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Third-Party Distributed Generation

Issues and Challenges for Policymakers

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OVERVIEW

THE EVOLVING NATURE OF ELECTRICITY MARKETS

Historically, electricity service involved two parties, a producer (the utility) and a consumer (the customer). Those lines have become blurred with the introduction of distributed generation, and even further muddied with the advent of third-party ownership of those resources.

For the purposes of this paper, we use the term distributed generation to refer to non-utility power supply located on the customer side of the meter. Such resources allow the customer to generate some of its power needs; the utility supplies the rest. As long as the customer owns the on-site generation and stays connected to the grid, we have a two-party arrangement, even though the customer is now both a producer and a consumer. The **third-party** notion enters the picture when an entity other than the customer or the utility owns the generation on the customer side of the meter. Then we have two distinct power providers, the utility and the party owning the on-site generation, and one consuming customer, which is a three-party arrangement.

A variety of energy sources ranging from biomass to diesel fuel can be used in distributed generation systems, but the exponential growth in distributed solar photovoltaic (PV) systems has caught the attention of affected parties, including utilities, regulators and renewable energy advocates. Much of our discussion considers that technology.

In a physical sense customer-owned and third-party distributed generation systems are often indistinguishable. Yet the third-party ownership option is a critical factor in that it provides financing flexibility to customers interested in on-site generation. Recent activities in states that allow third parties to provide distributed generation resources reveal that permitting this alternative substantially increases the penetration of distributed generation, thereby magnifying the impacts that the utilities experience.

While distributed generation can have significant physical impacts on the electrical system, we do not cover those issues in this report. Readers interested in learning about those impacts can find numerous reports and studies addressing them.[1] We focus on the impact of distributed generation on utilities' financial situations and the associated rate design implications.

This report provides a picture of the world in which energy interests are operating. The issues discussed in this paper are complex and in some cases controversial. The authors have endeavored to take an impartial look at customer-side distributed generation use and to portray the concerns and viewpoints of key affected parties. These portrayals are either the authors' interpretations of stakeholder views or taken directly from published sources. The authors do not speak for any of the stakeholders. Where we address opinions, we do so without prejudice as to the reasonableness of those statements.

The primary questions we seek to answer are:

1. What is happening with distributed generation use in the world, the U.S., and Wisconsin?
2. What are the financial and regulatory implications?

[1] For a discussion of electrical system impacts, see American Public Power Association, *Distributed Generation: An Overview of Recent Policy Developments*, November 2013.

FINANCIAL IMPLICATIONS OF THIRD-PARTY DISTRIBUTED GENERATION

The advent of third-party distributed generation shines a bright light on long-established regulatory practices. Rate design philosophy is at the heart of the controversy.

At present, ratemaking practices require utilities to collect a large proportion of their system fixed costs through volumetric (per-kWh) prices. While there are some good reasons supporting this pricing system, such as the fact that it sends a price signal perhaps more in keeping with long-run avoided costs (all costs are variable in the long run), which sends a signal to use energy efficiently. However, this rate-setting approach creates a significant price-historical utility cost mismatch in the short run.

While sending proper long-run economic price signals is important, it creates a significant problem if reaction to that rate design does not allow utilities to recover their accounting-based system costs. Customers installing distributed generation systems will purchase less power from the utility, thereby reducing their electric bills. Under standard volumetric-based pricing, the customers essentially receive credit for the variable costs the utility actually avoids when usage declines, and also receives credit for cost the utility doesn't avoid—its fixed costs.

When customers buy fewer kWh, the utility avoids the cost of fuel it doesn't need to burn to generate electricity. But what fixed costs does the utility avoid when customers reduce their purchases of power from the grid? No fixed costs are avoided, at least not in the short run. Fixed costs are, by definition, not going to change with changes in consumption. Since the standard rate design credits any reduction in use with some reduction in fixed costs, and because the utility doesn't actually avoid any of those fixed costs, it ends up short in a financial sense when usage declines. If the regulator is to make the utility whole, these lost contributions to system fixed costs must be recovered through an adjustment to the utility's rates, that is, spreading the costs over the remaining system sales.

But if regulators continue to use pricing that is largely volumetric-based, they will continue to allocate a large portion of the utility's fixed costs (which have not changed with reductions in load) to a shrinking sales base, thereby increasing the volumetric rate. As a result the regulatory response to a competitive threat to the utility is to raise utility prices. As distributed generation becomes more competitive, continuing to rely on this pricing approach may force the utility into a spiral in which it cannot recover all of its fixed costs and, perhaps, pricing itself out of a competitive market.

REVISING THE FIXED CHARGE/VOLUMETRIC CHARGE BALANCE

Utilities and other parties are asking regulators to undertake a fundamental rethinking of rate design philosophy. Shifting to a rate design that better matches prices to short-run utility cost structures would address this problem, at least initially. If customers pay all of their contributions to system fixed costs through a fixed charge, rather than partly through a volumetric charge, and pay for only truly variable costs through that volumetric charge, the load lost to distributed generation would lead to revenue losses for the utility equal to the costs they actually avoid in the short run. On net, the utility would be kept whole when load declines. We explore this in more detail later in the report. This precise matching of utility prices to utility costs has strong analytical appeal, but may also have some policy drawbacks as we discuss in the next section.

Note that the issues associated with pricing of **net metering** mirrors the discussion of the general rate design. Frequently, distributed generation customers may produce power in amounts greater than they need to meet their own electrical demand. Those customers can typically sell the excess power to the utility. Net metering is a way of compensating the customers for that power. The meters turn one direction when the customers purchase power from the utility; they move in reverse when the customers become the sellers.

Net metering is usually offered under the customer's retail rate. That is, at a given point in time the rate that a customer would pay to purchase a kWh is the same price it would receive if it sells a kWh to the utility. If a portion of the utility's fixed costs are recovered through the volumetric rate, then, when customers sell power back to the utility we have the same problem just discussed; one in which customers receive credit for costs that exceeds the costs that the utility actually avoids, at least in the short run.

Again, pricing that includes all system fixed costs in the fixed charge and all variable costs in the volumetric charge will solve the cost recovery problem for net metering as well as for general service. As such, the high fixed charge rate design has broad appeal, particularly among utilities, for those looking for a solution to the cost recovery problem third-party distributed generation presents.

COMPLICATIONS WITH THE NEW RATE DESIGN CONCEPT

There are, however, some problems associated with a high-fixed-charge rate design. As can happen with many regulatory issues, the sharp analytical focus that leads one to the high-fixed-charge rate design can actually cause us to miss some aspects of the problem. Recovery of utility costs is an important objective of any rate design, but there is more than one rate design that can achieve that end.

Public policy development is ultimately a process of synthesis, not analysis. This requires stepping back to see a broader picture, one that considers multiple, often conflicting, objectives. Bonbright's classic rate design principles reveal the challenging nature of the rate design process.[2] In summary his principles suggest that a rate design should:

1. Allow utilities to collect sufficient revenues to recover their costs and attract capital from investors;
2. Send price signals that lead to economic rationing of resources
3. Be fair to consumers and the utility

Cost Recovery

The high-fixed-charge rate design gets high marks on the cost recovery and capital attraction front, which is one of its strong selling points. Relative to traditional rate designs; it provides a more stable revenue stream for utilities, enhancing the ability of the utility to recover its costs. This reduces investor risk, allowing the utility to raise capital at lower cost. This benefits ratepayers as long as the regulator passes those costs savings on to customers.

Price Signals

The high-fixed-charge rate design performs poorly in terms of sending an economic price signal. While this rate design may reflect historical system costs, that is not the metric of interest in economic terms. Forward-looking marginal cost is the relevant benchmark. This includes both internalized costs as well as externalities, such as the social cost of utility air emissions. Even the traditional volumetric-based rate designs tend to under-price utility service when compared to the long-run marginal cost.[3] Increasing the fixed charge and lowering the volumetric charge exacerbates the problem, reducing the incentive for customers to conserve.[4]

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[2] James C. Bonbright, Albert L. Danielsen, and David R. Kamerschen, *Principles of Public Utility Rates*, Public Utility Reports, 1988, pp. 383-384.
[3] Richard Stevie and Raiford L. Smith, "Energy Efficiency Unmasked," *Public Utilities Fortnightly*, February 2014.
[4] Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry.*

Fairness

The degree to which any rate design is fair is the subject of thorny debate, which is usually the case with any discussion of fairness given its subjective nature. From the utilities' perspective, a high-fixed-charge rate design is among the most fair. The utilities build a system to meet the demands of their customers, standing ready to serve at the customer's flip of a switch, regardless of whether the customer actually does flip the switch. Therefore, charging customers a fixed fee to recover the cost of the capacity built to serve them seems inherently fair. Including those costs in the volumetric charge instead, permits customers who reduce their usage to lower-than-average levels to escape responsibility for some of the costs the utilities incurred in providing that service.

Nevertheless, since fairness is a subjective notion, no matter how strongly utilities feel about the degree to which a high-fixed-charge rate is fair, many customers and some regulators may disagree. Fairness has myriad aspects making it highly unlikely that one could find a rate design that all stakeholders consider to be optimal or even reasonable.

For example, many consider it unfair that under the high-fixed-charge rate design customers have little ability to significantly affect their bills by controlling their usage. This can be especially problematic for low-income customers.

> The higher fixed cost per month cannot be mitigated by consumer behavior, so the design penalizes the customers who most need to manage their bills by conserving energy.[5]

The literature suggests that when considering fairness, rather than looking at cost causation, most commissioners use customer reaction as the key indicator:

> Most measure the fairness of their decisions by the number of complaints, the source of the complaints, the intensity of the complaints, or whether there was equal complaining by the several interested parties.[6]

As we noted, the high-fixed-charge rate design is typically poorly received by customers, so utilities should expect complaints if they attempt to implement such designs, raising fairness flags for some commissioners. That said, fairness is not the only criterion that regulators use in reaching decisions. Furthermore, since fairness is in the eye of the beholder, some regulators may in fact find the high-fixed-charge rate design to be fair.

THE VALUE-OF-SOLAR APPROACH

With respect to the net metering issue, there is an alternative approach that is receiving consideration, one that has bearing on the basic pricing philosophy issue. Rather than paying the customer the retail rate for power supplied to the utility, the **value-of-solar** approach credits customers with the present value of the long-run system costs that solar PV facilities help the utility avoid.[7] This is more in keeping with a long-term resource planning perspective. While this concept, too, has merit, it is not without controversy. Some studies applying this framework suggest that distributed generation customers currently receive too much credit for long-run cost savings under current net metering approaches; others suggest that they receive too little credit.[8]

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[5] John Wolfram, *Straight Fixed Variable Rate Design*, Catalyst Consulting, 2013.
[6] Douglas Jones and Patrick Mann, "The Fairness Criterion in Public Utility Regulation," *Journal of Economic Issues*, 2001.
[7] Clean Power Research, *Draft Report: Minnesota Value of Solar: Methodology*, November 19, 2013.
[8] Lena Hansen and Virginia Lacy, *A Review of Solar PV Benefit and Cost Studies*, Rocky Mountain Institute, September 2013.

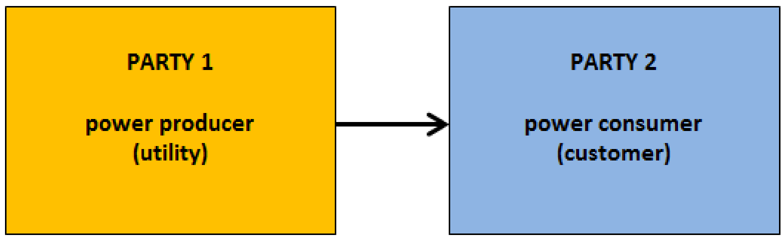
A COMPLEX PROBLEM

The complexity of the issues associated with third-party distributed generation presents substantial challenges for both utilities and policy makers. While this report provides conclusions based on our analysis of specific issues, we make no recommendations per se. The purpose here is to set the stage for discussion of these important topics. Creativity, flexibility and adaptability will likely be required to produce sustainable solutions that balance the needs of multiple parties and that ultimately serve the public interest.

INSTITUTIONAL ARRANGEMENTS: FROM TWO PARTIES TO THREE

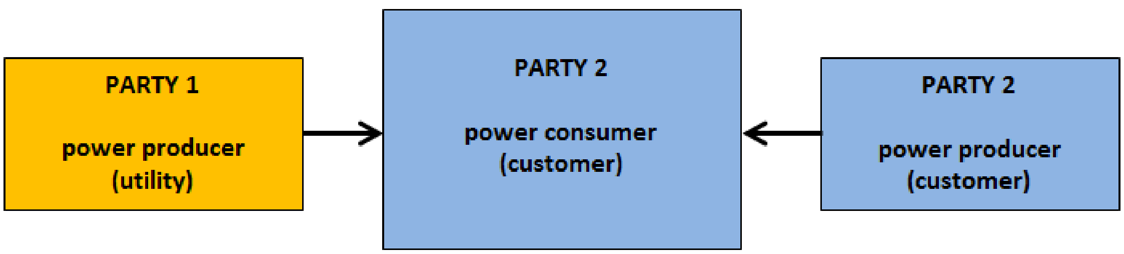
For most of the 20th century the U.S. retail electric utility market operated largely under a two-party structure with power flowing in one direction.[9] As illustrated in Figure 1, utilities provided the power; customers consumed it. Most customers today continue to take electric service under this arrangement.

Figure 1 - Two-party arrangement with uni-directional power flow from utility to customer



A growing number of customers have a more complicated arrangement in that they meet some of their power needs with their own generation. Nevertheless, under this structure there are still only two parties, and the power flow between the utility and the customer is still a one-way path. Figure 2 illustrates this structure.

Figure 2 - Two party arrangement with uni-directional power flow from utility to customer and customer self-generation

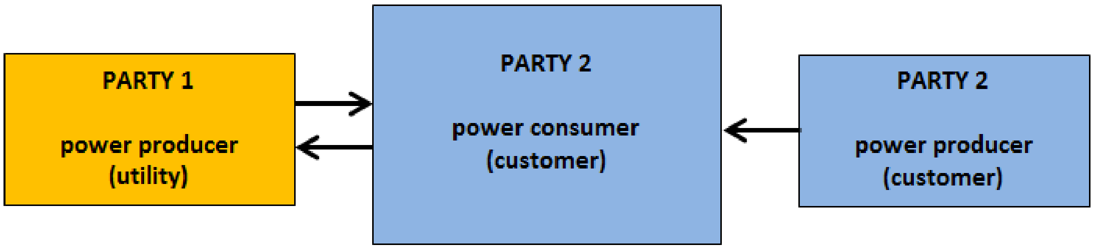


The power that the customer provides for itself is referred to as **distributed generation**. This reflects the fact that rather than being generated at a central utility power plant and then transmitted and distributed to the customer, this sort of generation is dispersed throughout the utility's service territory, sitting on the customer's side of the meter.

