BEFORE THE CORPORATION COMMISSION OF OKLAHOMA

IN THE MATTER OF THE APPLICATION OF	)	
OKLAHOMA GAS AND ELECTRIC COMPANY	)	
FOR AN ORDER GRANTING APPROVAL	)	CAUSE NO. PUD 201500274
OF NEW DISTRIBUTED GENERATION	)	
TARIFFS PURSUANT TO TITLE 17,	)	
SECTION 156 OF THE OKLAHOMA STATUTES	)	

Rebuttal Testimony

of

Ashley C. Brown

on behalf of

Oklahoma Gas and Electric Company

November 12, 2015

Q. **Please state your name, occupation, and address.**

A. My name is Ashley C. Brown. I am Executive Director of the Harvard Electricity Policy Group (HEPG) at the Harvard Kennedy School, at Harvard University. HEPG is a "think tank" on electricity policy, including pricing, market rules, regulation, environmental and social considerations. HEPG, as an institution, never takes a position on policy matters, so my testimony today represents solely my opinion, and not that of the HEPG or any other organization with which I may be affiliated.

Q. **Please describe your professional qualifications.**

A. I am an attorney. I served 10 years as a Commissioner of the Public Utilities Commission of Ohio (1983-1993), where I was appointed and re-appointed by Democratic Governor Richard Celeste. I also served as a member of the NARUC Executive Committee and as Chair of the NARUC Committee on Electricity. I was a member of the Advisory Board of the Electric Power Research Institute. I was also appointed by the U.S. Environmental Protection Agency as a member of the Advisory Committee on Implementation of the Clean Air Act Amendments of 1990. I am also a past member of the Boards of Directors of the National Regulatory Research Institute and the Center for Clean Air Policy. I have served on the Boards of Oglethorpe Power Corporation, Entegra Power Group, and e-Curve, and as Chair of the Municipal Light Advisory Board in Belmont, MA. I serve on the Editorial Advisory Board of the *Electricity Journal*.

I have been at Harvard continuously since 1993. During that time I have also been Senior Consultant at the firm of RCG/Hagler, Bailly, Inc. and have been Of Counsel to the law firms of Dewey & LeBouef and Greenberg Traurig. I have also taught in training programs for regulators at Michigan State University, University of Florida, and New Mexico State University (the three NARUC sanctioned training programs for regulators), as well as at Harvard, the European Union's Florence School of Regulation, Association of Brazilian Regulators, and a number of other universities throughout the world. I have advised the World Bank, Asian Development Bank, and the Inter-American Development Bank on energy regulation, and have advised governments and regulators in more than 25

countries around the world, including Brazil, Argentina, Chile, South Africa, Costa Rica, Zambia, Ghana, Tanzania, Namibia, Equatorial Guinea, Liberia, Mozambique, Hungary, Ukraine, Russia, India, Bangladesh, Saudi Arabia, Indonesia, and The Philippines. I have written numerous journal articles and chapters in books on electricity markets and regulation, and am the co-author of the World Bank's *Handbook for Evaluating Infrastructure Regulation.*

I hold a B.S. from Bowling Green State University, an M.A. from the University of Cincinnati, and a J.D. from the University of Dayton. I have also completed all work, except for the dissertation, on a Ph.D. from New York University. My current CV is provided as Ex.-OGE-Brown-1.

Q. **Have you previously testified before the Corporation Commission of Oklahoma?**

A. No. I have testified, however, before FERC and various state commissions as well as before numerous Congressional and state legislative committees.

Q. **On whose behalf do you offer testimony?**

A. On behalf of the Oklahoma Gas and Electric Company (OG&E).

Q. **What is the purpose of your testimony?**

A. The purpose of my testimony is offer my assessment of OG&E's proposed DG rate revision in response to SB 1456 and Executive Order 2014-07. In the course of my testimony I will address various points made in the direct testimony of Oklahoma Corporation Commission witness Kathy J. Champion and of TASC witnesses Mark E. Garrett and Julian R. Barnes.

In particular, I will address calls for delay, reviewing the deficiencies of the current "net metering" tariff, and examining the questions of whether a cross-subsidy from non-DG to DG customers currently exists and requires remedy, as well as claims that the "value of solar" meaningfully offsets, on a going forward basis, cross-subsidies embedded in the current rates. I examine the proposed OG&E tariff revision as a means of addressing cross-subsidies and also promoting the long-term future of solar DG. I will then turn to an

examination of a number of smaller substantive, procedural, and legal issues raised by the witnesses.

Q. **What conclusions do you reach in your testimony?**

A. I reach the following conclusions:

- That the distortions associated with the current net metering tariff, if not corrected before there is more pervasive market penetration by solar DG, will inevitably distort price signals, increase inefficiency, and cause potentially severe inequities to emerge between solar and non-solar customers. It is essential to address these issues as soon as possible, rather than waiting for a large DG customer base to develop, something which will erect new barriers to efficient and equitable pricing;
- That, while currently affecting a small number of customers, the cross subsidy from non-DG to DG customers is undeniable and requires action in order to be fully compliant with the directives of the state's government as expressed in Senate Bill 1456 and Executive Order 2014-07;
- That none of the elements associated with "value of solar" claims give any basis for delaying action on the proposed tariff change, or otherwise avoiding the legislative directive to have new tariffs in place by the end of 2015;
- That, in fact, the specific nature of the cross subsidy constitutes an unfair and unjustifiable transfer of wealth from lower income to higher income groups, giving an additional urgency to addressing existing cross-subsidies
- That the proposed tariff revisions, while contrary to the short-term interests of the DG solar industry, are in the long-term interest of the development of solar energy, including but not limited to DG itself, as a valuable resource;
- That calls for delay pending a new rate case are unjustified, that the use of the most recent cost of service study was appropriate, and that OG&E's proposed change is prospective only in its application so it has virtually no effect in terms of reallocating costs among existing solar and non-solar customers, and thus, there is no reason to wait for a new rate case to resolve what is, in fact, a generic pricing policy issue, rather than a matter best left for rate cases;

- That objections raised by the TASC witnesses based on language in the senate bill regarding customer classes and the definition of distributed generation customers are unfounded;
- That inclusion of a demand charge is a beneficial feature of the new tariff that helps align the charges paid by DG customers with the actual costs they cause on the system and reflects a more equitable allocation of costs going forward.

Q. **Why is it important to fulfill the requirements of SB 1456 and the Executive Order and to revise the tariff?**

A. The Senate and the Governor have taken an important and timely action in mandating that cross-subsidies from non-distributed generation customers to DG customers embedded in the current net metering tariff should be eliminated by the end of 2015. The old net metering system of reimbursing distributed generation, common around the country and now being reexamined and/or eliminated in many jurisdictions, was, with one possible exception, never truly a conscious policy decision. It is basically the default product of a variety of no longer relevant considerations, some practical and some technological. The practical reason is that distributed generation initially had such an insignificant presence in the market that its economic impact was marginal at best. Thus, no one was seriously concerned about "getting the price right." The second, technological, reason is that the meters most commonly deployed, especially at residential premises, until recently have had very little capability other than to run forward, backward, and stop. Thus, for technical reasons, net metering was simple to implement and administer and, as a practical matter, given the paucity of DG, there was no compelling reason to go to the trouble of remedying a clearly defective pricing regime. Beyond that, net metering began before we had the sophisticated price signals (e.g. locational marginal pricing, capacity bidding) that we now have in SPP and other organized markets, so when net metering was first adopted, there was no clear energy or capacity price marker to reference for establishing DG prices. To the extent that there was any policy consideration given to net metering, it was to provide an additional, cross-subsidy, boost to assist solar DG to get over the commercialization hump. Given the rapidly declining costs of solar panels, it cannot be seriously contended that the cross-

subsidy is needed, particularly given the fact that tax subsidies and renewable energy credit (RECs and SRECs) markets are in place in many markets. These evolutions in costs, public policies, and market functionality were, at least in part, anticipated, because advocates offering the public policy rationale for cross-subsidies for solar DG suggested that making non solar customers pay a retail price for a wholesale product should not be permanent, only a short term boost to facilitate market entry, and should last only until policy makers determined it was no longer needed, which, based on looking realistically at current market conditions, is precisely what the Oklahoma legislature has determined.

We now, as noted, have pricing measures and technology that are more capable of measuring DG production as well as consumption on a more dynamic basis. In addition, solar DG market penetration around the U.S. has demonstrated its capacity to dramatically increase to the point where it can no longer be dismissed as marginal, so appropriate pricing is a non-trivial issue.

States in which substantial solar distributed generation has been installed under net metering policies face a particularly difficult policy problem—whatever they do could well be unfair to one group of customers or another. Taking away a promised net metering benefit is, some would contend, unfair to customers who installed solar relying on this benefit. On the other hand, "grandfathering" existing net metering customers continues a significant cross subsidy which can burden other customers for decades. Nevertheless, Commissions in states such as Hawaii and Wisconsin have revised their net metering policies (the Wisconsin effort suffered a recent, largely procedural, thus likely temporary, setback in court). States, including California, Nevada, Arizona, Maine, Massachusetts, Ohio, Kansas, Louisiana, and Florida, are all in various stages of reviewing their net metering polices, as are a number of municipal and co-operative utilities around the nation. Stated succinctly, this proceeding in Oklahoma is one piece of a vigorous debate around the U.S. to design an optimal system for pricing rooftop solar. The old national *status quo* of net metering (in all but seven jurisdictions) is no longer acceptable in a growing number of states, as well as municipal and co-operative utilities.

Oklahoma is in a fortunate position in that it has recognized this issue relatively early in the development cycle for distributed generation in the state. The bulk of the cross subsidy problems lie in the future, if the rate is not amended. By acting now, Oklahoma is

able to fulfill the expectations of DG customers without unduly burdening other customers. But the longer Oklahoma waits to act, the less true this will be. More importantly, from a political perspective, it will avoid the divisive and often ugly nature of the political/regulatory battles to reform net metering practices that have characterized the processes going on in California, Arizona, Nevada, and Hawaii, to name just a few of the states where this is occurring. Recognition of this dilemma is presumably why SB 1456 included a firm deadline for action.

Q. **SB 1456 states that "No retail electric supplier shall allow customers with distributed generation installed after the effective date of this act to be subsidized by customers in the same class of service who do not have distributed generation." Can we really be sure this cross-subsidy is occurring?**

A. One of the central claims of witnesses Garrett, Barnes, and, to a somewhat lesser extent, Champion, is that OG&E has failed to demonstrate that under the current rate DG customers are in fact subsidized by non-DG customers. It is worth taking the time to examine exactly how they make this argument. Essentially, they argue that the only way for OG&E to successfully establish that cross-subsidy is occurring is to do both a new cost of service study and a separate "cost effectiveness study to review the benefits provided by DG customers." (Champion, p. 15). Without a detailed quantitative analysis of claims for the benefits of solar (a challenging technical analysis whose methodology Barnes suggests should be developed in a stakeholder process) (Barnes, p. 5), these testimonies argue that it is fair to reject OG&E's analysis that finds that a cross-subsidy exists and should be remedied. Their recommendation, therefore, is delay—either indefinite delay (Barnes) or delay pending completion of the next rate case (Champion and Garrett).

I suggest that if we look at the question of the existence of cross-subsidies from the perspective of how net metering actually works, the problems with it and the need (indeed, legal requirement) for immediate action are obvious. What would you have to believe about the "value of solar" in order to believe that it is even possible that there is no cross-subsidy from non-DG to DG customers? Not just that there is some marginal value being offered—the additional non-energy value would have to be quite

significant—approaching the value of the energy itself to offset the huge subsidy that is embedded in current net metering arrangements.

To support this claim, it is necessary to begin by reviewing how the current net metering tariff works. The bills customers receive for electricity cover a broad array of costs incurred in providing service to them, but they generally fall into three categories of costs: energy, fixed, and demand. The retail price paid by customers includes all three sets of costs. A modest customer charge covers some, but not nearly all, of the utility's fixed costs, and the remainder of the utility's costs—energy costs, but also costs associated with transmission and distribution, and any fixed costs not covered by the customer charge—are billed on a per kWh basis. The energy component of the total cost is just a subset of the total—in the neighborhood of 50%-60% of the cost of providing service. But, in the average residential bill, more than 80% of the amount collected is tied to kWh usage, and that is the rate at which net metering customers are compensated for their production. That means that DG customers get a credit for the energy they produce that reflects not only the value of the energy itself, but also costs associated with the delivery of energy (e.g. wires, maintenance, administrative, and other non-energy-related costs) plus the costs the utility incurs to be assured that it can meet the peak demands of each and every customer it serves. The simple reality of retail net metering is that the utility is required to pay a retail price for a wholesale product, and that those costs are passed on to the non-solar customers, who are, therefore, compelled to pay a retail price for a wholesale product, namely energy—intermittent (often unpredictably so) energy, at that.

