model #1: Based on Actual Existing DG Customer Data

<u>Data Sources</u>

1.) OG&E response to KJC-1, in PUD 201500274, providing an estimate of bill impacts if all residential DG customers were placed on R-TOU-kW as proposed in PUD 201500274. The spreadsheet contains billing data for a total of 201 existing residential DG customers and compares bills under the existing NEBO R-TOU tariff to the proposed NEBO R-TOU-kW tariff.

2.) Updated Fuel Cost Adjustment (FCA) values from Supplemental Package, Volume II, Section K-M, filed in PUD 201500273. Updated values are sourced from Section M, Individual Class Page, W/P M-4-1. The current rather than proposed FCA values were used in all calculations.

3.) Riders to be rolled into base rates, from Supplemental Package, Volume II, Section K-M, filed in PUD 201500273. Values are sourced from Section M, Individual Class Page, W/P M-4-1.

4.) OG&E proposed R-TOU-kW rates, as detailed in Wai Direct, pg. 27, Table 14.

<u>Methodology</u>
The estimate utilizes the existing formulas in OG&E response to KJC-1 in PUD 201500274. The FCA values contained in the Pricing tab were updated to reflect the current FCA values for winter, off-peak and on-peak times. The Pricing tab was also updated with the proposed customer charge, off-peak and on-peak energy rates, and non-coincident demand rate for R-TOU-kW. All riders that are proposed to remain riders were excluded from the calculations in order to isolate how changes to base rates affect customer bills. Likewise, the proposed additions to the FCA were excluded from the calculations they would affect both (current & proposed rates) monthly calculations equally. In other words, if the proposed FCA inclusions were incorporated into rates calculations for the proposed R-TOU-kW tariff, they would also need to be added to the rates calculations for the current R-TOU tariff so that both reflect their inclusion. Because the volumetric billing determinants would remain the same for each, the monthly monetary impact would be identical.

Estimate #1: The first estimate was prepared to show the *gross* increase relative to current rates, without considering the effects of riders that are proposed to be added into base rates. It therefore compares an average of DG customers' monthly bills under the current rates without considering any riders other than the FCA, with the average monthly bills for those same customers under proposed R-TOU-kW.

In this way, it captures the effects of both the proposed tariff change, and the more general increase in base rates attributable to riders being added to base rates.

Estimate #2: The second estimate adjusts for the inclusion of riders into base rates by subtracting the revenue that would have been raised under these riders from the average monthly bill calculation under the proposed NEBO R-TOU-kW tariff. The subtraction to monthly charges under the proposed NEBO R-TOU-kW tariff was calculated by multiplying the volumetric rates associated with those riders by the sum of total volumetric sales to residential DG customers in the Billing Determinant tab. The resulting revenue was then divided by 12 months and the 201 residential DG customers included in the Billing Determinants tab to arrive at a monthly charge attributable to riders. Thus in this estimate, the monthly average bill under the proposed NEBO R-TOU-kW tariff is decreased, eliminating the contribution of riders proposed to be added to base rates. This results in an apples to apples comparison where both monthly bill estimates exclude the cost of these riders to DG customers.

Model #2: Based on Average Residential Customer Data with a Reference 4 kW Fixed Tilt PV System

Data Sources

1.) OG&E Solar Sandbox model, provided in response to TASC 1-5 in PUD 2015000274. This model depicts the how the installation of a reference 4 kW fixed tilt PV system would have on residential DG customer bills under the current NEBO R-TOU rate and the proposed R-TOU-kW rate. It contains an hourly simulation of energy production from the reference PV system, and applies that energy production to average residential customer usage data to arrive at bill savings estimates for a customer under NEBO R-TOU and proposed NEBO R-TOU-kW.

2.) Updated Fuel Cost Adjustment (FCA) values from Supplemental Package, Volume II, Section K-M, filed in PUD 201500273. Updated values are sourced from Section M, Individual Class Page, W/P M-4-1. The current rather than proposed FCA values were used in all calculations.

3.) OG&E proposed R-TOU-kW rates, as detailed in Wai Direct, pg. 27, Table 14.