Complexity increases with distributed generation in that at some points the customer may generate more power than it needs, creating an opportunity to sell power back to the utility. Under this arrangement, as illustrated in Figure 3, power can flow in either direction between the utility and the customer, with the customer purchasing power from the utility at some points and selling power to the utility at others.

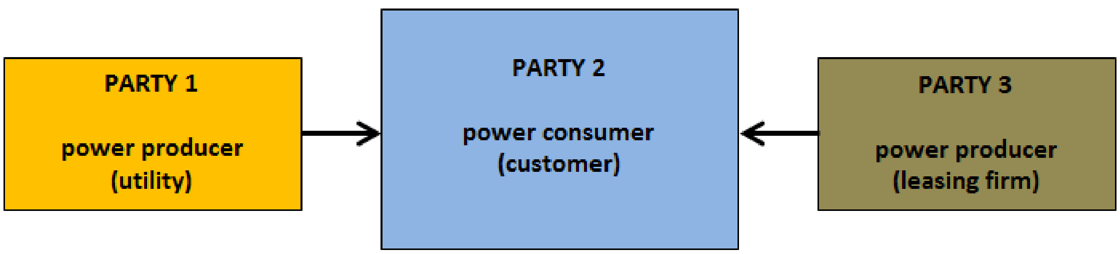
[9] This describes the "contract path," that is the flow assumed in the service arrangement. In the physical world electricity pulses back and forth at 60 cycles per second.

Figure 3 - Two-party arrangement with bi-directional power flow between utility and customer including customer self-generation



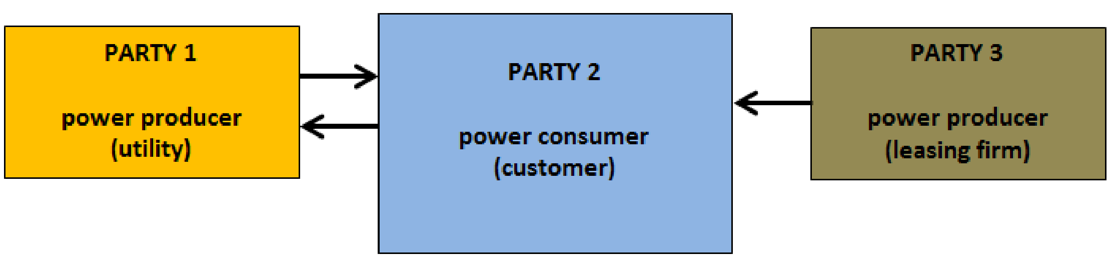
All of the arrangements discussed so far have only **two parties—the utility and the customer**. The notion of a third party arises when a separate entity provides the power on the customer's side of the meter. A common arrangement of this type involves companies that lease solar PV equipment to customers. Figure 4 shows this arrangement with uni-directional power flow between the utility and the customer.

Figure 4 - Three-party arrangement with uni-directional power flow from utility to customer and customer-leased generation



This schematic captures the essential nature of **third-party distributed generation**. We have a utility, a customer and a leasing company. We can take this arrangement a step further by showing power sales from the customer to the utility at certain times. This arrangement is shown in Figure 5.

Figure 5 - Three-party arrangement with bi-directional power flow between utility and customer and customer-leased generation



Third-party ownership arrangements require little if any upfront capital investment on the part of the customer, just as is the case when one rents rather than purchases an apartment. This removes a significant barrier to the development of distributed resources as it enables more customers to adopt PV systems than would otherwise be able to do so. With the structural relationship of the third-party arrangement in hand, we next examine market trends in PV installation.

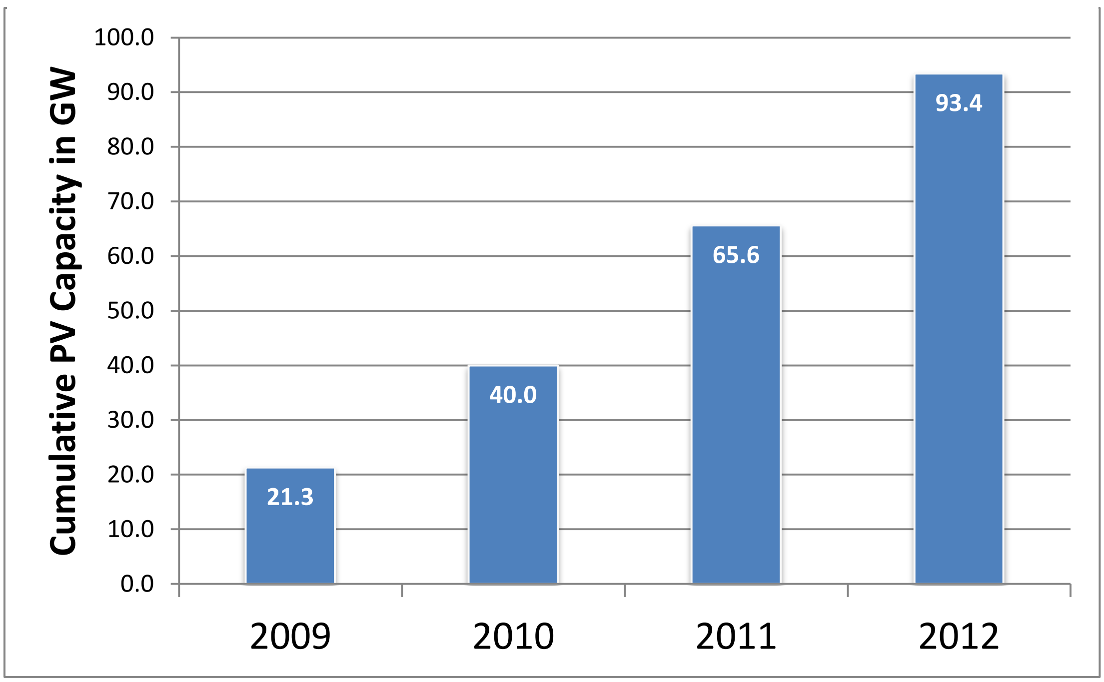
MARKET TRENDS IN DISTRIBUTED GENERATION

GLOBAL TRENDS

There is growing worldwide use of on-site distributed generation, and solar photovoltaic (PV) systems in particular.

Globally in 2012, several factors acted to dampen the rate of growth investment in PV systems to some extent. These included major regulatory changes in subsidies in several countries, resulting policy uncertainty, market overcapacity, and tighter credit conditions.[10] However, despite these confounding influences, grid-connected PV capacity expanded by 43 percent, or 28 GW, worldwide. Figure 6 shows the growth in cumulative installed capacity from 2009 to 2012.

Figure 6 - Annual worldwide growth in grid-connected PV installed capacity



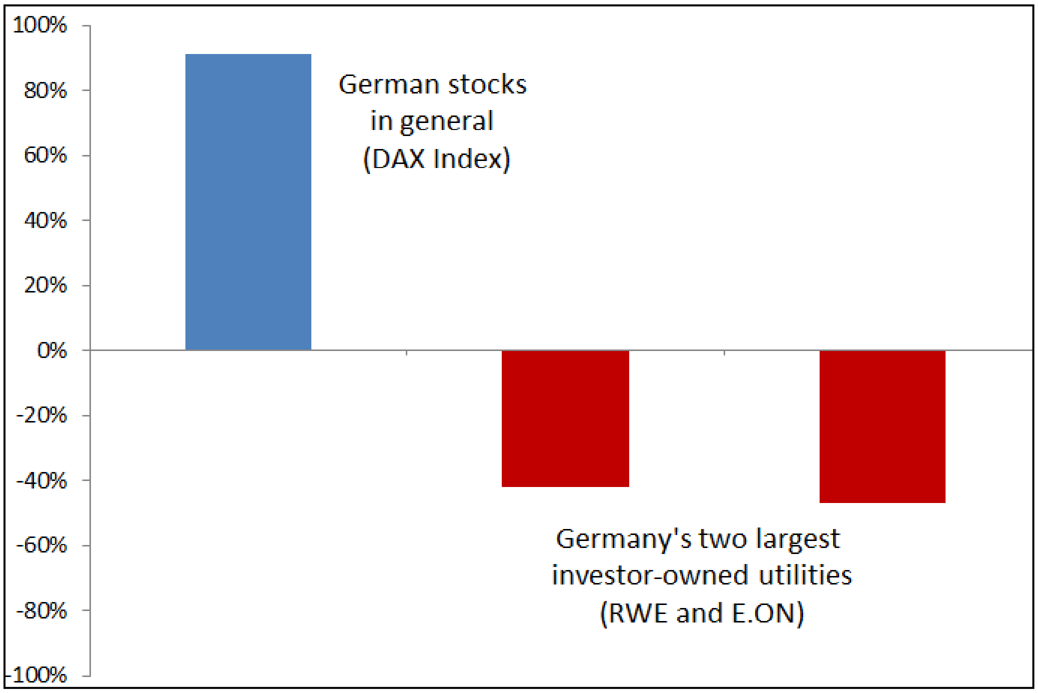
Source: Lahmeyer International, *Renewable Electricity Market, Installed Power and Annual Electricity Generation* (REMIPEG), 1st quarter 2013, as summarized in Renewable Energy Focus online version, October 9, 2013.

Some countries have moved early and decisively to adopt renewable technologies. Germany, the perennial leader in sustainable energy, currently leads the world in penetration of distributed generation technologies, but is now seeing some negative economic consequences. Higher energy prices that accompanied their national policy to promote renewable energy are now seen by some as presenting a risk to the country's global competitiveness.[11] Electricity prices charged to industry and residential customers have risen 20-40 percent since 2007, prompting calls for adjustments that would temper incentives and goals for renewable energy adoption.

[10] Lahmeyer International, "Renewable Electricity Market, Installed Power and Annual Electricity Generation," summarized in *Renewable Energy Focus* online version, October 9, 2013, http://www.renewableenergyfocus.com/view/34970/renewable-power-generation-2012-figures/.
[11] Folkerts-Landau D, "Energiewende 2.0 – Don't Risk Competitiveness," *Standpunkt, Deutschland*, Deutsche Bank AG, DB Research, Frankfurt am Main, Germany, November 26, 2013.

Expanding distributed generation installations and flat energy demand means German utilities today have plenty of excess capacity. This leaves them with billions of euros in sunk conventional generation costs that they cannot recover due to their inability to sell power from those units in competitive markets.[12] The two largest German investor-owned utilities have seen large decreases in market value as a result. Figure 7 shows the change in stock prices for these utilities from 2008 to 2013 relative to German stocks in general.

Figure 7 – German utilities' stock price changes (2008-2013) relative to other German stocks



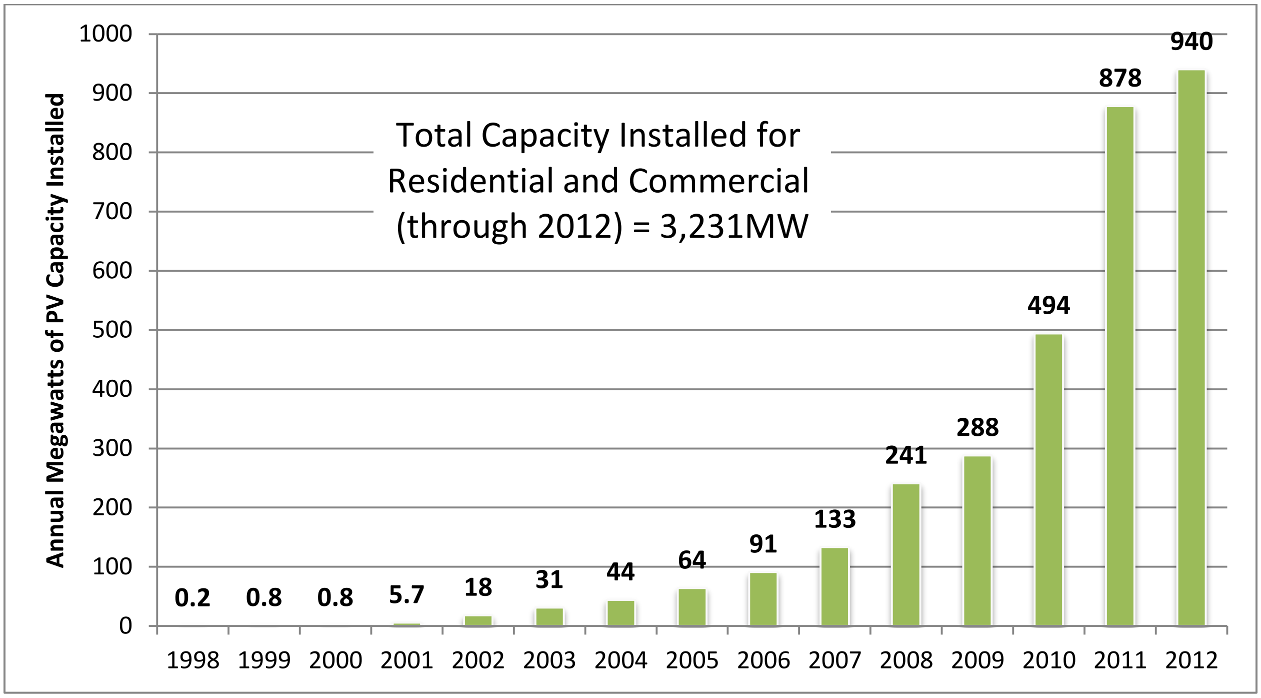
The example of Germany's pioneering advances in distributed renewable energy adoption reveals that without innovative financial and rate-design reform utilities can suffer severe financial consequences from policies that support distributed generation.

U.S. TRENDS

The U.S. has seen a precipitous rise in installations of PV systems in the residential and commercial sectors, as well as at the utility scale. Figure 8 below shows the annual capacity installations of residential and commercial scale PV in the U.S. since 1998.