That, in itself, produces a significant cross subsidy, but it does not stop there. It is critical to understand that each utility has an open ended legal obligation to meet all demand, no matter when and no matter the load shape. Thus, the system has to be sized to meet that obligation, and the utility has to be able to call upon generation, not to mention the entire delivery system, including distribution and transmission, to meet all of its energy requirements, regardless of whether customers actually consume it. It costs utilities money to have this capability, be it fully utilized or merely standby at times, to serve demand. Thus, when solar hosts are consuming the energy produced on their rooftops, they are not paying for the fixed costs the utility has to incur just in case the sun is not

shining and they call upon the utility to provide service, or in case they produce more than they consume and seek to use the distribution grid to export energy. (In essence, the utility is providing DG consumers with free energy storage service, in a fashion that often takes the energy in off peak, when prices are low, and returns them on peak when prices can be significantly higher).And since DG solar customers get a break from the whole retail cost of energy, much of the fixed and demand costs incurred by the utility to serve solar customers are not paid by those customers but, rather, are passed on to their non-solar neighbors, something which is contrary to a fundamental principle of regulation and pricing basics, namely that the cost causer pays. The result is that, under retail net metering, non-solar customers pay a significant part of the fixed costs incurred by solar hosts. Distributed generators pay the same rate as other residential customers when they buy electricity--and they are paid the full retail rate for excess electricity generated when they sell it back to the grid. And when they match their production to their consumption, they pay nothing.

This means that to the extent their production allows them to avoid purchasing energy from the grid, DG customers pay only about half of the roughly 40%-50% of the average non-DG bill that goes to support the operations of the utility, the maintenance of the grid, and the costs incurred by the utility to ensure a secure supply of electricity. Other customers must absorb this additional cost, creating the cross subsidies that are a concern and that OG&E now has a legal mandate to eliminate by the end of the year. To make matters worse, and the cross subsidy even more severe and obvious on its face, under net metering a solar DG provider who sells excess energy produced (i.e. more energy than needed for self-consumption), is paid the full retail price for the energy, even though he/she incurs no cost and invests absolutely nothing for all of the remainder of the retail system to deliver the energy to other customers and to provide back up when solar production is nil. In effect, when solar DG is producing excess energy, the cross subsidy per unit of energy provided is doubled. To believe that such cross subsidies among customers do not exist, you would need to believe that the "value of solar dg" supplied by the distributed generators is huge--worth an amount approaching the value of the energy they produce. This is simply not credible, no matter how creative one’s theories might be

about externalities and fantasies about avoided costs. As I argue below, zero is a far more plausible number.

Q. **Why can't customers carry over production credits from one month to another?**

A. As OG&E witness Walkingstick points out in his testimony, this tariff is not designed for customers whose systems are sized to produce more than the customer uses in a month—such customers are free to choose the sell-all, buy-all tariff, which may be more appropriate for them. Trying to provide for such carryover under the proposed new tariff would inappropriately complicate the task of trying to make sure no customer group cross-subsidizes another. Energy prices can fluctuate dramatically from month to month—an hour of energy produced in the winter, for example, is just not, from price, load shape, and cost allocation perspectives, the same as an hour produced in the summer. The netting policy accordingly reflects an appropriate balance between offering flexibility within a month-long period, but not an unlimited ability to carry energy credits from one season to another.

Significantly, carrying over from month to month or season to season would wreak havoc on price signals, perhaps diluting them to virtual incoherence, and will inevitably have the effect of shifting cost allocations among customers. It is antithetical to good economics and rate design. Indeed, it reveals a kind of mindset among some solar DG advocates, including the TASC witnesses in this proceeding, that promoting solar, or at least the short term financial interests of the solar DG vendors, trumps all other considerations, including sensible and coherent pricing, when it comes to rate design.

Q. **What about all of the additional sources of value of distributed solar generation identified in the checklist?**

A. Champion, Barnes, and Garrett all point to various elements that may be collectively referred to as the "value of solar" (although it might be more accurate to refer to them as the "value of solar DG")[1] that they suggest may offer sufficient benefits to the grid to

[1] Note that in the context of this testimony, whenever I refer to the "value of solar," I am referring to the value of distributed generation solar, not utility-scale solar.

make up for the obvious and self-evident subsidy being offered to DG customers under the current net metering tariff, referencing the following items from the "Technical Conference Checklist":

a) avoided energy costs
b) avoided generating capacity costs,
c) transmission and distribution (T&D) line loss reduction (avoided transmission/distribution investment)
d) environmental benefits (emission mitigation costs)
e) avoided purchased power/risk
f) avoided grid support
g) economic development

A discussion of these "value of solar" components is particularly central to the testimony provided by Julian Barnes, who states that a "comprehensive quantitative methodology for determining the value of DG benefits" should be developed, (p. 5) utilizing a renewed stakeholder process, and considering benefits over a long term (25 year) time horizon.

As an encouragement to Oklahoma to undertake such a project, Barnes cites the existence of a number of cost-benefit studies by other states, though he is selective about which studies he highlights. In his table summarizing "State Cost-Benefit Study Results," (10-11), for example, Louisiana, one of the states he mentions as an example of such an analysis (8), is not included—possibly because the Louisiana study found evidence of a substantial cross-subsidy from non-DG to DG customers.[2]

Without attempting in this context to evaluate these studies individually, the problem with all these studies is that there are so many variables and uncertainties, it is impossible to conduct an analysis that does not rely on a number of arbitrary assumptions and judgments, particularly as it relates to deciding which issues should be evaluated and which should not. Typically, for example, authors of such studies include "analyses" of externalities, which almost inevitably pick and choose which externalities to examine and

[2] Dismukes, David E. *Estimating the Impact of Net Metering on LPSC Jurisdictional Ratepayers.* Prepared on behalf of the Louisiana Public Service Commission by Acadia Consulting Group. DRAFT. February 27, 2015. http://lpscstar.louisiana.gov/star/ViewFile.aspx?Id=f2b9ba59-eaca-4d6f-ac0b-a22b4b0600d5

which to avoid. Such studies are also not inexpensive, and are frequently, if not usually, paid for by parties with a preexisting point of view they wish to vindicate. Barnes himself effectively acknowledges this in that, to his credit, he does not go so far as to argue that there is currently a solid, tried and tested empirical methodology for assessing "value of solar" claims. Instead, he suggests the existing studies "point to an emerging set of best practices." (9) He holds up a publication from the Interstate Renewable Energy Council (IREC) as providing a model for "qualitative" thinking about a methodology, and suggests that an appropriate methodology could be further defined through a stakeholder process. (9) That publication, rather than being a "best practices" guide, is an advocacy piece that simply lays out an outline for ways of articulating the very cross subsidization of solar DG that the Oklahoma Legislature has already mandated be terminated. Its approach to the subject is, therefore, considerably less robust and thorough than a neutral analyst might produce. It suggests, for example, an examination of the impact of solar DG on carbon reduction, but gives little guidance on how such an effort should be undertaken, and, remarkably, never even suggests that one might examine the cost effectiveness of solar DG in reducing carbon emissions compared to such alternatives as energy efficiency, large scale solar, nuclear, and wind. Similarly, it fails to even reference the fact that in order to assess the carbon effects of solar DG, one needs to clearly identify what generating resources are being displaced (e.g. coal, combined cycle) by solar DG when it is producing energy and what the impact of the intermittent nature of solar DG is on dispatch, as well as the environmental impact, not to mention economic efficiency, of ramping generation up and down to accommodate the intermittent injection of solar DG energy into the system.

The point here is not that the IREC document, or other value of solar studies, are incomplete and biased, although the IREC report clearly is, as are many of the value of solar studies. Rather, it is that such studies are highly subjective, often quite arbitrary, and extraordinarily complex (if the authors are truly disinterested analysts, as opposed to advocates with a point of view), and, to be done correctly, these studies require a great deal of time and expense. Moreover, the results, no matter how honestly derived, are always going to be highly subjective and subject to severe criticism by any number of interest groups with an axe to grind or a point of view to advance.

To expect a solid, unbiased scientific methodology for quantifying benefits in a complex energy system to emerge through a stakeholder process is profoundly misguided. It is an invitation to an expensive, time-consuming process which sheds more heat than light, no matter what the final analysis finds. Barnes himself, again to his credit, stops short of fully recommending this, noting that "The cost of the completion of a comprehensive DG cost-benefit analysis would likely be at least an order of magnitude greater than the $3,000 annual figure [which Barnes claims is the amount of the current subsidy], while also requiring substantial time commitments on the part of staff, utilities, and other stakeholders. I do not believe that such a substantial cost is warranted or in the interest of ratepayers and other parties at this time." (13) Moreover, even if one assumes the cost is justified, the report produced will be less than definitive and almost inevitably change no one's opinion as a result.

Though he sensibly sees that such a study at this point is not a good use of Oklahoma's resources, Barnes is wrong in his conclusion that the correct response in this case is to wait. Keeping in mind the substantial cross subsidy currently being offered to DG customers and the importance of transitioning as soon as possible to a fair tariff for distributed generation that can be sustained even as distributed generation grows in Oklahoma, the Commission is perfectly capable of doing a common-sense assessment of "value of solar" claims, as well as pricing principles, based on the type of analysis that the Commission usually carries out in the course of carrying out its obligations, and can evaluate OG&E's proposed treatment accordingly. I have every reason to believe that the Commission is capable of carrying out its mission in an efficient, analytical, and fair manner without having to go to the extraordinary effort of seeking out a consultant to carry out a highly subjective study.

Q. **Is it typical in rate proceedings for the Commission or utilities to carry out studies at the request of the litigants before it, or, in the case of utilities, of opposing parties?**

A. No, it is not. Typically, parties appearing before a Commission arrange for whatever studies they wish to have in the record. TASC, unlike so many other litigants before state commissions, failed to offer up any Oklahoma, or even SPP specific, studies they believe

the Commission should consider in the course of this proceeding. The fact that they failed to do so makes it plain that they not only do not believe such a study is justified, but are also not seriously seeking to have a study done to "enrich" the record before the Commission. While witnesses Garrett, Barnes, and Champion imply that such a study is necessary for OG&E to meet its burden of proof that is simply not the case. To meet its burden, a utility need not conduct every possible study that is requested by opposing parties; it simply has to present a reasonable case, which, of course, opposing parties have the opportunity to rebut. Thus, if TASC believes that OG&E, in making its proposal, has failed to look at the value of solar, or any other issue for that matter, then it has the burden of at least providing evidence as to why they claim the application is deficient. They have simply failed to do so in this matter. In fact, what they are actually doing is making every effort to delay the inevitable, namely compliance with the legislative mandate to eliminate cross subsidies. TASC members, not individual solar hosts, are the biggest beneficiaries of net metering. Indeed, their entire business model is based on deriving profits from a serious tariff flaw. Thus, the longer they delay repairing the flaw, as the Oklahoma legislature has required, the more the benefits accrue to their bottom line.

Q. **Why do you argue that there is no significant additional value provided to the grid by DG that needs to be considered in OG&E's tariff revision?**

A. My own analysis of the various individual elements generally offered up to inflate the value of solar suggests that there is little bankable value there, with the exception of avoided energy costs and, perhaps, dependent on localized circumstances, avoided transmission congestion. If the Commission determined that it wanted to consider externalities, which some, but not all, state commissions do, there might be some environmental value, but that is a highly complex question deserving of its own discussion (found in my next response).[3]

[3] For a more complete discussion, see Brown, Ashley and Jillian Bunyan, "Valuation of Distributed Solar: A Qualitative View," *The Electricity Journal* 27.10 (December 2014): 27-48, included as Exhibit RDW 13 in the testimony previously provided by Roger D Walkingstick.

Let me briefly address each of the other claimed ways in which solar adds value:

- *Avoided energy costs*

  DG solar generation, when produced, does reduce the amount of electricity OG&E must purchase in the spot market. These energy savings are reflected in the proposed energy rate that OG&E includes in its proposed new tariff. Whether those energy savings translate into cost savings, of course, is entirely dependent on the price in the market vs. the price paid for solar DG-produced energy. Under net metering, where energy price is full retail, vs. the LMP wholesale energy price (which includes transmission), there is a high likelihood that the energy savings not only fails to translate into cost savings, but may actually turn energy savings into increased costs for non-solar customers to pay.

- *Avoided generating capacity costs*

  The idea that having a lot of distributed solar on the system means that the utility requires less generation capacity (either owned or contracted for) is one of the most commonly asserted claims made by retail net metering advocates. It is, however, almost entirely a myth. Solar energy is intermittent. It is only available when the sun is shining. Utilities, however, are required to serve all of the demand of customers in their service territory. That means they have to plan for the capacity to serve peak demand, even when distributed solar PV may not be available (in OG&E, the true system peak occurs at about 5pm—by which time the 2pm hour of peak solar production has long passed). Because utilities can't count on it to be available, distributed solar PV does not offset capacity costs. Indeed, because solar DG is intermittent, absent storage and/or a commitment of the solar provider to provide alternative capacity in the event that it cannot produce energy when called upon to do so, solar DG has virtually no capacity value at all.

