

Comments of the
Florida Municipal Electric Association
in response to the
Florida Public Service Commission's Request for Comments on
Optimal Methods for Promoting Solar Energy in Florida

June 26, 2015

Introduction

Growing use of solar energy for generating electricity offers many benefits but also poses several challenges. Use of solar energy helps improve air quality, reduces greenhouse gas emissions, and depending on the application in Florida, can reduce the need to build new power plants and transmission lines.

Growth in solar energy, however, comes with some concerns, including matching customers' electricity demand with power production because of the intermittent nature of sunshine, and creating difficulties in fairly allocating the costs of maintaining the electric grid. As a matter of state policy, we can expand use of solar energy in a way that is reasonable in cost and sensitive to customer use if we follow a few key criteria: 1) fully understand the impact of solar energy production on the ability of Florida utilities to provide affordable and reliable power, and 2) analyze and understand the impact of various solar business models on customer rates, assuring they are affordable and the electric system maintains the same high reliability Floridians expect.

Florida's municipal electric utilities are statewide leaders in delivering solar energy. The public power business model, which is shaped around local control and prioritizing customer needs, supports innovative and effective approaches to further the growth of solar. We have experimented with a variety of options, including feed-in-tariffs, net metering, net billing, large-scale utility-owned solar, community solar and leased solar. We have direct experience with the effects of these models on the utility system, as well as the financial impact to solar owners and non-owners. We have experience with solar energy in our service areas and have a good understanding of the financial impact, what happens to the utility system, and the subsidies paid. Suggesting a policy statewide, however, requires in-depth study to determine impacts in various communities and energy production profiles. We want to ensure that one class of customers does not pay for or subsidize another class.

An important reality of solar energy is that today, and into the foreseeable future, it cannot meet all customer electricity needs, or even a major fraction. The sun shines only for a limited time in the day and energy cannot be economically stored in large quantities. While electricity storage technology (i.e., batteries) and applications are changing and expanding, consumers who use solar must remain connected to the utility grid, which in Florida supplies electricity generated 24/7 from other sources – such as natural gas, biopower, waste-to-energy, nuclear and coal – to supplement their part-time solar power.

Furthermore, poorly integrated solar energy creates grid imbalances caused by solar's variability; it makes load forecasting particularly difficult because utilities must build conventional power

plants to cover the utility peak generation, creates safety concerns for lineworkers trying to restore power during an outage – expecting that a downed wire is offline – but it may be energized by a customer’s solar panels, causing a danger for electrocution.

Our goal in this discussion is to help understand the optimal methods for implementing solar energy so that Florida achieves the maximum level of solar production at the times we need energy the most, while simultaneously minimizing the cost to consumers.

The Florida Municipal Electric Association represents the combined interests of 34 municipal electric utilities, who together serve 14 percent of Floridians, about one in seven, 1.3 million customer meters. Municipal electric utilities are not-for-profit and are customer-owned. Our governing boards are either elected or appointed locally. As such, we are highly responsive to each community’s needs, focused on high reliability and investing in our communities.

The Big Question

What is the best way to promote solar energy in Florida? The short answer is large-scale utility-owned or community solar (customer-owned). The reason is because only large-scale solar can minimize or eliminate subsidies, as well as provide for appropriate back-up power that assures continuous service. All other forms of solar energy are suboptimal, including net metering.

We call this best way to promote solar power Smart Solar.

Top Issues

1. Municipal electric utilities are actively involved in solar energy, and have a variety of experiences with different delivery mechanisms.
2. Demand-side solar, in its current business model – net metering – creates significant rate inequity among solar haves and have-nots, because net metered users do not pay for the electric distribution system (i.e., they use the poles and wires, but do not pay for them).
3. The net metering rate structure needs reform for all customers to realize the full benefit.
4. Large supply-side solar is the optimal method for expanding solar energy throughout society.
5. Large-scale supply-side solar offers significant benefits over demand-side solar:
 - There is a 50% production benefit (16% solar conversion efficiency for net metering versus 24% for large-scale).
 - Large-scale purchasing allows utilities to lower costs by taking advantage of economy of scale.
 - Projects can be controlled by the utility and integrated into utility operations.
 - Large-scale solar is well-suited for subsequent installation of energy storage when it becomes cost-effective in the future.
 - It eliminates the significant subsidies associated with net metering.

6. FMEA strongly recommends the Florida Public Service Commission initiate a large-scale study of Smart Solar practices and how best to expand solar in Florida. While a few other states have studied some of these impacts, they are highly specific by state and region. Therefore, Florida should conduct its own methodical study. Only then will we be able to determine the optimal methods for expanding solar energy in Florida.

Discussion

Demand-Side Solar – Net Metering

The prevailing demand-side solar program in Florida is net metering. Net metering offers both positive and negative impacts to Floridians. It allows customers the opportunity to lower their electric bill by generating and replacing electricity they would have purchased from the electric utility. Furthermore, net metering provides an environmental benefit by replacing conventional energy production – oftentimes fossil-fired – with zero-emission solar power. This benefit can help Florida meet the greenhouse gas emission targets for the state set forth in EPA’s proposed Clean Power Plan. However, while FMEA’s member utilities support customer-owned renewable generation through net metering programs, we believe that net metering provides an overgenerous incentive to solar production at the expense of customers who do not have solar energy.

Net metering results in cost-shifting to non-solar customers

Solar-generated electricity is inherently sporadic and uncertain and is thus not a dependable power source. Electric utilities are required by national reliability organizations to maintain the highest level of reliability, or pay significant fines. Solar-generating facilities are disruptive to electric reliability, as solar photovoltaic panels do not produce electricity at night, reduce their production significantly when a cloud passes by or the sky is overcast, and during storm events. Solar panels do not generate electricity when they are shut down for maintenance. Currently, there is no economically viable method to store solar-generated electricity for use during these nonproductive periods, although commercial battery storage options are being introduced. As a result of this lack of reliable production, solar electric customers must use conventional electricity when solar-generating facilities are unable to generate electricity. In Florida, this fact forces the electric utility to build its electric generation facilities or contract for power supply to provide power as if the solar generation does not even exist.

Electric utilities must continue to maintain the infrastructure necessary to provide electric service to solar energy customers irrespective of whether the customer is able to generate solar electricity. Constructing and maintaining the electric grid infrastructure represents approximately one-third of the retail cost of electricity. Utilities must build peaking power plants to cover the winter peak, which occurs from 7-8 a.m., usually during a cold period in mid-December to mid-January, a time when solar power is generally unavailable. Large-scale battery storage could improve the effectiveness of solar, as discussed under the Supply-Side Solar section below. However, the latest home battery innovation, the Tesla Powerwall, costs \$7,000 for a 10 kW battery but produces only 2 kWhs of continuous power until its stored power is exhausted.

Moreover, customers who generate solar electricity have a disparate cost impact on a utility's infrastructure that is not shared by the customers who do not generate or consume solar electricity. To name a few, electric utilities must monitor the flow of solar electricity through transmission lines and substations, must account for the solar generated electricity in their billing system, must conduct safety inspections during the construction of solar generating facilities, must conduct safety reviews of the facilities' electrical systems, and must install net meters. Any solar rebates offered by utilities will also increase costs to non-solar customers.

This cost-shifting can be especially significant for smaller municipal utilities with fewer customers over which to spread the costs.¹ With the modest number of net metering programs that currently exist, the overall magnitude of the subsidy is small and can potentially be remedied through additional fixed charges and fees on solar customers. However, if an increasing number of municipal customers are incentivized to install customer-owned renewable generation while the utility must build and maintain the grid to provide for its peak load regardless of the availability of customer-owned renewable generation, the subsidy could grow to an untenable level. At a modest level of solar penetration, less than one percent, the subsidy is small; however, if we imagine half of all customers of a utility have solar and are not paying for the grid, and the other half are paying the full cost of the grid, electric rates would rise substantially as the subsidy would be large.

An important example of this cross-subsidization is in California, where there is a relatively high penetration of distributed photovoltaic installations. The three investor-owned utilities in California estimate they will have to make up \$1.4 billion in lost revenues once the original caps on distributed generation have been reached. Spread evenly among the 7.6 million traditional customers, each customer is estimated to experience an average annual increase of \$185 in electricity costs as a result of distributed generation.

Net metering does not benefit all customers

Net metering is also a suboptimal way to encourage solar generation because not all customers are able to take advantage of its benefits. The average up-front cost to install a five kilowatt solar panel system is \$15,000. Even with available rebates and tax credits, this is a significant investment that not all customers are able to afford. Additionally, renters and people living in multi-family housing are often unable to install customer-owned renewable generation where they live. To the extent that net metering is unavailable to low-income customers and renters, they will be left subsidizing those who can afford the large up-front investment of customer-owned renewable generation. Leasing solar facilities from a third-party may alleviate much of the up-front costs, but these for-profit companies must charge rates that are well-above the cost of the system to pay for overhead, advertising, and investor profits.

Another inequity is the availability of sunlight to the average residential home. In Florida, only approximately 20 percent of homes are properly oriented to take advantage of solar power. That is, they have a south-facing roof to achieve maximum solar gain for fixed-plate solar collectors.

¹ Florida's municipal electric utilities vary greatly in size, from JEA in Jacksonville with 422,315 customers and a peak load of 2,665 MW, to the City of Moore Haven with 1,058 customers and a peak load of 3.8 MW. In fact, of FMEA's thirty-three utility members, six utilities have peak loads less than 10 MW.

So not only is solar unavailable financially to many and unavailable to renters and those living in multi-family housing – in some cases 40 percent of housing – solar is largely unavailable to the vast majority of residential structures across Florida and the U.S.

Net metering has the potential to negatively affect energy conservation efforts

Most residential rates have only two components: a fixed monthly customer charge (often fairly minimal), and a variable energy charge. The customer generally pays for the cost of metering and billing, a cost that does not change monthly even if consumption fluctuates. For most residential customers, therefore, their energy bill is largely determined by the amount of energy consumed throughout the billing cycle, and the total bill rises and falls in sync with energy usage. This encourages customers to use energy efficiency measures to reduce bills. One reasonable method to assure solar customers properly pay for the cost of the electric grid they are using and not paying for, is to increase the fixed, monthly customer charge.

However, if utilities are forced to increase the customer charge portion of their bills in order to fully recover fixed grid costs, these higher fixed charges could hamper energy conservation efforts. For solar customers, because a smaller portion of the electricity bill is tied to actual usage, the rewards for energy efficiency and conservation, and distributed generation itself, become smaller as a greater fraction of costs are shifted to the part of the bill that does not vary with consumption. Thus, a smaller incentive for energy conservation is an unintended consequence of expanded net metering.

Demand-side solar presents serious safety concerns

There are other potential safety issues involving net metering. Of particular concern is “islanding,” where the customer-owned renewable generation continues to energize a feeder even though the utility is no longer supplying power due to an outage or other cause. This creates a significant safety risk to utility workers who might not realize that a circuit they are working on is energized. Solar installations are required to “anti-island” and discontinue power production once an islanding situation occurs, and as such have inverters that allow the unit to cease generation.

Even if islanding remains a remote possibility, there are other risks involved. High-voltage spikes can occur, thus damaging the facilities of neighboring customers. The loss of the utility system reduces the impedance necessary for the PV inverters to function properly, leading to abnormal voltages before the inverter trips. This also potentially damages other loads. Since the utility distribution system creates the sole ground source for a DG system feeder, the loss of grounding due to an outage could lead to overvoltage. This could damage both utility and customer equipment, especially surge protectors.

Net metering could potentially be improved through rate restructuring

To realize the potential of net metering programs to promote solar generation in a way that is fair for all, net metering customers need to be unbundled in their own rate class with a rate structure that better separates fixed and variable costs. This could include a non-bypassable surcharge to

ensure that net metering customers are paying their share of the utility's fixed costs, or as alluded to earlier, an increase to the fixed charge. For example, in 2014, Lakeland Electric established a demand pricing schedule for net metering customers. The demand charge is based on the customer's "maximum 30-minute integrated kilowatt demand in the month." The purpose of this modified tariff is to better align revenues to actual costs.

The use of a feed-in-tariff could also help reduce or eliminate the cost-shifting effects of demand-side solar by more closely tying compensation for solar energy production to the value of solar at the time it is delivered to the grid. For instance, solar energy produced during peak demand and in areas of high transmission or distribution congestion may have more value than in areas of low demand or in off-peak time periods, and could be compensated at a higher price.

There are many variables to consider when thinking about how to fairly structure demand-side solar incentives, like net metering. Florida has a vast and varied population and unique geographical features. Although many studies have been conducted on the effects of demand-side solar programs in other regions, these results may not necessarily apply here. FMEA strongly believes that more research should be done to analyze the costs and benefits of various rate designs in order to implement demand-side practices for Florida in the most equitable and effective way.

Supply-Side Solar

FMEA believes that supply-side solar is the optimal method for delivering solar electric energy in Florida. That is, large-scale utility owned or long-term contracted projects, whereby all customers share in the cost of solar production and experience the benefits as well. Benefits include lower costs, higher energy production, and fairness for all Floridians.

Costs are lower for several reasons. First, the economy of scale in procuring a large quantity of solar panels helps lower the cost of large-scale projects. We have seen that buying in bulk – such as purchasing larger packages of consumer goods at Costco or Sam's Club – without question lowers costs. Compared to small-scale net metering, large-scale solar costs are lower, in some recent cases, by more than 50 percent. That is a benefit to society in which we should recognize and invest.

The second reason why overall costs are lower is because large-scale solar is designed to produce more electricity. Panels are installed in a treeless field without shady obstructions, so converting sunlight to electricity is unimpeded, as it can be by trees in a residential neighborhood in a net metering installation. With large-scale solar, vegetation management is also much less of an issue.

A third reason why costs are lower is because large-scale installations can be designed to track the sun as it moves across the sky each day. In a typical household net metering fixed-panel installation, sunlight in the morning and late afternoon hits the panels at an angle less than 45 degrees (90 degrees is optimal), producing up to 80 percent less electricity. Conversely, tracking systems that follow the sun are generally 50 percent more efficient on a full daily basis and

produce more electricity per kilowatt installed. That benefits all customers equally, which is another benefit – fairness to all.

Finally, large-scale solar has lower maintenance costs. Dirt and pollen in the air are a fact of life, and all solar panels are subject to deposits that block solar energy from energizing the photovoltaic panels at the maximum, expected levels. All panels must be maintained. Ground-mounted panels, typical of large-scale projects, are easy to access, easy to clean, safer (on the ground versus climbing a roof) and easy to maintain and modify if necessary. To maintain a rooftop system, maintenance workers, or the homeowner, must climb onto the roof and physically clean the panels, sometimes in difficult-to-reach configurations. Ground-mounted, large-scale projects are easily maintained, can be cleaned or altered (if necessary) on a regular basis, and are inherently safer, for not having to climb on a roof. The economy also benefits from local workers hired to clean and maintain the project. Fewer net metering installations are properly cleaned and maintained.