[12] *Ibid.*

Figure 8 - Capacity of PV installed at U.S. residential and commercial projects each year



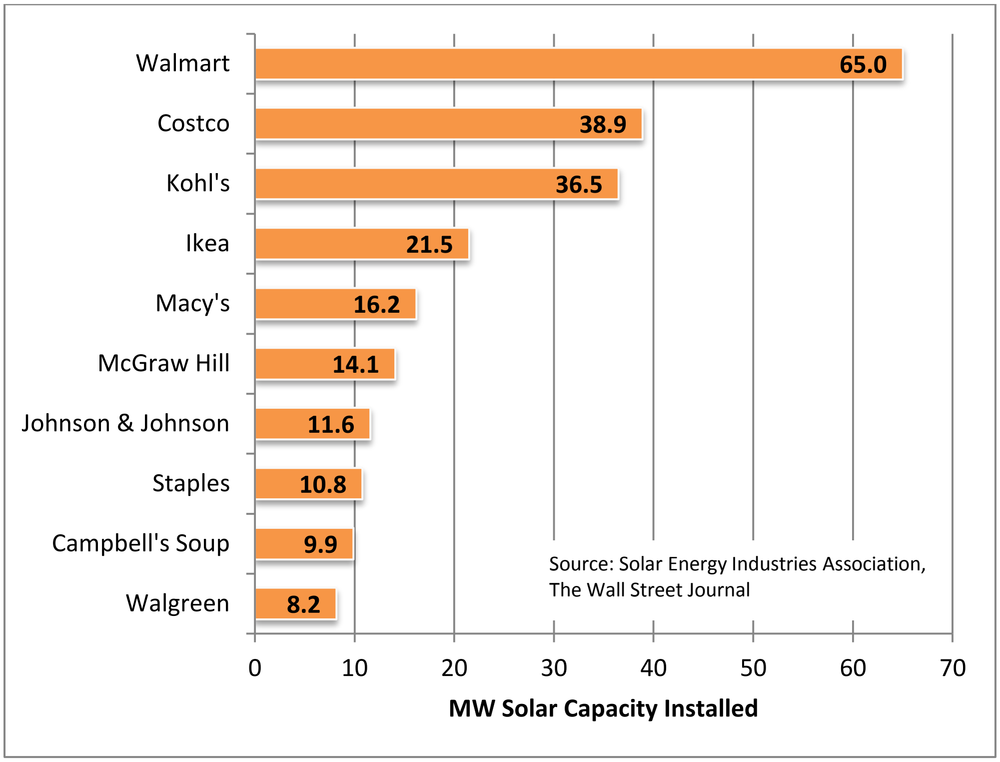
Source: Barbose G, et al., *Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*, SunShot, US Department of Energy, July 2013.

In a recent report, Citi Research predicted that growth in investments in solar PV looks set to continue for the long term, with solar taking an ever greater share of energy generation.[13] These trends point to a decrease in the importance of incentives as a market driver.

In the U.S., the number of distributed generation installations at commercial and industrial facilities have gone from about 10,000 in 2006 to about 40,000 in 2013. Solar PV systems in particular now amount to roughly five percent of all U.S. energy production, some of which is on the utility side of the meter.[14] A growing number of U.S. companies have established initiatives to produce their own power on-site using PV and other renewable technologies such as on-site wind and anaerobic digestion.[15] Figure 9 below shows the leading U.S. companies using solar PV for their on-site generation.

[13] Pourreza S, et al., “Rising Sun: Implications for US Utilities,” Published by Citi Research, a division of Citigroup Global Markets Inc., August 8, 2013.
[14] Sullivan C, “Distributed generation Could Rattle 'Existing Order' for Utilities -- Former Federal Regulator,” *E&E Reporter*, December 5, 2013, http://www.eenews.net/energywire/2013/12/05/stories/1059991315. distributed generation is defined loosely here as smaller generation units that operate off the traditional electric grid.
[15] Smith R, and Sweet C, “Companies Unplug from the Electric Grid, Delivering Jolt to Utilities,” *The Wall Street Journal*, September 17, 2013, http://online.wsj.com/news/articles/SB10001424127887324906304579036721930972500.

Figure 9 - Top U.S. companies using distributed solar PV



Smith, R, and Sweet C, *The Wall Street Journal*, September 17, 2013.

This appears to be just the beginning of a significant trend. Walmart intends to increase its on-site generation from the current four percent of the company's energy demand, to 20 percent by 2020 by installing PV panels on thousands of store rooftops. Furthermore, technology leaders such as Google[16] and Apple[17] have publicly expressed commitments to using 100 percent renewable energy. Google reports currently using renewable energy to power 34 percent of its operations, and Apple reports using 75 percent renewables for its operations in 2012.

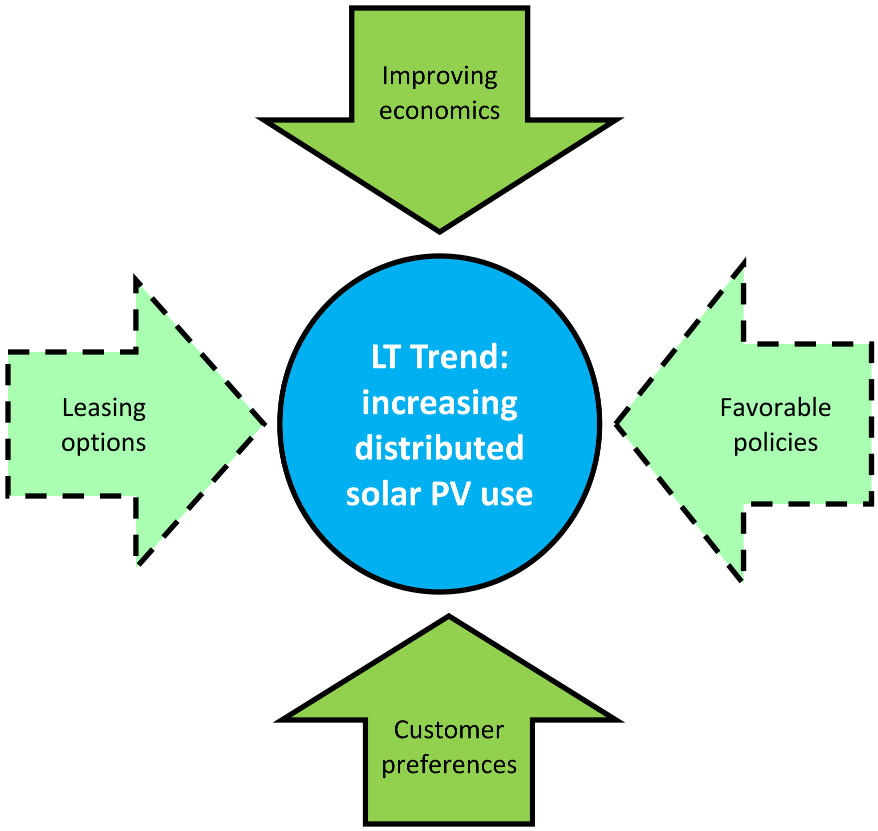
DRIVERS OF MARKET CHANGES

There are a number of factors influencing the long-term growth in adoption of solar PV systems. Figure 10 below illustrates some of these factors.

[16] Google Green web page, http://www.google.com/green/energy/#power. Google has committed over $1 billion to wind and solar projects and also buys green energy through renewable energy tariffs offered by utilities near their data centers. They also entered into long term power purchase agreements directly with large renewable energy facilities, primarily wind farms throughout the world.

[17] Apple and the Environment, web page, http://www.apple.com/environment/renewable-energy/. Apple states that "we're investing in our own onsite energy production, establishing relationships with suppliers to procure renewable energy off the grid."

Figure 10 - Factors influencing long-term trend of solar PV adoption



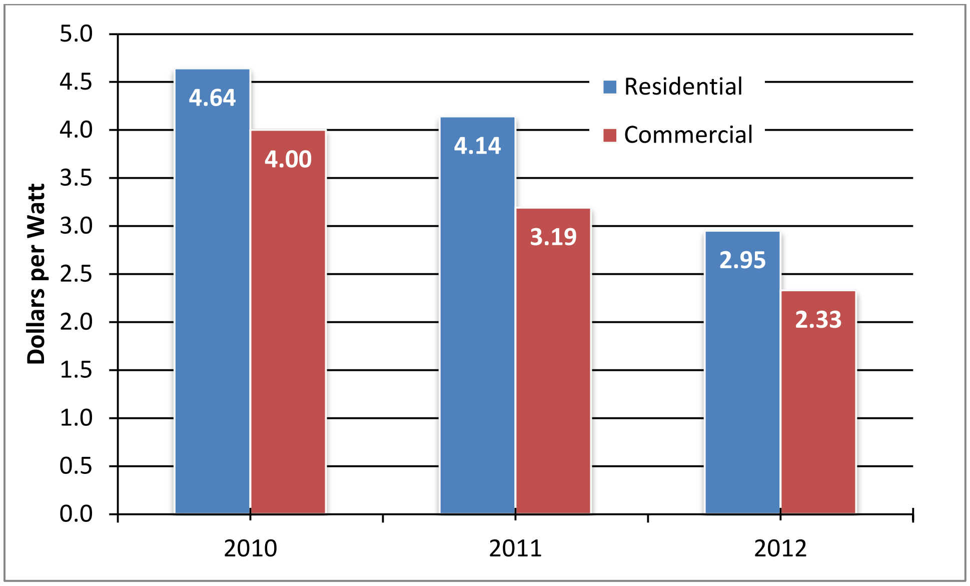
The factors in solid-outlined arrows, improving economics and customer preferences, are globally-influenced and generally not likely to be affected by any U.S. policy changes. The factors in dashed-outlined arrows are possible policy levers that could theoretically be influenced within the U.S. to affect the rate of distributed PV adoption. In considering trends and possible responses, it is important to understand this distinction.

Improving Economics – PV System Cost

The declining cost of small PV systems is an important influence on the expanding use of PV. In 2012 rooftop solar panels cost about one percent of what they did 35 years ago.[18] In the U.S. between 2010 and 2012, PV modules have dropped in price by 36 percent for residential and 42 percent for commercial scale installations, on average.[19] Figure 11 below shows the average prices for installed solar PV modules for these installation types for the years 2010 through 2012.

[18] Tillemann L, "Revolution Now: "The Future of Arrives for Four Clean Energy Technologies," US DOE, September 17, 2013.
[19] Bloomberg New Energy Finance, *Sustainable Energy in America 2013 Factbook,* January 2013, revised July 2013.

Figure 11 - U.S. solar module average prices



Source: Bloomberg New Energy Finance, *Sustainable Energy in America 2013 Factbook*, January 2013, revised July 2013.

A U.S. Department of Energy white paper states that a “generational shift” to solar technology is happening,[20] fueled in part by the dramatic reduction in price for PV systems.

This cost-reduction trend is likely to continue in the near future. Tillemann points out that in the U.S. there is still substantial room for reducing “soft costs” (i.e., customer acquisition, permitting and installation costs) associated with installing PV systems.[21] In comparison, with the more mature market in Germany, the soft costs of installing a solar panel on a German rooftop are currently about one-fifth the soft costs of installation in the U.S. In a recent ruling, the Federal Energy Regulatory Commission (FERC) took a step in the direction of reducing these costs by approving a rule that eases some restrictions on smaller solar PV projects connecting to the grid, giving them a fast-track approval process.[22]

Customer Preferences

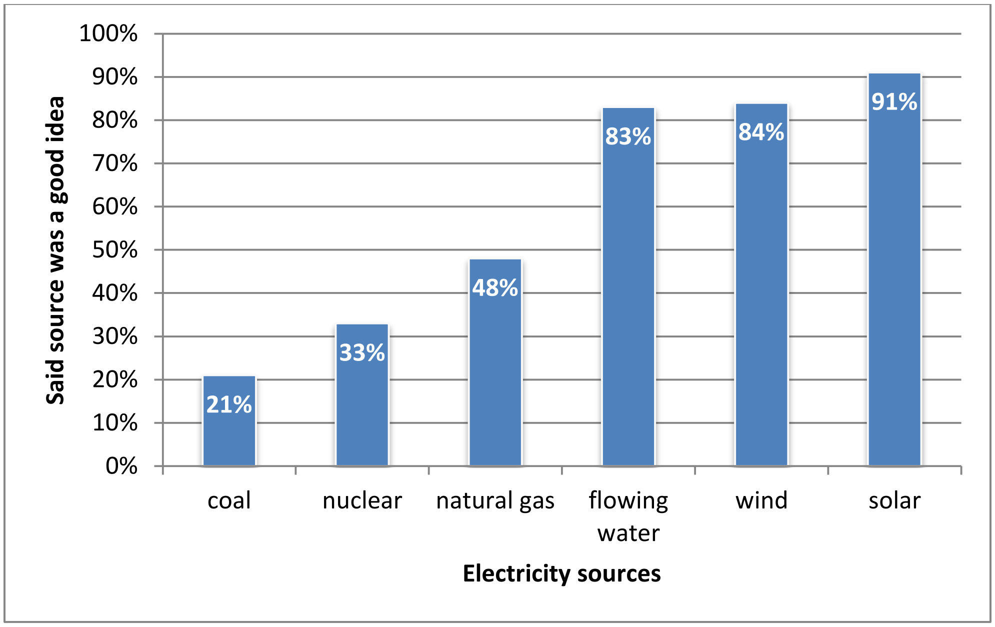
Focusing solely on costs of PV ignores other motivations people and companies have for producing their own power. High-tech companies, such as Google and Apple, are increasingly adding renewable generation to both improve energy security and achieve sustainability objectives. Use of distributed PV is also seen as a means of reducing investor risk. A growing list of large companies (e.g., see Figure 9) are using PV systems, not only for environmental reasons, but also as a hedge against future energy price increases, and as a means of lessening the risks of disruptive weather events.

In the U.S., interest among the general public in solar energy is high. A recent Stanford University, Resources for the Future, and *USA Today* poll found large majorities of respondents thought renewable methods of electricity generation were a “good idea” while more-traditional methods were seen as far less

[20] Tillemann L, “Revolution Now: “The Future of Arrives for Four Clean Energy Technologies,” US DOE, September 17, 2013.
[21] Also Bloomberg New Energy Finance notes that currently about 50% of the cost of systems is permitting, customer acquisition and profits. *Sustainable Energy in America 2013 Factbook*, January 2013, revised July 2013.
[22] Northey H, “FERC Greenlights Rule to Ease Restrictions for Small Generators,” E&E News PM, November 21, 2013, http://www.eenews.net/eenewspm/2013/11/21/stories/1059990881.

desirable.[23] Figure 12 below summarizes the percentage of responders who had a favorable view of each electricity generation method.

Figure 12 - Favorability ratings for electric generation sources



Source: Stanford University /Resources for the Future /USA Today Poll, December 2013.