- *Transmission and distribution (T&D) line loss reduction (avoided transmission/distribution investment)*

  Whether or not solar PV systems "reduce the amount of energy lost in generation, long distance transmission and distribution" is a fact specific question. It is flat wrong to claim that solar PV systems, *ipso facto*, reduce losses. On distribution

systems, this point is being debated among experts, and it appears to be that the truthful answer is that sometimes it may be true, but often, it is not only not so, but may, in some circumstances, increase losses or cause additional costs to be incurred to cope with the newly bi-directional energy flow on the distribution grid. With regard to transmission losses, it is certainly true that solar PV on distribution systems does not rely on high voltage transmission. It does, nonetheless, impact the transmission system because of its intermittent nature and its steep ramps up and down, which require utilities to be able to quickly bring other resources on line. That necessarily results in changes in the flow of energy that can lead to increased, not decreased, losses. Moreover, the likelihood that solar DG avoids the need to build new transmission is way off the mark for a couple of reasons. The first is, as in the case of generation, the intermittent nature of solar DG means that it cannot be relied on to meet peak demand. Thus the high voltage grid will have to be sized based on the assumption that solar DG is not present at peak, since intermittency precludes any certainty of its availability. The second reason is that new transmission is built with the ideas of maximizing the use of scarce right of way, capturing economies of scale, and enabling future growth. Thus, adding new transmission capacity is a lumpy rather than a mathematically precise or "just in time" undertaking, and as such, installing even a substantial number of rooftop solar units would have, at best, a negligible effect on planning for adequate transmission capacity.

- *Environmental benefits (emission mitigation costs)*

  These will be discussed separately below.

- *Avoided purchased power/risk*

  In theory, solar power is a "hedge" against price volatility in other power sources. As discussed in my *Electricity Journal* article, however, solar's intermittency greatly erodes its value as a hedge: "solar DG is the equivalent of a risky counterparty whose financial position renders him incapable of assuring payment

when required."[4] And under net metering, the price being paid for solar is higher than any prices the utility is likely to see elsewhere—this is like paying for vacation insurance that costs more than the trip itself.

- *Avoided grid support*

  It is notable that proponents of retail net metering almost never offer specifics as to the grid benefits claimed. That is because there are virtually none. In fact, distributed generation imposes costs and burdens on the grid by adding transaction costs and, in many cases, by compelling substantial changes in local networks to reflect the fact that the flow of energy is being changed from one directional to bidirectional. Significant geographic concentration of solar PV may cause the utility to have to make very substantial capital investment to upgrade the grid to accommodate the new flows put on the system. In California, in fact, serious consideration is being given to totally restructuring distribution grids in order to effectively manage the new flows, both physical and financial. While such accommodations can be made, policy makers do need to understand that there are costs associated with making them and should be mindful of who must bear responsibility for those costs.

- *Economic development*

  Advocates of subsidies for distributed solar generation often point to supposed economic benefits—particularly job creation in the solar installation field. But claims about a positive impact on job creation are one-sided—they count new jobs created in solar—but if the cost of electricity is higher as a result of paying retail prices for wholesale energy produced by solar DG, jobs are likely to be lost elsewhere in the economy—there is no reason to assume that the net job impact of distributed solar power is positive. Indeed, it is not at all clear that if net metering were eliminated, the effect would even be to reduce solar installation jobs.

[4] Brown and Bunyan, p. 40.

Q. **What about the value of reductions in carbon emissions?**

A. Clearly, the biggest single factor in the potential "value of solar" has to do with the externalities of carbon emissions. These externalities may be real and important, but not all state regulators believe that they have the power to take such matters under their consideration. Nonetheless, even assuming that regulators and state elected officials believe that carbon externalities should be incorporated into electricity generation decisions, preserving "net metering" payment for distributed solar generation is, to understate the point, an inefficient way to do this. Distributed solar PV is, of all common forms of renewable electricity generation, the most expensive way to reduce carbon emissions—utility-scale solar and wind power, in particular, are both significantly cheaper. No less an environmental advocate than Amory Lovins acknowledges that solar energy (even utility-scale solar energy) is less cost effective than energy efficiency, wind and hydro in terms of reducing carbon emissions.[5] To give a targeted cross-subsidy the least cost effective way of reducing carbon is poor public policy from any perspective, and certainly not a sensible or effective approach to reducing carbon emissions.

Finally, on the question of carbon emissions, should the Commission choose to consider this externality in deciding the issues before it in this case, there are two more important considerations. The first is that should the U.S.EPA proposed Clean Power Plan survive legal challenge in some form and go into effect, carbon will no longer be an externality and become fully internalized into electricity prices. As a result, utilities and regulators will be searching for optimal compliance plans. Technology set asides/preferences, such as net metering for solar DG, will almost certainly become impediments to economic optimization in compliance. Solar DG in particular, because it is so cost ineffective in reducing carbon, will become an albatross for states seeking least cost compliance strategies. The EPA itself seemed to recognize the inherent complexity of relying on solar DG as a method for reducing the carbon footprint. As detailed in a blog post from the Bipartisan Policy Center, "In the final rule, EPA notes that distributed generation was excluded from calculations of the "best system of emission reduction" because of unique

[5] Lovins, Amory B. "Sowing Confusion about Renewable Energy." *Forbes* August 5, 2014.

data and technical challenges that complicate identifying a technically feasible and cost-effective level of generation from these resources."[6] States are not prevented from using these resources to comply with the CPP—but the path is, as noted, very complex.

In addition, decision makers on this issue should carefully consider the German experience. That country made huge investments in intermittent generation, including solar DG, using subsidies and cross-subsidies to do so, with the objective of reducing carbon emissions. The result to date has been very, very disappointing for policy makers there. Carbon emissions actually increased from 2009-2013 (with the steep increase of 2009-2013 falling off in 2014, but still leaving power sector carbon emissions higher than 2009 levels), and rates have increased dramatically.[7] The reasons for that almost counter-intuitive result are complex and varied, but the point is that the linear arguments often made by TASC and other solar DG advocates, that renewable resources, *ipso facto*, will reduce carbon emissions, is simply wrong. There is very little that is linear about electricity markets, so in contemplating the environmental impact of solar DG and other energy resources, one needs to carefully examine issues analytically and holistically, and not resource by resource out of the full context.

Q. **Are there any relevant social effects of the current system of support for distributed generation?**

A. Yes, there are. Net metering constitutes a wealth transfer from less affluent to more affluent customers. It is intuitively obvious that less affluent customers lack the means to invest in solar, and often do not own their residences, so they are unable to install solar, even if they could afford to do so. This is a huge social externality that comes along

[6] McGuinness, Meghan. "Beyond the Building Blocks: Implications of the Clean Power Plan for Distributed Resources and Advanced Grid Technologies." *Bipartisan Policy Center Blog* (October 19, 2015): http://bipartisanpolicy.org/blog/beyond-the-building-blocks-implications-of-the-clean-power-plan-for-distributed-resources-and-advanced-grid-technologies/

[7] See Conca, James. "Germany's Energy Transition Breaks the Energiewende Paradox." *Forbes Energy Blog* (July 2, 2015): http://www.forbes.com/sites/jamesconca/2015/07/02/germanys-energy-transition-breaks-the-energiewende-paradox/. See also Schwagel, Christian. "A Clash of Green and Brown: Germany Struggles to End Coal." *Yale Environment 360 Blog* (July 7, 2015): http://e360.yale.edu/feature/a_clash_of_green_and_brown_germany_struggles_to_end_coal/2891/

with distributed generation cross subsidies. A 2013 study by E3 Consulting of net metering in California found that the median income of net metering customers was 168% of the median California household income—and the system as a whole was projected to see another $1.1 billion annually in costs by 2020—costs which would have to be borne by those (on average, poorer) households not participating in net metering.[8]

Q. **But if you cut this additional support for distributed solar energy, is this consistent with the long-term development of the solar renewable resource?**

A. Yes. The long-term interests of the development of solar as an energy resource are very different from the short-term financial interests of the solar DG industry, as represented by TASC. In the long term, in order to be fully sustainable, solar energy needs to be fully competitive on both a price and qualitative basis. That means both that solar should be competitive on a price basis, independent of any subsidy, and that steps need to be taken to reduce the intermittency of solar (e.g. link it to storage, or use western rather than southern exposure in order to better align production with peak demand). Net metering is exactly the wrong incentive, since it simply throws ratepayer money at solar DG in its most inefficient and primitive. Net metering not only fails to incent increases in productivity, but actually discourages them, by making solar artificially more profitable by not investing in technological development or take other steps to improve productivity What is critical to understand is not only that net metering is a very poorly designed subsidy, but that it works only in the short term financial interest of TASC and its members but is contrary to the long run interest of solar energy. The MIT study, *The Future of Solar Energy,* observes, "the future of PV technology will be strongly influenced by the PV industry's ability to sustain recent price declines." (77) But MIT also observes a "striking differential" between MIT's estimate of the cost of installing residential PV systems (including a profit margin) and the reported average prices for residential PV systems—actual prices for residential systems were approximately 150% of MIT's cost estimate—a difference between cost and price not observed for utility-scale

[8] *California Net Energy Metering Ratepayer Impacts Evaluation.* Prepared for the California Public Utilities Commission by Energy and Environmental Economics (October 8, 2013).

installations. (86) **It seems that profit margins for residential PV systems are being inflated, raising system costs for homeowners—a development that may be in the short-term interests of residential PV system developers, such as TASC members, but which is not in the long-term interest of solar power.**[9]

In the short term, as noted, the current rate benefits the solar industry, because of the inherent wealth transfer from non-solar to solar customers. Actually, to be more precise, net metering forces non-solar customers to pay higher prices to subsidize solar companies such as TASC members. As documented in the MIT study, there is evidence now that the declining costs of solar panels, which have been quite dramatic in recent years, are not being passed through to consumers, but are being offset by inflated "installation" costs, thereby allowing most of the benefits of declining panel costs to be retained by TASC members and other solar vendors, to the detriment of all consumers, solar and non-solar alike. This may have something to do with why a recent study by Lawrence Berkeley National Labs found that out of six countries it compared to the U.S. (Germany, Japan, Italy, China, France, and Australia, only France had higher costs for installed residential PV systems.[10]

Beyond that, and perhaps more important in the long term evolution of solar energy, net metering is actually harmful to solar energy because the current tariff provides absolutely no incentive to improve the performance of a generating resource that, as we have seen, ranks last among renewables in efficiency and cost effectiveness, both in terms of economic efficiency and as a tool for reducing carbon emissions. In effect, the solar industry is putting its short-term profits ahead of the long-term value of solar energy. It is also putting its financial interest ahead of providing value to its customers and ahead of the long run value of the product they are selling. If TASC and other similar minded solar DG industry advocates prevail in delaying or perhaps permanently preventing OG&E

---

[9] *The Future of Solar Energy: An Interdisciplinary MIT Study.* MIT (2015). https://mitei.mit.edu/system/files/MIT%20Future%20of%20Solar%20Energy%20Study_compressed.pdf

[10] Barbose, Galen and Naim Darghouth. *Tracking the Sun VIII: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States.* Lawrence Berkeley National Laboratory (August 2015).

from complying with the legislative mandate to eliminate cross-subsidies by the end of the year that victory will be short-lived, because markets, both regulated and unregulated, do not prop up inefficient resources over the long term. It will also needlessly transfer the hard earned money of Oklahoma ratepayers to a small group of vendors with little of value to show for it, and, ironically, to the detriment of the long term value of solar energy.

Q. **Can you provide examples of how net metering does not provide incentives for the long run viability of solar energy?**

A. Yes, I can. There is one issue in particular that beautifully illustrates the way in which the current tariff discourages the kind of technical innovation that could make solar DG much more valuable to the electricity system as a whole—the issue of energy storage. As discussed above, under the current tariff, the utility is essentially a giant free battery available for use by DG solar customers—any excess energy they produce goes to the grid, and they can import an equivalent amount of energy back from the grid any time within the month. What this means is that DG customers, who would seem to be a natural market for some of the new battery storage products available on the market from Tesla and others, have no incentives to invest in this new technology—delaying the development of the integrated solar/battery home systems that may be a logical next step for distributed generation—posing a dilemma for Elon Musk, who is simultaneously the CEO of Tesla Motors and Chairman of Solar City (see Ex.-OGE-Brown-2), a leading member of TASC, "The Transformation of the Energy Sector: Net Metering vs. Storage Creates Clash Between Some Allies")

Another example of the potential of solar systems to provide value is mentioned by Barnes (32). "Smart inverters" installed as part of a DG system have the potential to provide voltage regulation services to the distribution grids. But Barnes suggests that this *potential* value be considered in an assessment of the current value of solar. To the extent that this potential value is incorporated and reimbursed prospectively, the ironic result is to remove any incentives for DG customers to participate in the actual utilization of the resource. To the extent that grid developments make it possible to utilize this potential resource, a way should be found to compensate solar DG customers for the value of this

additional service—but if we compensate them prospectively, before the grid realizes any benefit from this potential service, we remove the incentive to make this potential a reality.

Q. **Are the interests of TASC members aligned with the interests of the consumers who install or are considering installing solar panels on their roofs?**

A. No, they are not. Solar and prospective solar customers are looking for cost effective means of meeting their need for electricity. In seeking cost effective means of reducing their electricity bills, such customers have a variety of options, most notably including energy efficiency, as well as a solar panel on their roof. Their desire for reducing costs, however, is not necessarily technology specific, so going solar is but one option. Many may also be motivated by concerns for the environment. To the extent to which such activities are cross-subsidized, obviously, they would want to be the beneficiaries of the cross subsidy, although few if any of those customers are explicitly seeking rents from their neighbors. Again, however, a customer's desire to reduce his/her carbon footprint is not technology specific; it is results driven, and there are methods beyond solar that can accomplish the desired end. As noted, Amory Lovins' calculations would suggest beginning with energy efficiency.