Methodology

The modeling used OG&E's energy production modeling from a reference 4 kW fixed tilt PV system and average customer energy usage numbers. Modifications to the rate inputs were made to reflect current FCA rates for winter, on-peak and off-peak times, and to reflect the proposed R-TOU-kW tariff rates. From this, annual and monthly bill savings estimates attributable to PV were calculated for the average customer under the current NEBO R-TOU rate and the proposed NEBO R-TOU-kW rate. One adjustment was made to the existing formulas used by OG&E in the model to correct an error in the calculation of customer bill savings under the current NEBO R-TOU rate. The original model calculated savings under existing winter rates by multiplying total winter energy production by the rate for winter energy consumption of 600 kWh or less. This formula was adjusted to reflect that winter energy production would first offset winter energy consumption above 600 kWh, with any remaining energy production offsetting consumption at the rate for energy consumption of 600 kWh or less. This calculation illustrates the loss in monthly customer bill savings provided by PV under the new rate.

Exhibit MG_3

A second calculation was performed to compare a standard residential customer's bill under the existing R-TOU and proposed R-TOU-kW rate *without* PV. This calculation is necessary to discover how the rate change itself would affect average customer bills, which is the starting point from savings would accrue. These estimates were prepared using the average customer billing data provided by OG&E in its original model and devising new formulas as necessary to generate customer bill estimates.

The total impact of the proposed R-TOU-kW is the sum of lost savings and the estimated change in a customer's bill if they were placed on the R-TOU-kW tariff. These two values were summed together to generate the estimated monthly bill impact from the tariff change. The percentage bill increase is the monetary increase divided by the estimated annual bill with PV under the current R-TOU tariff.

Exhibit MG_4

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.

Jim Lazar (jlazar@raponline.org) is a senior advisor at the Regulatory Assistance Project.

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.

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.

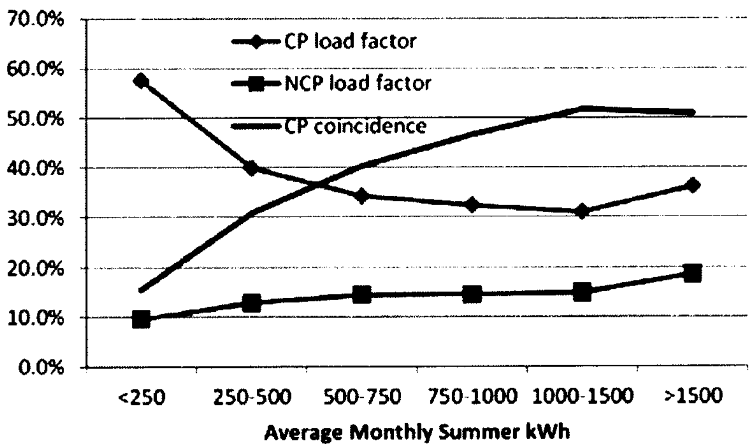
Time-varying rates do this very well, while simple CP and NCP demand charges do not.

IMPACT ON LOW-USE CUSTOMERS

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

  / DOI 10.1002/gas

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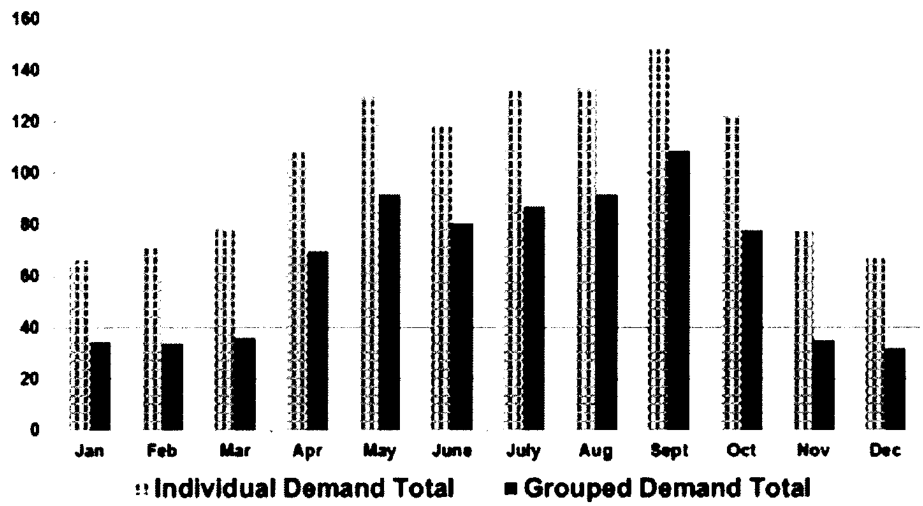
Exhibit 5. Individual and Group Peaks for a 26-Unit Apartment Building



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.