A strong majority of respondents viewed favorably the three renewable technologies covered in the study, while only a minority viewed traditional technologies in a positive light. More specifically, solar received the highest favorability rating while coal received the lowest. Further, 75 percent of respondents favored the federal government giving tax breaks to companies making energy from water, wind and solar technologies. However, it should be noted that public sentiment favoring renewable technologies does not always translate directly into renewable energy purchases, for multiple reasons. For example, a 2010 survey found that while about 70 percent of respondents say they care about the use of renewable energy, the consumers' actual choice of renewable energy options is hampered by availability, awareness of the options, and price. [24]

New political coalitions supporting use of distributed solar are emerging between groups who are often at odds. In Georgia (through the Green Tea Coalition),[25] Arizona[26] and Wisconsin,[27] solar energy proponents, including environmental groups, such as the Sierra Club, and Tea Party Republicans have

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[23] Stanford University /Resources for the Future / *USA Today* Global Warming and Clean Energy National Poll, December 2013, http://rff.org/Documents/Stanford-RFF-USAT-2013-TOPLINE.pdf.

[24] The study found that only 14 percent of consumers were aware of an option to buy renewable energy either through a utility or other provider, even though these options were available to more than half of them. For the respondents in general, only about 25 percent said they would be willing to pay $5 to $20 more each month for renewable energy. Rogers G, *Consumer Attitudes about Renewable Energy: Trends and Regional Differences*, Natural Marketing Institute, prepared for U.S. Department of Energy National Renewable Energy Laboratory, Report No. NREL/SR-6A20-50988, April 2011.

[25] Martin C, "Tea Party, Sierra Club Unite to Support Solar Energy in Georgia," Bloomberg BusinessWeek, November 27, 2013, http://www.businessweek.com/articles/2013-11-27/tea-party-sierra-club-unite-to-support-solar-energy-in-georgia.

[26] Schwartz J, "Fissures in G.O.P. as Some Conservatives Embrace Renewable Energy," *New York Times*, January 25, 2014, http://www.nytimes.com/2014/01/26/us/politics/fissures-in-gop-as-some-conservatives-embrace-renewable-energy.html?_r=0.

[27] Haugen D, "In unlikely alliance, Wisconsin Libertarians back solar plan," *Midwest Energy News*, September 6, 2013, http://www.midwestenergynews.com/2013/09/06/in-unlikely-alliance-wisconsin-libertarians-back-solar-plan/.

announced alliances in their desire for access to residential solar PV under business arrangements of their choosing, including leasing of PV systems from third-party providers.

Short-term economics are not always the driver in decisions regarding distributed generation. In Wisconsin, some companies and municipalities have expressed preferences for increased use of on-site or distributed renewable generation as a means to advance their own sustainability objectives. Gundersen Lutheran and Epic Systems are two examples of Wisconsin companies moving toward energy independence and reliance on renewable technologies. Epic, a Verona, Wisconsin-based software company, owns multiple renewable energy systems, as well as cutting edge efficiency technologies, and is the largest solar producer in the state with 2.2 MW of installed capacity.[28] The company's goal is "100 year sustainability."[29] Gundersen is a health care company that has a goal of being entirely energy self-sufficient by 2014.[30] The company plans to offset all energy used by its operations through a series of renewable energy projects, and more efficient use of energy in its facilities. The motivation is to reduce the costs of health care and lessen the company's effect on the environment.[31]

Consumers' preference for using renewable distributed generation is clearly multi-faceted, and runs across many sectors of the economy. Recognizing these preferences is important in finding workable solutions to the evolving energy system.

Policy Levers and Actions in Other States

As Figure 10 shows, the dashed-outline arrows represent some factors contributing to the growing use of distributed PV that could be influenced via policy action. These are described as "Favorable Policies" and "Leasing Options." This section describes these factors in more detail and looks at recent activities attempting to influence them throughout the U.S.

Before proceeding with this discussion, it is important to clarify the use of the term "grid parity." Parity from a utility's perspective is achieved when the cost of providing electricity from solar PV is equivalent to the cost of providing it from conventional generation. From the customer's perspective, parity is achieved when the cost of generating its own electricity from solar PV is equivalent to the retail rate charged by the utility (i.e., retail grid parity). Parity is usually discussed from the customer's perspective under which the cost of solar competes with the retail rate charged by the utility. However, there are numerous ways regulators could design those rates. Some rate designs would lower the per-kWh cost of electric service, changing the parity comparison.

Deutsche Bank analysts estimate that solar PV is already at retail grid parity[32] in 10 states, and will likely soon be at retail grid parity in another 12 states, including Wisconsin.[33] These estimates are based on the

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[28] Content, T, "Epic, State's Largest Solar Producer, to Build Own Wind Farm," *Milwaukee Journal Sentinel*, October 12, 2012, http://www.jsonline.com/blogs/business/173895121.html#ixzz2lPGOFNVY.

[29] Content T, "With sales soaring, Epic invests in solar 'farm'," Milwaukee Journal Sentinel, June 5, 2011, http://www.jsonline.com/business/123206273.html.

[30] Gundersen Lutheran, Envision Plan, http://www.gundersenenvision.org/our-plan.

[31] In a sustainability policy trend with indirect energy use implications, many companies are adopting "zero waste" initiatives to control costs and demonstrate their corporate environmental responsibility. For example, in Ohio, Ohio State Football, Cleveland Browns, Cleveland Cavaliers, Cleveland Clinic, and Anheuser Busch have all committed to having zero-waste facilities. (Nally S, presentation at the BioCycle 13th Annual Conference, Ohio EPA, Columbus, Ohio, October 20, 2013.) Walmart has adopted a zero-waste initiative with a goal sending nothing to landfills, and other large supermarkets are likely to follow suit. (Information on Wal-Mart's corporate Zero Waste Initiative can be found here: http://corporate.walmart.com/global-responsibility/environment-sustainability/zero-waste.) Distributed processing of organics increasingly involves some type of anaerobic digestion, producing biogas that is used to generate electricity and heat. The origins of this erosion of energy demand are in waste reduction, but the results are more distributed energy generation and less demand for electricity from traditional utility sources.

[32] In this case, the term "grid parity" is used to mean on average equal to the delivered cost of electricity.

nature of the solar resource in the states (level of insolation), the cost of solar PV, and the cost of electricity in these states. Navigant Consulting forecasts that even with conservative predictions of PV price declines, the technology will be at retail grid parity, without subsidies, in all but the least expensive electricity markets by 2020.[34]

NET METERING POLICY

A common favorable policy for distributed generation is net metering. This policy requires utilities to allow distributed generators to sell excess power to the utility. In some cases, utilities must pay generators the retail rate for any power the customer provides to the grid. From one standpoint, if net metering is used with traditional utility rate designs, distributed generation owners will systematically underpay for the grid and system upkeep and are then effectively subsidized by those who are not selling power to the utility under net-metering. Alternatively, others maintain that it is the owners of on-site generation systems such as PV who subsidize the remaining customers because their systems avoid substantial long-run utility costs.[35]

Utility Response to Distributed Generation Growth

Some utilities have acted to reduce the short-term financial impact of distributed generation by requesting approval of increased monthly fixed fees for customers, or for PV owners in particular. Some utilities have also sought approval to reduce the payments to customers for electricity sold under net metering. These two actions reduce the value of distributed generation to owners, and provide greater assurance that utilities will be able to recover their fixed costs. We analyze the consequences of these rate design changes later in this report.

Recent attempts to use these policy levers to stem the tide of distributed generation have been largely unsuccessful.

- Arizona Public Service requested $50-$100 fixed fee for solar PV owners; it was granted a $5 fee.[36]
- In response to expected applications for fixed fee increases, California passed a law limiting monthly fixed charges to $10 for residential bills, and they may not unreasonably impair incentives for conservation and energy efficiency.[37]
- Idaho Public Power requested permission to pay below the retail rate and increase charges to net metering customers but the request was denied.[38]
- A group of Louisiana utilities requested approval to reduce the credited net metering rate from retail to wholesale, but the request was denied.[39]

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[33] Parkinson G, "Deutsche Bank Says US Solar Boom to Reach 50GW by 2016," RenewEconomy, http://reneweconomy.com.au/2013/deutsche-bank-says-us-solar-boom-to-reach-50gw-by-2016-18298, September 4, 2013.

[34] Gauntlet D, and L Mackinnon, *Solar PV Market Forecasts: Installed Capacity, System Prices, and Revenue for Distributed and Non-Distributed Solar PV*, Navigant Research, 3rd Quarter, 2013.

[35] Rocky Mountain Institute, *A Review of Solar PV Benefit and Cost Studies*, September 2013. The authors point out that there is a significant range of estimated value across benefit cost studies. This is primarily driven by differences in local context, input assumptions, and methodological approaches. This value is likely to continue to be the subject of debate since there is no clear definitive value.

[36] Randazzo R, "Commission votes to raise APS solar customers' bills," *The Republic*, azcentral.com, http://www.azcentral.com/business/arizonaeconomy/articles/20131114aps-solar-customer-bills-higher.html, November 14, 2013.

[37] California AB327, October 7, 2013.

[38] Idaho Clean Energy Association, "Net Metering Decision Made: Good News For Clean Energy Producers," July 3, 2013, http://idahocleanenergy.org/?p=512.

- Madison Gas and Electric proposed an increase in their monthly fixed charges of 40%, and asked the Wisconsin Commission to adopt a principle that rates should reflect system costs. The Commission granted the utility a 20% increase in fixed charges, but declined to adopt the rate design principle.[40]

As the American Public Power Association observed in their recent report:

> Even in states where utilities garner some concessions, state rulemaking bodies tend to either temper their requests or grant even greater concessions to solar rooftop customers.[41]

While rate design change is a policy lever that could conceivably slow the growth in distributed PV, it has been a difficult one for the utilities to pull. Nevertheless, this issue is receiving much consideration in jurisdictions across the country and in some cases may ultimately be resolved in the utilities' favor.

POLICY OPTIONS FOR LEASING OR THIRD-PARTY OWNERSHIP OF DISTRIBUTED GENERATION

There has been some concern about inequity because solar PV options are available only to those who can afford them, and to those who own homes that are suitable for rooftop installations. If this trend continues, it could create a form of energy poverty in which affluent customers have access to a wide variety of resources, while lower income customers would have only one option.

Business model innovations have begun to emerge that address these concerns. Because up-front costs of PV systems are a hurdle, third-parties have begun offering leasing arrangements for home and business owners to have PV installed on their structures. This removes the up-front cost and can greatly increase adoption rates. This type of agreement is currently legal or currently in use in 22 states and the District of Columbia. Figure 13 below shows the status of third-party leasing options throughout the U.S.

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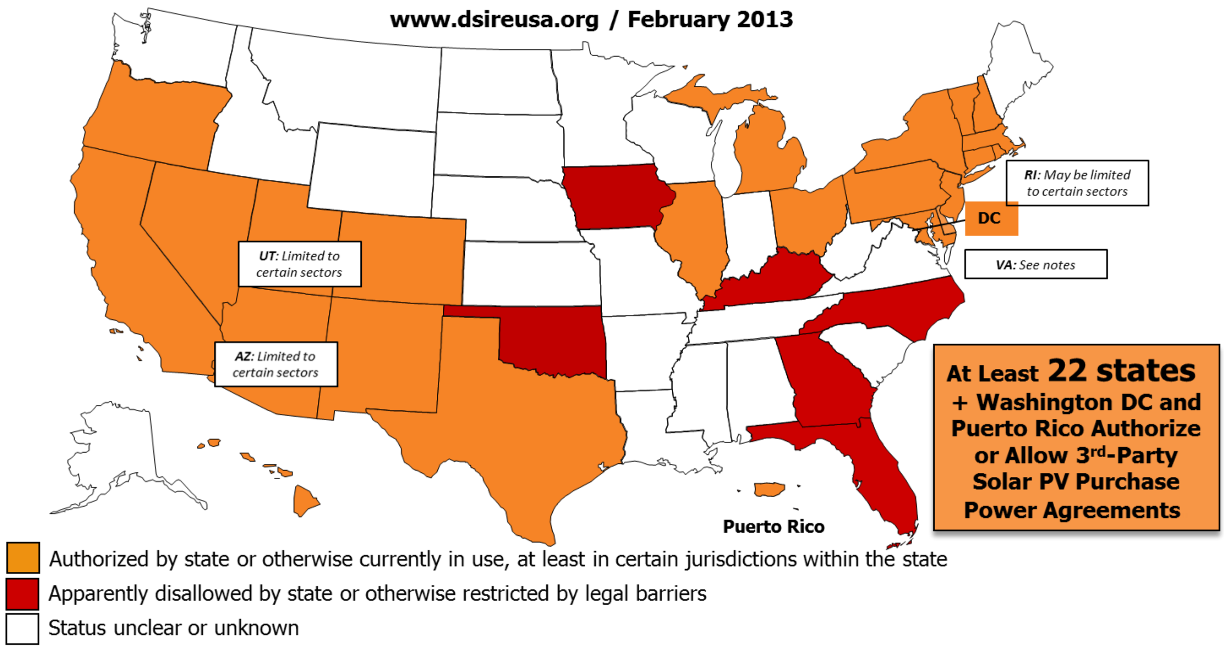
[39] Passera L, "Louisiana rules to preserve net metering," Interstate Renewable Energy Council, July 11, 2013, http://www.irecusa.org/2013/07/louisiana-rules-to-preserve-net-metering/.
[40] Public Service Commission of Wisconsin, Docket 3270-UR-118, December 2012.
[41] American Public Power Association, *Distributed generation: An Overview of Recent Policy and Market Developments*, November 2013.

Figure 13 - Status of 3rd party solar PV leasing power purchase agreements



Source: Database of State Incentives for Renewables and Efficiency, version February 2013, http://www.dsireusa.org/documents/summarymaps/3rd_Party_PPA_map.pptx.