TASC members, on the other hand, represent large corporate interests with a single purpose, namely making profits by selling and installing rooftop solar. In fact, it should be pointed out that TASC does not represent smaller, local solar vendors, but only the largest corporate interests in the solar DG space. There is nothing wrong with that structure and purpose, but it does make their interests quite different than those of solar and prospective solar customers. First, unlike customers, who are interested in having accurate, unbiased information in order to make sound decisions whether or not to install solar panels, the incentive to TASC members is to provide customers with "information" skewed to motivate customers to buy their goods, included inflated estimates of future energy costs and carbon reductions from solar DG. TASC members and solar customers, share an interest in potential renewable energy credits (or SRECs where there is a market for it), cross-subsidies, and tax credits, but their interests in those subjects are, in fact, competitive, as TASC members seek to structure deals with customers in such a fashion

as to capture those benefits for themselves and deprive their customers of the opportunity to obtain them. Customers, of course, have a very real interest in getting the best deal for themselves in regard to the purchase and installation of panels. Thus, when the cost of panels declines as it has in recent years, customers want to see those saving passed on to them. That, of course, is precisely the opposite of what TASC members would like to happen. As the cited MIT and LBL studies point out, solar DG vendors, rather than passing on the savings, are retaining the savings for themselves by increasing "installation" costs. TASC members are enabled to deprive their customers of declining costs because net metering provides an artificially high price for their product that is immune to the ordinary pressures of the marketplace. That brings us to the ultimate irony in the divergence of interests between TASC members and solar dg, indeed, all customers.

TASC claims to champion competition and oppose monopoly power, and thereby serve as the consumer's champion in creating a competitive marketplace. In fact, the reality is exactly the opposite. Their advocacy of net metering in this proceeding and others around the country, calls for perpetuation of an inefficient, highly inflated, price not subject to any competitive pressure, a price that can only survive in a non-competitive environment. In effect, they are seeking a market where they are free to sell their product to customers, but where those very same customers have little opportunity to see competitive pressure on the prices they are compelled to pay for either purchasing solar DG or having to pay the cross-subsidies inherent in net metering. In short, net metering provides TASC with the protection of a monopoly derived price (i.e. mandated net metering), while customers are deprived of the pricing benefits associated with competitive markets. Thus, rather than being a champion of competition, the TASC business model is to opportunistically seek to use monopoly power for their profit and to the detriment of consumers. How else can one explain why they demand a fixed, long-term price for their product, enabling them to keep cost savings and other benefits for themselves as well as not having to invest in increased productivity and reliability, in the context of a dynamic energy market where other suppliers are under severe competitive pressures to increase productivity and reduce prices? TASC's business model is to take an advantage of a severely flawed tariff,

net metering, and exploit it for their members' advantage while depriving consumers of the benefits that might otherwise accrue to them.

It is important to note that, historically, U.S. regulators have used three different rationales on which to base tariffs: cost based, prices derived from viably competitive markets, and, since the passage of PURPA in 1978, avoided costs. Net metering is neither cost based nor market driven. Similarly, since it pays a retail price for a wholesale product, it does not reflect avoided cost either. Net metering, for all of the reasons noted, fails to achieve the appropriate balance regulators are always seeking out, namely balancing benefits and risks for all affected parties. It is heavily skewed in favor of short term financial interests of the vendors of solar dg, including TASC members, to the detriment of the interest of consumers, not to mention, as the MIT study pointed out, to the long term sustainability of solar energy itself.

Q. **Given the severe flaws of net metering as a pricing methodology, what does the testimony of the TASC witnesses in this proceeding tell us about how TASC defends its position in support of the *status quo*?**

A. The TASC witnesses make no effort to defend net metering. They do not even bother to present a "Value of Solar" study, or any other analysis to defend a pricing methodology that is out of step with regulatory practice in the United States, and reflects almost no serious economic thought or analysis. Rather, neither TASC witness in this case even bothers to defend net metering as a reasonable or economically sensible pricing methodology. Incredibly, having failed to offer any serious economic analysis of net metering, they criticize OG&E for failing to do so, as if the company had some sort of obligation to perform studies TASC failed to conduct, and, as noted by TASC witness Barnes, would probably not be cost justified in this matter anyway. Rather, they direct their comments to criticisms of the OG&E proposal, many of them trivial or irrelevant, offer various excuses for delaying a decision on the matters before the Commission in this proceeding, and, in effect, asking the Commission to defy the legal mandate to remove the cross-subsidies by the end of this year.

Q. **What are the effects of delaying a decision on or rejection of the OGE proposal?**

A. The first effect, of course, is that the company and the Commission will be in violation of the statute requiring that cross subsidization from non-solar to solar customers be eliminated by the end of 2015.

The second effect will be a windfall for TASC members and other solar DG developers in Oklahoma. By paying the full retail price for a wholesale energy product, net metering has the effect of insulating TASC and the rest of the solar industry from the competitive pressure so keenly felt by other energy suppliers. In effect, they are guaranteed a price well in excess of the wholesale energy price, so they not only have no incentive to become more efficient, they also have no incentive, as noted, to pass on declining costs to the public. It is this luxury of doing business in a rarified environment largely free of the competitive pressures felt by other energy producers that TASC seeks to defend in this proceeding. Witnesses Barnes and Garret make no serious effort in their testimony to defend net metering. Rather, they simply try to change the focus of the discussion from what the legislature set out to do, eliminating cross subsidization of solar DG, to a critique of OG&E's effort to comply with the law. The goal is to delay, delay, and delay the inevitable, namely when TASC and its members will have to compete like every other energy supplier. For obvious reasons, their preference is to retain all of the tariff flaws inherent in net metering because it is in their self- interest, regardless of the public interests, consumer benefits, and the dictates of the law in Oklahoma.

The third effect will be adverse to customers. Non-solar customers will lose because they will be required to pay cross-subsidies for even more solar DG units. Solar customers, or, more precisely, prospective solar customers, will lose because they will be required to purchase their solar installations in a market where cost savings are retained by vendors because of the competition free environment afforded them by net metering.

The only winners will be TASC and other vendors. Ironically, as noted above, while the biggest member of TASC, Solar City, will profit from delay, its Tesla battery manufacturing affiliate will lose, because there will be no incentive for solar interests to purchase the batteries they produce, a product that has the potential for enormous enhancement of the value of solar.

Finally, perhaps, the biggest loser will be solar energy itself, because the rejection of the OG&E proposal would mean that, in Oklahoma, at least, there will be no real incentive for enhancing the efficiency and reliability of solar energy.

Q. **Turning from the big picture issues of this case to some of the smaller, more specific points raised in the testimony, should this change be handled in a rate case?**

A. While I agree with witnesses Champion and Garrett that single issue ratemaking is something to be avoided, I completely disagree that OG&E's proposal, if approved, constitutes single issue ratemaking. There are three reasons that I say that. The first is that the Oklahoma legislature has mandated that cross subsidies from non-solar to solar customers should be eliminated by the end of 2015, so the proposal is simply an attempt to comply with the law, not some rate benefit that OG&E seeks for itself. Secondly, what is being proposed is a prospective change that leaves almost all customers, solar and non-solar alike, unaffected. Thus, witness Garrett's assertion that there is a rate increase for solar customers that requires a downward adjustment for non-solar customers is simply wrong. Were the Commission to approve the OG&E proposal, virtually the only customers affected would be new solar customers, who would, on a prospective basis, no longer be receiving the net metering cross subsidy. Non-solar customers are only affected to the extent that they will not have to pay cross subsidies to the new solar hosts. In short, customers under existing rates, unless they choose to install rooftop solar, are simply unaffected by the change. Finally, the pricing of solar DG is a generic policy question, and it should be treated that way. This kind of general pricing proposal does not fit well into the nuts and bolts of a rate case. It requires a broader perspective, and input from parties who would not ordinarily participate in a company specific rate case, and who may lack standing to do so. Indeed, the proceeding herein is closer to a generic rulemaking, since broad policy regarding pricing is being addressed. Such discussions are best handled by regulators in a less judicialized decision making environment than is characteristic of rate cases.

Q. **Is there a need for a new cost of service study?**

A. In calling for a cost of service study, the Garrett, Barnes and Champion are all essentially calling for delay and for incorporating the current issue into a new rate case. The arguments against delay and waiting for a new rate case have been made above. The conducting of a cost of service study would inevitably delay implementation of the statute and lead to a failure to comply with the December 31, 2015, deadline.

Beyond that, there is no reason to conduct a new cost of service study because OG&E's proposal is based on the rates currently in effect and the cost of service study that was foundational for the establishment of those rates. Since the new pricing for solar DG is applied prospectively, and is based on pricing principles, the costs to which the principles are to be applied are simply the ones underlining the existing rates. Obviously those costs may be revised in the course of a new cost of service study and a new rate case, but the pricing principles remain constant. In short, the establishment of pricing principles, as OG&E seeks to do, is a completely independent variable from the underlying cost of service to which the principle is to be applied, so a new cost of service study, an expensive undertaking, is irrelevant to consideration of the company's proposed pricing for solar DG. TASC's advocacy of it is simply a "red herring" designed to further delay compliance with the legislature's directive to eliminate the cross subsidy inherent in net metering. Thus, while the rate making process strikes a needed, cost-effective balance between staying up to date with costs and minimizing the costs and disruptions associated with constant rate cases, it is not necessary in this matter. In fact, the legislature recognized this, because SB 1456 does not call for a new rate case—merely a fix, applied prospectively only, to a specific cross-subsidy. A cost of service study is unneeded, would delay compliance with the law, and, within the context of this case, would add nothing of value.

Q. **Where are the rate savings, since the utility is proposing what amounts to increased payments for DG customers?**

A. One of the issues raised by Garrett is the claim that OG&E has an obligation to redistribute increased revenues from the proposed tariff change. (13) The confusion here comes from the fact that the revenue revision is entirely prospective. OG&E's proposed

revision heads off future distortions—it does not revise tariffs or obligations for existing customers. It simply applies to new solar customers. Thus, there is no revenue to be redistributed—just future cross subsidies to be avoided.

Q. **Is there any reason to read the Senate bill as prohibiting the use of a demand charge in the revised tariff?**

A. No. In his testimony (pages 24-25) Garrett makes a particularly strange argument that the Senate bill, because it excludes from consideration customers who already pay a demand charge, intends to exclude the use of demand charges as a rate tool. Speaking as a lawyer, it is astonishing to me that another lawyer could come up with such a tortured interpretation of the law. All the legislature was doing by precluding application of the new law to customers already paying demand charges was making it clear that such customers would not be required to pay demand charges twice. The law says absolutely nothing to even suggest the prohibition of demand charges or the application of such charges to a new set of customers.

Q. **Does OG&E have any obligation to develop a special educational outreach program to accompany this change in the tariff for distributed generation customers?**

A. In his testimony, Garrett asserts that OG&E is "inconsistent" in not planning an educational outreach campaign to educate people about the new tariff, in contrast to its approach in implementing TOU rates (p. 33). The cases are entirely different. In offering TOU rates, OG&E was trying to broadly reach all of its customers to let them know about a new rate opportunity which could be of marginal benefit to any individual but of significant benefit to the system as a whole. OG&E's educational responsibility related directly to its general obligation to enhance the efficient use of energy in ways that are societally beneficial. Solar DG systems are the opposite. The comparatively few individuals who choose to make a private investment in a solar DG system are making a highly individualized decision in how they procure energy for themselves. It is almost inconceivable that anyone would make such an investment without first familiarizing himself/herself with all of the economic and technical issues associated with that investment. Such investors are presumably motivated to pursue the information they

need (which, of course should be clear, accurate, and available)—just as with other major investments in their homes or businesses.

While OG&E certainly has an obligation to provide timely and accurate information regarding rates and tariffs, it has no affirmative duty to advise customers on the efficacy or economics of investment in alternative forms of energy. Indeed, requiring it to do so raises the specter of OG&E, or any other utility, for that matter, being accused of offering advice or "information" that was biased in such a fashion as to be "anti-competitive." To do proactive outreach along the lines of the TOU initiative, as the TASC witnesses suggest, one would have to assume that customers who invest thousands of dollars are too ignorant to understand what they are doing. Indeed, that assumption by the TASC witnesses shows a surprising level of disrespect for the intelligence and capability of their own customers. That is not entirely surprising because, if there is an educational problem here, it comes from the members of TASC and other solar vendors who may find it in their interest to misrepresent or over promise the benefits that consumers will realize from installing solar systems (I for one regularly receive robotic phone messages at my home in Massachusetts from DG companies that warn me, in dire tones, about dramatic impending electricity rate increases, which I know to be largely false and misleading, and urge me to "protect myself.") But it is hardly fair for TASC to criticize OG&E for not having an adequate education program to counteract miseducation by their own members.

Q. **In determining the existence of a cross-subsidy within a "customer class," what counts as a "class?"**

A. Another strange argument presented by Garrett is the argument that in determining the existence of cross-subsidies among customers in the same class, customers on the TOU rate should be considered as constituting a distinct class, separate from their fellow residential or commercial customers (35). Speaking as a former regulator, customer class is not defined by a customer's choice of tariffs; rather, classes are a way of categorizing customers based on the costs they impose on the system. Residential and commercial customers are considered two different classes because the different ways they use the system, different load profiles, different demand characteristics, and other circumstances that affect and distinguish the cost of serving them. A given customer class (say,

residential or commercial), may be given a suite of tariffs from which they can choose the one they prefer. The same underlying costs go into calculating the how much the tariffs should collect. The different tariffs are just different methods of collecting the resulting costs, among which customers can choose what they prefer. Garret simply confuses cost characteristics that go into defining classes of customers, and the establishment of methods of collecting the revenue responsibility allocated to each class, which is what tariffs are designed to do.