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.
3. Hledik, R. (2015). *The landscape of residential demand charges.* Presented at the EUCI Demand Charge Summit, Denver.
4. Testimony of John Howat, National Consumer Law Center, Indiana Utility Regulatory Commission, Cause No. 44576, 2015.
5. SRP "EZ-3" Rate. Retrieved from http://www.srpnet.com/prices/home/ChooseYourPricePlan.aspx.

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Exhibit MG_5

C. The Minimum-System vs. Minimum-Intercept Approach

When selecting a method to classify distribution costs into demand and customer costs, the analyst must consider several factors. The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted.

The results of the minimum-size method can be influenced by several factors. The analyst must determine the minimum size for each piece of equipment: "Should the minimum size be based upon the minimum size equipment currently installed, historically installed, or the minimum size necessary to meet safety requirements?" The manner in which the minimum size equipment is selected will directly affect the percentage of costs that are classified as demand and customer costs.

Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost.

When allocating distribution costs determined by the minimum-size method, some cost analysts will argue that some customer classes can receive a disproportionate share of demand costs. Their rationale is that customers are allocated a share of distribution costs classified as demand-related. Then those customers receive a second layer of demand costs that have been mislabeled customer costs because the minimum-size method was used to classify those costs.

Advocates of the minimum-intercept method contend that this problem does not exist when using their method. The reason is that the customer cost derived from the minimum-intercept method is based upon the zero-load intercept of the cost curve. Thus, the customer cost of a particular piece of equipment has no demand cost in it whatsoever.

D. Other Accounts

The preceding discussion of the merits of minimum-system versus the zero-intercept classification schemes will affect the major distribution-plant accounts for FERC Accounts 364 through 368. Several other plant accounts remain to be classified. While the classification of the following distribution-plant accounts is an important step, it is not as controversial as the classification of substations, poles, transformers, and conductors.

1. Account 369 - Services

This account is generally classified as customer-related. Classification of services may also include a demand component to reflect the fact that larger customers will require more costly service drops.

2. Account 370 - Meters

Meters are generally classified on a customer basis. However, they may also be classified using a demand component to show that larger-usage customers require more expensive metering equipment.

3. Account 371 - Installations on Customer Premises

This account is generally classified as customer-related and is often directly assigned. The kind of equipment in this account often influences how this account is treated. The equipment in this account is owned by the utility, but is located on the customer's side of the meter. A utility will often include area lighting equipment in this account and assign the investment directly to the lighting customer class.

4. Account 373 - Street Lighting and Signal Systems

This account is generally customer-related and is directly assigned to the street customer class.

III. ALLOCATION OF THE DEMAND AND CUSTOMER COMPONENTS OF DISTRIBUTION PLANT

After completing the classification of distribution plant accounts, the next major step in the cost of service process is to allocate the classified costs. Generally, determining the distribution-demand allocator will require more data and analysis than determining the customer allocators. Following are procedures used to calculate the demand and customer allocation factors.

A. Development of the Distribution Demand Allocators

There are several factors to consider when allocating the demand components of distribution plant. Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation.

Exhibit MG_6

THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES RESOLUTION 2015-1

OPPOSING GAS AND ELECTRIC UTILITY EFFORTS TO INCREASE DELIVERY SERVICE CUSTOMER CHARGES

Whereas, the National Association of State Utility Consumer Advocates ("NASUCA") has a long-standing interest in issues and policies that ensure access to least-cost gas and electric utility services, which are basic necessities of life in modern society; and

Whereas, in recent years, gas and electric utilities have sought to substantially increase the percentage of revenues recovered through the portion of the bill known as the customer charge, which does not change in relation to a residential customer's usage of utility service, through proposals to increase the customer charge or through the imposition of what have been called Straight Fixed Variable or SFV rates; and