Support federal tax incentives and grants for large-scale solar

Large-scale solar projects of several megawatts and larger may benefit further from federal tax incentives. If a private utility owns the panels, they can take advantage of the federal benefits and hopefully pass those savings on to customers. The municipal electric utility model for large-scale systems is one whereby the utility, and the local government, do not own the solar equipment. Instead, the municipal electric utility partners with a private contractor who builds the solar project, takes advantage of the solar tax incentives, thus lowering costs for the project. Then the municipal electric utility enters into a 20-year power purchase agreement, or PPA, which typically offers a fixed or slightly escalating price over the contractual period. In the municipal electric model, the lower costs are passed on to local customers. The FPSC should support such incentives as the production tax credit, which has the impact of lowering costs for large-scale solar projects. Finally, if the federal government desires to promote solar energy, it could provide solar developers with grants to encourage more projects.

Support action in the Florida legislature to exempt all solar facilities from property tax

The value of land can have a significant impact on the ultimate cost of a large-scale solar project, perhaps by as much as one cent per kilowatt-hour in output, which today equates to about 20 percent of a project's wholesale cost. In the municipal utility business model, constructing a facility on municipally owned land eliminates this cost, a benefit to customers. However, if such land is unavailable, the property tax must be paid, increasing costs to customers. In the private utility model, such taxes are always a factor. If the intent is to promote solar energy in Florida, all solar real property should be exempt from property tax, regardless of who owns the property.

In addition to real property taxes, the tangible personal property tax can also have substantial impact on the cost of solar. Even if the land on which the solar facility is built is owned by a municipality and therefore exempt from taxation, the facility's tangible personal property, e.g., the PV panels and other nonpermanent structures, can be subject to taxation if owned by private entities (as would be the case in a power purchase agreement business model). This can substantially add to the cost of solar energy. Again, if the intent is to encourage solar energy

throughout the state, tangible personal property used in the production of solar energy should be exempt from property tax.

Support research and investigation into solar storage

Florida is unique among most states in the U.S. because we experience a peak of electric use in the winter. As stated earlier, the statewide peak usually occurs on a cold weekday morning in mid-December to mid-January, and usually between 7-8 a.m., when consumers are waking up, heating their homes with electric heat pumps, making coffee and using hair dryers, while simultaneously businesses are turning on their heating systems in advance of employees arriving for work. The combination creates a “needle peak,” whereby utilities must own or contract for sufficient physical power to keep the lights on for these few hours in the year.

At that time of day, in morning darkness, solar power does not contribute to lowering the peak. If we could take advantage of energy storage, e.g., charging large batteries and discharging them during the peak, utilities might avoid constructing new peaking power plants. That would be a significant benefit in avoiding power plant construction, as well as the emissions that would be avoided. While there is an environmental impact to constructing and disposing of such large-scale batteries, further study and analysis is necessary to understand the life-cycle impacts of energy storage compared to traditional forms of power generation.

Exempt large-scale solar projects from the Power Plant Siting Act

The power plant siting act (PPSA) requires projects 75 MW and above to be reviewed by state agencies for need. We have seen several projects sited just under the 75 MW cap, perhaps to avoid spending the time and expense to go through the PPSA approval process. If large-scale solar projects were exempt from the need determination and certification requirements of the PPSA, utilities would be freer to expand solar projects above the 75 MW threshold, thus offering the opportunity for greater efficiency and lower costs with larger bulk purchases and more productive use of construction personal and equipment. Such projects would still be reported to the PSC and DEP for planning purposes.

Expand the role of the Florida Energy Office to more aggressively educate Floridians about optimal methods for promoting solar

The Florida Energy Office could easily take up the responsibility to educate Floridians about the pros and cons of all forms of solar, general cost information, and optimal ways to take advantage of it. The mission on this task would be to help the citizens of Florida develop a deeper understanding of solar and the best approaches to expand it. As solar expands, the role of the Energy Office will become increasingly important in explaining the facts surrounding the various financial approaches. It should not be the decision of the Florida Energy Office to choose winners and losers. Rather, the office should provide unbiased facts and information for others to use in their decision-making.

One area of controversy in the solar industry is the role of leasing photovoltaic panels to residential and commercial customers who then engage in utility net metering programs. We

have heard stories from other states that promoters and sales people of this model are over-promising the financial savings that can be achieved, customers are signing long-term leases, and then are disappointed by the lack of the resulting savings. If such a model were to come to Florida, it is vital that our citizens have an independent body they can turn to for facts and to verify promised savings. While it is the Attorney General who would deal in consumer fraud, the Florida Energy Office can serve the role of consumer educator.

Research the economic development opportunities of supply-side solar

As an energy resource, supply-side solar is more beneficial than demand-side solar in many ways. It is unclear, however, whether supply-side or demand-side solar is better for generating jobs. Construction jobs are needed to develop both forms. The type of construction is different, however, and involves a different set of employee skills and equipment. For example, supply-side solar requires greenfield construction working in a field, pouring concrete and setting foundations, while demand-side solar involves extensive experience working on residential and commercial roofs. Because the job requirements are not parallel we need to study the issue in greater depth to fully understand the impacts to society. Nationwide, there exists extensive experience with both forms of construction, so the data to complete such an analysis should not be difficult to compile. For distributed solar, the job opportunities generally go to small businesses, while the economic activity for supply-side solar would likely take place at a larger construction company. It's logical to consider that local small solar businesses could be integrated into and partner with a larger construction company so that the goals for expanding local jobs and economic development dovetail. This can easily take place with thoughtful planning and specification in RFPs for new solar projects.

On the issue of impact to the utility system, as energy storage options become more technologically feasible and cost effective, large-scale supply-side solar would likely become more valuable for electric utilities seeking to supply peak demand on dark winter mornings when sunshine is unavailable. By combining solar and storage into a single, large facility, the entire operation becomes more efficient. Compared to individual homes installing energy storage, there is little debate about which is a more valuable investment. Utilities will be able to replace fossil-fired peaking generators that operate for only a few hundred hours per year, and the result will be something akin to increasing of load factor (but not precisely so), whereby the peak is replaced by solar generation. Except for the unstudied impact of solar manufacturing and battery production, it appears as if the result would be positive on the environment, reducing air emissions.

Furthermore, because solar "fuel" is essentially free once the solar arrays are installed, there is the economic benefit of *not purchasing* fossil fuels from out of state. On a macro level, more of Floridians' money would be staying in state, and not paid to places like Louisiana to purchase natural gas or West Virginia to purchase coal. These impacts, along with an economic comparison, should be carefully studied before investing significantly in such technology so we have a full understanding of the impacts before establishing state policy to promote solar.

Understand the impact of taxes and fees paid to state and local governments of each form of solar energy delivery

There appears to be significant impacts to the tax structure of state and local governments from installation of demand-side versus supply-side solar. This has been studied to some degree by state of Florida economists, who discussed the issue publicly while evaluating the economic impacts of the proposed constitutional amendment to promote third-party solar sales. Thus, we have a head start in the research, even though economists mostly collected and did not extensively analyze the information. The data are available at the following website: <http://edr.state.fl.us/Content/constitutional-amendments/2016Ballot/SolarAdditionalInformation.cfm>

The impacts are many and significant, including:

- Franchise fees – Utilities pay hundreds of millions of dollars in franchise fees to local governments, estimated to be about \$850 million annually. If sales from utilities are substantially reduced as the result of expanding demand-side solar projects, local governments will see a significant drop in revenues and may be unwilling to continue some services.
- Franchise agreements could be in jeopardy – These agreements exist under the condition the utility is the exclusive energy provider. Third party solar providers serve customers in concert with and in many conditions in place of the utility, substantially reducing utility sales. If the solar third party avoids paying franchise fees and other taxes, there is a provision in many franchise agreements that may be breached. The result might be that all franchise fee revenue to local governments could be in jeopardy.
- The Public Service Tax and Gross Receipts Tax will also be impacted. State and local governments would see significantly lower revenue as a result of misplaced sales from third-party solar providers if tax considerations are unaddressed.
- Municipal electric utilities make substantial payments to their local governments in lieu of traditional franchise fees. Statewide among Florida's 34 municipal electric utilities, these payments are greater than \$300 million, and are in jeopardy if they are avoided by third-party solar providers.

These tax- and fee-avoidance impacts exist primarily in the demand-side solar model. In the supply-side model, these taxes and fees continue to be paid. The data exist to fully study and understand the impacts. Before engaging in a new policy to promote solar energy in Florida, we recommend the FPSC analyze and understand the impacts on taxes and fees.

Understand land use impacts of both supply-side and demand-side solar

There is no question that large-scale supply-side solar generally follows that of a “greenfield” project. That is, land is developed in a rural area away from shading trees. Demand-side solar is nearly always placed on the roof of an existing structure, such as a house or commercial building. Thus, we might conclude that supply-side solar has a greater negative impact on land

use. However, with thoughtful siting, brownfield sites can be excellent candidates for such a project, which is an appropriate re-use of already environmentally damaged land. Supply-side projects are made more efficient if they are located near utility transmission and substation infrastructure, so sites in rural areas near large scale power plants are also good candidates. There are several such sites across Florida. Both JEA in Jacksonville and Orlando Utilities Commission have installed supply-side solar adjacent to existing power plants, both with positive co-location benefits to existing infrastructure that have lowered the cost of the supply-side project. From FMEA member experience, we note that supply-side projects require 4-8 acres of land per megawatt of solar installed, which includes all aspects of the facility, such as roads, structures and proper spacing of panels.

Supply-side solar allows for expansion of a “community solar” model, where individual customers can invest in and receive the benefits from solar energy without installing solar on their roofs

Community solar is a relatively new concept, introduced within the last few years as a way to achieve the benefits of supply-side solar while delivering the positive attributes that demand-side utility customers are seeking. Another concept describing community solar is “virtual net metering.” Community solar projects look much like supply-side solar. In its most collaborative form, a utility issues a request for proposals for various size projects, such as 10, 20, 30, 50, 75, 100 megawatt installations. With the results, the utility can determine a 20-year levelized kilowatt-hour cost that is comparable to the residential rate. Today, we are seeing such costs in the range of conventional energy. If we use \$130 per megawatt-hour as an average in Florida, including energy storage (this is an unverified estimate only for use in this example), the utility would then ask its customers if they would like to commit to buying the output of a fraction of the project (say, up to 5 kilowatts) for 20 years. The cost would remain level for that period, and would include all taxes and fees, including franchise fees, state and local taxes, and appropriate maintenance. The utility would be responsible for administering the program, properly crediting each customer who “invests” or commits. There are many benefits of such programs. All customers can participate, regardless of home ownership or building orientation. There are no up-front costs, but there is a long-term commitment. Non-solar customers are generally unaffected, as the only customers investing in the project pay for the solar. Their costs are fixed for the 20-year time frame, so the investment is a hedge against future price increases. The point of this example is that this is a relatively new solar business model that appears to merge the combined benefits of both supply- and demand-side solar, and deserves further investigation. Orlando Utilities Commission has initiated such a project, and is already expanding it for a second round of customer investment.

All solar will provide a benefit to the state of Florida to help address EPA’s proposed Clean Power Plan to reduce greenhouse gas production

EPA’s proposed Clean Power Plan (CPP), if fully implemented, will move the nation away from use of coal as a fuel source for electric generation, and move us more toward greater adoption of renewable energy. There are many facets to this discussion and the impacts of the CPP on the nation, as well as the difficult-to-quantify desire by some to reduce production of greenhouse gases at any cost. We mean not to open that debate here. Nevertheless, in CPP’s building block

#3, renewable energy, there is an expectation each state will act to achieve its renewable energy potential, based on the limitations of current technology and improvements over time. Thus, we expect solar power to be an expanding and economically beneficial factor in the provision of energy in the future. Even though we see difficult problems with solar variability and reliability, it still has an important role that we must continue to understand and expand. It is important not to treat every new idea as an opportunity to experiment with consumer funds. Instead, we should rely on agencies like the U.S. Department of Energy, the Florida Solar Energy Center, and the National Renewable Energy Laboratory to research and test new ideas that can lead to successful commercialization.

Conclusion

Ultimately, it is impossible for anyone to recommend a specific “best approach” to deliver solar in Florida. Because of the many unstudied financial, operational and environmental impacts, FMEA strongly recommends the PSC initiate a study of Smart Solar practices – that is, how best to expand solar in Florida – in order to understand the pros and cons of various approaches, as well as to identify with greater confidence the best approach for our state. While other states have analyzed some of these impacts, the pros and cons are highly specific by region. Therefore, Florida should conduct its own in-depth study. The FPSC should collaborate with stakeholders to identify assumptions and parameters to study. Only then will we be able to determine the optimal methods for expanding solar energy in Florida.

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and Market Developments

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Introduction

The number of residential and commercial customers who have installed solar generating panels at their homes and businesses has increased in recent years. Motivated by environmental concerns and a desire to reduce their electric bills, these customers have spurred a dramatic increase in the amount of distributed generation (DG) in the United States. Advances in solar photovoltaic (PV) technology, combined with decreasing capital costs and construction subsidies, have further sparked the construction of new capacity.

The advance of DG as a complement to traditional electric service has potential benefits for electric utilities. Customers producing rather than consuming electricity at peak demand times mitigate the need to construct new generating capacity. Consumption of generation near its source could lead to lower transmission and distribution line losses and has other potential benefits for distribution and transmission systems.

DG also poses many operational challenges to electric utilities. Generators must still rely on the electric grid for backup service during periods when they are not meeting all of their electricity needs (e.g., during the early morning and evening hours, during prolonged overcast conditions, during periods of unexpected PV installation failure, etc.). The variability of PV solar generation creates further challenges in maintaining system balance. There are also safety issues involved with customers having on-site generation, as power from DG installations can back-feed into distribution systems and cause occupational hazards for lineworkers.

DG installations also pose revenue challenges for electric utilities. Because DG customers are typically compensated at times when they provide excess power to the grid and charged when they consume power from the utility, their electric bills potentially net to zero, and in some cases their net balance over the relevant billing period may even be negative, meaning the utility must pay the customer. Since residential electric bills are based primarily on electric consumption, and the associated customer charges rarely reflect the full amount of fixed costs utilities incur to provide retail electric service, utilities could face a revenue shortfall. As a result, other retail customers ultimately subsidize those customers with distributed generation or the utility under-recover the cost of providing service.

This paper examines the many challenges that DG poses, as well as ways utilities can address these challenges and encourage DG development without unduly burdening other customers or adversely impacting utility operations and fiscal stability. The first section provides background on what DG is and the different pricing mechanisms utilities are using to compensate distributed generators. The second section explores the operational impacts DG has on the electric grid as well as the costs and benefits of DG for the distribution and transmission systems. The third section discusses the financial implications of DG, and ways different utilities have attempted to mitigate its impact on their bottom lines. The final section details the types of programs and rates public power utilities have implemented to ensure rate equity.