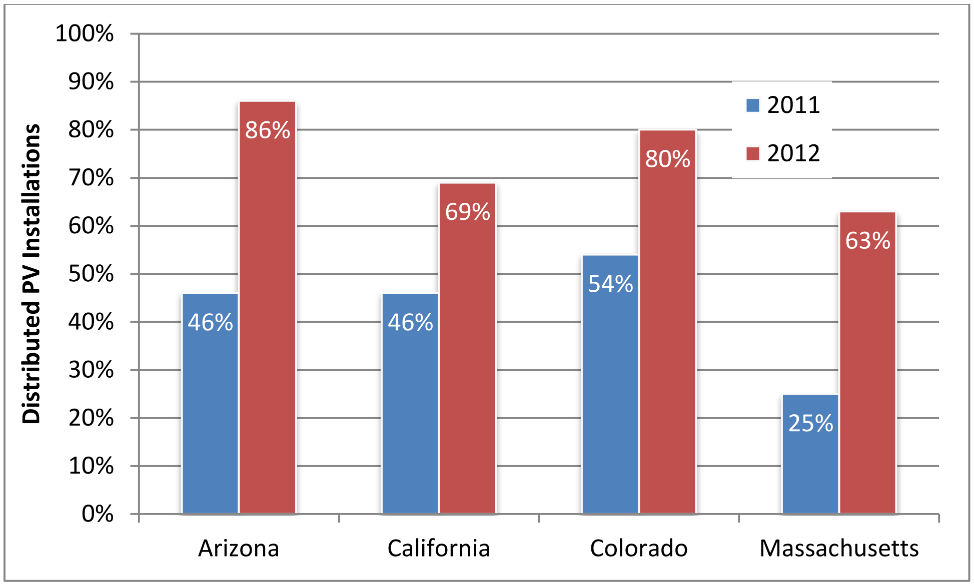
Two of the states shown on the map in red, have displayed some political or judicial inclinations to legalize third-party ownership of customer-sited distributed generation. While the map shown above lists Iowa as having disallowed third-party ownership, policy in that state is in flux. The Iowa Utilities Board issued a ruling that would prohibit such ownership (which is the policy reflected on the map), but an Iowa District Court later overturned that ruling. That case is now before the Iowa Supreme Court. The issue before it is whether a third-party developer can install a PV system at a municipality-owned facility and sell electricity to the municipality without being considered to be a utility.[42] In Georgia, a Republican-backed bill was introduced to allow third party financing and operation of solar PV systems at residential and commercial properties.[43] Passage of this bill into law would flip Georgia from red to orange on the map.

In Wisconsin, where the legality of third-party leasing agreements is currently unclear, the City of Monona has entered into an agreement to lease the roofs of four city buildings to a solar developer in exchange for renewable energy credits from the solar electricity generated.[44] It is not yet apparent whether this type of agreement, selling RECs instead of energy, could produce a model that could promote expansion of third-party ownership in Wisconsin. Furthermore, in early 2014 a bipartisan bill was proposed in the Wisconsin State Legislature that would formally legalize third-party leasing of distributed generation systems in the state.[45]

[42] Rodgers G, "Court to decide if solar energy installer is infringing on utilities' rights," The Des Moines Register, January 22, 2014, http://www.desmoinesregister.com/article/20140122/NEWS/301220051/Court-decide-solar-energy-installer-infringing-utilities-rights.
[43] Jones W, Georgia bill would allow rooftop leasing for solar panels," Online Athens – Athens Banner-Herald, January 29, 2014, http://onlineathens.com/general-assembly/2014-01-29/georgia-bill-would-allow-rooftop-leasing-solar-panels.
[44] City of Monona, "Monona's Solar Project Receives Award for Innovative Renewable Energy Project of the Year," January 20, 2014, http://www.mymonona.com/CivicAlerts.aspx?AID=18.
[45] Content T, "Proposed bill looks to light up Wisconsin's solar sector," Wisconsin Journal Sentinal – JS Online, March 16, 2014., http://m.jsonline.com/198610491.htm

In some regions with more mature PV markets, leasing of PV systems has grown to become the dominant method of PV adoption in recent years. Figure 14 below shows the proportions of distributed PV installations that occurred in 2011 and 2012 under third-party leasing agreements for some of these states.

Figure 14 - Percent of residential distributed generation installs of leased PV systems



Source: Pourreza S, et al., "Rising Sun: Implications for US Utilities," August 8, 2013.

Citi Research, an arm of the investment banking firm Citigroup, points out that because capital has so far been unable to keep up with demand in the U.S. for third-party leasing, it has become a primary impediment to even greater expansion.[46] It predicts that as more capital becomes available, widespread use of third-party financing (e.g., third-party ownership and leasing) "could propel the U.S. solar distributed generation market to new heights."

In some states, options for owning solar PV are also emerging for renters and homeowners whose houses are not configured to hold rooftop panels. Referred to as solar gardens or community solar, these are centralized PV systems that residents can subscribe to and get net-metering type benefits without having solar generation on their property. Seven states have implemented legislation explicitly allowing community solar, and four states and the District of Columbia have passed but not yet implemented such legislation.[47] Thirteen states have proposed legislation allowing community solar.

SUMMARY OF POLICY LEVERS AND STATE ACTIONS

The potential policy levers examined here—efforts to weaken or remove favorable policies for distributed PV systems (e.g., net metering, ratemaking with most fixed costs in volumetric rates) and opposing use of third party leasing options—appear to offer limited relief to utilities seeking to stem the tide of solar PV development. Attempts throughout the U.S. to get fixed charges increased in rate plans have either been refused or granted in smaller amounts than requested.

[46] Pourreza S, et al., "Rising Sun: Implications for US Utilities," Published by Citi Research, a division of Citigroup Global Markets Inc., August 8, 2013.
[47] Source: Solar Gardens Community Power, March 31, 2014, http://solarpanelhost.org/garden/policy.

UTILITY COST STRUCTURES

With the dynamic action in the solar PV distributed generation market as a backdrop, we now view the implications of those developments from the utilities' perspective. This, by necessity, considers regulatory implications, as well. We start by looking at utility cost structures.

Visual inspection of an electrical utility system reveals a lot of concrete, steel and wires. Most utility assets are long-lived, serving customers for many decades. In economic parlance they are fixed in nature. Once incurred the costs of these assets do not vary with usage, and stand ready to serve customers whether they use power or not.

To maintain their financial solvency, utilities must be able to recover the costs of these facilities, along with the variable costs associated with the business. When a utility builds a power plant, it does not recover from its customers the full cost of that plant during the first year of operation. Rather those costs are recovered over the life of the asset, often 30 years or more. Cost recovery for these assets occurs in two ways: there is an annual expense for **return of capital** (depreciation expense) and an annual **return on capital** for costs yet to be recovered. This is akin to cost recovery for a lender under a home mortgage. The monthly payment includes a return of capital (principal) and a return on capital (interest).

There are other sorts of utility fixed costs, as well, especially in the near term. For example, when utility loads decline, their employee base, and therefore employee wages and salaries, stays about the same. Contractual payments to other parties, such as lease payments, also are fixed. In the very short-run, the principal item that varies with use is the fuel burned to produce power.

To get some perspective on how fixed costs dominate utility costs structures, we refer to a recent rate case decision for Madison Gas and Electric Company.[48] In that rate order, the Commission shows $108 million of steam power generation expenses, i.e., the cost of generating electricity. The utility's total costs were $362 million. That puts power supply costs, the ones that could vary in the short run with changes in load, i.e., a variable cost, at only about a third of the total cost.

We present this data as illustrative. A full cost-of-service study is beyond the scope of this analysis. Nevertheless, our qualitative conclusions hold over a wide range of cost structures. The key point to note is that the more heavily the cost structure swings to the fixed category, the more significant the problems will be for the utility in terms of cost recovery under traditional rate designs.

Our analytics assume that we are dealing with an investor-owned utility. Note, however, that conceptually the problem is largely the same if the utility is municipally-owned or a cooperative. To survive over the long run, all utilities must recover the costs of providing service. If utility rate designs do not achieve this end, the utility will eventually run short of the cash it needs to continue operating.

We present the impact of under-recovery of fixed costs as a deterioration in the return on equity that the investor-owned utility earns. This is on point because the equity holders stand last in line in terms of claims on utility cash flows. Fixed costs not recovered end up being borne by the equity holders.[49] The failure of the German utilities to fully recover their fixed costs led to declines in their earned return on equity, causing the significant decline in their stock prices.

[48] Docket 3270-UR-116, December 22, 2009.

[49] In the extreme case if the equity balance is depleted, utility bondholders would absorb some of the shortfall.

For publicly-owned utilities, failure to recover fixed costs ends up reducing the contribution to their margin that supports their assets, which is analogous to the common equity account for investor-owned utilities.

UTILITY RATE DESIGN

In this section, we will examine how the utility fares under various rate designs when distributed generation enters the mix. We consider a design that recovers all costs through the volumetric charge, and then move to a series of more sophisticated rate designs, introducing the notion of a monthly fixed charge. The purpose is to determine the degree to which rate design can remedy the problems encountered.

To illustrate the degree to which rate design affects utility fixed-cost recovery we assume a hypothetical utility with the following characteristics:

Key Input Assumptions

• Fixed assets	$2,700,000,000	
• Estimated asset life	30 years	
• Variable costs	$0.05 per kWh	
• Capital structure		
o Debt	50%	$1,350,000,000
o Equity	50%	$1,350,000,000
o Total	100%	$2,700,000,000
• Authorized rates of return		
o Debt	6%	
o Equity	10%	
• Tax rate	40%	
• Annual sales	5,000,000,000 kWh	
• Number of customers	600,000	

These inputs produce the following outputs

Key Output Results

• Annual variable costs	$250,000,000
• Annual fixed cost recovery	$396,000,000
• Total costs	$646,000,000

In a financial sense, the managers of the investor-owned utility are focused ultimately on the return it must produce for its shareholders, which is shown below.

Key Variable of Interest

• Return to equity holders (after taxes)	$135,000,000

As noted earlier, all shortfalls in cost recovery flow to the equity holders, since they stand last in line in terms of claims on utility funds. Our analysis will therefore focus on the degree to which the utility can meet this target.

VOLUMETRIC PRICING

For sake of simplicity, we assume that all of the utility's customers are in the residential class. This allows us to have a single rate design for the utility. We start with the assumption that the utility's regulator prefers to use only volumetric pricing. Under that assumption the utility's retail price would be:

$$\text{price} = \frac{\$646{,}000{,}000}{5{,}000{,}000{,}000\ \text{kWh}} = 0.129\ \text{per kWh}$$

With our initial rate set, let us next assume that distributed generation unexpectedly reduces utilities sales by 5 percent, leaving the utility with 95 percent of its forecasted sales:

$$\text{sales} = 5{,}000{,}000{,}000 \text{ kWh} \times 0.95 = 4{,}750{,}000{,}000 \text{ kWh}$$

Fewer sales mean less fuel burned, which reduces variable costs. Before the arrival of the distributed generators, the utility incurred variable costs of $250,000,000. Loss of load to distributed generators reduces that cost to:

$$\text{variable costs} = 4{,}750{,}000{,}000 \text{ kWh} \times 0.05 = \$237{,}500{,}000$$

The 5 percent reduction in sales leads to a 5 percent reduction in **variable costs**. But it does not change the level of the utility's fixed costs of $396,000,000. Its total costs are now:

- Annual variable costs $237,500,000
- Annual fixed cost recovery <u>$396,000,000</u>
- Total revenue requirement <u>$633,500,000</u>

The 5 percent loss of load to distributed generation therefore reduces the utility's **total costs** from the original $646,000,000 to $633,500,000, which is only a 1.9 percent reduction.

Since the utility prices its service strictly on a volumetric basis, the revenue it collects will go from $646,000,000 (before distributed generation) to:

$$\text{revenue collected (after distributed generation)} = 4{,}750{,}000{,}000 \text{ kWh} \times 0.129 \text{ per kWh} = \$612{,}750{,}000$$

This reveals the nature of the problem. As distributed generators enter the utility's service area, to serve its remaining load the utility incurs costs of about $633 million, but collects only about $613 million from its customers, leaving it short by about $20 million. This shortfall flows to the utility's bottom line.

There is a bit of a complexity that bears noting for completeness sake. The shortfall reduces taxable earnings for the utility, which therefore reduces its income tax expense, which softens the blow a bit. We assume a tax rate of 40 percent for the utility in question.

$$\text{tax savings} = \$20{,}750{,}000 \times 0.40 = \$8{,}300{,}000$$

Therefore, the impact of the loss of load to the utility is that net of income tax savings:

$$\text{net shortfall} = \$20{,}750{,}000 - \$8{,}300{,}000 = \$12{,}450{,}000$$

While the tax savings reduces the financial impact of the loss of revenue, the net loss still has a noticeable effect on the utility. The target return to shareholders is $135,000,000. Loss of load to distributed generators reduces that after-tax return to:

$$\text{return to equity holders} = \$135{,}000{,}000 - \$12{,}450{,}000 = \$122{,}550{,}000$$

Ironically, the fact that municipal utilities are not subject to income taxes makes them more vulnerable to distributed generation in this respect. If all else were equal, while the investor-owned utility in this example would suffer a $12,450,000 reduction in net margin, the municipal utility operating under the same condition would suffer the full $20,000,000 loss because losses to municipal utilities do not create tax savings.

Returning to the investor-owned utility, we can convert the end result in terms of earnings to a return on equity in percentage terms. The input assumptions show a common equity balance of $1,350,000,000. The return on equity is therefore:

$$\text{return on equity} = \frac{\$122,550,000}{\$1,350,000,000} = 0.091 \text{ or } 9.1\%$$

In our assumptions we note that the regulator determined that the utility was entitled to a reasonable opportunity to earn a return on equity of 10.0 percent. A rate of return that is almost 100 basis points lower would get the attention of utility managers and their investors. The more load the utility loses to distributed generation, the more its return on equity declines. See Figure 15.

Figure 15 – Impact of distributed generation on utility's return on equity—volumetric-only rate design

It is clear that if the loss of load potential from distributed generation is as large as many suggest, a volumetric-only rate design would put the utility at considerable risk of earning sub-par returns.

This leads to an important question—who bears this loss? The answer depends on the time frame. In the short run, i.e., between rate cases, the utility shareholder absorbs the impact. Utility rates of return are not guaranteed, and regulators cannot retroactively adjust rates to allow the utility to recover shortfalls, or to force it to refund excess earnings, for that matter.[50]

[50] Charles Phillips, *The Regulation of Public Utilities*, Public Utilities Reports, 1988, p. 363.

But if the utility seeks rate relief from its regulator, that body must set rates that allow the utility in a prospective sense a reasonable opportunity to earn a fair return.[51] That is, when the regulator looks forward, the rate design must not produce rate-of-return deficiencies.

This is one area of difference between investor-owned utilities and their municipally-owned counterparts. The latter often have automatic adjustments that permit them to recover immediately at least some of the shortfall created by loss of load. Note, however, that while this solves some of the near-term problems created by distributed generation, it does not address the larger rate design issue we discuss later in the report. Simply put, under rate designs with high volumetric charges, automatic adjustment clauses merely hasten the speed at which the utility arrives at a non-competitive pricing arrangement, one that encourages more customers to adopt distributed generation resources.