Q. **Can you discuss the pros and cons of the proposed new demand charge, which Champion, Barnes, and Garrett seem to particularly object to?**

A. Yes. Champion, Barnes, and Garrett raise several objections to the demand charge: they argue that the use of demand charges in residential rates is "unprecedented;" they think it will be too hard for customers to understand; they express concern that, in conjunction with higher fixed charges, demand charges will discourage energy efficiency and conservation; and, in the case of Champion, they worry that the use of the demand charge might result in over-compensation of distributed generation customers. I propose, first, to explain why demand charges are an extremely helpful tool for ensuring customers are billed proportionately to the costs they impose on the system and incentivized to minimize these costs, and then to address each of the concerns raised above.

Q. **What makes demand rates as a component of tariffs useful in ensuring customers are billed proportionately to the costs they impose on the system and in giving customers incentives to minimize these costs?**

A. As discussed above, the cost to the utility associated with serving a customer has a number of different components. Some costs—for example, the costs of the delivery system (e.g. wires and control technology) and of billing and account management—are fixed, no matter how much energy a customer uses or when. Other costs—the cost of the energy itself—are exactly proportional to the amount of energy use (with the additional nuance that energy costs vary over time). And a third category of costs—costs associated with sizing the capacity of distribution, transmission and generation—vary with the peak demand from customers—the number that is reflected in the demand charge. The use of

the demand charge is a means to bill the customer fairly for the costs associated with the peak usage the utility must be prepared to accommodate for him or her. In short, OGE, like every other utility, incurs costs to be able to meet all demand at all times. It is those costs which a demand charge seeks to recover

Q. **Is the use of demand charges for residential rates "unprecedented?"**

A. The use of demand charges in residential rates has been debated for years, but actually applying it has, in recent years, become more seriously considered. That recent emphasis on it has been, ironically, driven to a large degree by the emergence of net metered intermittent solar DG, which enables a subset of customers to avoid paying their fair share of the fixed and demand costs of the system. That results in reallocating the costs solar DG customers avoid to non-solar customers, in violation of the critical regulatory principle that the cost causer should pay. Indeed, for TASC, which has contributed greatly to the inequitable reallocation of costs, to complain about demand charges is akin to the son who kills his parents and throws himself on the mercy of the court because he is an orphan. In any event, demand charges for residential customer are not "unprecedented." As Garrett and Barnes actually do acknowledge, a demand charge is in use in Salt River Project, one of Arizona's largest utilities, and such charges are actively being contemplated in a number of jusrisdictions in the U.S. and elsewhere. The Wisconsin Public Service Commission recently approved such a charge (recently remanded by the Circuit Court for more evidence, in what seems likely to constitute simply a procedural delay, not a policy reversal). Also driving the impetus for change, besides distortions caused by net metering, are the trend towards unbundling utility services, the increased sophistication in metering and billing, the desire to have more meaningful price signals to encourage the efficient use of energy, and the growing challenges of integrating distributed generation. Indeed, a recent blog post (attached as Ex.-OGE-Brown-3) from the Rocky Mountain Institute, one of the nation's foremost proponents of energy efficiency, hails demand charges:

> *Demand charges are a promising step in the direction of more sophisticated rate structures that incent optimal deployment and grid integration of customer-sited DERs. A demand charge more equitably*

charges customers for their impact on the grid, can reward DG customers with bill savings, and opens up potential for an improved customer experience using load management tools. It can also benefit all customers through reduced infrastructure investment and better integration of renewable, distributed generation.[11]

Q. **Are demand charges too hard for customers to understand?**

A. In my opinion, Champion, Barnes, and Garrett seriously underestimate the capabilities of DG customers, with a dismissive attitude exemplified by Barnes' comment that "The simple conceptual difference between a kW and a kWh is hard for customers to grasp, let alone the meaning of a '15-minute average maximum demand,' or how each individual electric load contributes to their electric demand." (17) In fact, there is reason to believe that DG customers are unusually sophisticated customers with a keen interest in understanding and managing their electricity usage. After all, these are customers willing to make a significant investment and undertake a complex home improvement project to become DG customers

Q. **Doesn't a demand charge and an increased fixed customer charge discourage energy efficiency?**

A. Yes and no. This criticism mostly applies to increased fixed charges, not demand charges. To the extent that the costs paid by customers are shifted away from their usage and towards costs that do not vary with total usage, this could have the effect of failing to incentivize energy conservation and energy efficiency. This is why, as long as distributed generation was not a significant factor, the traditional utility approach to billing, in which costs associated with system maintenance were largely bundled into energy charges, made a lot of sense.

---

[11] Lehrman, Matt. "Are Residential Demand Charges the Next Big Thing in Electricity Rate Design?" Blog Post, *RMI Outlet* (May 21, 2015) http://blog.rmi.org/blog_2015_05_21_residential_demand_charges_next_big_thing_in_electricity_rate_design

As I have discussed in an article for *Electricity Policy*, the rise of net metering and the growth of distributed generation represents a significant threat to the sustainability of this approach to billing for electricity and the positive incentives it offers for energy efficiency.[12] The more net metering for distributed generation continues, the more problematic the inclusion of additional costs within the "energy charge" becomes. For TASC to raise this issue is extraordinarily ironic—they once again resemble the patricidal child who pleads for mercy because he is an orphan.

The only sustainable way to largely preserve the energy efficiency incentivizing benefits of the traditional approach to billing is to break out distributed generation and give it a separate tariff, as the OG&E proposal does. Doing this makes it possible to maintain a more traditional approach to billing for non-DG customers, with the benefits this approach offers in terms of supporting energy efficiency and energy conservation.

In this context, it is worth addressing Barnes' assertion that DG customers are no different from customers who take steps to improve their overall energy efficiency by, for example, installing more efficient light bulbs. (Barnes, 18) In fact, from the point of view of the utility and its costs, these customers are very different. Energy efficiency customers by and large reduce their overall energy consumption in a predictable way—so the utility actually can reduce its generation and capacity requirements. In contrast, the unevenness of reductions associated with distributed generation customers (who may tend to have especially high demand when their DG is not producing), as discussed above, means that similar capacity and generation benefits do not exist for these customers.

Q. **Should we worry that DG customers who successfully manage their demand will be over-compensated under the proposed tariff?**

A. This is a surprising concern expressed by Champion in her testimony (15). In raising this concern, she misses the point of demand charges—that they are linked to actual costs

[12] Brown, Ashley and Louisa Lund. "Distributed Generation: How Green? How Efficient? How Well-Priced?" *The Electricity Journal* 26(3): 28-34 (March 2013).

caused by customer usage patterns. So if a DG customer succeeds in trimming his or her bill by lowering his or her peak demand, this is a win for everybody—the utility is passing on real savings to the customer. There is no inherent cross-subsidy here.

Q. **Does that conclude your testimony?**

A. Yes, it does.

ASHLEY C. BROWN

EXECUTIVE DIRECTOR
HARVARD ELECTRICITY POLICY GROUP

MOSSAVAR-RAHMANI CENTER FOR BUSINESS AND GOVERNMENT
JOHN F. KENNEDY SCHOOL OF GOVERNMENT
HARVARD UNIVERSITY
79 JOHN F. KENNEDY STREET
CAMBRIDGE, MA 02138
617-495-0959
ashley_brown@harvard.edu
http://www.hks.harvard.edu/hepg/brown.html

Ashley Brown is an attorney admitted to practice in Ohio, Massachusetts, and the District of Columbia. He is the Executive Director of the Harvard Electricity Policy Group at Harvard University's John F. Kennedy School of Government. It is a leading "think tank" on matters related to electricity restructuring, regulation, and market formation. He is an instructor in Harvard's Executive program on "Infrastructure in a Market Economy." Mr. Brown has also served as an arbitrator in matters relating to the evolution of competition in infrastructure industries.

Before his current activities, Ashley Brown served as Commissioner of the Public Utilities Commission of Ohio, appointed twice by Governor Richard F. Celeste, first for a term from April 1983 to April 1988 and for a second term from April 1988 to April 1993. As Commissioner, he was of five members responsible for the regulation of the state's electricity, telecommunications, surface transport, water and sanitation, and natural gas sectors.

Prior to his appointment to the Commission, Mr. Brown was Coordinator and Counsel of the Montgomery County, Ohio, Fair Housing Center. From 1979-1981 he was Managing Attorney for the Legal Aid Society of Dayton, Inc. From 1977 to 1979 he was Legal Advisor of the Miami Valley Regional Planning Commission in Dayton. While practicing law, he specialized in litigation in federal and state courts, as well as before administrative bodies. In addition, Mr. Brown has extensive teaching experience in public schools and universities.

EDUCATIONAL BACKGROUND	1968	B.S.	Bowling Green State University, Bowling Green, Ohio
	1971	M.A.	University of Cincinnati, Cincinnati, Ohio
	1977	J.D.	University of Dayton School of Law, Dayton, Ohio
			Doctoral Studies (all but dissertation) New York University, New York, New York
	1967		Attended Universidade do Parana; Curitiba, Parana, Brazil as an exchange student
FAMILY	Wife		Edith M. Netter
	Daughter		Sara Mariasha Brown
	Daughter		Mariel Schaefer Brown

CURRENT AFFILIATIONS

Member, Board of Directors, Entegra Power Group

Member, Editorial Advisory Board of *The Electricity Journal*

Member, Editorial Advisory Board of *Electric Light and Power*

Member, Editorial Board, *International Journal of Regulation and Governance*

Member, Policy Committee, David Rockefeller for Latin American Studies, Harvard University

Member, Brazilian Studies Committee, David Rockefeller Center for Latin American Studies, Harvard University

Member, Advisory Board of Development Gateway Site, The World Bank

Frequent speaker and lecturer on regulatory, infrastructure, and energy policy matters in North and South America, Europe, Africa and Asia.

PREVIOUS AFFILIATIONS

Chairman, Town of Belmont Municipal Light Advisory Board

Member, Board of Directors, Oglethorpe Power Corporation, Tucker, GA

Vice-Chair, American Bar Association Committee on Energy, Section of Administrative Law and Regulatory Practice

Chair, American Bar Association Annual Conference on Electricity Law

Member, The Keystone Center Energy Advisory Committee

Member, National Association of Regulatory Utility Commissioners

Member, Executive Committee, National Association of Regulatory Utility Commissioners

Chair, Committee on Electricity, National Association of Regulatory Utility Commissioners

Chair, Subcommittee on Strategic Issues, National Association of Regulatory Utility Commissioners

Member, Great Lakes Conference of Public Utilities Commissioners

Member, Great Lakes Conference of Public Utilities Commissioners

Executive Committee

Member, Mid-America Regulatory Conference

Member, Board of Directors, The National Regulatory Research Institute

Member, Advisory Council to the Board of Directors of the Electric Power Research Institute

Member, U.S. EPA Acid Rain Advisory Committee

Chair, Planning Section, National Governors' Association Task Force on Electric Transmission

Member, the Keystone Center Dialogue on Emissions Trading

Member, the Keystone Center Project on the Public Utility Holding Company Act of 1935

Member, The Keystone Center Project on State/Federal Regulatory

Jurisdictional Issues Affecting Electricity Markets

Member, Policy Steering Group, The Keystone Center Project on Electricity Transmission

Member, Advisory Council of the Board of Directors of Nuclear Electric Insurance Limited

Member, Advisory Council of the Consumer Energy Council of America Project on Electricity

Member, Advisory Committee of the Consumer Energy Council of America Air Pollution Emissions Trading Project

Member, National Task Force on Low Income Energy Utilization and Conservation

Member, Board of Directors, Center for Clean Air Policy

Member, National Blue Ribbon Task Force on Allocating the Cost of New Transmission

INTERNATIONAL EXPERIENCE

Member, U.S. Delegation of State Government Officials in the Center for Clean Air Policy/ German Marshall Fund Sponsored Exchange on Clean Air Issues to Germany, 1989

Member, U.S. Delegation to International Electric Research Exchange (IERE), Rio de Janeiro, Brazil, 1991

Consultant, Hungarian Ministry of Industry and Trade on Gas and Electric Regulatory policy, 1991-1992

Advisor to Ministry of Trade and Industry on Writing New Laws Governing Electricity, Natural Gas, and Regulation

Consultant, SNE, Costa Rican Regulatory Agency, on Transmission Access Issues, 1992

Advisor on Development of Independent Power Producers and Transmission Access

Consultant, World Bank Mission to Hungary Investigating the Financing of New Power Plants for MVM (Hungarian Electric Co.), 1992

Preparation of Background Materials in Preparation of a World Bank loan to the Hungarian Power Sector

Member, U.S. Delegation, in Conjunction with the U.S. Department of Energy, to the Argentina and United States Natural Gas and Electricity Regulatory Meetings, 1992

Consultant, ENARGAS, the Argentine gas regulatory agency, 1992

Providing Training for ENARGAS Commissioners and Staff

Consultant, USAID India Private Power Initiative Program on the Introduction of Private Generation and Competition into the Public Sector, 1993