Whereas, these gas and electric utilities have sought to justify such increases by arguing that all utility delivery costs are "fixed" and do not vary with the volume of energy supply delivered to customers, and that reductions in customer usage due to conservation and energy efficiency increase the risk of non-recovery of utility costs; and

Whereas, based on these arguments, these gas and electric utilities have proposed that a greater percentage of utility costs (distribution costs such as electric transformers and poles and natural gas mains, traditionally recovered through volumetric rates) should be collected from customers through flat, monthly customer charges; and

Whereas, gas and electric utilities' own embedded cost of service studies,[1] in fact, show that a substantial portion of utility delivery service costs are usage-related, and therefore, subject to variation based on customer usage of utility service; and

Whereas, increasing the fixed, customer charge through the imposition of SFV rates or other high customer charge structures creates disproportionate impacts on low-volume consumers within a rate class, such that the lowest users of gas and electric service shoulder the highest percentage of rate increases, and the highest users of utility service experience lower-than-average rate increases, and even rate decreases,[2] in some instances; and

Whereas, nationally recognized utility rate design principles call for the structuring of delivery service rates that are equitable, fair and cost-based; and

Whereas, SFV and other high customer charge rate design proposals, in which low-use customers would see greater than average increases, while high-use customers would experience lower-than-average increases and even decreases in their total distribution bill, are unjust and inconsistent with sound rate design principles; and

Whereas, data collected by the U.S. Energy Information Administration show that in a vast majority of regions called "reportable domains,"[3] low-income customers (with incomes at or below 150% of the federal poverty level) on average use less electricity than the statewide residential average and less than their higher-income counterparts;[4] and

Whereas, these data also show that in every reportable domain but one, elderly residential customers (65 years of age or older) use less electricity on average than the statewide residential average and less than their younger counterparts;[5] and

Whereas, these data also show that in a vast majority of reportable domains, minority (African American, Asian and Hispanic) utility customers on average use less electricity than the statewide residential average and less than their Caucasian counterparts;[6] and

Whereas, data from the U.S. Department of Energy's Residential Energy Consumption Survey for the Midwest Census region, show that natural gas consumption increases as income increases, and that higher incomes lead to occupation of larger sizes of housing units,[7] thereby increasing the likelihood of higher gas utility usage, and that natural gas usage increases as income increases in the vast majority of reportable domains throughout the U.S;[8] and

Whereas, given these documented usage patterns, the imposition of high customer charge or SFV rates unjustly shifts costs and disproportionately harms low-income, elderly, and minority ratepayers, in addition to low-users of gas and electric utility service in general; and

Whereas, because the imposition of high customer charge or SFV rates results in a smaller percentage of a customer's utility bill consisting of variable usage charges, customers' incentive to engage in conservation as well as federal and state energy efficiency programs is significantly reduced; and

Whereas, NASUCA supports the adoption of cost-effective energy efficiency programs as a means to reduce customer utility bills, help mitigate the need for new utility infrastructure, and provide important environmental benefits; and

Whereas, given that the imposition of high customer charge or SFV rates means that a smaller percentage of a customer's utility bill is derived from variable usage charges, the imposition of SFV-type rates reduces the ability of utility customers to manage and control the size of their utility bills;

Now, therefore, be it resolved, that NASUCA continues its long tradition of support for the universal provision of least-cost, essential residential gas and electric service for all customers;

Be it further resolved, that NASUCA *opposes* proposals by utility companies that seek to increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills and the imposition of SFV rates;

Be it further resolved, that NASUCA urges state public service commissions to reject gas and electric utility rate design proposals that seek to substantially increase the percentage of revenues recovered through the flat, monthly customer charges on residential customer utility bills – proposals that disproportionately and inequitably increase the rates of low usage customers, a group that often includes low-income, elderly and minority customers, throughout the United States;

Be it further resolved, that state public service commissions should promote and adopt gas and electric rate design policy that minimizes monthly customer charges of residential gas and electric utility customers in order to ensure that delivery service rates are equitable, cost-based, least-cost, and encourage customer adoption of conservation and federal and state energy efficiency programs.

Be it further resolved that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution.