I. Distributed Generation, Net Metering, and Feed-in Tariffs

What Is Distributed Generation?

Distributed Generation refers to power produced at the point of consumption. DG resources, or distributed energy resources (DER), are small-scale energy resources that typically range in size from 3 kilowatts (kW) to 10 megawatts (MW) or larger. A typical household's peak demand is about 3.5 kW, so the smaller resources are used by residential customers, while the larger systems are typically used by commercial and industrial customers. In addition to PV, DERs can include small wind turbines, combined heat and power (CHP), fuel cells, microturbines, and other sources. More than 90 percent of installed distributed generation in the United States today is solar. Therefore solar is the primary focus of this paper.

The definition of DG has evolved over time. When the Public Utility Regulatory Policies Act (PURPA) was enacted in 1978, utilities became statutorily obligated to purchase power from qualifying facilities (QFs) at the utility's "avoided cost," (defined as the cost of the utility's incremental cost for its next block of power). These QFs included CHP facilities and small power production facilities with 80 MW or less of installed renewable generation capacity.¹ These QFs were generally thought of as DG facilities. Later on, however, the California Public Utilities Commission (CPUC), for purposes of establishing a roadmap for rulemaking regarding DG, defined DG as "small-scale electric generating technologies installed at, or in close proximity to, the end-user's location."²

Some definitions of DG turn on location rather than size. The Swedish Royal Institute of Technology's Department of Electric Power Engineering defines DG as "an electric power source connected directly to the distribution network or on the customer side of the meter."³ Both this definition and the CPUC definition cover the types of distributed resources discussed in this paper.

Compensating DG Supply

Though utilities have developed varying formulae for compensating distributed generators for the generation that flows onto their grids, there are two basic methods of compensation: net metering and feed-in tariffs.

Net Metering

Under net metering programs, customers with on-site generation are credited for the amount of kilowatt-hour (kWh) sales sold back to the grid and are charged for periods when their consumption exceeds their generation. To put it another way, their meters literally run backwards when a DG unit is producing more power than the customer is using. Utilities then charge the net difference between consumption and generation.

¹ Itron, Inc. *Impacts of Distributed Generation, Final Report*. Prepared for the California Public Utilities Commission Energy Division Staff, January 2010, p. 3-1.

² *Ibid.*, p. 3-2.

³ *Ibid.*

There are different mechanisms for billing customers. If a customer has a negative net balance, that balance may carry forward to the next month. Most utilities have a “true-up” period (at the end of the year, or some other pre-determined time). In some circumstances, a customer with a negative net balance may be compensated for its excess generation, while in other situations the balance reverts to zero at the end of the designated period.

State policies on net metering also differ. Some states limit the technology and fuel types eligible for net metering. Many states also cap the total generator capacity eligible for net metering, placing caps on both individual generators and aggregate load eligible for net metering.⁴

Under most net-metering programs, the customer is both charged and credited at the utility’s full retail rate of electricity. The meter simply records how much energy is consumed on-site and then how much is sold to the grid, with the difference in kilowatt-hours either charged or credited to the customer. Since net metering generally does not account for time of usage, it potentially over-compensates distributed generators and credits them with a value of generation that is higher than the utility’s avoided cost.

Feed-in Tariffs

Some states and utilities have mandated feed-in tariff (FIT) programs. A FIT is a long-term contract under which the utility agrees to purchase the excess generation from a distributed generator or DER. The utility establishes a per-kWh purchase price. This rate varies from utility to utility and is a source of much contention (explored below). Ultimately, utilities pay distributed generators as they would a non-utility wholesale power producer.

FITs have been employed more commonly in Europe than in the United States, but they are seen as a means of incentivizing more DG. Though similar to net metering, under a FIT the generator is compensated at the predetermined rate for the excess generation supplied *to* the grid, while its purchases *from* the grid are charged at the retail rate.⁵ In other words, the FIT rate can be higher or lower than the retail rate. Some early adopters of FITs, both in Europe and the United States, intentionally set rates high in order to encourage the development of distributed resources. Other utilities have chosen to set rates closer to the wholesale purchase price of electricity – and thus closer to the avoided cost level.

Some utilities have developed a blend of net metering and FITs, crediting distributed generators at less than the retail rate for electric service. Still other utilities have attempted to develop a tariff that more accurately reflects the value of DG for their system. These “value of solar” tariffs have been implemented by utilities such as Austin Energy in Texas and are discussed at greater length below.

PURPA

PURPA adds another complication to FITs. Under Section 210 of PURPA, utilities are required to purchase power from QFs. PURPA mandates that any rate set under PURPA cannot exceed the avoided cost. PURPA defines avoided cost as “the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility

⁴ See Energy Information Administration (EIA) article, “Policies for compensating behind-the-meter generation vary by State,” May 9, 2012. Accessed at: <http://www.eia.gov/todayinenergy/detail.cfm?id=6190>.

⁵ For more information see EIA article, “Feed-in tariff: A policy tool encouraging deployment of renewable electricity technologies,” May 30, 2013. Accessed at: <http://www.eia.gov/todayinenergy/detail.cfm?id=11471>.

would generate or purchase from another source.”⁶ The Federal Energy Regulatory Commission (FERC) later added in its decision in the *Southern California Edison* case⁷ that “externality adders,” such as the value of reduced air emissions, could not be included in the avoided cost calculation. Furthermore, certain exemptions from the obligation to purchase power from QFs exist under PURPA. In some regional transmission organizations (RTO), QFs with greater than 20 MW capacity are presumed to have “non-discriminatory access,” and thus utilities may apply to FERC for an exemption from their obligation to purchase the surplus power.⁸

Though FERC’s ability to set wholesale electric power rates under the Federal Power Act (FPA) is limited to “public utilities,” (i.e., generally investor-owned utilities, or IOUs), the “must purchase” provisions of Section 210 of PURPA are applicable to all “electric utilities,” including publicly owned electric utilities and rural electric cooperatives.⁹ Therefore, public power utilities are subject to the same restrictions as IOUs and other utilities in setting avoided cost rates in compliance with PURPA. Further, if a distributed generator makes a sale of electric power to a public power utility and the rate is not PURPA-compliant, then as a legal matter, the sale transaction is considered a “sale for resale” (a wholesale sale) of electric power under the FPA and the entity that makes such a sale must submit to FERC regulation under the FPA.¹⁰

For a rate to be compliant with PURPA, the rate must be set at the avoided cost. Some have argued, however, that an avoided cost rate might be too low to encourage installation of DERs. Utilities might be able to structure their FITs in order to avoid FERC jurisdiction.¹¹

The Current DG Marketplace

The amount of DG, particularly solar PV, has risen sharply in the United States over the past few years. As of 2011, 4 gigawatts (GW) of distributed capacity had been installed in the United States,¹² with 200,000 residential electric customers owning at least some PV capacity. The

⁶ Federal Register. 12214-12237 (1980), as cited in Justin Wynne. *Feed-in Tariffs and Implications for Public Power*. Memphis, TN: APPA Legal Seminar, November 29, 2011, p. 13. Accessed at:

<http://www.publicpower.org/files/LegalSeminar/Wynne.pdf>

⁷ 70 FERC ¶61, 215 (1995), as cited in Wynne.

⁸ Wynne, p. 14.

⁹ *Ibid.*, p. 15.

¹⁰ This issue does not arise in the context of net metering because FERC has held that no jurisdictional sale of power takes place. In *MidAmerican Energy*, 94 FERC ¶61,340 (2001) and *Sun Edison LLC*, 129 FERC ¶61,146 (2009), FERC held no FPA-jurisdictional sale takes place when a generator participates in a net metering program if, over the course of a retail billing period (e.g., a month), there is no net delivery of energy from the generator to the grid. Both orders make clear the holdings apply to both QFs and non-QFs participating in net-metering programs.

¹¹ See, for example, Scott Hempling, et al., *Renewable Energy Prices in State-Level Feed-in Tariffs: Federal Law Constraints and Possible Solutions*, January 2010. Hempling offers three alternative methods to pay generators at higher than the avoided cost: awarding the generator renewable energy credits (RECs); offering tax credits equal to the amount paid at above avoided cost; or using funding from sources such as tax credits, grants, and loans. These proposals, however, have not been tested in court proceedings and it is unclear whether they would comply with PURPA.

¹² Tom Stanton. *State and Utility Solar Energy Programs: Recommended Approaches for Growing Markets*. Silver Spring, Md.: National Regulatory Research Institute, 2013, p. 5.

amount of distributed capacity is expected to increase to approximately 9 GW by 2016, and to as much as 20 GW by 2020.¹³

One of the main drivers for this increased capacity is the declining cost of solar panels. Solar panel costs have fallen from \$3.80 to 86 cents per watt as of 2012.¹⁴ This, in turn, has led to a reduction in total solar installation costs. Solar installation costs have decreased 70 percent since 2008 and are still falling.¹⁵ In 2012 alone, prices dropped an average of 14 percent. The price fell by 90 cents per watt for small systems (10 kW or less), 80 cents per watt for mid-sized systems (10-100 kW), and 30 cents per watt for larger systems (greater than 100 kW). The average price for a small system is now \$5.30 per watt.¹⁶ Installation costs vary throughout the country and are as low as \$3.90 per watt in Texas.¹⁷

American customers have largely benefitted from developments in the European marketplace. The rapid expansion of solar DG led to an expansion in worldwide solar module manufacturing, which in turn led to reduced costs. The increase in American PV installations coincided with the bottoming out of module prices, meaning that American customers are paying far less than European customers did at the time of peak European expansion.¹⁸

In addition to declining panel prices, there are state, federal, and even utility incentives for solar panel installations. The current federal tax credit for installing PV panels is 30 percent of total installed costs. In some states, customers receive an additional 30 to 40 percent tax credit. For example, the combined federal and state tax credits for a North Carolina resident mean that the government is covering 70 percent of the total costs for installing solar paneling.¹⁹

The Edison Electric Institute (EEI) notes several other reasons for the increased reach of solar distributed generation:

- Increasing utility rates (particularly tiered rate structures with higher rates in higher usage tiers) make self-generation more viable for rate-payers.
- Renewable portfolio standards, in place in 29 states plus the District of Columbia, encourage development of more PV resources.
- Time-of-use rates, which set higher rates for consumption during peak-demand hours, create further incentives for installing distributed solar PV.²⁰

¹³ Edison Electric Institute. *Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business*, 2013, p.4. Some estimates of future growth are even more optimistic, with one analysis predicting 20-30 GW of new installed solar distributed capacity by 2017. See Andy Colthorpe, "US Solar capacity to total 50 GW by end of 2016, says Deutsche Bank." Accessed at: http://www.pv-tech.org/news/us_installed_capacity_to_total_50gw_by_the_end_of_2016_including_20gw_to_30.

¹⁴ Ibid.

¹⁵ Travis Bradford and Anne Hoskins. *Valuing Distributed Energy: Economic and Regulatory Challenges*, Columbia University and Princeton University, 2013, p. 5.

¹⁶ Galen Barbose, Naim Darghouth, Samantha Weaver, and Ryan Wiser. *Tracking the Sun VI: A Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012*. Lawrence Berkeley National Laboratory, 2013, p. 1.

¹⁷ Ibid., p. 2.

¹⁸ Phillip Brown. *European Union Wind and Solar Electricity Policies: Overview and Considerations*, Congressional Research Service, August 7, 2013, pp. 33-34.

¹⁹ Bob Curry. *The Law of Unintended Consequences*. Public Utilities Fortnightly, March 2013, p. 46.

²⁰ *Disruptive Challenges*, p. 4.

EEI concludes that a 10 percent reduction in load due to DER would lead to a 20 percent increase in rates for non-DER customers. This combination of increasing electric rates with falling PV costs could lead to greater market penetration throughout the country for solar DG. Though the variability of solar DER resources means customers will remain tied to the grid for some time, the development of improved battery storage technology, fuel cells or micro turbines could eventually allow customers to become totally grid-independent.²¹

It will likely take quite some time for the most aggressive predictions to come to fruition. Even under optimistic projections of potential distributed capacity installations, distributed PV would represent only a small fraction of total U.S. electric generating capacity. Moreover, solar and other renewable resources are not viable in all parts of the country, even if there is further development of energy storage technologies. However, even minimal DER market presence can have significant impacts on utility system reliability and revenue streams. The rest of this paper will closely examine the potential impacts and ways that utilities can ameliorate them.

²¹ Ibid., p. 5.

II. The Impact of Distributed Generation on the Electric Grid

Proponents of DG tout a number of ancillary benefits. Since DG is consumed largely on site, it would presumably lower distribution, transmission, and generation infrastructure and operating costs. Another advantage of the electricity being consumed closer to its source would be a reduction in electric line losses.

A study commissioned by the Solar Energy Industries Association (SEIA) looked at the benefits and costs of solar DG for Arizona Public Service (APS).²² The study attempted to place a monetary value on the costs and benefits of DG on the APS system. Among the benefits of DG this study posited:

- Avoided generation capacity costs. Increased level of DG penetration could reduce the need for new generation assets. Higher levels of DG penetration would especially displace new, natural gas-fired generation.
- Avoided ancillary services. The Western Electricity Coordinating Council (WECC) requires utilities to maintain spinning reserves of at least 7 percent of load. Load reductions attributable to DG would mean APS would have to procure fewer reserves.
- Avoidance of higher transmission costs. In addition to demand response (DR) and energy efficiency (EE), DG would help reduce APS's peak demand by 1,150 MW in 2017. This would negate higher transmission costs due to increased demand.
- Environmental benefits. Since DERs are generally non-emitting, renewable resources, they would displace fossil fuel energy, thereby reducing greenhouse gas emissions as well as emissions from sources such as SO₂ and NO_x.
- Avoided renewable costs. Though APS has procured enough renewable resources to meet the state's renewable energy standard (RES) requirements, DG could be a hedge against the failure of those resources, particularly those that have not yet come on line.
- Grid security. Since DG capacity is dispersed throughout the utility's territory, it is unlikely that all generators would fail at the same time. Furthermore, since the end-user and producer are one and the same time, DG mitigates against outages due to transmission or distribution system failures.

Though this study concentrated on one utility service territory, most of these arguments about the advantages of DG are employed by DG advocates in other areas of the country. While there is some merit to these arguments, DG proponents have been known to overstate these benefits while minimizing or disregarding other risks. This section will detail some of the technical and operational challenges associated with DG.

Interconnection

Distributed generators must enter into interconnection agreements with their local distribution utilities. These agreements lay out the technical parameters of the interconnections and usually

²² R. Thomas Beach and Patrick G. McGuire. *The Benefits and Costs of Solar Distributed Generation for Arizona Public Service*. Crossborder Energy, May 8, 2013.

require that feasibility studies be carried out to ensure that the proposed interconnection meets applicable safety and reliability standards. FERC has established standardized procedures for interconnecting small generators²³, but specific interconnection agreements vary among states and utilities.