Preparation of a Report on Introducing and Promoting Private Investment in the Indian Power Sector

Instructor, Regulatory Training Program of the National Regulatory Research Institute at Ohio State University and the Institute of Public Utilities at Michigan State University,

Buenos Aires, Argentina, 1993
Providing Training to Commissioners and Staff of ENARGAS

Consultant, The Province of Salta, Argentina on infrastructure regulation, 1996
Providing Training to Commissioners and Staff of the Regulatory Agency of the Province of Salta

Consultant, USAID, Philippines Electric Sector Restructuring, 1994
Preparation of Analysis and Report on Restructuring the Philippine Power Sector Including the Attraction of Private Capital in Generation, and Introduction of Competition

Consultant, USAID, Russian Electric Sector Restructuring, 1994
Preparation of Analysis and Report on Restructuring the Russian Power Sector Including the Attraction of Private Capital in Generation, and Introduction of Competition

Participant, Harvard University's East Asian Electricity Restructuring Forum, 1994-1995
Delivering a Series of Lectures in China, Indonesia, and Thailand on Reforming the Power Sector

Consultant, Government of Ukraine on Electricity regulatory policy and industry restructuring, 1994-1995
Advisor to the National Energy Regulatory Commission on the Structure, Processes and Substance of Electricity Regulation

Consultant, Government of Brazil on Electric Sector Restructuring, 1995-1996
Adviser to the Ministry of Mines and Energy on Various Issues Related to Privatization and Introduction of Competition in the Power Sector

Consultant, Energy Regulatory Board of Zambia, 1997- 2001
Advisor to the Energy Regulatory Board on the Structure, Processes and Substance of Electricity Regulation

Member, Brazil-U.S. Energy Summit, 1995-1996
Preparation of a Report and Lecture on the Options for the Regulation of a Restructured Brazilian Power Sector

Consultant, Nam Power, the electric utility in Namibia, 1998-1999
Advisor on Development of Independent Power Project and on Restructuring of the Electric Distribution Sector

Consultant, Government of Indonesia on electricity regulation, 1999
Training Government and Industry Personnel on Electricity Regulation

Consultant, Government of Mozambique on reform of the commercial code, 2000
Advisor on Reformation and Rewriting of the Commercial Code

Instructor, South Asia Forum for Infrastructure Regulation, 1999-present
Annual Training Regulatory Personnel from Five South Asian Countries

Consultant, Government of Tanzania on electricity regulation, 2002
Advisor of Rewriting the Laws Governing Energy and Transport Regulation

Consultant to Inter-American Development Bank on Sustainability of Sector Reform in Latin American energy markets, 2001-2002

Preparation of a report and Analysis on the Sustainability of Power Sector and Regulatory Reform in Latin America, with Specific Focus on Colombia, Honduras, and Guatemala

Consultant to Inter-American Development Bank, Brazilian Electric Restructuring, 2002

Preparation of A Report and Analysis on Problems in the Privatization and Market Reform on the Brazilian Power Sector

Consultant to World Bank on Brazilian energy regulation, 2002-2004

Preparation of A Report and Analysis of Means for Improving Regulation of the Brazilian Power Sector.

Consultant to the Brazilian Government on Redesign of Electricity Market, 2003-2004

Advisor to Ministry of Mines and Energy on Electricity Market Design

Consultant to Government of Dominican Republic on Electricity Regulation, 2004

Delivery of a Series of Lectures on Problems in Restructuring and Privatization in Dominican Power Sector

Consultant to Eskom, South Africa, 2004-2005

Advisor on to Eskom on Restructuring of South African Electric Distribution Sector

Consultant to World Bank on Regulation and Market Reform in Russian Power Sector, 2004-2005

Preparation of Report and Lecture on Regulatory Issues in proposed New Market Design of Russian Power Sector, and Attraction of Private Capital

Consultant to Government of Guinea-Bissau on Infrastructure Regulation, 2005

Training Government and Industry Personnel on Infrastructure Regulation

Consultant to the Government of Mozambique on Electricity Regulation, 2006-2007

Assisting in the Re-Establishment of the Electricity Regulatory Agency

Consultant to the Government of Equatorial Guinea, 2007

Assisting in writing the country's electricity law

Consultant to the Public Utilities Commission of Anguilla, 2008

Report on Funding Regulatory Agencies

Languages: English, Knowledge of Spanish and Portuguese

PUBLICATIONS

Brown, Ashley, Jillian Bunyan. "Valuation of Distributed Solar: A Qualitative View." The Electricity Journal. 27.10 (2014): 27-48.

Brown, Ashley. "Power of Connections." The Indian Express, March 10, 2014.

Brown, Ashley and Louisa Lund. "Distributed Generation: How Green? How Efficient? How Well Priced?" The Electricity Journal, April 6, 2013.

Brown, Ashley, and Victor Loksha. "International Experience with Open Access to Power Grids: Synthesis Report." ESMAP Knowledge Series 016/13, November 2013.

Brown, Ashley. "Concessions, Markets and Public Policy in the Brazilian Power Sector." September 5, 2012.

Brown, Ashley. "Coming Out of the Dark: For one, prices must communicate to customers the actual cost of energy at the time of consumption." The Indian Express, August 8, 2012.

Tolmasquim, Mauricio T. Power Sector Reform in Brazil. Preface by Dilma Rousseff. Afterword by Ashley C. Brown. 2012 Empresa de Pesquisa Energetica (EPE).

Brown, Ashley, and Francesca Ciliberti-Ayres. "Development of Distributed Generation in the United States." A Report Prepared for Empresa de Pesquisa Energetica (EPE), November 20, 2012.

Brown, Ashley, Steven Levitsky, and Raya Salter. "Smart Grid and Competition: A Policy Paper." Prepared for the Galvin Initiative, July 28, 2011.

Brown, Ashley. "Can Smart Grid Technology Fix the Disconnect Between Wholesale and Retail Pricing?" Vol. 24, Issue 1 (Jan./Feb. 2011): 1040-6190.

Brown, Ashley, and Raya Salter. "Smart Grid Issues in State Law and Regulation." White Paper sponsored by the Galvin Electricity Initiative, September 17, 2010.

Brown, Ashley, and James Rossi. "Siting Transmission Lines in a Changed Milieu: Evolving Notions of the 'Public Interest' in Balancing State and Regional Considerations." *University of Colorado Law Review* 81, no. 3 (Summer, 2010).

Brown, Ashley. Infrastructure: The Regulatory and Institutional Dimension. June 2010. 36 pages.

Brown, Ashley, James F. Bowe Jr., Julio A. Castro, and Sonia C. Mendonca (Dewey & LeBoeuf LLP) The Financial Crisis and Implications for U.S.-Mexico Brazil's New Natural Gas Law. *Latin American Law and Business Report* Volume 17, Number 5, May 31, 2009. 5 pages.

Brown, Ashley and James Rossi. *Siting transmission lines: evolving the "public interest" to balance state and regional considerations.* Version 1.0, dated August 3, 2009. The paper was originally prepared for the National Renewable Energy Laboratory‟ s Conference on Multistate Decision Making for Renewable Energy and Transmission: Spotlight on Colorado, New Mexico, Utah, and Wyoming, August 11, 2009, Denver, Colorado.

Brown, Ashley. *Equitable Access to Basic Utilities: Public versus Private Provision and Beyond*. *Poverty in Focus.* International Policy Centre for Inclusive Growth Poverty Practice, Bureau for Development Policy, UNDP. Number 18, August 2009. 36 pages.

The Funding of Independent Regulatory Agencies. A Special Report to the Public Utilities Commission of Anguilla. June 2008. Report, 66 pages.

Walking the Tightrope: Balancing Competing Interests in Pursuit of Good Public Policy. Fair Trading Commission of Barbados, Third Annual Lecture. 23 February.19 pages.

Baldick, Ross and Ashley Brown, James Bushnell, Susan Tierney and Terry Winter. *A National Perspective on Allocating the Costs of New Transmission Investment: Practice and Principles*. September, 2007.

Brown, Ashley C.; Stern, Jon; and Tenenbaum, Bernard. *Handbook for Evaluating Infrastructure Regulatory Systems.* Washington, DC: World Bank Publications, 2006.

Brown, Ashley C. Epilogue to *Keeping the Lights On: Power Sector Reform in Latin America* (Millan, Jaime, and Nils-Henrik M. von der Fehr, editors), Inter-American Development Bank (ISBN 1-931003-55-6).

Brown, Ashley C. and Damon Daniels: "Vision Without Site; Site Without Vision," *The Electricity Journal* (October 2003), Vol. 16, Issue 8: 23-34.

Brown, Ashley C. "Regulators, Policy-Makers, and the Making of Policy: Who Does What and When Do They Do It?" *International Journal of Regulation and Governance* (June 2003), Vol. 3, No. 1: pp 1-11.

Brown, Ashley C. "SMD Drawing RTO Battle Lines," *Electric Light & Power* (February 2003): 4.

Brown, Ashley C. "Strengthening of the Institutional and Regulatory Structure of the Brazilian Power Sector," The World Bank: December 2002.

Brown, Ashley C. "The Duty of Regulators to Have Ex Parte Communications," *The Electricity Journal* (March 2002): 10-14.

Brown, Ashley C. "The Privatization of Brazil's Electricity Industry: Sector Reform or Restatement of the Government's Balance Sheet," Inter-American Development Bank (January 2002).

Brown, Ashley C. "Confusing Means and Ends: Framework of Restructuring, Not Privatization, Matters Most, " *International Journal of Regulation and Governance* (January 2002), Vol. 1, No. 2: 115-128.

Brown, Ashley C. "Six Critical Choices of Regulatory Models for Brazil," *The Journal of Project Finance* (2002), Vol. 4, No. 1: 29-40.

Brown, Ashley C. "When do Risk Mitigation Measures Exacerbate Risks in Infrastructure Industries Abroad? Some Long-Term Considerations for Investors." In *Global Infrastructure Development, World Markets in 1999*, London: World Market Research Centre, McGraw-Hill Companies, Inc. 1998.

Brown, Ashley C. "Six Critical Choices of Regulatory Models for Brazil." *The Journal of Project Finance*, Volume 4, Number 1 (Spring 1998): 29-40.

Brown, Ashley C. "Regulatory Risk: Is the Subject Still Relevant or do Markets Govern?" 13 *Yale Journal on Regulation,* (Winter 1996): 403-411.

Brown, Ashley C. "Honey, I Shrunk the Franchise!" *The Electricity Journal* (March 1995): 72-77.

Brown, Ashley C. "The Trinity of Transmission Issues: Siting, Access, and Pricing." *Maine Policy Review*, Volume 2, Number 1 (April 1993): 53-58.

Brown, Ashley C. "Electricity After the Energy Policy Act of 1992: The Regulatory Agenda." *The Electricity Journal*, (January-February 1993): 33-43.

Brown, Ashley C. "The Energy Policy Act of 1992: The Paradox Facing the States." *Public Utilities Fortnightly*, Volume 131, Number 1 (January 1, 1993): 26-28.

Brown, Ashley C. "Sunshine May Cloud Good Decision Making." *Forum for Applied Research and Public Policy*, Volume 7, Number 2 (Summer 1992): 113-116.

O'Neil, Richard P. and Brown, Ashley C. "Privatization and Regulation of the Oil, Natural Gas, and Electric Industries in Hungary." *Energy Law Journal*, Volume 13, Number 1 (1992): 25-42.

Brown Ashley C. and Barnich, Terrence L. "Transmission and Ratebase: A Match Not Made in Heaven." *Public Utilities Fortnightly*, Volume 127, Number 11 (June 1, 1991): 12-16.

Brown, Ashley C. "State Public Utility Regulation and Title IV." In *The New Clean Air Act: Compliance and*

Opportunity, edited by Reinier Lock and Dennis P. Hakawik, 177-182. Arlington, Virginia: Public Utilities Reports, Inc., 1991.

Brown, Ashley C. "The Overjudicialization of Regulatory Decisionmaking." *Natural Resources and Environment*, Volume 5, Number 2 (Fall 1990): 15-16

Brown, Ashley C. "A Possible Tradeoff of Federal and State Transmission Jurisdiction." *Public Utilities Fortnightly*, Volume 124, Number 10 (November 9, 1989): 21-23.

Brown, Ashley C. "State Power Over Transmission Access and Pricing: The Giant Will Not Sleep Forever." *Public Utilities Fortnightly*, Volume 124, Number 10 (November 9, 1989): 21-23.

Brown, Ashley C. "The Balkans Revisited: A Modest Proposal for Transmission Reform." *The Electricity Journal*, Volume 2, Number 3 (April 1989): 32-39.

Brown, Ashley C. "Breaking the Transmission Logjam." *The Electricity Journal*, Volume 1, Number 1 (July 1988): 14-19.

Brown, Ashley C. "Percentage of Income Payment Plans: Regulation Meets Social Reality." *Public Utilities Fortnightly*, Volume 119, Number 6 (March 19, 1987): 9-12.

TECHNOLOGY:

Net metering vs. storage creates clash between some allies

Anne C. Mulkern, E&E reporter

Published: Wednesday, September 23, 2015

SAN DIEGO -- Tesla Motors Inc. and SolarCity Corp. consider themselves partners. On the issue of energy storage, however, they're in an uncomfortable marriage.