ADJUSTING RATES TO RECOVER THE SHORTFALL

Returning to our example, we saw that the 5 percent loss of load to distributed generators left the utility with sales of 4,750,000,000 and total costs to $633,500,000. The utility comes to the regulator seeking rate relief. Using the volumetric-only rate design, the regulator will determine a new price, one designed to make the utility whole in a financial sense.

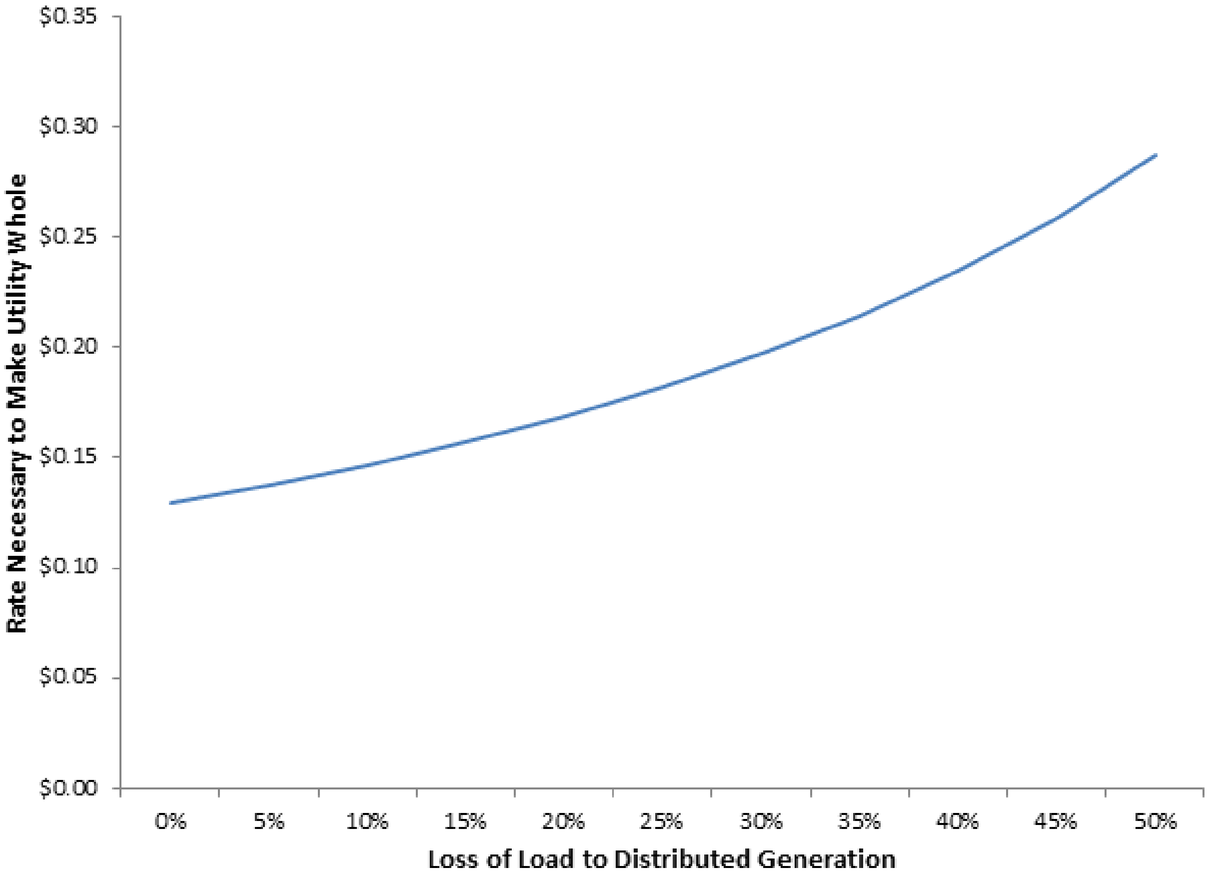
$$\text{new price} = \frac{\$633{,}500{,}000}{4{,}750{,}000{,}000\ \text{kWh}} = 0.133\ \text{per kWh}$$

If the utility loses no further load, this new rate design will produce the $135,000,000 return to shareholders that is necessary to yield a 10.0 percent return on equity.

But note what happened to the utility price in response to competition. This rate design approach requires that the utility increase, not decrease, its price when competition enters, which makes little sense. If distributed generation offers a competitive alternative to conventional electric service, raising prices is the last thing the utility would want to do. This simply encourages other customers to adopt distributed generation technologies. Figure 16 shows how increasing loss of load to competitive alternatives leads to ever-increasing utility prices.

[51] This assumes that the utility is not subject to intense competition from other providers. The U.S. Supreme Court has found that utilities have no constitutional protection from economic forces. See *Market Street R. Co. v. Railroad Commission*, 324 U.S. 548 (1945).

Figure 16 – Utility prices rise as distributed generation penetration increases (volumetric-only rate design)



This phenomenon demonstrates why some suggest that relying heavily on volumetric-based utility pricing in the face of increased penetration of distributed generation can lead to a utility "death" spiral. Rather than checking competition, this rate design approach invites competition into the service area. The more load the utility loses to competitors, the more it raises its prices and the less competitive it becomes.

USING FIXED CHARGES IN RATE DESIGN

So far we have examined a rate design at an end of the spectrum, one that uses only a volumetric-based price. Regulators typically do not price utility service using only volumetric charges. The standard approach is to use a combination of fixed monthly charges and volumetric charges. We demonstrate now how introducing the fixed-charge pricing concept changes the situation for utilities.

Let us assume that the regulator permits the utility to recover some of its costs through a $10 monthly fixed fee. Returning to the original set of assumptions we see that the utility has 600,000 customers. The $10 per month fixed charge allows the utility to recover the following costs independent of sales volume:

$$\text{revenues from fixed charges} = \$10 \text{ per month } \times 12 \text{ months per year} \times 600{,}000 \text{ customers} = \$72{,}000{,}000$$

The utility has total costs of $646,000,000. Instituting the $10 monthly fixed charge leaves the following to be collected from the volumetric charge:

$$\text{revenues from volumetrc charges} = \$646{,}000{,}000 - \$72{,}000{,}000 = \$574{,}000{,}000$$

The per-kWh price is then:

$$\text{price} = \frac{\$574{,}000{,}000}{5{,}000{,}000{,}000\ \text{kWh}} = 0.115\ \text{per kWh}$$

The new volumetric price is now lower than the original volumetric price because under the new rate design some of the utility's fixed costs are recovered through the fixed charge. Under either rate design, however, the utility expects to sell the same amount of power, incur the same costs, and recover the same amount of revenue.

Initial Rate Design

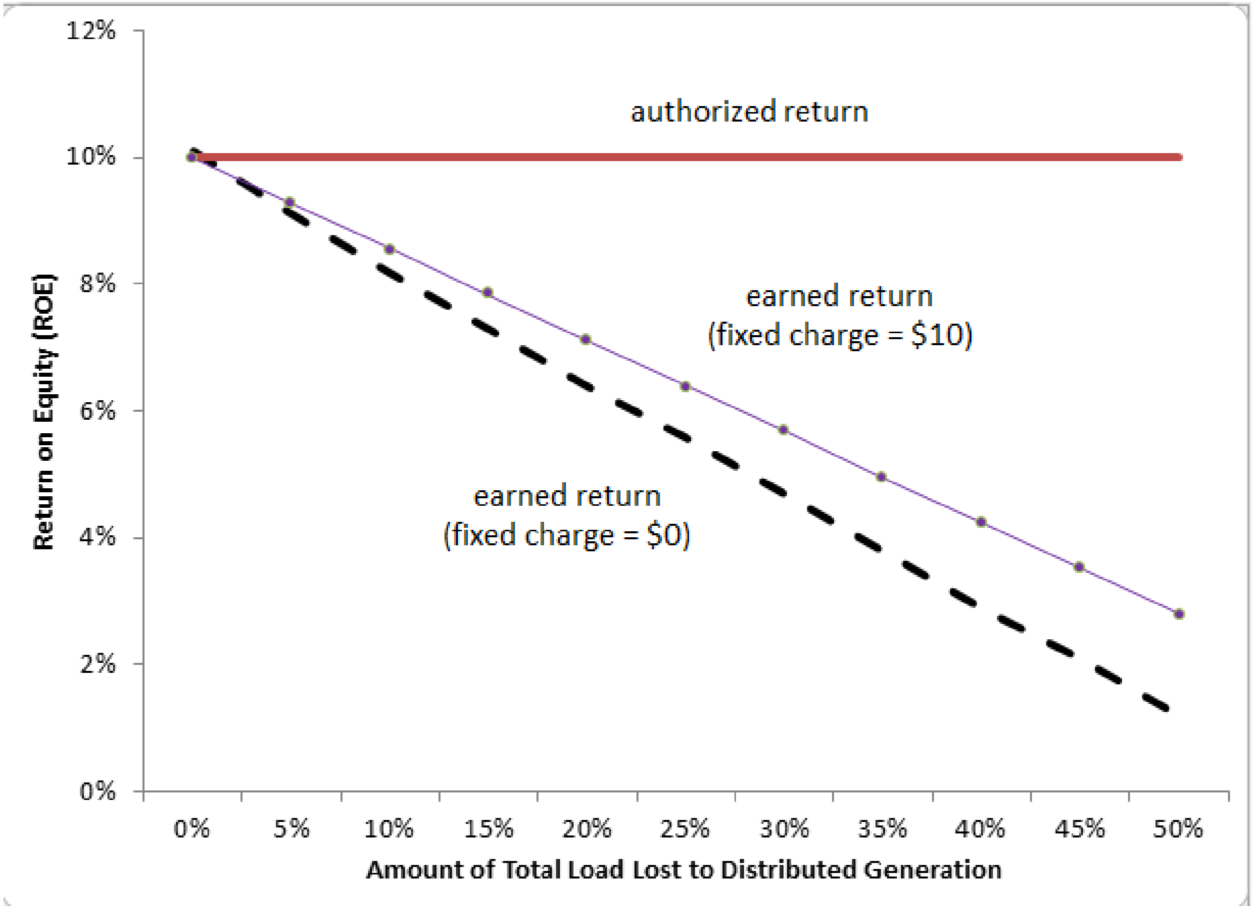
- Fixed charge
  - Monthly fee — $0
  - Revenue collected — $0
- Volumetric fee
  - Per kWh charge — $0.129
  - Revenue collected — $646,000,000
- Total revenue collected — $646,000,000

Revised Rate Design

- Fixed charge
  - Monthly fee — $10
  - Revenue collected — $72,000,000
- Volumetric fee
  - Per kWh charge — $0.115
  - Revenue collected — $574,000,000
- Total revenue collected — $646,000,000

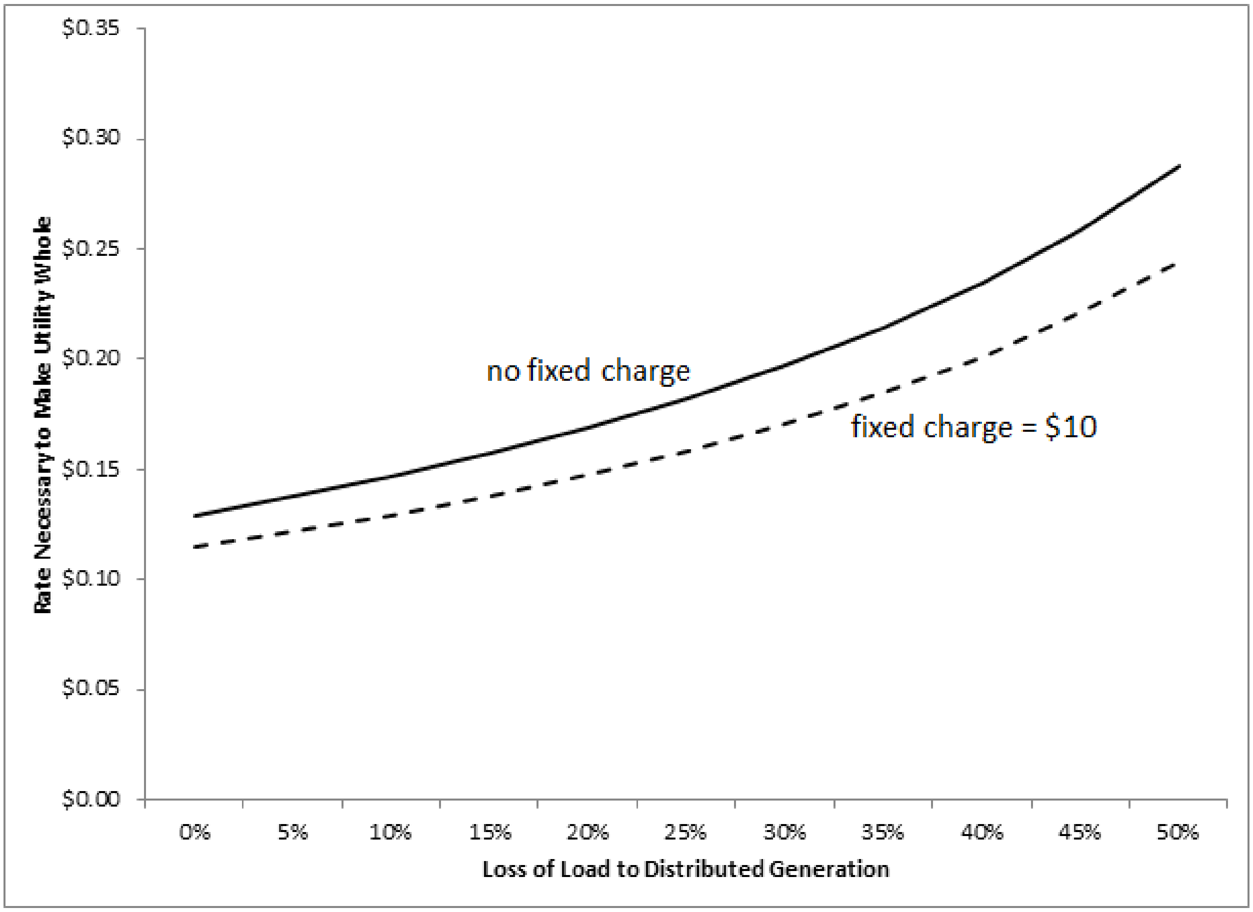
Without showing all the intermediate calculations, let's examine how the loss of load to distributed generators affects the utility's return on equity. We see that impact in Figure 17.