California provides an example of one state's approach to interconnection. California issued Rule 21 in order to streamline the interconnection process. The state issued the California Interconnection Guidebook²⁴ to offer guidance to DG customers and utilities. Though Rule 21 applies only to utilities under the jurisdiction of the CPUC (IOUs), many publicly owned electric utilities modeled their rules after Rule 21.

Under Rule 21, a customer wishing to interconnect has five options:

1. Isolated operation, unconnected to the utility's distribution system.
2. Interconnected but not exporting power to the distribution system.
3. Interconnected and incidentally exporting power.
4. Net energy metering.
5. Exporting power for sale.²⁵

"In each of the last four relationships, the generator operates 'in parallel' with the utility's distribution system, generating power while interconnected, and thus having to match the utility power characteristics."²⁶ Most generators fall into these latter groupings and as such must match utility voltage characteristics and meet certain minimum power requirements.²⁷

Generators seeking to interconnect with a utility's distribution system are graded on a pass/fail basis in their initial review based on whether the proposed generator is likely or not to damage the distribution system or disrupt its operation. If a generator fails the initial screen, a supplemental review is conducted to see if the issue can be addressed with minor alterations.²⁸

Rule 21 lays out further technical specifications. Applicants must provide detailed specifications, including net nameplate rating, operating voltage, and power factor rating. Rule 21 and the accompanying guidebook also lay out procedures for the utility to follow in the screening process, and even offers model agreements from utility examples.

Other states offer similarly detailed guidelines for interconnection. Though both the federal and state parameters have helped to keep distribution grids stable as more DG resources are

²³ Federal Energy Regulatory Commission. *Standardization of Small Generator Interconnection Agreements and Procedures*. Docket No. RM02-12-000; Order No. 2006, May 12, 2005. FERC procedures apply to FERC-regulated "public utilities" (generally IOUs) that own, control, or operate facilities used for transmitting electric energy in interstate commerce. A non-public utility (for example, a public power utility) that seeks voluntary compliance with the reciprocity conditions of a FERC-regulated public utility's open access transmission tariff may satisfy that condition by adopting these procedures and form of agreement.

²⁴ Chris Cooley, Chris Whitaker, and Edan Prabhu. *California Interconnection Guidebook: A Guide to Interconnecting Customer-owned Electric Generation Equipment to the Electric Utility Distribution System Using California's Electric Rule 21*. Consultant Report prepared for California Energy Commission, Public Interest Energy Research Program, September 2003. Available at: <http://www.cpuc.ca.gov/PUC/energy/DistGen/>.

²⁵ *Ibid.*, p. 7.

²⁶ *Ibid.*

²⁷ *Ibid.*, p. 8.

²⁸ *Ibid.*, p. 16.

integrated, the further expansion of distributed resources may cause complications down the road. As expressed in joint comments filed by three utility trade associations with FERC:

For example, if a 2-MW retail project request comes in simultaneously with a 2 -MW wholesale project request, and both projects seek to interconnect at the same line section and both require the same line capacity, the utilities in these jurisdictions must choose to connect one project over the other because of the limited line capacity. Although Transmission Providers and electric utilities in these jurisdictions have created elaborate systems to limit the potential for such situations, this kind of scenario will increase with the growth of small generation interconnection requests and is already causing increased concern among electric utilities.²⁹

System Balance

Another challenge that DG presents to the electric grid is maintaining system balance. A Massachusetts Institute of Technology (MIT) study on the future of the electric grid explains that low levels of DG penetration merely reduce load at the nearby substation, but high DG penetration could create excess load at the substation. This would cause power to flow from the substation to the transmission grid, creating a reverse power flow that grids are not designed to handle. This could lead to high voltage swings and other stress being placed on electric equipment. These potential strains on the system will require utilities to make further capital investment in system upgrades.³⁰

Some standards currently exist to address these variable voltage situations. The Institute of Electrical and Electronics Engineers (IEEE) created IEEE Standard 1547 to ensure that DG customers do not negatively impact other customers or the grid. It requires that no objectionable “flicker” occur for other customers due to voltage variation. It also enumerates safety standards, particularly standards requiring that DG units disconnect when local faults occur. It also requires DG units to detect unintentional islanding, where DG systems supply a localized section of the grid that has been disconnected from the larger grid system.³¹

Though the standard has been effective in securing lineworker safety and in maintaining grid balance, it is somewhat outdated. The standard was issued in 2003. With the growth of DG, the standard should be updated. For instance, as mentioned above, increased DG penetration could lead to greater voltage variability, and thus to an increased incidence of flickering; however, DG systems with voltage regulation capability could guarantee voltage stability. The current standard disallows voltage regulation at the interconnection point and thus needs modification.³²

DG can also complicate fault detection. These units could potentially increase current at a fault while reducing it at the protection device. This makes it harder to detect a fault and disconnect the unit. Changing fault currents could also hamper how other protection devices function.³³

²⁹ Comments of the National Rural Electric Cooperative Association, Edison Electric Institute, and American Public Power Association on the Notice of Proposed Rulemaking to Update the Small Generator Interconnection Rules and Procedures. *Federal Energy Regulatory Commission, Docket No. RM13-2-000*, June 3, 2013, p. 29.

³⁰ MIT. *The Future of the Electric Grid*. Cambridge, Mass.: Massachusetts Institute of Technology, 2011, p. 17.

³¹ *Ibid.*, p. 112.

³² *Ibid.*, pp. 113-14.

³³ *Ibid.*, p. 116.

Safety Concerns and “Islanding”

There are other potential safety issues involving DG. Of particular concern is “islanding,” where the DG unit continues to energize a feeder even though the electric utility is no longer supplying power due to an outage or other cause. This creates a very high safety risk to utility workers who might not realize that a circuit is still energized. DG units are required to “anti-island” and stop power generation once an islanding situation occurs, and as such have inverters that allow the unit to cease generation.

Even if islanding remains a remote possibility, there are other risks involved. It is possible for a high-voltage spike to occur, thus damaging other customer loads. The loss of the utility system reduces the impedance necessary for the PV inverters to function properly, leading to abnormal voltages before the inverter trips. This also potentially damages other loads.³⁴ Since the utility distribution system creates the sole ground source for a DG system feeder, the loss of grounding due to an outage could lead to overvoltage. This could damage both utility and customer equipment, especially surge protectors.³⁵

Another consequence of islanding is out-of-phase reclosing. As General Electric explains, “If DG keeps the system downstream of a recloser or reclosing circuit breaker energized, the subsystem is likely to drift out of phase with the main system.” Reclosing on an out-of-phase islanded system could damage the generator and could harm utility and other customer equipment under certain circumstances.³⁶

Another remote consequence of very high DG penetration levels could be a system-wide blackout. If an area or region had a very high number of DG installations – on the order of 100,000 100-kW generators – and a bulk system event occurred that caused these DG systems to trip, it could have the same impact as losing a nuclear plant. One study posited that an initiating event that tripped these generators could lead to a blackout of the entire western interconnection.³⁷ Again, this could occur only with very high levels of DG penetration – on the order of 20 percent of system load.

Impacts on Load and System Planning

In a certain sense, PV distributed resources provide a greater level of system protection, especially over large-scale utility PV installations. Since PV resources are generally distributed over a wide geographic area, intermittent cloud cover affects a smaller percentage of DG installations at one time, whereas cloud cover could adversely impact production at an entire utility-scale installation.³⁸ On the other hand, system operators do not have the ability to observe as closely the operation of DG systems. This particularly impacts load forecasting as system

³⁴ GE Energy. *Impact of Photovoltaic Generation on Distribution Systems*. Schenectady, NY: Distribution Systems Testing Application and Research, 2013, p. 59.

³⁵ Ibid.

³⁶ Ibid, pp. 60-61

³⁷ Ibid, p. 70.

³⁸ Ibid., p. 71.

operators cannot distinguish between increases in load due to higher demand and decreased solar output.³⁹

The impairment of load forecasting capabilities is of increasing concern in the power industry. Distributed generation, along with utility-scale renewable resources and the increase in demand response resources, are all making load forecasting more difficult.⁴⁰ If load spikes more than expected when transmission and/or generation assets are down for service, this can lead to forced outages and blackouts. Though rare, this happened twice in 2013.⁴¹

Distributed resources especially impact system peak planning. Because DG customers – particularly those with PV installations – can shift the demand curve and shave peak usage, this may enable utilities to avoid adding peak generation resources; however, because these are localized resources, they “may shift the geographical areas of the grid requiring expansion, reinforcement, or upgrade.”⁴²

DERs also place increased strain on the distribution system. DG customers rely on the transmission, distribution and generation systems more than non-DG customers. DG customers use the distribution system for electric consumption when they are not producing power, and they also use the distribution system to carry away excess power. So, unlike traditional utility customers who use the distribution system one way, DG customers rely on the distribution system both for consumption and production. DG customers also rely on the system to maintain sufficient line voltage to support their activities.⁴³

A study produced by Xcel, a Colorado-based IOU, rebuts or modifies some of the purported benefits of DG. For example, the report notes that while the immediate impact of DG is to displace coal fired units, in the longer term DG may displace more efficient natural gas units.⁴⁴ The highest levels of avoided costs occur in the first tranches of DG deployment as high-cost units are displaced; however, “increasing levels of solar penetration result in avoidance of energy from lower cost generation units.”⁴⁵ While there might be environmental benefits from displacing efficient, low-cost natural gas units with PV resources, the long-run avoided cost benefits are fairly minimal.

Also, distributed resources may not be as efficient at reducing line losses as has been suggested. As the Xcel study explains, “Given the relatively low correlation between solar generation and feeder load across an entire calendar year, annual *avoided* distribution line losses are no greater than annual *average* distribution line losses.”⁴⁶

³⁹ Ibid., p. 72

⁴⁰ Tom Tiernan. “Load forecasting is getting more difficult.” *Megawatt Daily*, September 20, 2013.

⁴¹ Ibid.

⁴² Cristin Lyons, Stuart Pearman, and Paul Quinlan. *Distributed Resources and Utility Business Models – The Chronicle of a Death Foretold*. Scott Madden Management Consultants, 2013, p. 10.

⁴³ Xcel Energy Services. *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System*. 2013, p. ii.

⁴⁴ Ibid.

⁴⁵ Ibid., p. 5.

⁴⁶ Ibid., p. iii.

Hawaii Solar Integration Study

The National Renewable Energy Laboratory (NREL) conducted a study of solar integration in Hawaii. Solar DG developed comparatively early in Hawaii, and so presented an opportunity for researchers to examine the effects of renewable generation on the grid. This study examined both utility-scale and DG-scale renewable resources on the grids of Maui and Oahu.

The NREL study found that power production from distributed solar installations were less variable than utility-scale installations because of their geographic diversity. For example, scattered cloud cover could disrupt power production at a few distributed generators at a time, while it could halt all generation at a utility-scale site. Conversely, high-scale penetration of distributed solar generation presents operational issues due to the inability of the utility to curtail power production.⁴⁷

Variability in renewable generation impacts how other fuel sources are deployed. When renewable production is high, it may be necessary to ramp down fossil fuel plants, perhaps to minimum operating levels. At some locations in the study, fossil fuel plants operated in this manner over 90 percent of the time. The study did not examine the operation and maintenance expenses associated with operating baseload plants at minimum levels for such a long duration.⁴⁸

Another effect of high renewable penetration is greater reliance on nonsynchronous generation. Conventional plants use a synchronous generator “that literally spins in synchronicity with the frequency of the power supply; the generator’s rotation period is exactly equal to an integral number of alternating current cycles.” This helps the grid to maintain operating parameters and controls voltage. Nonsynchronous generators such as wind and PV do not provide this kind of grid support, thus potentially destabilizing the grid.⁴⁹

The rapid rise and fall of production in variable resources creates other risks. When PV generation drops off for five or more sustained minutes, it challenges the ability of conventional plants to compensate by ramping up production. A 30-60 minute sustained drop in production “consumes up-reserve resources and requires quick-start units.”⁵⁰ While the conventional units responded during periods of sustained outages, there were times during when 20-60 MW of contingency reserves were used while renewable production ramped down. During one event, 128 MW of contingency reserves were tapped to compensate for the loss of renewable power. Considering that this took place on the island of Oahu’s power grid, where there is a total of approximately 1,800 MW of firm power, this represented a significant portion of the island’s electric generating capacity.

The opposite situation presents more of a challenge to the grid. If conventional units are already operating at a minimum level due to high renewable output, the output cannot be reduced further if there is a sudden increase in wind and solar generation output. This means conventional plants must use more down-reserves (reserves for periods when renewable output is high), with the

⁴⁷ Kevin Eber and David Corbus. *Hawaii Solar Integration Study: Executive Summary*. National Renewable Energy Laboratory, 2013, p. 2.

⁴⁸ *Ibid.*, p. 10.

⁴⁹ *Ibid.*, p. 11.

⁵⁰ *Ibid.*

result being that the down-reserves fall below minimum levels. During the study, there were more than 2,000 hours of down-reserve violations, which endangered grid reliability.⁵¹

Though in most cases the risks to the grid of blackouts or equipment damage due to DG are fairly minimal, there are costs associated with keeping these risks low. Utilities will have to make further capital investments to ensure that the grid continues to operate efficiently as more distributed resources are deployed. Utility customers must pay for these capital investments. Since owners of DERs may have electric bills approaching zero (depending on the rate and net metering regime that applies), the customers who create the need for these capital investments may be contributing little or nothing to the associated capital costs. Rate structures surrounding DG generally inhibit utilities from collecting the revenues necessary to maintain reliable operations in the face of increased DG penetration and variability in output, and therefore they must rely on traditional customers to pay for the costs associated with DG customers.

⁵¹ Ibid.

III. The Costs of Distributed Generation

Beyond operational and safety issues associated with DG the financial implications of increased DG penetration are also important. Utilities lose revenue as more customers choose self-generation. Moreover, it may be difficult through traditional rate design practices to recover the costs associated with DG programs from the DG customers. Both factors can lead to increased rates for the non-DG customers, financial losses to the utilities, or both.

The full scale of revenue loss can be seen in California, where there is a relatively high penetration of distributed PV installations. The three investor-owned utilities in California estimate they will have to make up \$1.4 billion in lost revenues once the original caps on DG have been reached.⁵²

As discussed above, proponents of DG argue that the benefits outweigh or at least mitigate the costs. A report produced by the National Regulatory Research Institute (NRRI) analyzed and summarized several studies attempting to estimate the monetary value of distributed resources. NRRI summarized the other studies' conclusions:

[T]hat there is little, if any, subsidy to solar producers when solar electricity is valued at the customer's average retail price, which it is in many net metering programs. This is because solar PV production in many jurisdictions generally coincides with high-cost days and hours, thus displacing what would otherwise be above-average cost, marginal energy production, or purchases.⁵³

If these studies are to be believed, net metering may actually under-compensate solar generators.