Tesla wants to expand the battery storage market and has launched a new arm to pursue that aim. When it opens its Gigafactory now under construction in Nevada, the electric vehicle company plans to dedicate up to a third of production for grid-connected storage systems that SolarCity and others will market.

But a position of SolarCity and other solar partners clashes with that vision. Solar companies have been pushing in California to protect net metering, the policy that allows those with rooftop photovoltaics to earn electricity bill credit for excess power sent to the grid. It's a benefit available in some form in 44 states.

Net metering creates a disincentive to add storage, Mateo Jaramillo, Tesla's director of powertrain business development, said at the National Association of State Energy Officials meeting here.

"Net metering is essentially a free battery," Jaramillo said. "You basically sell your power back to the utility, then you just buy it back at the same rate later. So it's hard to compete."

That limits the value of battery storage in many places in the United States to keeping the lights on if the power goes out, along with overall grid support, he said. Asked during the NASEO event to reconcile SolarCity's position fighting for net metering and Tesla's goal to expand battery storage, Jaramillo laughed softly, then said that the market is in flux.

"The trend is that the market design will change, for sure," Jaramillo said. "I don't think that net metering will be around forever. I don't think anybody does."

SolarCity and Tesla are just two of the companies likely to be affected as the California Public Utilities Commission (CPUC) and officials in other states re-examine net metering, the role of storage and what customers with solar pay. It's a trend across the West.

Arizona Public Service Co. last spring filed an application with utility regulator the Arizona Corporation Commission seeking to increase the "grid access fee" from $5 to $21 per month for future solar customers. The Salt River Project in Arizona in March approved up to $50 per month in fees on those with rooftop photovoltaics (***EnergyWire***, April 24). Solar advocates say interest in adding PV plummeted as a result.

Hawaii is looking at net metering and storage as it works to grow levels of locally based renewable energy resources. The Aloha State wants to generate 100 percent of its power from renewable sources by 2045.

Storage likely will be a big part of that, said Robert Harris, spokesman for the Alliance for Solar Choice, a coalition of companies including SolarCity and Sunrun Inc. Harris also works for Sunrun, which, like SolarCity, is partnering with Tesla to sell the Powerwall system.

"It's critically important now. We don't know what future technologies are going to look like; 2045 is a long time away," Harris said. "Right now, there's no way you can achieve it without storage being a component of it."

Interest in storage high

On Hawaii, there's been a surge of interest in energy storage, he said. Tesla and its partners are selling Tesla's Powerwall. Blue Planet Energy Systems is offering a Sony product and telling prospective customers it can help them go off-grid through a combination of storage with wind or solar.

Chris Yunker, program manager for energy systems and transportation with Hawaii's Energy Office, is looking for the path to 100 percent clean energy.

"The only thing we know for sure is if we take ourselves to 100 percent [renewables] with today's business model, it's not an optimal solution," Yunker said. "Obviously there's a mismatch" between current rates and policies for electricity, and what's needed to drive people to add storage, he said.

"We need to support storage because that will play a role," Yunker said.

Tesla CEO Elon Musk is chairman of SolarCity. That company is among those selling the automaker's new battery storage offering. Asked about Jaramillio's comments, Tesla spokeswoman Alexis Georgeson said that Tesla isn't lobbying for changes to net metering.

Demand for Tesla's 10-kilowatt-hour Powerwall is "huge," she said, even in places with net metering. The storage product offers energy independence, she said in an email, "so a consumer's solar panels can continue to operate when the grid goes down."

Meanwhile, "Tesla is experiencing enormous demand for the 7-kWh daily cycling Powerwall in markets like Hawaii, Germany and Australia, where the price of electricity is significantly more expensive than the price a utility will pay a homeowner for excess solar production," she said.

Tesla doesn't release sales figures. In its conference call on second-quarter financial results, officials said that more than 100,000 reservations have been placed for the Powerwall and Powerpack.

Jonathan Bass, SolarCity's vice president of communications, said in an email that "solar and storage are highly complementary, and in the coming years, we believe every solar system will be accompanied by a battery."

"To build the cleaner, more distributed, more resilient grid of the future, we need current policies like [net energy metering], and future policies that could allow homeowners to provide storage capacity services to utilities. Utilities in [New York] are already starting to consider them," he added.

Susan Glick, senior manager of public policy at Sunrun, also said that net metering and storage work together. In terms of net metering already serving as a battery, Glick said that "a lot of people's [systems] don't offset all of their power use so they're still buying a fair bit from the grid. With storage, you end up buying less from the grid."

Others said that electricity rates and rules will need to shift to really drive adoption of battery storage.

"Absolutely there's a conflict" between net metering and encouraging storage, said California Energy Commission member Andrew McAllister.

The inducement to add storage should come through rates, he said, and "to the extent that our [current] rates have a sort of blunt, one-size-fits-all per-kilowatt-hour charge, that doesn't differentiate."

Without a rate based on the time power is used, and perhaps whether power is going into or out of the grid, he said, "you don't

Storage hits roadblock with EPA's Clean Power Plan

Rebuttal Exhibit ACE

SAN DIEGO -- As energy storage advances on many fronts, there's one place it's not made inroads: with U.S. EPA on its rule requiring power plants to lower greenhouse gas emissions.

Some in the energy storage world want EPA to allow storage as an option for meeting carbon pollution cuts under the Clean Power Plan. It mandates that states develop a means of shrinking GHGs, or adopt the federal model.

The grid right now is "sized two times larger than it needs to be," said Mateo Jaramillo, director of powertrain business development at Tesla Motors Inc., during the National Association of State Energy Officials meeting here. It's because the system has to be able to crank out enough juice on peak demand days, he said.

Jaramillo said he has met with EPA and that it was clear that storage won't be allowed as part of the CPP.

"That is one ... that I think merits being in there. So that it can be considered as part of the plan and it can be evaluated and it can be discussed alongside wind, solar, retirement of coal, whatever other solutions are there," Jaramillo said.

"Storage can be a component of a efficient, reliable and low-cost electric grid," he added. "We're already proving that in instances of projects we're doing right now."

He told NASEO representatives that Tesla would share "whatever information might be supportive for your conversations that you're having at the state level when considering projects."

EPA spokeswoman Laura Allen said that "the CPP covers the emissions from fossil fuel-fired electric generating units."

"Energy storage is not an eligible measure that can be used to adjust a CO2 emission rate, because storage does not directly substitute for electric generation from the grid or avoid electricity use from the grid," she said in an email. "Counting both the generation input to energy storage and the output from the energy storage unit would be a form of double counting.

"Energy storage is not an element of the [best system of emission reduction] but can be used as an enabling measure that facilitates greater use of [renewable energy]," she added.

"Utility-scale energy storage may be used to facilitate greater grid penetration of RE generating capacity and can also be used to store [renewable energy] generation that may have otherwise been shed in times of excess generating capacity," Allen said. "On-site energy storage at an electricity end-user can enable greater use of [renewable energy] to meet on-site electricity demand."

-- Anne C. Mulkern

really have a way to provide that incentive to storage. ... Rates do not transmit that signal."

Switch to time of use coming

Both California and Hawaii are likely switching to rates that will be based on when power is used, as opposed to a flat rate charged per energy unit consumed, said those familiar with the discussions in those states.

The CPUC has told California's three investor-owned utilities that they need to develop proposals for time-of-use rates. Those will be the default by 2019, said Harris, who also advocates in the Golden State.

Jim Avery, chief development officer at San Diego Gas & Electric (SDG&E), said time-of-use rates will prompt people to use power when rates are low and conserve when rates are high. They also could encourage behaviors like cooling a building early in the day before demand spikes, and then allowing the air conditioner to cycle on and off, he said.

That's more efficient than what many residential consumers do now, which is to come home at 6 p.m. and turn on the air. That has pushed the peak demand time to about 8 p.m., when solar power has stopped producing. It forces the utility to run its natural gas-fueled peaker plants.

Customers with solar and net metering have no incentive to conserve in the evenings, he said, because they're probably not paying much for that energy. Their PV systems likely sent power to the grid early in the day, generating bill credits. But that electricity was made at a time when there was an abundance of power on the system, he said, and they're taking it back out when demand is highest.

"The utility grid is acting like a battery for you," Avery said. "It's a fundamental flaw in the design of net metering."

SDG&E statistics show that 40 percent of customers with net metering have increased their electricity demand during peak hours, he said.

An "aggressive" time-of-use rate can allow for net metering while still encouraging people to add storage, said Harris with the Alliance for Solar Choice. That group in a white paper proposed a time-of-use rate with a large differential between peak and non-peak rates. Customers would pay 51.5 cents per kWh of power used from 2 p.m. to 8 p.m. every day, and 26.6 cents per kWh for all other times.

That's likely to flatten out peaks in demand, helping the grid, he said. It's also likely to drive adoption of storage, he said.

"If you do a time-of-use rate and you encourage solar customers to adopt it, you could potentially see huge deployment of storage at the distributed level paid for by private citizens at low cost to the rest of the grid," Harris said. "That's kind of exciting."

The Hawaii PUC is expected soon to issue an interim proposal that would cover distributed energy resources, net metering and other issues, he said. The agency would then spend the next year studying costs, benefits and possible paths forward.

In California, time-of-use rates will make storage attractive, said Glick with Sunrun. People will store energy at times when there's an abundance and take it out for home use when utility prices are high, she said.

Separate look at storage urged

In California, the battle to determine the next version of net metering is already looking to be hard-fought.

SolarCity CEO Lyndon Rive, in an August editorial in Greentech Media, lashed out against utility proposals for fixed fees and cutting the level of net-metering bill credits.

"No state with a thriving rooftop solar industry has adopted residential demand charges or failed to guarantee solar customers full bill credit through net metering," Rive wrote.

Pacific Gas and Electric Co. (PG&E), the state's largest utility, last month proposed demand charges that would start at $3 and rise with consumption. Bills would be a minimum $10 per month, even if net-metering credits were greater than charges for energy used. PG&E and other utilities argue that customers without solar panels pay more to support the grid because those with net metering pay less.

In California, one business group wants the CPUC to look at how to encourage more storage, separate from net metering 2.0. The California Energy Storage Alliance, or CESA, filed papers asking the agency to open a separate case that would look just at storage and storage with solar.

The group said that the utilities' net energy metering 2.0 pitches fail to adequately consider storage's role.

"The lack of consideration of energy storage in the Proposals could lead to flawed proposals and designs," CESA said in the filing. "Each of the IOUs propose some combination of fixed charges, demand charges, and time-of-use rate plans that would be introduced for to the residential and small commercial customer classes, overlooking a potential role for energy storage in each of these cases.

"While CESA is not taking a position or endorsing any of the Proposals at this time, CESA's view is that the proposed retail market designs could be improved through better consideration of the roles and value-added of energy storage."

CESA, however, criticized the fixed charges as a "blunt instrument which can fail to encourage customer-sited Distributed Generation ('DG') deployment to address time-variant grid needs and can fail to account for the benefits of avoided T&D infrastructure investment costs attributed to distributed PV solar and energy storage technologies."

Twitter: **@AnneCMulkern** | Email: **amulkern@eenews.netamulkern@eenews.net**

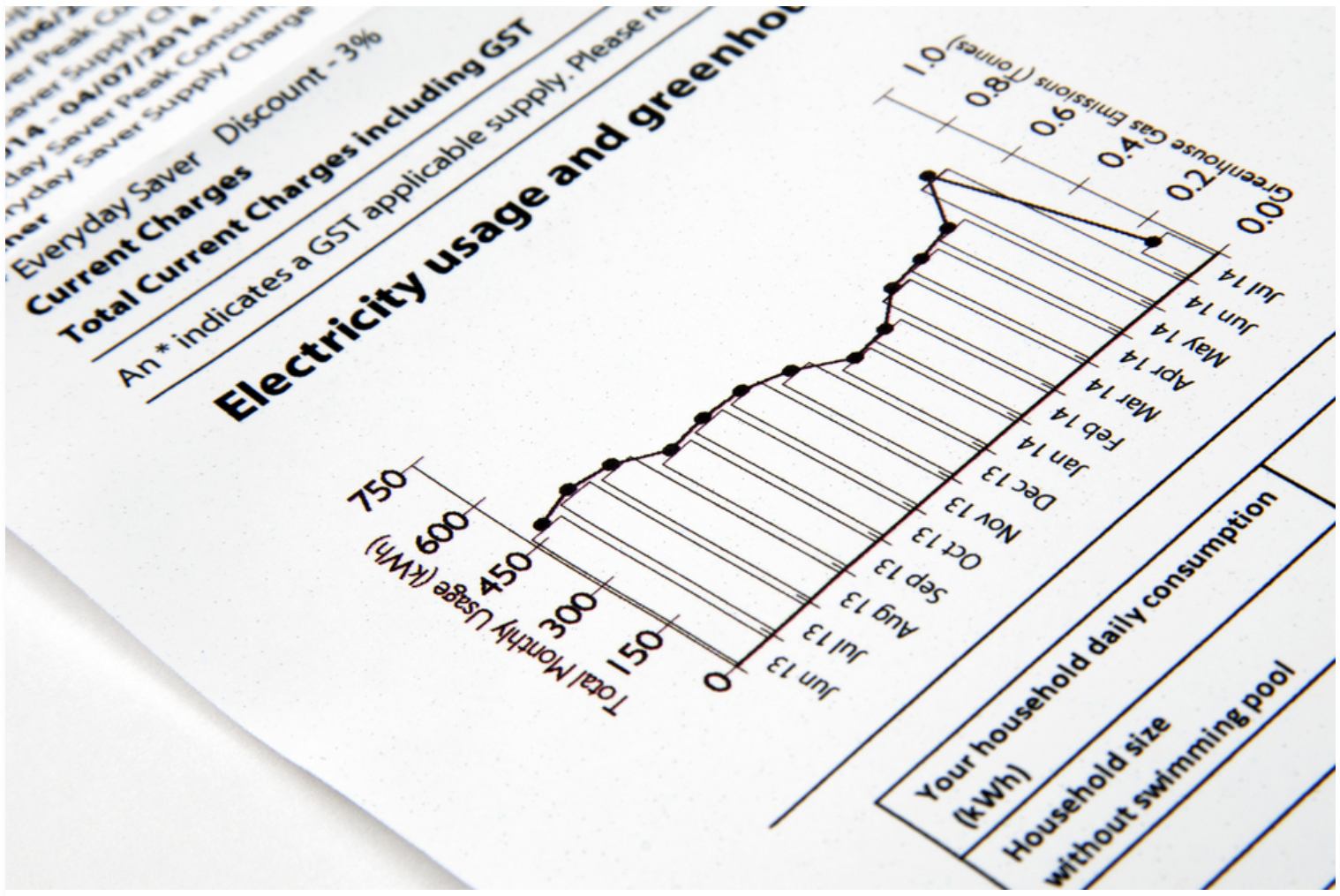
MAY 21, 2015

16 COMMENTS

Are Residential Demand Charges The Next Big Thing in Electricity Rate Design?