Figure 17 – Introducing a fixed charge mutes the ROE impact of distributed generation



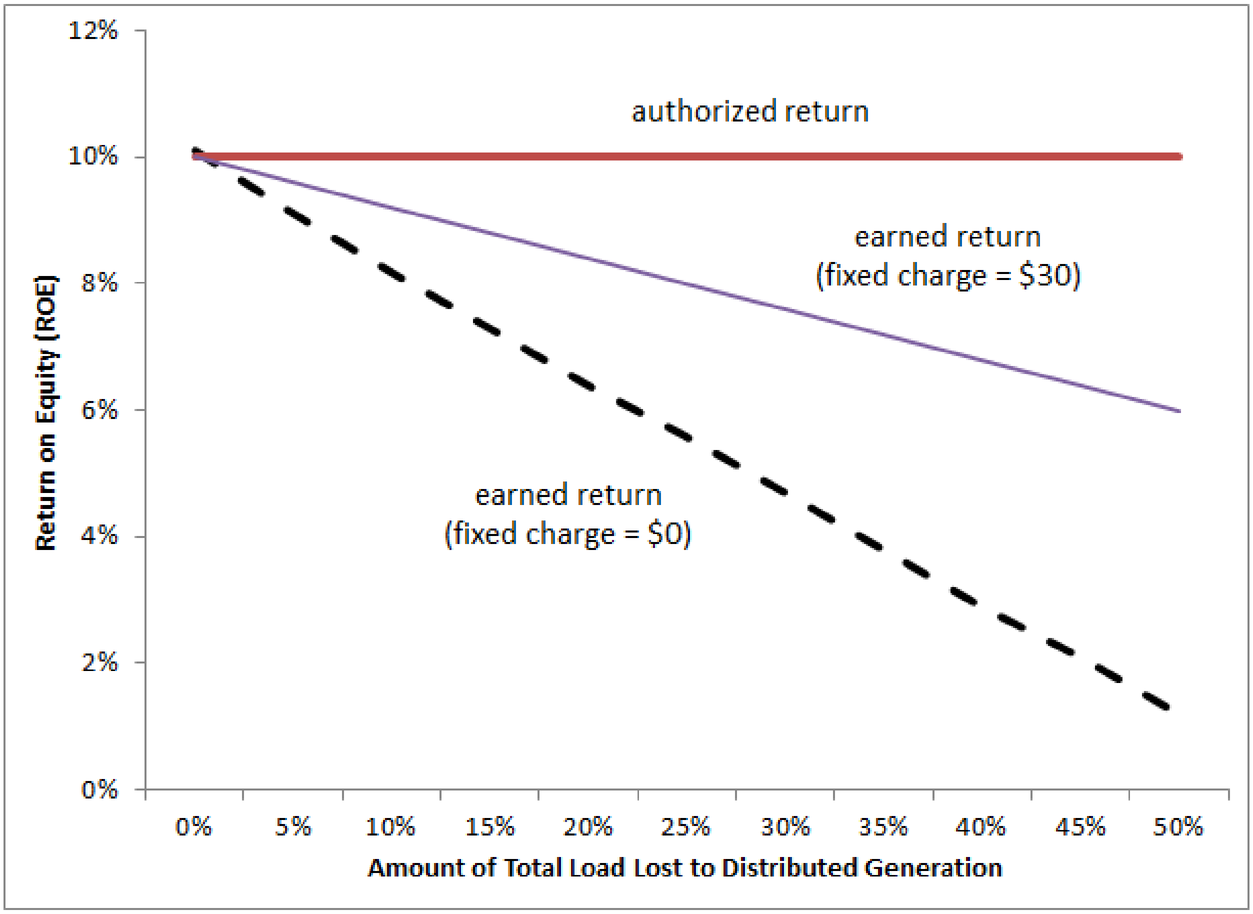
While loss of load still takes its toll on the utility's return on equity, the impact is less severe, although still problematic. The utility will still need to increase its rates to recover the shortfall, but the rates remain lower than they would be under volumetric-only pricing. See Figure 18.

Figure 18 – Introducing a fixed charge also mutes the rate impacts



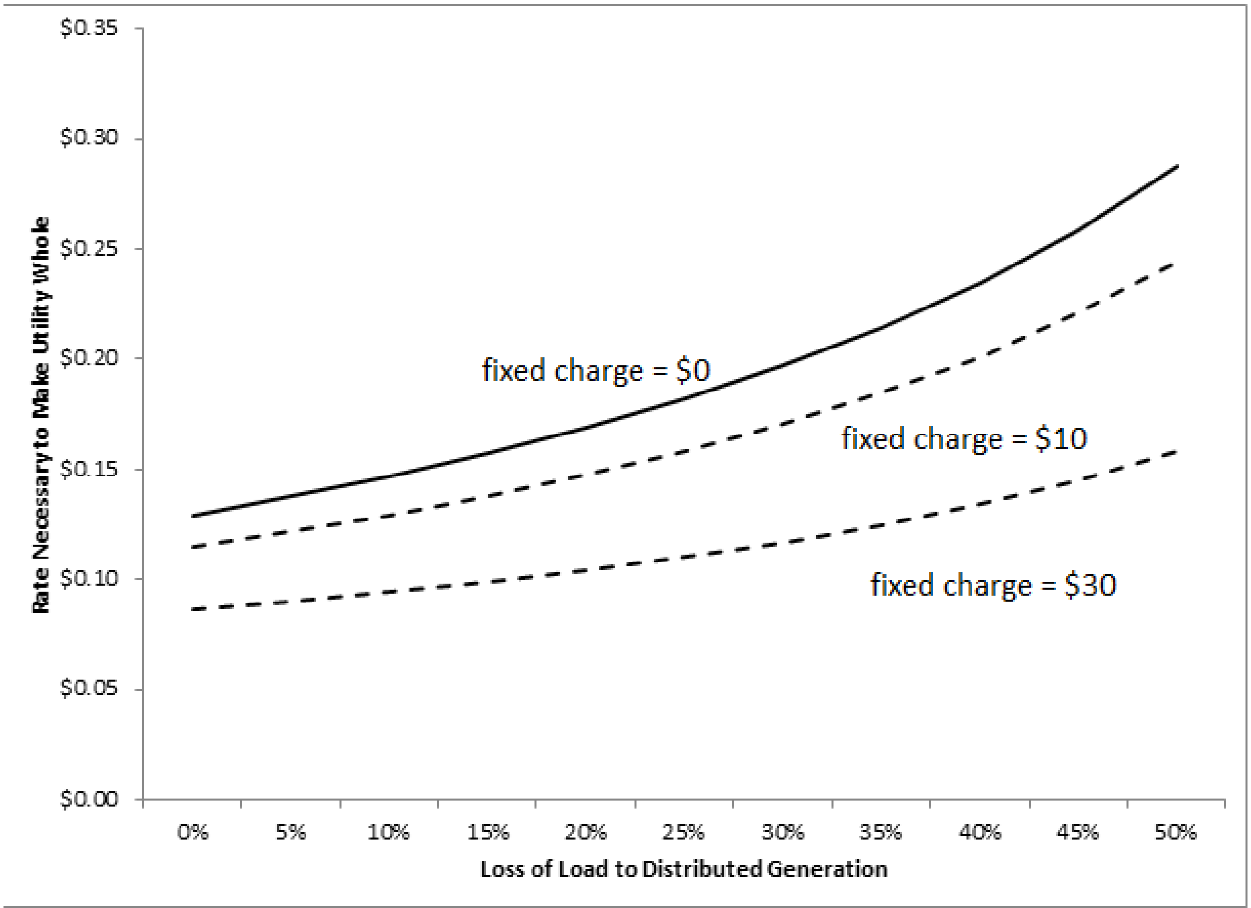
It should not be surprising to find that further increases in the monthly fixed charge to $30 per month, for example, which reduces the volumetric charge to $0.086 per kWh, provide further relief to the utility in terms of limiting deterioration in its return on equity. See Figure 19.

Figure 19 – The higher the fixed charge the lower the impact of distributed generation on the utility's ROE



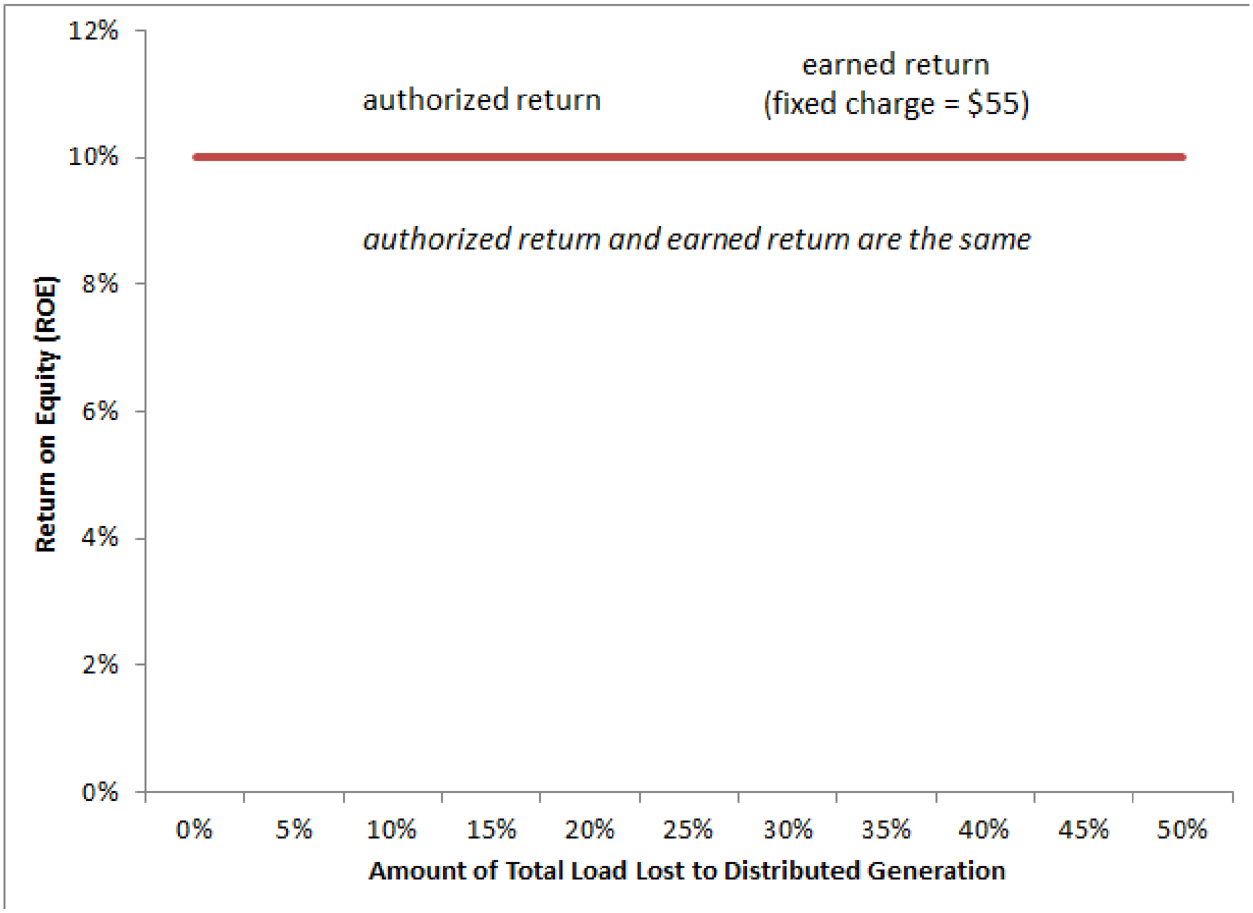
This also helps to keep rates from increasing as quickly when load declines. See Figure 20.

Figure 20 – Higher fixed charges also help to keep rates in check



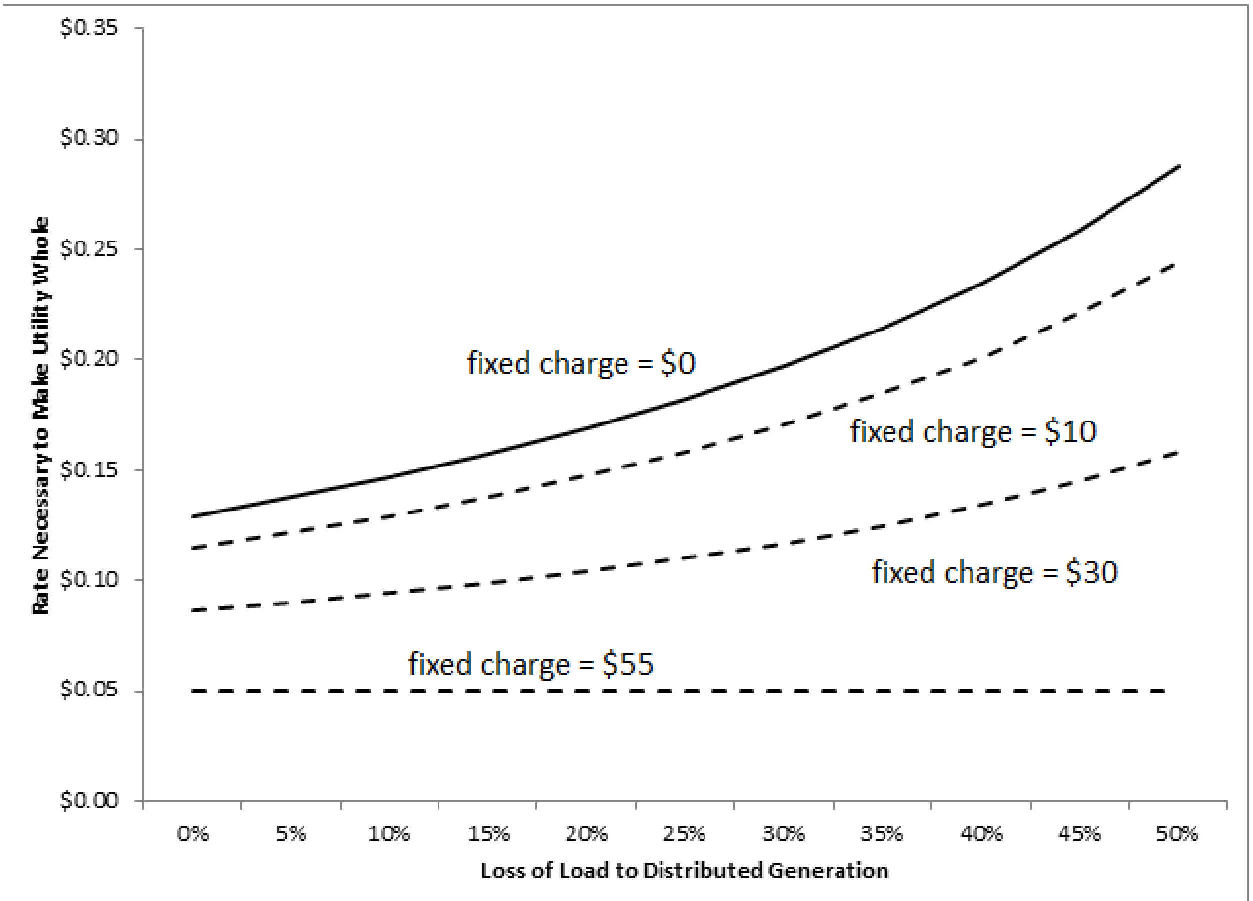
Note what happens if the regulator sets the fixed charge so that the utility collects all of its fixed costs through the monthly fixed charge, and collects only variable costs through the volumetric charge. Under this rate design, the monthly fee is $55, and the volumetric charge is $0.05 per kWh. See Figure 21.