However, it should be recognized that varying circumstances affect costs and benefits associated with DG. For instance, the avoided energy cost benefit for utilities in states without a RPS are less than for utilities in states that have a RPS. Since PV distributed resources are not helping utilities in non-RPS states meet a requirement, this diminishes the value of these resources.⁵⁴

Rate structures further complicate the cost/benefit analysis. As NRRI points out, most residential rates have only two components: a fixed monthly customer charge (often fairly minimal), and a variable energy charge. In the service territories of the vast majority of utilities throughout the country, a residential customer's energy bill is largely determined by the amount of energy consumed throughout the billing cycle, and the total bill rises and falls in sync with that customer's energy usage. Commercial and industrial customers, on the other hand, usually have a third component to their bill: a fixed demand charge per kilowatt that reflects the highest hourly demand of any billing period. These demand charges do not necessarily change when solar PV is installed.⁵⁵ Therefore fixed cost recovery may be less of a concern in the commercial sector than in the residential sector, even if overall revenue losses would be more substantial in the former category.

⁵² Diane Cardwell, "Utilities Confront Fresh Threat: Do-It-Yourself Power," *New York Times*, July 26, 2013

⁵³ Tom Stanton. *State and Utility Solar Energy Programs: Recommended Approaches for Growing Markets*. Silver Spring, MD: National Regulatory Research Institute, 2013, p. 24.

⁵⁴ *Ibid.*, p. 25.

⁵⁵ *Ibid.*, pp. 25-26.

The NRRI report also notes that benefits of PV generation are reduced after a certain level of penetration. For example, minimal penetration leads to fairly low operations and maintenance (O&M) costs, but high levels of market penetration could lead to increased O&M costs due to the capital investments needed to manage more variable, two-way energy flows. These increased O&M costs would negate many of the system benefits provided by DG.⁵⁶ The value of avoided energy and capacity costs might also diminish after a certain level of market penetration.

The Impacts of Increased DG Penetration

As discussed earlier, even generally optimistic projections show that DG penetration will be fairly small, especially when placed in the context of traditional generation resources. However, that does not mean distributed resources will constitute an insignificant portion of the electric market.

Navigant estimates that by 2018 worldwide revenues from PV distributed resources will reach \$118 billion a year.⁵⁷ More significant from the American market perspective is that solar may be approaching the point of competitiveness with traditional grid power in many parts of the country. Parts of the Northeast could reach grid parity within three years and it is possible a majority of states will see solar PV rates that are equal to or less than retail electricity prices within the next decade.⁵⁸ This means it would be no more expensive in many parts of the country to generate your own power than to buy it from the electric utility.

Many businesses are seeing an opportunity to save money by installing solar panels. Wal-Mart plans to install solar PV on 1,000 of its retail stores (or approximately one-quarter of its U.S. locations) by 2020.⁵⁹ Other businesses, such as Verizon and MGM Resorts, have similar plans, though on a smaller scale. Even the partial loss of the load of these large customers would lead to a significant reduction in utility revenues.

Customer Subsidization

Utilities are certainly not the only ones impacted by the growth of distributed generation resources. Utilities already are recovering lost revenues from DG customers by passing these costs to remaining retail utility customers. Returning again to the California utilities mentioned above, these three utilities estimate that if the costs associated with lost revenues were spread evenly among the 7.6 million traditional customers, each customer would experience an average annual increase of \$185 in electricity costs.⁶⁰

In essence, DG customers are subsidized by non-DG customers. As Ashley Brown and Louisa Lund pointed out in a recent article, generally speaking, DG customers tend to have higher incomes than other customers. “Thus, any additional cost or delta revenue loss attributable to DG that is passed on to the balance of customers has a high probability of being a wealth transfer

⁵⁶ Ibid., p. 28.

⁵⁷ Chris Martin, Mark Chediak, and Ken Wells. “Why the U.S. Power Grid’s Days Are Numbered,” *Business Week*, August 22, 2013, accessed at <http://www.businessweek.com/articles/2013-08-22/homegrown-green-energy-is-making-power-utilities-irrelevant>.

⁵⁸ Ibid.

⁵⁹ Ibid.

⁶⁰ “Utilities Confront Fresh Threat: Do-It-Yourself Power.”

from the less affluent to the more affluent.”⁶¹ This socially regressive outcome is compounded by the institution of higher fixed charges (which utilities will have to implement to recover lost revenues), which are shared equally by all customers, Brown and Lund said. Low-income customers who consume comparatively less electricity than other customers will thus potentially face substantially higher electric bills, at least as a percentage of their current bills.

These are not the only potential unintended consequences of DG, according to Brown and Lund. When DG customers are paid or compensated for their excess generation – especially when the compensation is at the full retail rate – distribution costs are included in the amount, even though DG customers often do not help the utility save on distribution costs through their generation activities, and do not incur such distribution costs themselves. Since utilities will lose money on DG, they will try to recoup some of that money through higher fixed charges.⁶² These higher fixed charges could hamper energy efficiency efforts. As Brown and Lund put it:

The ironic result would be that less and less of the electricity bill is tied to actual usage, with the anti-green result that the rewards for energy efficiency, energy conservation, and distributed generation itself become smaller and smaller as more and more costs are shifted to the one part of the bill that everybody has to pay without regard to the level of consumption. In short, the fundamental environmental principle, “polluter pays,” which in electric pricing means greater emphasis on the part of the bill that rises with consumption, will be violated in the name of promoting “green energy.”⁶³

As discussed below, not all state regulators may be amenable to raising fixed charges, though that leads to other potential problems.

Community Solar and Solar Leasing

Community solar programs represent another challenge. Under these programs, customers are able to purchase shares of generation either from an apartment complex or other large, fixed PV installation. Community solar programs provide an opportunity for lower income customers and non-homeowners to gain access to distributed generation, but they also create new concerns for local distribution utilities.

Community solar programs can be designed a number of ways. One example can be found in San Diego, California, where solar power provides output equivalent to 100 percent of the power

⁶¹ Ashley Brown and Louisa Lund. “Distributed Generation: How Green? How Efficient? How Well-Priced?” *Electricity Journal*, April 2013, p. 32. A California PUC study showed that customers who had installed DG systems since 1999 in the state had average household incomes of \$91,210, compared to median household incomes in the IOU service territories of \$54,283 and \$67,821. Seventy-eight percent of net metered customers had incomes higher than the median California income, though this gap has been declining somewhat in recent years. See Ehren Seybert, *California Net Energy Metering (NEM) Draft Cost-Effectiveness Evaluation*, prepared by California Public Utilities Commission Energy Division, September 26, 2013, p. 110.

⁶² *Ibid.*, p. 30.

⁶³ *Ibid.*, p. 31.

needed for the recently opened Solterra EcoLuxury apartment complex. A total of 338 kW of electricity is being furnished to 114 units in the complex.⁶⁴

Colorado's community solar gardens program allows a higher cross-section of customers to own solar generation. These solar gardens are ground-mounted or solar installations from which individuals can purchase power. The Colorado Public Utilities Commission drafted rules governing the solar gardens, mandating that they cannot be more than 2 MW and must have at least 10 subscribers, each of whom must own at least a 1-kW share. Utilities must also purchase 6 MW of power from solar gardens by 2013, half of which must come from solar gardens smaller than 500 kW.⁶⁵ When Xcel Energy's program opened in 2012, it sold out in 30 minutes.⁶⁶

These programs allow customers who either do not own their homes or who do not have the finances to pay directly for solar installations the means to own at least some distributed capacity. A 1 kW share in the Colorado program costs \$3,700, so it still may be difficult for low-income customers to gain access to the Colorado program, though Cooper Credit Union does offer loans to cover the purchase costs.⁶⁷

Electric customers have other means of accessing solar generation without paying up-front costs for installations. Companies like SolarCity will install solar panels on home rooftops without up-front cost to the customer; the customer leases the panels and pays for them on a monthly basis. As the company touts on its website, the payment remains fixed through the life of the lease. Therefore, customers may see significant savings if their electric rates increase during the lease period.⁶⁸

Utilities with high electric rates are uniquely susceptible to developers such as SolarCity coming into their service territory, particularly if the monthly lease payment is much lower than the typical electric bill the customer is already paying. SolarCity has marketed aggressively in areas with high electric rates and is looking to expand its reach. Jimmy Chuang, a vice president for SolarCity, recently said "[t]he utility will not be able to stop us." He added, "The power will be decentralized . . . Going forward, at some point, 20 percent or 30 percent will be on-site generation, which means we will take some of the money away from utilities. So they have to kind of work with us." Chuang concluded, "This is the future. It doesn't matter if they like it or not."⁶⁹

Even if these threats fall short, these comments demonstrate that certain participants in the distributed solar sector have a very aggressive attitude toward penetrating the utility market.

⁶⁴ LPI Communications. *KYOCERA Solar Modules Power San Diego's First net-Zero Energy Apartments*. May 29, 2013, retrieved May 29, 2013 from ElectricityPolicy.com at http://www.electricityonline.com/?page=show_news&id=170504.

⁶⁵ Colorado Community Solar Gardens Act, available at <http://www.solargardens.org/legislation-news-2/colorado-community-solar-gardens-act/>.

⁶⁶ John Farrell, "Colorado's Community Solar Program Allots 9 MW in 30 Minutes," August 16, 2012, retrieved from IRLS.org. at <http://www.ilsr.org/colorados-community-solar-program-allots-9-mw-30-minutes>.

⁶⁷ Mark Jaffe. "Solar gardens give access to green energy to more Coloradans." *Denver Post*, June 23, 2013, retrieved at: http://www.denverpost.com/ci_23515682/solar-gardens-give-access-green-energy-more-coloradans

⁶⁸ <http://www.solarcity.com/residential/solar-lease.aspx>.

⁶⁹ Michael Copley. "SolarCity exec: Distributed generation is the future, whether utilities like it or not." *SNL Financial*, September 25, 2013.

SolarCity said it is willing to forgo profits in the immediate short-term to expand its presence throughout the country, a clearly risky business strategy.⁷⁰ The company hopes to benefit long-term by developing a large customer base through generous lease terms.

Minimizing DG Risks

As DG becomes more widespread across the United States, utilities and utility advocates have begun developing proposals to address lost revenues. Rick Tempchin of the Edison Electric Institute (EEI) wrote two articles discussing the risks DG imposed on utilities. The loss of revenues, he said, “makes it more difficult for utilities to meet their fixed-cost obligations.” Even when self-generating customers produce all or most of their power needs, the utility still incurs fixed costs in providing stand-by or back-up service. Furthermore, the utility under a net-metering arrangement often buys back power at the full retail rate, though this rate may be higher than the true value of the generation to the utility. As Tempchin put it:

Paying credits at the full retail rate costs the utility money because that cost will be higher than the cost that the utility actually avoids by purchasing the DG power. For example, in centralized markets, a utility can buy all of its power needs at the wholesale rate. This rate will always be less than the full retail rate it would have to pay to buy the same power from a customer.⁷¹

It may be time to design rates that separate fixed and variable costs, Tempchin said. DG customers could pay some kind of non-bypassable surcharge to ensure that they are contributing covering their share of the utility’s fixed costs. Tempchin also advocated a system that ties compensation for DG more closely to its value to the grid. For instance, in areas of high congestion, DG can provide cost savings to utilities in reduced capacity on the distribution network. Similarly, DG produced during peak demand periods has more value than off-peak generation.⁷²

Fitch Ratings, one of the ratings companies that monitor utility finance issues, also has concerns about revenue stability and DG. It noted that net metering “can create pricing incentives to benefit one utility customer class over the majority of the customer base.” That being the case, Fitch prefers a net-metering system to a feed-in tariff that provides cash payments to customers. “We consider credits for excess supply and caps on total net-metering production with higher fixed demand charges as essential components of rate design as net-metering programs grow,” Fitch said.⁷³

Fitch’s approach would provide greater certainty. On the other hand, net metering has the disadvantage of compensating DG customers at the full retail rate and this rate may

⁷⁰ Avi Salzman. “Dark Clouds Over SolarCity.” *Barrons Online*, August 31, 2013, accessed at: http://online.barrons.com/article/SB50001424052748704719204579025283044181654.html#articleTabs_article%3DI.

⁷¹ Rick Tempchin. “Time to rethink metering rules: cost and fairness.” *Intelligent Utility*, May 29, 2013. Accessed at <http://www.intelligentutility.com/article/13/05/time-rethink-metering-rules-cost-and-fairness>.

⁷² Rick Tempchin, “Time to rethink metering rules: public policy.” *Intelligent Utility*, June 3, 2013. Accessed at <http://www.intelligentutility.com/article/13/06/time-rethink-metering-rules-public-policy>.

⁷³ Fitch Ratings. *Solar Panels Cast Shadow on U.S. Utility Rate Design*. July 17, 2013. Accessed at http://www.fitchratings.com/gws/en/fitchwire/fitchwirearticle/Solar-Panels-Cast?pr_id=796776.

overcompensate DG customers. Both rate designs have benefits and drawbacks that must be considered fully before developing DG programs.

Rate and Policy Alternatives

NREL produced a report that examined some potential rate design options for mitigating risks of feed-in tariffs. The first option, and one implemented by many jurisdictions that have FITs, is to place volume caps on the amount of program capacity eligible for FITs. In Hawaii, for example, the program cap was set at 5 percent of peak demand for each of the Hawaiian Electric Co. (HECO) affiliates. Hawaii also imposed program size caps to limit the size of individual projects.⁷⁴

Volume caps provide a measure of predictability and cost control. But they might inhibit a jurisdiction's ability to foster clean technology development.⁷⁵ Volume caps also favor projects with faster development times. If early-developing projects have higher cost profiles, growth of DG might put upward pressure on prices.⁷⁶ Caps also engender "speculative queuing." Since projects are rewarded on a first-come, first-served basis, some projects with minimal potential to come on line may take up space in the queue, thus shutting out more viable projects.⁷⁷ Finally, caps increase uncertainties for project developers. If utilities do not award FIT treatment until a project reaches certain milestones, projects might be partially built before developers realize the cap has been reached.⁷⁸

NREL also examined payment level adjustments, which are methods of keeping payments in line with market developments over time. There are several options for establishing payment level adjustments, all of which are aimed at adjusting rates over the life of a FIT contract. One option is to establish a pre-determined degression rate over the life of the contract, while another option is to peg the degression rates so they respond to market prices. A third option is a volumetric approach where rate level adjustments are tied to achievement of specified capacity milestones. A final approach is a system of bidding similar to what is done in Spain.⁷⁹

Payment level adjustments offer some protection for ratepayers, as they reduce the potential for overpayments. This approach, unlike rate caps, might spur short-term development as investors see that payments are scheduled to go down over time.⁸⁰ But price adjustments could induce market volatility. It is also possible for these payments to deviate markedly from market realities, thus requiring some level of oversight to ensure that they do not differ significantly from market prices.⁸¹ Additionally, if the rates exceed avoided costs, PURPA provisions would come into play, thus requiring FERC to set the rates.