Submitted by Consumer Protection Committee

Approved June 9, 2015
Philadelphia, Pennsylvania

No Vote: Wyoming
Abstention: Vermont

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[1]*See, e.g.,* Illinois Commerce Commission Docket No. 14-0244/0225, *Peoples Gas Light & Coke Co. – Proposed Increase in Delivery Service Rates,* PGL Ex. 14.2, p. 1, lines 8, 14, 38 and 42, col. D; Illinois Commerce Commission Docket No. 13-0384, *Commonwealth Edison Company,* AG Ex. 1.0 at 12-13, *citing* ComEd Ex. 3.01, Sch. 2A, p. 13, col. Tot. ICC, line 248.

[2]ICC Docket No. 14-0224/0225, AG Ex. AG/ELPC Ex. 3.0 at 15, 25.

[3]The U.S. Energy Information Administration's Residential Energy Consumption Survey provides detailed household energy usage and demographic data for 27 states or regions of the U.S. referred to as "reportable domains."

[4]*See* Wis. Pub. Serv. Com'n Docket No. 3270-UR-120, *Application of Madison Gas and Electric Co. for Authority to Adjust Electric and Natur4al Gas Rates,* Public Comments of John Howat, National Consumer Law Center, October 3, 2014, *citing* 2009 U.S. EIA Residential Energy Consumption Survey data by "Reportable Domain" at 5-6.

[5] *Id.* at 7-8.

[6] U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

[7] *See* ICC Docket No. 14-0224/0225, *North Shore Gas, Peoples Gas Light & Coke Company – Proposed Increase in Gas Rates,* AG Ex. 4.0 at 11-12; AG Ex. 4.1, RDC-5, p.1-3.

[8] U.S. Energy Information Administration, 2009 Residential Energy Consumption Survey.

Exhibit MG_7

The Alliance for Solar Choice
Data Request TASC-6
Cause No. PUD 201500273

6-2 In reference to page 15, lines 1 through 7, Mr. Scott states that "OG&E established separate classes for DG customers."

a. Did the Company undertake load research on distributed generation customers?

b. Please provide a detailed description of the methods and inputs used to create the load research study for distributed generation customers and any associated workpapers.

c. To the extent that the updated tariff prices for the distributed generation residential class are lower than the rates proposed in Cause No. 201500274, does this reflect the fact that the residential distributed generation class has a lower cost to serve than the general residential class?

Response*:

a. Yes, Load Research was performed on the distributed generation customers.

b. Residential distributed generation (DG) customers and General Service DG customers were both treated like the other customer groups (except Lighting) by starting with the mean-per-unit (MPU) load shape and then performing several adjustments to arrive at the final load shape for that customer group. However, for DG customer groups, the energy flows two ways: in and out. The meter measures the net flowing in (Channel 1) and the net flowing out (Channel 3). The MPU is computed as follows:

   For each DG customer, for each hour, Channel 3 was subtracted from Channel 1; any negative results were changed to zero. [see Subchapter 9 - Optional Net Energy Billing Purchase Rate (165:40-9-3)]. The MPU is the average of these calculations. The results were then used in the development of the Production Demand Allocator and the Transmission Demand Allocator (see WP L-13 Pg4).

   The maximum of Channel 1 and Channel 3 for each DG customer, for each hour, was used to calculate another MPU. The results for this MPU were then used in the development of the Distribution Demand Allocator (see WP L-13 Pg2).

   Please see **TASC 6-2_Att** for the MPU for the Residential DG group and the General Service DG group, for both methods, and the adjustments made to these load shapes.

c. No. The prices for the standard residential rate for the general residential class were not at issue in Cause No. 201500274.

In addition, OG&E has not performed an analysis comparing the residential DG tariff prices proposed in this Cause with those proposed in Cause No. 201500274. OG&E believes the prices it proposed in both Causes were and are cost justified within normal rate design parameters.

Response provided by: Bryan Scott
Response provided on: March 22, 2016
Contact & Phone No: Sheri Richard 405-553-3747

*By responding to these Data Requests, OG&E is not indicating that the provided information is relevant or material and OG&E is not waiving any objection as to relevance or materiality or confidentiality of the information or documents provided or the admissibility of such information or documents in this or in any other proceeding.