AUTHORS

Matt Lehrman
Former Sr. Associate



Demand charges for commercial and industrial customers have long been a part of the electric industry. Since utilities need to build infrastructure to meet both instantaneous and long-term requirements, the utility bill contains both an energy charge, which measures the amount of electricity a customer uses over time, and a demand charge, which measures how much power is used at any given point in time.

However, residential customers are rarely subject to a bill with a demand charge. This is because, until recently, residential electricity loads were pretty much the same from one customer to the next. We all (more or less) woke up, took a shower, went to work, came home, turned on the lights, cooked dinner, watched TV, did a load of laundry, went to bed. With each customer in the residential class looking an awful lot like the next, utilities and regulators could lump energy and demand elements together into one $/kWh price.

But today, this assumption is no longer true. All residential customers are not the same. We now have access to LED lights, smart thermostats, plug-in electric vehicles, rooftop solar, demand-flexible water heaters, battery energy storage, and myriad other technologies that make our respective loads and our consumption patterns potentially very different. Critically, it is now inexpensive to meter these differences, including time of use and the magnitude of the demand. Separating out demand charges may be a good way to promote more fairer cost allocation among ratepayers, while also motivating customers to reduce strain on the system. More than a dozen utility companies across the country have implemented or are currently considering residential demand charges.

WHAT IS A DEMAND CHARGE?

A demand charge is based on the maximum amount of energy a customer uses at any one instance over the course of a billing cycle. It reflects the cost that a utility incurs to maintain the

Welcome to the RMI Blog

RMI Outlet, Rocky Mountain Institute's blog, explores topics critical to RMI's mission to drive the efficient and restorative use of resources.

Most Popular

Four Trends Driving Profitable Climate Protection

Hawaii just ended net metering for solar. Now what?

Today's U.S.-China Announcement is the Most Significant Milestone to Date for Battling Global Climate Change

Archived Posts

Browse By Author

Browse By Category

Transportation
Buildings
Industry
Electricity
General Energy
Spark

Browse By Date

> 2015
> 2014
> 2013
> 2012
> 2011
> 2010

infrastructure to deliver what the customer wants, when the customer wants it. Think of it as the “size of the pipe” (figuratively) that delivers electricity to customers—a bigger pipe costs more, but can deliver more juice at any instant.

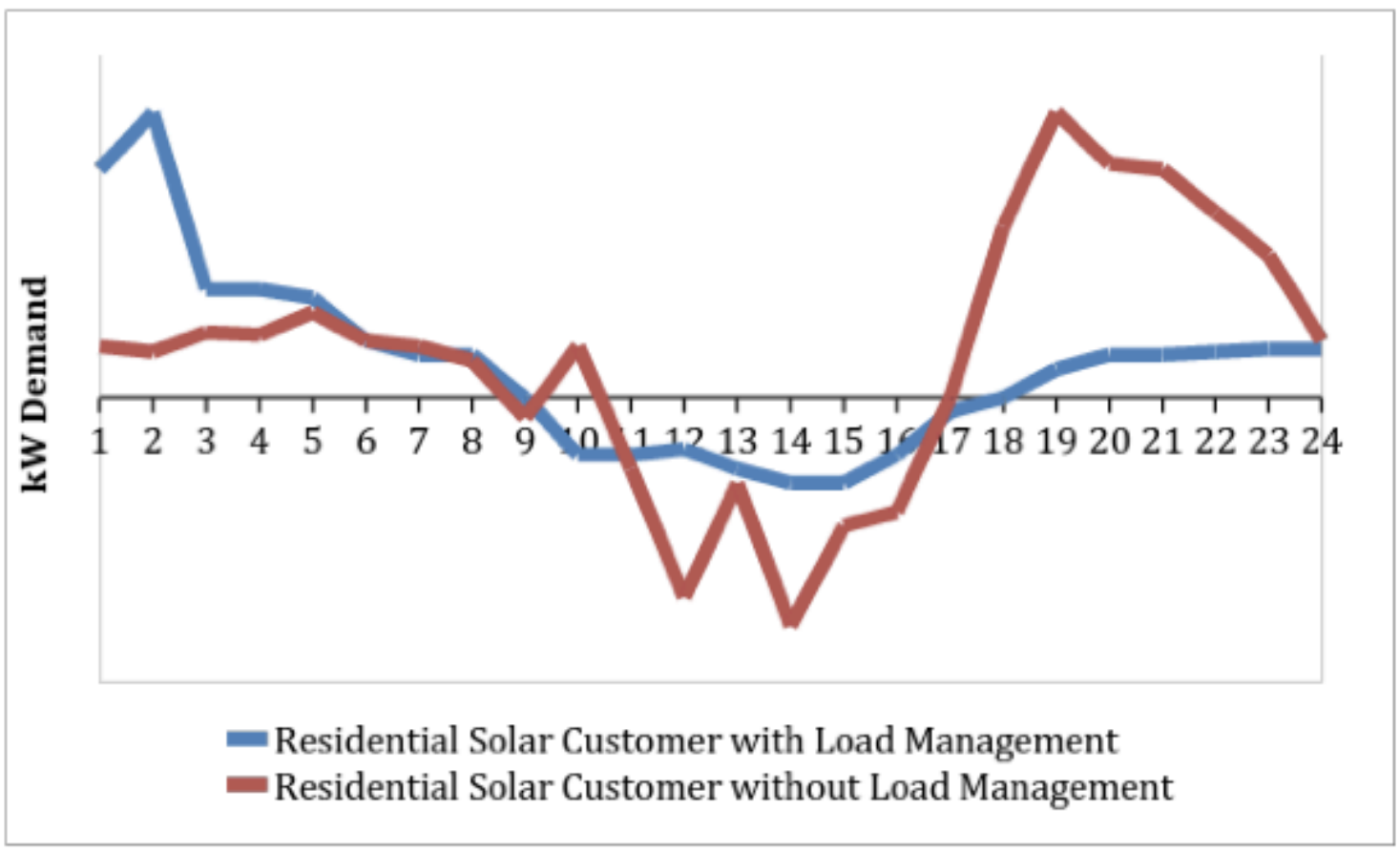
The distinction between how much electricity you need right now and how much you need in total over time is important. Imagine you want to fill a swimming pool with water. You could fill it in minutes with a fire hose. Or you could fill it in hours with a trickle from a garden hose. In both cases, you get the same amount of water. But how much water you get how fast is quite different, and that difference incurs costs to the system.

Historically, this has only been important for large customers that require high amounts of power throughout the day. But as the penetration of distributed energy resources from rooftop solar PV to electric vehicle charging to programmable, controllable thermostats to stationary storage grows, the demand charge can be both a promising solution to the puzzle of how to more equitably collect grid infrastructure costs as well as a price signal that encourages efficiency, load shifting and peak management, and the diverse array of DER product combinations that can perform these tasks.

Consider two hypothetical residential customers, both with the same monthly kWh usage:

- Customer A has no DERs and uses approximately the same number of kWhs each day. The customer works at home and has a consistent demand throughout the day.
- Customer B has rooftop solar and an electric vehicle. The rooftop solar ramps up production just as Customer B shuts off lights and appliances and leaves for work, seriously depressing that home’s net demand on the grid (and even likely exporting surplus solar PV). Solar production later decreases in the afternoon just as Customer B gets home, turns on the same lights and appliances, and plugs in an electric vehicle, greatly increasing the home’s net grid demand.

At the end of the month, the kWh usage is the same, but the peak demand and benefits and costs to the grid of each customer are very different. Yet both pay the same $/kWh energy charge. In this example, a demand charge would more equitably charge each customer for the service required from the grid closer to each customer’s true cost of service. The customer with a “traditional” and smoother load curve would cause fewer system costs, while the customer whose net grid demand surges from essentially zero to peak would cause greater costs for grid resources (generation, transmission, distribution) to meet that surging need.



Source: Adapted from SDG&E

The above chart shows two similar customers each with rooftop solar, air conditioning, and a pool pump. The blue line shows one customer using timers and other load controls to align consumption with solar output and away from peak periods (assuming demand charges vary by peak and off-peak periods). The red line shows a customer with unmanaged load. While the overall peak demand is comparable, a demand charge with peak and off-peak rates would charge the blue customer much less (with demand shifted to off-peak hours) than the red customer (with demand coincident with peak hours).

Thus, the demand charge accomplishes two important goals as DERs proliferate:

- *Promoting customer equity:* The demand charge bills customers based on the demand

the customer places on the grid. This helps differentiate between a customer with a 2 kW solar PV array and an electric vehicle and a customer with a 10 kW array with load that does not align with the solar output.
- *Providing a price signal for DERs to provide value on both sides of the meter:* A demand charge creates a price signal for customers to smooth load. Whether the customer does this through efficiency, battery storage, or automation of EV charge management, this creates both short- and long-term benefits—monthly bill savings in the short-term (through reduced demand charges) and the deferral or elimination of new infrastructure investments to meet growing peak demand (stabilizing rates over the long-term).

DEMAND CHARGES CAN ALIGN DER INCENTIVES WITH SYSTEM BENEFITS

Demand charges can also help to address one of the most vexing debates between utilities, regulators, DER providers, and customers—how to properly charge and compensate distributed generation (DG) customers. Proposals to increase fixed charges or to offer value of solar tariffs remain controversial; there is little agreement on an appropriate value of solar calculation and on which charges are fixed and which charges are variable. This uncertainty creates an unclear value proposition for DG customers, making financing more difficult (and expensive) and constraining the growth of DERs. So while demand charges could be good for all residential customers, they're especially suited to customers with DERs.

Two utilities recently added demand charges for DG customers. While these charges might slow adoption of solar, or may be too drastic a change all at once, they could potentially unleash new combinations of DERs to help customers better manage the demand, which can bring value to the entire system.

- Salt River Project (SRP) added a seasonal, inclining block demand charge to future net-metered PV customers. One reason for this was to create an incentive for customers to install west-facing PV systems, so that generation better aligns with system peak. SRP also states the demand charge will help customers adopt new technology (e.g., load controllers, smart thermostats, or battery technology), and change their behavior to respond to those price signals.
- In its March 2015 general rate case filing, Westar Energy proposed a choice for residential DG customers. One of the two options entailed a lower fixed customer charge plus a demand charge.

Demand charges can be beneficial for customers without solar as well. At least 14 utilities have implemented demand charge rate options for residential customers with or without solar. For example:

- In South Dakota and Wyoming, Black Hills Power offers a demand charge option for all residential customers. To help customers manage their electricity demand, maximize operational benefits to the grid, and minimize their monthly bills, the company promotes a Demand Controller Program. The program connects load control devices to heating and cooling systems, hot water heaters, clothes dryers, and hot tubs to cycle these appliances on and off in 15-minute cycles to help customers manage demand charges. The controller is owned and operated by the customer instead of the utility, leaving ultimate decision making over appliance control to the customer.

CONCLUSION

Demand charges are a promising step in the direction of more sophisticated rate structures that incent optimal deployment and grid integration of customer-sited DERs. A demand charge more equitably charges customers for their impact on the grid, can reward DG customers with bill savings, and opens up potential for an improved customer experience using load management tools. It can also benefit all customers through reduced infrastructure investment and better integration of renewable, distributed generation.

Image courtesy of Shutterstock.com

TAGS: ELECTRICITY | RATE DESIGN | RATE STRUCTURES | DEMAND CHARGES | DERS | DEMAND FLEXIBILITY

RECOMMENDED READING

- Report Release: Renewable Microgrids
- The Renewable Energy Market is Evolving. Here's How.
- BRC Companies Win EPA Green Power Awards