⁷⁴ Claire Kreyzik, Toby D. Couture, and Karlynn S. Cory. *Innovative Feed-in Tariff Designs that Limit Policy Costs*. Golden, CO: National Renewable Energy Laboratory, 2011, p. 8.

⁷⁵ *Ibid.*, p. 9.

⁷⁶ *Ibid.*, p. 10.

⁷⁷ *Ibid.*

⁷⁸ *Ibid.*, p. 11.

⁷⁹ *Ibid.*, pp. 13-14.

⁸⁰ *Ibid.*, pp. 22-23.

⁸¹ *Ibid.*, p. 23.

The Utility Experience

With utilities growing more worried about the impact of DG, several have begun suggesting reforms to existing programs to alleviate some of the financial concerns associated with DG.

Arizona Public Service

One of the most public controversies is taking place in Arizona, where Arizona Public Service (APS), an IOU, is proposing to amend its net metering program. In a July 12, 2013, filing with the Arizona Corporation Commission (ACC), APS made two policy proposals. Under the first policy option, existing net metering customers would pay a higher service charge based on the amount of electricity they use. This demand charge would range from \$45 to \$80 per month. A second option would establish a credit system for new DG customers. Under this system, distributed generators would be compensated for electricity sold to the grid at a rate set by the ACC, and this would appear as a credit on the customer's monthly bill.⁸² The first proposal would reduce monthly savings for residential solar customers from 14-16 cents per kWh to 6-10 cents per kWh for the current 18,000 solar rooftop customers. The second proposal would reduce savings to about 4 cents per kWh per month.⁸³

APS's proposals drew considerable criticism from both its DG customers and solar industry groups who believe these actions would stunt the growth of PV generation. APS defended the proposals, arguing that they are designed to create a fairer system in which DG customers would compensate the utility for their continued reliance on the grid:

Even APS's customers who generate their own electricity with rooftop solar panels rely on the grid 24 hours a day: for power to supplement their solar supply when it does not meet all their needs; as a means to export electricity; and for backup power when panels fail or the sun does not shine.⁸⁴

APS says that the total subsidization of rooftop solar customers amounts to approximately \$18 million per year for APS customers. The utility also said the excess generation from solar rooftops does not save the utility money. Under the current system, rooftop generators are compensated at the full retail rate. If that power were not available, the utility would have purchased that electricity on the wholesale market at a lower cost.⁸⁵

Xcel Energy

Xcel Energy in Colorado is proposing to add a surcharge on all retail customer bills to cover the costs of net metering for new installations. To maintain rate neutrality, this surcharge would be cancelled out by a credit to the Electric Commodity Adjustment (ECA).⁸⁶

The proposal is part of Xcel's plan to educate the public about the cost of DG and its subsidization effects. In its filing before the PUC, Xcel said:

⁸² Michael Copley. "APS's distributed solar proposals meant to create 'fair' system, utility says." *SNL: Electric Utility Report*, July 12, 2013.

⁸³ Michael Copley. "Demand charge under APS rooftop solar proposal would add up to \$80 in monthly fees." *SNL: Electric Utility Report*, July 15, 2013.

⁸⁴ Michael Copley. "APS defends proposed regulatory changes with focus on value of rooftop solar." *SNL: Electric Utility Report*, July 22, 2013.

⁸⁵ *Ibid.*

⁸⁶ Jeff Stanfield. "Xcel Energy proposes surcharge to show costs of net metering for solar programs." *SNL: Electric Utility Report*, August 5, 2013.

Our recommended plan also incorporates our efforts to start a dialogue about the need for and the equity of the incentives in the on-site solar program. In particular, we seek to transparently show the impact of the incentive net metering provides to customers that install PV systems, and to discuss the equity of that incentive. We seek to discuss the prospect that the net metering incentive either needs to be ramped down over time or that other rate design solutions must be explored to address the incentive net metering provides for future installations.⁸⁷

Xcel does not propose any changes for its existing DG customers.

Kansas City Power & Light

An IOU in Missouri, Kansas City Power & Light (KCP&L), wants to suspend solar rebates through the remainder of 2013. The current rebate, \$2 per watt, was established under the state's renewable portfolio standard. The utility says the program is now at capacity. KCP&L said it is not seeking to hurt the solar industry, but is hoping to "protect our customers who do not receive solar rebate payments from paying a subsidy that is no longer rationally related to the solar market."⁸⁸ More than 95 percent of solar installations are located in affluent zip codes, thus burdening low-income and small business customers to cover the rebates, the utility said.⁸⁹

The Xcel and KCP&L examples highlight two of the growing concerns with DG, namely that non-DG customers are paying a disproportionate share to cover DG costs, and that these non-DG customers are generally less wealthy than the DG customers they are effectively subsidizing. DG supporters have disparaged these claims, and as discussed earlier, have argued that DG provides an overall monetary benefit in terms of system costs.

State Actions Regarding DG Reform

Idaho

Two states have recently rejected proposals to amend utility net metering programs. Idaho Power had proposed to increase the customer charge for residential net metering customers from \$5 per month to \$20.92, and from \$5 to \$22.49 for small business net metering customers. Idaho Power would have also established a load capacity charge of \$1.48 per kW for residential customers and \$1.37 for small business net metering customers. It would have also reduced the retail energy rates for net metering customers, while increasing the capacity limit for the program.⁹⁰

The Idaho Public Utilities Commission denied this request, citing concerns over the chilling effect this could have on net metering. The commission expressed concern that this proposal would encourage "rate gaming," where large customers install small solar systems to qualify for lower electric rates. The commission approved a proposal to switch to a credit system that allows

⁸⁷ Before the Public Utilities Commission of the State of Colorado, In the Matter of the Application of Public Service Company of Colorado for Approval of its 2014 Renewable Energy Standard Compliance Plan, Docket No. 13A-___E, July 24, 2013. Accessed at:

<http://www.snل.com/Cache/18477192.PDF?Y=&O=PDF&D=&FID=18477192&T=&OSID=9&IID=>

⁸⁸ Kelly Harrington-Andrejasich. "KCPL-GMO seeks suspension of solar rebate until 2014. *SNL: Electric Utility Report*, July 22, 2013.

⁸⁹ Ibid.

⁹⁰ Idaho Public Utilities Commission. "Most of Idaho net metering proposals denied." Case No. IPC-E-12-27, Order No. 32846, July 3, 2013.

net metering customers to receive a kilowatt-hour credit for excess generation instead of receiving a payment; however, the commission rejected Idaho Power's suggestion that the credits expire at the end of the December billing cycle. Instead, the credits would carry forward as long as the customer continues on a net metering program at the same site.⁹¹

Louisiana

The Louisiana Public Service Commission (PSC) also vetoed a proposal to decrease payment rates to DG customers. State law requires utilities to purchase customer-generated energy at the full retail rate. Commissioner Clyde Halloway suggested basing compensation on the utility's avoided cost, but the PSC rejected his proposal on a 3-2 vote.⁹²

California

In California, legislation passed in September 2013 gave the CPUC authority to implement up to a \$10 surcharge on all of the regulated IOUs' monthly bills for retail electric service, with a \$5 surcharge for low-income customers. AB 327 also removes some limitations on and extends the deadline for mandatory time-of-use (TOU) rates. The bill paves the way for the removal of net metering volume caps. Net metering programs had been capped at 5 percent of a utility's aggregate customer peak demand. Under this bill, large electric utilities (over 100,000 customers) must establish a standard contract or tariff for net-metering customers and must make this contract available to eligible customer-generators by July 1, 2017, or sooner, if so ordered by the commission once the current cap is met. This effectively removes the net metering volume cap.⁹³

Minnesota

Minnesota implemented its solar energy standard in May 2013, mandating a 1.5 percent solar standard for the state's IOUs by 2020, meaning that 1.5 percent of their energy sales must be solar-powered. The standard also calls for utilities to develop a clean contract, feed-in tariff or standard offer for solar projects less than 1 MW in capacity. The standard increases the net metering cap from 40 kW to 1 MW for IOUs, creates a \$5 million investment pool for small solar projects (under 20 kW), and authorizes community solar gardens.⁹⁴

The CLEAN contract is one of the central pieces of this new standard and is modeled in part on Austin Energy's (Texas) Value of Solar program (discussed below). The value of solar has five components: energy, generation capacity, transmission and distribution value, transmission capacity, and environmental value. The price will vary annually, but distributed solar generators lock in their prices for 20 years when their projects come on line.⁹⁵ One caveat to the contract is that distributed solar producers are unable to profit from net generation. A distributed generator's

⁹¹ Ibid.

⁹² Amanda H. Miller. "Louisiana PSC upholds net metering." Clean Energy Authority, July 1, 2013. Accessed at: <http://www.cleanenergyauthority.com/solar-energy-news/louisiana-psc-upholds-net-metering-070113>.

⁹³ Dana Hull. "Energy bill that could change electric rates heads to Gov. Jerry Brown." *San Jose Mercury News*, September 12, 2013. Accessed at http://www.mercurynews.com/business/ci_24081881/energy-bill-that-could-change-electric-rates-heads. A summary of the bill can be found here: http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140AB327.

⁹⁴ John Farrell. "Minnesota's New (Standard Offer) Solar Energy Standard." Grist.com, May 28, 2013. Accessed at Grist.com: <http://grist.org/article/minnesotas-new-standard-offer-solar-energy-standard/>.

⁹⁵ Ibid.

production is netted against its consumption, and if the former is greater than the latter, the bill is zeroed out.⁹⁶

As these examples illustrate, even in states where utilities garner some concessions, state rulemaking bodies tend either to temper their requests or grant even greater concessions to solar rooftop customers in exchange for any concessions. Industry analysts will be keeping a close eye on the developments in Arizona, as they may provide influence how other states will treat attempts at reform.

These developments serve as a warning to public power utilities that changing DG pricing regimes may be difficult once they have been put in place, especially if the proposed changes are seen as being too onerous for solar PV customers. Public power utilities may have more independence in establishing rates and policies on DG.

⁹⁶ Ibid.

IV. The Public Power Experience

Accelerated implementation of distributed energy resources poses a fundamental challenge to the IOUs, rural electric cooperatives and publicly owned electric utilities. Yet, publicly owned utilities are better positioned to deal with these challenges. The local, community-owned aspect of public power's business model affords these utilities the opportunity to develop strategies to mitigate adverse effects of DG penetration. However, because public power utilities are highly attuned to local community sentiment, they may encounter greater pressure to encourage further development of customer-owned generation, even if it adversely impacts utility operations and revenues in the long run.

This section details how certain publicly owned electric utilities have dealt with DG, the strategies they have put in place to integrate these resources in the most cost effective manner possible, and the political pressures to accelerate integration of distributed resources that some utilities have faced.

Gainesville Regional Utilities (GRU)

Gainesville Regional Utilities in Florida implemented its feed-in tariff – the first one implemented by any utility in the United States – in 2009. The GRU tariff was set at a high rate to encourage investment. The FIT for a rooftop solar system (less than 25 kW) was set at 32 cents per kWh, while the FIT for ground-mount systems (greater than 25 kW) was set at 26 cents per kWh. Participation was capped at 4 MW per year.

GRU's aggressive tariff reflected local considerations regarding renewable energy. Both the City Commission and GRU residents expressed support for increasing GRU's solar portfolio. It was hoped that greater solar implementation would promote both job growth and reduce carbon emissions.

GRU has modified the program in the intervening years. Initially, the FIT price was to be adjusted by an annual degression schedule, but now the price is determined before the beginning of each calendar year. GRU also implemented a size limit (previously there had been none) of 300 kW at each DG location. GRU also added administrative and capacity reservation fees as well as monthly customer charges in an effort to recoup more administrative costs.

As of the beginning of 2013, GRU's FIT was 21 cents per kWh for a small rooftop system. The price for a ground-mount system was 15 cents per kWh. GRU created a third class for larger rooftop systems (greater than 10 kW), and the 20-year fixed rate for systems installed in 2013 was 18 cents per kWh. The decline in the FIT over the past four years has coincided with a decline of about 30-40 percent in the overall installed price of solar PV systems over the same period.

Solar customers are also eligible for GRU's net metering program, which compensates excess generation at the full retail rate. The current policy does not prohibit customers from intentionally over-sizing systems in order to take advantage of this rate structure. GRU attempted to revise its net metering program and pay a rate that was more in line with avoided costs plus a modest premium; however, customer feedback prompted the utility to modify plans for

restructuring the net metering program, instead aligning it with Florida’s regulated net metering policy governing IOUs. GRU is now evaluating possible rate design options.

Austin Energy

Like GRU, Austin Energy in Texas had distributed solar customers who sold excess energy, and thus profited from the utility’s net metering program. In response to this, Austin Energy worked with Clean Power Research (CPR) to develop a “value of solar” rate, which is an attempt to set a more equitable rate for solar PV customers. The rate is based on an algorithm that incorporates six value components:

- Loss savings – reduction in line losses by producing power where it is generated.
- Energy savings – the offset of wholesale purchases.
- Generation capacity savings – benefits of added capacity that DG brings to the utility’s resource portfolio.
- Fuel price hedge value – the value of having no fuel price uncertainty associated with solar PV.
- Transmission and distribution capacity savings – the value of reduced peak loading on the T&D system, postponing the need for capital investments.
- Environmental benefits – a recognition that the environmental footprint of solar PV is less than that of traditional fossil-fuel generation.⁹⁷

These components are meant to reflect the value of solar energy to Austin Energy. As explained by those who designed the rate, it represents a “break-even value for a specific kind of distributed generation resource and a value at which the utility is economically neutral to, whether it supplies such a unit of energy or obtains it from the customer.”⁹⁸

The proponents tout several benefits:

- A fairer, more accurate rate.
- A reduction in the payback period for solar customers.
- Decoupling the credit from customer’s consumption of energy encourages conservation and efficiency.
- Greater assurance that Austin Energy is charging for the full cost of serving customers.⁹⁹

Under the program, the customer is billed for total consumption, then gets a credit from Austin Energy for PV production at the value-of-solar rate. If the customer’s production exceeds consumption in a given month, then the customer receives a credit at the end of the monthly billing cycle that is rolled over to the next month. If the credit carries over to the end of the calendar year, the bill is zeroed out.

⁹⁷ Karl R. Rabago, Leslie Libby, Tim Harvey, Benjamin L. Norris, and Thomas E. Hoff. *Designing Austin Energy’s Solar Tariff Using a Distributive PV Value Calculation*. Austin, TX: Austin Energy, 2013, p. 2.