Figure 21 – Load loss does not reduce the utility's ROE if all fixed costs are collected through the fixed fee



The utility's return on equity is the same regardless of the degree to which it loses load. (This assumes that the loss of load is not created by customers exiting the system entirely, which we discuss in the next section.) Since there is no revenue shortfall when all fixed costs are recovered through the fixed charge, there is also no upward pressure on rates. See Figure 22.

Figure 22 – Utility rates stay more competitive if all fixed costs are collected through the fixed fee



When the fixed charges reflect exactly the system fixed costs, there is no revenue shortfall, no reduction in return on equity, and no need to increase rates. If ensuring cost recovery is the goal, then a rate design that recovers all of the utility's fixed costs through the monthly fixed charge seems to be the answer.

While the high-fixed-charge rate design clearly has merit in terms of utility cost recovery, there may be some other issues to consider. We discuss those next.

CONCERNS ABOUT HIGH FIXED CHARGES

CUSTOMER REACTION

It is likely that a high-fixed-charge rate design will serve utilities well in the near term. It will make it highly likely that the utility will recover its fixed costs. It will also make distributed generation less attractive in an economic sense. This can have some unintended consequences in the realm of public opinion.

An example as to how high fixed charges make distributed generation less attractive may be illustrative. We return to our hypothetical utility. Assume that a customer uses the average amount of electricity, which is 694 kWh per month. If the **average customer** purchases all of its power from the utility, its bill will essentially be the same under any of the rate designs we have discussed so far.

- All-volumetric pricing $0 + 694 kWh @ $0.129 = $90
- $10 fixed charge $10 + 694 kWh @ $0.115 = $90
- $30 fixed charge $30 + 694 kWh @ $0.086 = $90
- $55 fixed charge $55 + 694 kWh @ $0.050 = $90

The customer is considering purchasing power from a hypothetical solar PV distributed generator through a lease arrangement. The solar PV company offers the customer power at $0.11 per kWh. (Note that we are not suggesting that solar PV systems today can produce electricity in Wisconsin today at a cost of $0.11 per kWh. This example is illustrative.)

The customer will purchase 400 kWh of power from the distributed generator and the remainder (294 kWh) from the utility. The bill to the solar PV company will be:

- Cost of distributed generation 400 kWh @ $0.110 = $44

The cost of power from the utility is the same under each rate design only at the average level of consumption. At lower usage levels, as the fixed charge increases, the bill is noticeably higher for lower-usage customers. The following table shows the cost of purchasing 294 kWh from the utility, which the customer needs to back up its solar PV system.

- All-volumetric pricing $0 + 294 kWh @ $0.129 = $38
- $10 fixed charge $10 + 294 kWh @ $0.115 = $44
- $30 fixed charge $30 + 294 kWh @ $0.086 = $55
- $55 fixed charge $55 + 294 kWh @ $0.050 = $70

The combined bill for the distributed generator is the cost of purchasing 400 kWh power under the lease ($44) plus the cost of purchasing the remaining 294 kWh from the utility, which depends on the utility rate design:

- All-volumetric pricing $44 + $38 = $82
- $10 fixed charge $44 + $44 = $88
- $30 fixed charge $44 + $55 = $99
- $55 fixed charge $44 + $70 = $114

Recall that purchasing all 694 kWh from the utility costs the customer $90 per month. Changing the rate design therefore changes the economics of the distributed generation.

		all utility	dist. gen. + utility	decision
•	All-volumetric pricing	$90	$82	choose dist. gen.
•	$10 fixed charge	$90	$88	choose dist. gen.
•	$30 fixed charge	$90	$99	reject dist. gen.
•	$55 fixed charge	$90	$114	reject dist. gen.

Under the no- and low-fixed-charge rate designs, distributed generation is cost effective; it is not cost effective at the higher levels of fixed charges.

From the utility's perspective, this appears to be another benefit of moving to higher fixed charges. Not only is the utility insulated from loss of load, it also makes distributed generation less cost effective for consumers, meaning there will be less of it for the utility to deal with.

Nevertheless, to the extent that the high-fixed-charge rate design thwarts the development of solar PV, utilities should be ready for pushback from society at large. Mainstream utility industry publications note that there is real potential for customer negative reactions to higher fixed charges.

> Utilities understandably oppose competition in the distribution business, and their first instinct likely will be to block it or marginalize it. But doing so poses its own risks—including the real possibility of a backlash.[52]

The Edison Electric Institute acknowledges that higher fixed charges are generally not popular among consumers.[53]

Maintaining good customer relations is in the utilities' financial interest. Consumer unrest can lead to unfavorable outcomes for utilities in the regulatory and legislative arenas. If utilities move toward a high-fixed-charge rate design they may see substantial reductions in customers' satisfaction ratings. Furthermore, the notion that utilities can alleviate customer concerns by educating customers about utility cost structures seems to be a questionable assumption.

POSSIBLE LOSS OF CUSTOMERS

While a high-fixed-charge rate design might ensure recovery of fixed costs in the near term, it might increase the likelihood of under-recovery in the long term. Note that the **effective cost per kWh** for our hypothetical customer under a high-fixed-charge rate design is quite high. The effective cost is the total bill divided by the kWh purchased.

- All-volumetric pricing — $38 / 294 kWh = $0.129 per kWh
- $10 fixed charge — $44 / 294 kWh = $0.150 per kWh
- $30 fixed charge — $55 / 294 kWh = $0.187 per kWh
- $55 fixed charge — $70 / 294 kWh = $0.238 per kWh

This sends a signal to entrepreneurs. In the most extreme case, the utility raises its fixed charge to $55 per month, and if there is a technology that can provide the customer with 294 kWh per month at an effective cost that is less than $0.238 per kWh ($70 per month total), the customer will have an incentive to disconnect from the grid.

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[52] Michael Burr, "Economy of Small: How DG [Distributed Generation] and Microgrids Change the Game for Utilities," *Public Utilities Fortnightly*, May 13, 2013.

[53] Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry*.

To further illustrate this point, assume that gas-fired home generators can produce 294 kWh of electricity at an all-in cost of $0.22 per kWh ($65 per month in total). Recall that the cost of power from solar PV equipment in our example is $44 per month (400 kWh x $0.11 per kWh). Then if the utility adopts the $55 per month fixed charge, the customer will save money by disconnecting from the utility and using a hybrid system involving solar PV panels and a gas-fired generator.

• Solar PV and gas generator backup	$44 +	294 kWh @ $0.220 =	$109
• Solar PV and utility backup	$44 +	$55 + 294 kWh @ $0.050 =	$114

This possibility is more than speculation. NRG Energy, among others,[54] has announced its plans to package solar PV and gas generator systems to allow customers to disconnect from the grid, just as the example above sets forth.[55] There are serious questions, however, as to whether these new systems can be as reliable as utility grid power. Therefore, the market appeal of these systems may be lower than proponents suggest. The consumer demand for reliability is yet to be tested in this market.

Note that ironically the utility would be more competitive in this scenario if it used a lower fixed charge, such as the $10 per month version.

• Solar PV and gas generator backup	$44 +	294 kWh @ $0.220 =	$109
• Solar PV and utility backup	$44 +	$10 + 294 kWh @ $0.115 =	$88

If the situation comes to pass, it would be better for the utility to collect some contribution to fixed costs from the customer, as it would under the $10 per month fixed fee, than to collect nothing from the customer who is no longer there under the $55 per month fixed fee scenario.

LONG-RUN PRICE SIGNAL

The high-fixed-charge rate design approach does a good job in matching prices to the utility's historical fixed cost structure. That is, it matches its accounting-based costs.

This sort of focus on cost recovery of accounting costs, however, is not truly economic in nature. Economic principles suggest that regulators should look forward to avoidable costs, not backward to historically-incurred costs.

If economics is to guide us here, the focus should be on long-run price signals and spurring innovation of new technologies. The fact is that economists have generally not followed those principles when dealing with utility rate issues. As Alfred Kahn noted in his critique of the performance of economists in regulatory environments:

> Economists have a particular advantage when it comes to taking a direct role in the regulatory process. The job is an extremely technical one and becomes more so each year… But for decades there has been great and increasing dissatisfaction with their performance. One important criticism has been that they were behaving too much like lawyers and bookkeepers—excessively concerned with proper administrative procedures, the balancing of equities and covering of accounting costs—and too little like economists—paying

[54] Woody T, "Car Companies Take Expertise in Battery Power Beyond the Garage," *The New York Times, Business Day*, March 25, 2014, http://www.nytimes.com/2014/03/25/business/car-companies-take-expertise-in-battery-power-beyond-the-garage.html?_r=0.

[55] Christopher Martin and Naureen S. Malik, "NRG Skirts Utilities Taking Solar Panels to U.S. Rooftops," *Bloomberg*, March 25, 2013, http://www.bloomberg.com/news/2013-03-24/nrg-skirts-utilities-taking-solar-panels-to-u-s-rooftop.html, last visited March 2, 2014.

> practically no attention to things like marginal cost, elasticities of demand, or the dynamic conditions of innovation and growth.[56]

From an economic perspective, the problem with the high-fixed-charge rate design is that it must in turn produce a low volumetric rate. In the long run all costs are variable, suggesting high, not low, volumetric rates as the long-run price signal. In our hypothetical example, if the utility moves to a $55 per month fixed charge, to avoid over-collection of revenue, the volumetric cost must drop to $0.05 per kWh, which is likely below the present value of the long-run avoided cost of providing utility service.

This creates a poor price signal for customers adopting distributed solar PV, which operates at full bore during peak times. Under the right conditions, solar PV reduces the need to add new generation, transmission, and distribution facilities. Since solar PV involves no fuel costs, it also removes fuel price uncertainty for the life of the system, which adds to its value.

There is considerable controversy, however, as to whether solar PV systems do avoid all of these costs and if they do what quantitative value should be assigned to them.[57] If solar PV systems are not operating at the time of system peak, for example, then generation capacity costs would not be avoided. Quantitative estimates of the impact of solar PV systems on utility demand would be useful in analyzing this issue.

Even though the value-of-solar pricing approach applies to net metering, in principle it provides insights as to how utility prices should be set. It is more in keeping with the notion of a long-run price signal. Its major drawback in this regard is that if we use it to price service in general the revenue the utility collects is not matched to its historical cost structure, meaning it may not necessarily cover its accounting costs.

The State of Minnesota commissioned a study of the value of solar PV as a distributed resource.[58] That report suggests that the volumetric price associated with a solar resource should include avoided costs in the following categories:

- fuel costs (including fuel price uncertainty costs)
- operation and maintenance costs
- generation capacity costs
- reserve capacity costs
- transmission capacity costs
- distribution capacity costs
- environmental costs

The specific avoided cost values for individual utilities under this approach can vary substantially. Ultimately, the value of solar is a function of its location, even within an individual utility's service area, the circumstances related to system operations, capacity reserve margin, load growth rate, and timing of system peaks, both winter and summer.

Note also that the value of solar analysis pays no attention to most of the fixed costs of the existing system. For example, it considers the avoidable cost of new generation, not the accounting-based cost of the existing generation. It also considers costs that the utility creates, but does not have to bear, such as environmental externalities. Utilities have challenged the estimates of avoided costs from distributed solar

[56] Alfred Kahn, *The Economics of Regulation*, John Wiley & Sons, 1988.
[57] *Comments of Xcel Energy*, In the Matter of Establishing a Distributed Solar Value Methodology Under Minn. Stat. 216b.164, Subd. 10 (E) And (F), February 13, 2014. Docket No. E999/M-14-65
[58] Clean Power Research, *Draft Report: Minnesota Value of Solar: Methodology*, November 19, 2013.

PV suggesting that advocates substantially overstate them. Furthermore, the utilities also suggest that the inherent value of a reliable grid, one that delivers power on demand and instantaneously, fails to receive full recognition in most distributed generation related cost-benefit analyses. A recent industry report pointed out that:

> Electricity consumers and producers, even those that rely heavily on distributed energy resources, derive significant value from their grid connection. …the full value of DER [Distributed Energy Resources] requires connection to provide reliability, virtual storage and access to upstream markets."[59]

It goes on to state that:

> DER and the grid are not competitors but complements, provided that grid technologies and practices develop with the expansion of distributed energy resources.[60]

While a forward-looking approach to pricing is more in keeping with an economic perspective, from a public policy perspective it is not necessarily better than the accounting-based pricing system. The economic approach is better at sending price signals that encourage innovation. But any pricing system must ultimately enable the utility to recover its accounting-based costs. So even if the regulator adopted the value-of-solar approach for sales from the customer to the utility, it could use a high-fixed-charge rate design for sales from the utility to the customer.

OTHER PRICING APPROACHES

There are other rate designs that might be used to address the concerns related to distributed generation. These include demand charges, real-time pricing, time-of-use rates, interruptible pricing, among others. An analysis of these complex rate designs is beyond the scope of this report, but would be a useful extension of this analysis.

We do not recommend this or any particular rate design, as that is not the purpose of our report. As is typically the case in regulation, the ultimate solution may be to develop compromise pricing systems that do a reasonable job of sending signals to the market without threatening the utility's financial integrity.

[59] Electric Power Research Institute, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources*, February 2014.
[60] *Ibid*.