⁹⁸ Ibid.

⁹⁹ Ibid., p. 4.

Los Angeles Department of Water and Power (LADWP)

The nation's largest public power utility has developed an incentive program to encourage the development of more renewable resources. The Los Angeles Business Council, policymakers and other stakeholders helped LADWP develop the feed-in tariff program in an effort to develop 150 MW of solar electricity in the city¹⁰⁰ The first phase of the FIT program was launched in January 2013 and is a 100-MW program that starts with a set price of 17 cents per kWh until the first 20 MW are subscribed, then decreases 1 cent per kWh for each additional 20 MW. LADWP plans to add 50 MW to complete the 150-MW FIT program, which "will be competitively priced through an RFP that is bundled with a utility-scale solar project."¹⁰¹

The city's ratepayer advocate suggested that LADWP is overpaying for the electricity, with the cost being born by non-solar customers. However, General Manager Ron Nichols said the rates are in line with market prices. "We've acknowledged we're paying a slightly higher incentive to make absolute certain we get major players here." Nichols said.¹⁰² Currently, the program is aimed at large systems (150 kW to 3 MW), and likely will not include single-family homes, though there is a 4-MW carve-out for smaller systems (30-150 kW).¹⁰³

CPS Energy (San Antonio)

CPS Energy in San Antonio, Texas, offers one of the most robust rebate programs in the nation to customers who install solar PV systems. There are four customer tiers with different rate incentives. The first three tiers cover customers (schools, residential and commercial) who use installers who are registered with the CPS Energy solar rebate program and are local; the fourth tier is for customers who use non-local registered installers.¹⁰⁴

The rebate program amounts and caps were reduced during the summer of 2013. The current rebate tiers are as follows:

- Tier 1: Schools - \$2 per AC watt for the first 25 kW AC in power capacity production and \$1.30 per AC watt for all remaining capacity output greater than 25 kW AC. This tier applies to commercial solar PV installations at accredited, nonprofit schools. The maximum rebate is \$80,000.
- Tier 2: Residential - \$1.60 per AC Watt up to \$25,000 or 50 percent cap, whichever is less. This rebate is available for residential solar PV installations. The maximum rebate is \$25,000.
- Tier 3: Commercial - \$1.60 per AC watt for the first 25 kW AC in power capacity production and \$1.30 per AC watt for all remaining capacity output greater than 25 kW AC. This rebate is available for commercial solar PV installations. The maximum rebate

¹⁰⁰ Catherine Green. "In L.A., getting paid to go green." *Los Angeles Times*, June 27, 2013. Accessed at: <http://articles.latimes.com/2013/jun/27/business/la-fi-solar-buyback-20130627>.

¹⁰¹ "LADWP Takes Another Big Step to Create L.A.'s Clean Energy Future, Finalizes 150 MW Local Solar Program Plus 200 MW Utility Scale Solar." LADWP Press Release, May 21, 2013. Accessed at: <http://www.ladwpnews.com/go/doc/1475/1780671/LADWP-Takes-Another-Big-Step-to-Create-L-A-s-Clean-Energy-Future>.

¹⁰² "In L.A., getting paid to go green."

¹⁰³ Ibid.

¹⁰⁴ DSIRE USA website, accessed at http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=TX60F.

is \$80,000, or 50 percent of total costs, whichever is less.

- Tier 4: \$1.30 per AC watt for residential and commercial systems not installed by a local contractor, as defined in the tier 1 through 3 offerings. The maximum rebate is \$25,000 for residential and \$80,000 for commercial.

CPS Energy is addressing the challenge many utilities face with net metering and stranded infrastructure investment. Earlier this year, it proposed a credit per kilowatt-hour, known as SunCredit, rather than net metering. Instead of solar customers receiving the full retail rate, which is approximately 9.9 cents per kWh for residential customers, the SunCredit would be based on a market approach, taking into account the wholesale energy market price, transmission cost of service, etc. Working groups from both CPS Energy and local stakeholders are evaluating the proposal with the goal of reaching a consensus on the SunCredit rate.

Seattle City Light

Net metering is available in Seattle City Light's service territory on a first come, first served basis, with a 10-MW volume cap. Customers receive a credit for each kilowatt-hour of excess generation, but Seattle City Light is prohibited by law from paying for generation, thus net bills cannot fall below zero.

The utility also has developed a community solar program that allows multiple customers to receive credit for the energy produced by a large solar array. Seattle City Light pays for the construction of a large solar array placed in a location of optimum solar exposure. Any utility customer can purchase solar units representing a share of the total output from the array. The customer receives a corresponding credit which is netted against the monthly electric bill. Additionally, customers receive the Washington State Production Incentive, which is double the rate paid to individual solar PV customers. Seattle's first community solar project was completed at Jefferson Park and has generated more than 24,000 kWh of electricity.¹⁰⁵

Santee Cooper (South Carolina Public Service Authority)

Santee Cooper's net billing program is a hybrid approach to DG, incorporating elements of both a feed-in tariff and net metering. The utility measures energy consumed and *separately* measures energy generated. Both the consumption charge and production credit are based on time of day pricing. Additionally, there is an on/off-peak demand charge designed to recover fixed costs.

A Santee Cooper analyst explained the rationale for this approach:

Under the net billing rate design, customers only receive compensation for the energy delivered to our grid, and are not compensated for the fixed costs incurred by Santee Cooper. The underlying theory is that self-generating customers do not reduce Santee Cooper's obligation to serve their load, and we must still build generation, transmission, and distribution facilities to serve them; therefore fixed costs should still be appropriately allocated to and recovered from self-generating customers.

Like other utilities, Santee Cooper is seeking to keep rates as neutral as possible to avoid cross-class subsidization.

¹⁰⁵ "Community Solar Project at the Seattle Aquarium Now Enrolling." Accessed at: <http://www.seattle.gov/light/solar/community.asp>.

Concord Light (Massachusetts)

Concord Light has a net metering tariff for solar PV customers who generate electricity in excess of their home consumption. The utility subtracts the excess production from the amount of electricity purchased by the customer from the utility, and the customer is then billed the net amount at the end of the period. If customers produce more generation than they purchase in a given month, they receive a credit equal to the price that Concord pays the New England Independent System Operator (NE-ISO) for energy on the spot market. The spot market price in 2012 was under 4 cents per kWh and was projected to be the same for 2013. This is substantially lower than the residential retail price, which ranges from approximately 14 to 17 cents per kWh.¹⁰⁶

Concord Light recommends that its PV customers not attempt to size their solar systems to generate 100 percent of their electricity needs:

If a system is sized to generate 100 percent of the customer's annual electricity needs, it is likely that the system will generate more than the customer needs during some months of the year. Sizing a system to generate somewhat less than 100 percent of the customer's annual electricity consumption minimizes the amount of excess electricity that is credited at the spot market price, which can be substantially lower than the applicable residential service rate. For this reason, a system sized to generate somewhat less than 100 percent of the customer's annual electricity needs will pay for itself more quickly than a system designed to produce 100 percent of the customer's annual electricity needs. Further, a system sized to generate somewhat less than 100 percent of the customer's annual electricity needs may allow the customer to take energy conservation actions to reduce home electricity consumption without increasing the likelihood that the system will generate more than the customer needs during some months of the year.¹⁰⁷

Finally, Concord assesses PV customers a monthly distribution charge that increases incrementally as the system size increases. The monthly charge for the smallest unit (2-4 kW) is \$3.60 per month. Twenty percent of each customer bill goes toward maintaining the distribution system and to cover the utility's operating costs. The distribution charge thus ensures that these costs are shared among all Concord customers, even those who generate some of their own electricity:

Customers with solar PV systems continue to receive all of the services provided by the electricity distribution system in town and by Concord Light. Customers' adoption of solar does not reduce Concord Light's costs for maintaining local infrastructure and providing services. The customer acknowledges that the distribution charge is a condition of receiving net metering credits from Concord Light.¹⁰⁸

City of Wadsworth (Ohio)

Customers who self-generate and produce excess generation can receive a billing credit "equal to

¹⁰⁶ "Concord Light: Residential Solar PV Net Metering Policy Acknowledgement." Accessed at: http://www.concordma.gov/pages/ConcordMA_LightPlant/Netmeteringpolicyacknowledgement081613.pdf

¹⁰⁷ Ibid.

¹⁰⁸ Ibid.

the city’s wholesale cost of energy, adjusted to include line losses.” Net excess generation (NEG) credits carry over month-to-month, but zero out after the end of the calendar year.¹⁰⁹

Long Island Power Authority (New York)

Long Island Power Authority offers net metering for both wind and solar DG. Under its Backyard Wind Initiative, LIPA pays a rebate that is the lesser of the first 16,000 kWh (at \$3.50/kWh) of use or 60 percent of total installed cost.¹¹⁰ Under its Solar Pioneer Program, LIPA pays rebates to customers who buy their PV system. Rebates are calculated using the expected performance based buy-down (EPBB) method. EPBB “is an up-front incentive payment (rebate) for new grid-connected solar PV systems and inverters based on the expected output of the system compared to an ideal solar system installation.”¹¹¹

Both solar and wind generating customers are eligible for net metering. If a customer generates more than he consumes, he is billed for the daily service charge (line and meter costs) and excess generation in kilowatt-hours (credits) is placed in an energy bank. Customers can rely on the energy bank to pay for electricity in months when consumption exceeds generation.

¹⁰⁹ City of Wadsworth Net Metering Rate Schedule Ordinance 2013. Accessed at: <http://www.wadsworthcity.info/economic-development/25-pages/the-city/electric-department/759-net-metering.html/>.

¹¹⁰ Information retrieved from LIPA website at: <http://www.lipower.org/residential/efficiency/renewables/wind-cost.html>.

¹¹¹ Information retrieved from LIPA website at: <http://www.lipower.org/residential/efficiency/renewables/solar-buy.html/>

Conclusion

Distributed generation presents both opportunities and risks for electric utilities. Relative to fossil fuel resources, there are environmental benefits to on-site generation produced by renewable resources such as solar and wind. Distributed generation may also help utilities avoid energy, capacity and ancillary service costs associated with conventional technologies. These resources may also help customers reduce electric bills and save money over the long term.

However, DG also presents a number of challenges. Under-recovery of costs, increased difficulties in operating the electric grid and safety issues are three of the foremost concerns related to the growth of distributed resources. Cross-class subsidization, particularly from lower-income customers to high-income customers, is another concern.

Publicly owned electric utilities may be uniquely situated to deal with DG. The independence of most public power utilities offers the opportunity to develop more equitable rates that do not stifle development of these resources nor unduly burden non-DG customers. However, publicly owned electric utilities may face pressure to encourage development of distributed resources even at the expense of revenue and operational stability. It is therefore imperative that publicly owned utilities fully understand the impact of distributed resources on their systems and explain those impacts to their boards, city councils and communities. DG regimes must be considered and designed carefully to ensure all customers benefit and provision of retail electric service is not adversely impacted.

Public outreach and communication is essential for all utilities when discussing and deciding DG-related issues. If a utility is preparing to change its rate structure to recover fixed costs, it needs to communicate reasons for doing so to avoid or at least minimize adverse customer reaction. Utilities may open themselves to the charge of being “anti-green” or “anti-consumer” if they try to implement significant changes without explaining why the changes are necessary.

Finally, utilities should prepare for a full range of potential outcomes from DG integration. In the event that DG is not disruptive to utility operations and revenue, it is better to have planned for the worst case than to be unprepared for the potential adverse impacts of wider DG implementation.

Appendix: The German and Spanish Experiences

Germany and Spain experienced high growth in distributed capacity in the latter part of the previous decade. Though both countries put policies in place that promoted this growth, Spain's high growth came much more swiftly than anticipated, leading to a sudden slowdown in its promotion of the solar industry, which consequently resulted in economic turbulence. Though the German experience with distributed generation (DG) has been more positive, it has created some concerns about the long-term stability of the grid and has put upward pressure on prices. Though neither country is entirely similar to the United States, their early adaptation of solar PV provides lessons to us as the American market takes root.

Germany

Germany was one of the first countries to develop a feed-in-tariff. The first German feed-in tariff (FIT) was established in 1990. The rates were too low to engender much market growth, but high rebates (up to 70 percent of system costs) and low-interest financing helped spur the development of 67 MW of capacity by the end of the decade.¹¹² After passage of the Renewable Energy Law (*Erneuerbare-Energien-Gesetz* or "EEG") in 2000, national FIT rates were more in line with the generation cost of PV systems and, by the end of 2003, 435 MW of PV capacity had been installed. Amendments to the renewable energy law in 2005 encouraged installation of additional capacity, bringing the total installed capacity to 5,979 MW by the end of 2008.¹¹³

Another round of significant capacity additions began in 2009 after more amendments to the EEG made FITs more favorable to developers. In 2009 alone, 3,806 MW of solar capacity were added to the grid. The new rate included a "corridor" or "flexible" digression system under which PV rates decreased based on the volume of PV capacity installed in the previous year. Since installations greatly exceeded projections, the rates decreased by 7.5 percent instead of the projected 6.5 percent.¹¹⁴

Growth was unprecedented in 2010, as 7.4 GW of new capacity was installed, much higher than the government projections of 6 GW. Due to this rapid increase in capacity, the government introduced two non-scheduled digressions, in addition to the already-scheduled price digression.¹¹⁵

Germany revised the EEG again in June 2012 to impose a subsidy cap once the cumulative capacity of solar generation reaches 52 GW (capacity was 27 GW in June 2012). The revision also eliminated all subsidies for installations larger than 10 MW. FITs were reduced by 25

¹¹² Mark Fulton and Nils Mellquist. *The German Feed-in Tariff for PV: Managing Volume Success with Price Response*. Deutsche Bank Group, May 23, 2011, p. 15.

¹¹³ *Ibid.*, p. 16.

¹¹⁴ *Ibid.*

¹¹⁵ *Ibid.*, p. 17.

percent for the largest systems (40 kW to 1,000 kW), by 26.4 percent for systems between 10 and 40 kW, and by 20.4 percent for systems under 10 kW.¹¹⁶

Germany further reduced solar PV FITs at the beginning of 2013 as solar capacity continued to grow. The rates for small installations were reduced to just over 15 [Euro] cents per kWh, while the rates for the largest systems dropped to 10.4 cents per kWh. These changes applied only to systems installed in early 2013 and not to existing systems. These rates are still much lower than the overall retail rate for energy in Germany, which is approximately 27 cents per kWh.¹¹⁷

The German DG market has expanded to the point that there are now over 1.3 million households, farms and cooperatives generating power in Germany, providing 22 percent of the country's energy needs. This has had a tremendous impact on energy markets. For example, on a sunny day in June 2013, solar and wind supplied 60 percent of the nation's power needs, which actually led to negative wholesale prices in parts of the country.¹¹⁸

Though the rapid development of the solar industry in Germany is often touted as a success story, there have been negative repercussions. The average annual household subsidy for renewable generation is €144, or \$181 (U.S.) and is anticipated to rise to over €200. This has exacerbated some class tensions. "Recipients of 'Hartz IV' welfare benefits for the long-term unemployed, for example, receive a fixed sum for electricity and can't afford energy-saving fridges or washing machines. At the other end of the scale, the owners of well-located houses install solar panels on their roofs and are paid for the privilege. Meanwhile, industrial companies that use a lot of electricity are being given more and more tax breaks."¹¹⁹ One estimate calculates that those who are responsible for 18 percent of the consumption pay only 0.3 percent of the costs.

Germany's average retail electric prices are the highest in Europe and the average electric bill for a three-person household is €90 Euros, or twice the average bill in 2000. It is forecasted that prices could reach as much as 40 cents per kWh by 2020, or 40 percent more than today's prices. This has particularly put a strain on poorer customers and more than 300,000 households per year have their power shut off. This produces an even greater burden, as the reconnection fee to restore power can be as much as €100.¹²⁰

The rapid expansion in the number of solar arrays, together with the variability in their generation, has also put a strain on the power grid. More land lines are needed, but grid expansion is years behind schedule. Solar and wind have priority on the grid, which means German industry is powered by renewable resources. Consequently, conventional resources are used primarily for backup. There are no financial incentives to promote construction of new

¹¹⁶ Scott Burger. "Big Changes in German Solar Subsidy Policy Approved Today." *Greentechsolar*, June 29, 2012. Accessed at: <http://www.greentechmedia.com/articles/read/Big-Changes-in-German-Solar-Subsidy-Policy-Approved-Today>

¹¹⁷ Renewables International. "German PV drops to 15 cents max." May 2, 2013. Accessed at <http://www.renewablesinternational.net/german-pv-drops-to-15-cents-max/150/510/62457/>.

¹¹⁸ Matt McGrath. "German tariffs make green energy too expensive to store." *BBC News Online*, July 11, 2013.

¹¹⁹ Stefan Schultz. "Germany Rethinks Path to Green Future." *Der Spiegel Online*, August 29, 2012.

¹²⁰ "Germany's Energy Poverty: How Electricity Became a Luxury Good." *Der Spiegel Online*, September 4, 2013. Accessed at: <http://www.spiegel.de/international/germany/high-costs-and-errors-of-german-transition-to-renewable-energy-a-920288.html>.

conventional resources.¹²¹ In fact, at least 20 percent of the fleet of 90,000 MW of conventional power in Germany is at risk of closure and the loss of these resources could lead to blackouts.¹²² The largest gas, electric and water utility in Germany, E.ON, is threatening to relocate to Turkey if its fossil-fuel and nuclear plants remain unprofitable.¹²³

This expansion, and the regulation and legislation that have supported it, have rankled Germany's neighbors. The European Commission is threatening legal action over German energy subsidies. There has been an aggressive drive toward renewable energy, with a goal of 50 percent by 2030 and 80 percent by 2050. Costs for this transformation could exceed \$1 trillion and will fall largely on German taxpayers. As Ambrose Evans-Pritchard writes, "The macro-economic effect of this distorted tax regime has been to compress household consumption while supporting companies, a mix that curbs imports and acts as a disguised form of protectionism. It is one of the many features of the German system that has led to accusations of mercantilism by other EU states."¹²⁴

Spain

The Spanish experience has been even more turbulent. A National Renewable Energy Laboratory report summarizes all that has happened. In 2005, Spain established a renewable energy target of 12.5 percent to be reached by 2010. The solar target was 400 MW. By 2006, installed solar capacity began to exceed the targets. A number of factors were at play. As the Spanish economy began declining, investors saw an opportunity for growth in the solar market, especially because of generous feed-in tariffs. Investors also perceived that a trigger mechanism in Spanish renewable energy legislation would weaken support for solar and so there was a rush to develop solar projects under the framework then in existence. This trigger mechanism was initiated when 85 percent of the 400-MW goal was reached. This initiated a one-year transition period during which developers had to bring their generation on line. Any generation not completed at the end of the one-year period would be paid much less than the FIT then in place. This led to a drastic boom in production between 2007 and 2008.¹²⁵

The Spanish FIT established in 2007 guaranteed payments of up to 44 Euro cents per kWh for projects plugged into the grid by September 2008. Ground-based projects could receive a rate of return of up to 575 percent of average retail prices. The combination of high tariff rates and rapidly declining costs for PV systems "created an artificial market." There was no mechanism to reduce tariff rates if capacity targets were met. 350 MW of solar capacity had been installed in

¹²¹ "Germany Rethinks Path to Green Future."

¹²² The Global Warming Policy Foundation. "German Energy Companies Threaten Shutdown of Power Plants." July 16, 2013. Accessed at: <http://www.thegwpf.org/german-energy-companies-threaten-shutdown-power-plants/>

¹²³ William Pentland. "German Utility Revolts Against Renewable Energy, Threatens to Relocate in Turkey." *Forbes*, August 19, 2013. Accessed at: <http://www.forbes.com/sites/williampentland/2013/08/19/german-utility-revolts-against-renewable-energy-threatens-to-relocate-in-turkey/>.

¹²⁴ Ambrose Evans-Pritchard. "Berlin facing EC bias claim over energy subsidies." *Daily Telegraph*, July 16, 2013.

¹²⁵ Claire Kreyck, Toby D. Couture, and Karlynn S. Cory. *Innovative Feed-in Tariff Designs that Limit Policy Costs*. Golden, CO: National Renewable Energy Laboratory, 2011, p. 5.

the country by the fall of 2007, just shy of the 400 MW that had been anticipated to come on line by 2010.¹²⁶

A combination of soaring prices and taxpayer backlash ignited reforms. It was estimated that total payments to solar generators were \$26.4 billion in 2008, during a time when the worldwide economy was in an enormous recession.¹²⁷

In light of these developments, the Spanish Legislature aimed to scale back production, limited capacity additions to 500 MW for 2009 and 2010 and 400 MW for 2011 and 2012. The government also lowered the capacity limits for individual projects. In response to these changes, developers fled the Spanish market, leading to job losses in Spain. Investors and developers are now looking elsewhere.¹²⁸

¹²⁶ Paul Voosen. "Spain's Solar Market Crash Offers a Cautionary Tale About Feed-in Tariffs." *New York Times*, August 18, 2009.

¹²⁷ Ibid.

¹²⁸ Kreytic, et al. p. 4.

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Solar Photovoltaic Power:

Assessing the Benefits & Costs





Solar Photovoltaic Power: Assessing the Benefits & Costs

I - Introduction

Solar photovoltaic (PV) makes up only a small fraction of the nation's electric generation capacity, but it has grown rapidly over the last several years. According to a report by the Solar Energy Industries Association (SEIA), PV installations in the U.S. grew by 76 percent (3.3 GW) in 2012, after doubling in 2011, bringing the total amount of PV operating in the U.S. as of year-end 2012 to 7.2 GW.

Despite the growth, questions remain about the efficacy of solar PV as a power resource. Issues such as benefit-cost profile, the nature and magnitude of subsidies, impact on electric rates, and the degree of cost shifting among utility customers — all engender considerable debate.

A balanced assessment of solar PV requires an examination of all these components keeping in mind that parochial interests and stakeholder perspectives can affect the measurement and treatment of key variables, and hence the conclusions. Utilities considering solar PV because of mandated net metering programs, renewable portfolio standard requirements, customer interest, or integrated resource plan considerations, might find it difficult to reconcile conflicting benefit-cost claims.

This paper uses simple analytical models to highlight the key dynamics underpinning solar PV. The intent is not to offer a final assessment on the merits of solar PV as a power resource, but rather to present an analytical framework that may help decision makers assess the benefits and costs, and manage the trade-offs inherent in the use of this technology.

II - Basic Framework

Conceptually, the fundamental question of whether solar PV makes economic sense as a power resource can be addressed with a basic economic benefit-cost (B/C) analysis, in which the levelized cost of electricity produced with a PV system is compared to the levelized value of its output. There are numerous ways to think about project economics, but one common approach is to derive a B/C ratio with the net present value (NPV) of project benefits in the numerator and the NPV of project costs in the denominator.

$$\text{B/C Ratio} = \frac{\text{Net present value of project benefits}}{\text{Net present value of project costs}}$$

B/C ratio > 1 means the project is economic, as benefits exceed costs.

B/C ratio < 1 means the project is uneconomic, as costs exceed benefits.

The relative cost-effectiveness of projects can be assessed by comparing their benefit-cost ratios — the higher the B/C ratio, the greater “bang for the buck.”

Although the conceptual framework is simple, there is no single, standard modeling approach that would be accepted by all for this purpose. The results and conclusions can differ depending on how the analysis is conducted. There are at least three key elements of the modeling that will crucially affect the results:

- (1) Structure of the benefit-cost ratio in terms of the variables included and how they are arranged
- (2) Values assigned to the variables
- (3) Perspective from which the analysis is conducted (and how cash flows rebound to stakeholders)

Similar to energy efficiency and some other types of utility projects, the economics of solar PV can be viewed from at least three broad perspectives — of solar customers, non-solar customers, and society as a whole. The benefit-cost assessment can differ across the stakeholder groups because the specific terms included in the respective benefit-cost equations vary across the groups. As discussed below, there are a number of reasons for this, but one factor is the presence of subsidies, and/or cost shifting among customers.

III - Subsidies and Cost Shifting

Many solar projects benefit from various types of “societal” subsidies. These include federal and state tax credits, grants, renewable energy credits, local property tax relief and more. In addition, solar net metering projects can benefit from de facto subsidization in the form of cross-customer cost shifting. Larger scale, utility-owned projects are effectively subsidized by all customers, through higher utility rates, whenever project costs exceed the economic value of the output. Currently, these subsidies are crucial for the development of solar PV.

The purpose of this paper is not to challenge the policy initiatives behind the subsidies, or to suggest that the solar PV is the only category of energy resource that enjoys subsidies or gives rise to cost shifting. The purpose is simply to show that subsidies exist for solar PV, and to understand how they might affect the B/C analysis. As seen in the illustrative benefit-cost analysis presented in the next section, the impact of the “societal” subsidies is generally straightforward, simply offsetting certain costs incurred by those who receive them. However, the subsidization that

results from cross-customer cost shifting and higher electric rates deserves more explanation.

Cost-shifting issues are particularly pronounced with net metered projects where subsidization arises because the solar output displaces utility production and sales. In a given time frame, the electric output from the PV system will be less than, equal to, or greater than the host customer's electric load (usage). When the output is less than or equal to the customer's usage, utility sales drop, causing both revenues and costs to decline. But, whenever volumetric electric rates exceed unitized avoided costs, revenues fall by more than costs and the utility faces a net revenue loss unless it makes up the shortfall by raising rates and shifting costs to its non-solar customers .

When customer output is less than or equal to customer usage

Decline in utility revenue = Project output x Volumetric rate per unit (\$/kWh or \$/kW)

Decline in utility cost = Project output x Marginal cost per unit (\$/kWh or \$/kW)

Decline in net revenue = Project output x (Rate – unitized marginal cost)

If the output from a net energy metering (NEM) system exceeds the customer's usage, he or she can "sell" the excess power to the utility. The NEM payments are often based on the utility's volumetric rates, but they might also be based on average rates, or determined on some other basis such as the estimated "value" of the output. Rather than actual sales transactions, this typically involves crediting NEM production from a given period against customer usage in another period, but the utility is, in effect, purchasing the net output of the project. The incremental costs of this purchase will be offset to some degree because the utility avoids the costs of procuring the output from a different source. If the NEM payments exceed avoided costs, the utility's total net cost will rise and the non-solar customers will end up subsidizing the project because higher total costs translate into higher electric rates.

When customer output is greater than customer usage

Increase in utility cost = Net output x Net metering payment per unit

Avoided utility cost = Net output x Marginal cost per unit

Net increase in utility cost = Net output x (Payment – avoided cost)

In this model, the basic dynamic -- non-solar customers subsidize the solar customers whenever the volumetric electric rate, or NEM payment, exceeds the unitized, avoided cost -- holds both when solar production is below

the customer's usage and the customer simply avoids the volumetric charge, and, when production exceeds usage, allowing the customer to sell the excess.

One should expect volumetric charges to exceed avoided costs in many net metering arrangements because volumetric rates are often used to recover not only marginal energy and generation capacity costs, but also, transmission, distribution, and other embedded costs of providing retail electric service, while the costs avoided through NEM projects usually include marginal energy and generation capacity, perhaps some transmission, but very little, if any, distribution or other fixed costs. Net metering customers continue to rely on the utility's distribution system to meet their needs when the solar panels are not producing, when usage exceeds output and when selling excess power to the grid. So, for the most part, distribution costs are not avoided through solar net metering projects and solar customers are simply not carrying their corresponding share of distribution and other embedded costs when they avoid, or are paid, volumetric rates designed to recover those costs.

Two factors affect the change in rates paid by the non-solar customers on account of solar NEM programs - reduction in utility sales and the relationship between the NEM payments and the actual costs avoided by the utility as a result of the NEM production. For a utility,

$$\text{Average rate} = \frac{\text{Total Cost}}{\text{kWh Sales}}$$

NEM programs will affect both components, and hence average rates, in different ways depending on the scale and structure of the program.

To illustrate, consider a hypothetical utility with an initial year peak load of 500 MW and sales of 3 million MWh per year, assumed to grow at 0.5% per year over a 20-year period. The total cost of service in the first year is assumed to be \$360 million, which yields an average retail rate in the first year of \$.12/kWh. The total retail rate contains a variable component of \$.07/kWh and a fixed component of \$.05/kWh, both of which escalate at an assumed 2.5% annual inflation rate. The variable component reflects all the costs avoided by the utility as a result of the NEM production, and the fixed component contains all remaining costs, including distribution system costs not avoided through NEM production. Given these assumptions the 20-year levelized rate for the base case is \$.144/kWh.

TABLE 1

20-Year Levelled Rate Impacts, Percent Change

	NEM Payment \$/Kwh	NEM Payment \$/Kwh	NEM Payment \$/Kwh	NEM Payment \$/Kwh
NEM as % of Load	\$0.120	\$0.150	\$0.090	\$0.070
5.00%	1.95%	1.55% ¹	1.03%	0.00%
10.00%	3.90%	3.11%	2.06%	0.00%
15.00%	5.85%	4.66%	3.09%	0.00%
20.00%	7.80%	6.22%	4.13%	0.00%

Table 1 shows rate impacts on the utility's non-solar customers for different levels of NEM production and payments. We start by deriving a base 20-year levelled rate assuming no NEM programs. Then, NEM programs of different scales and costs are introduced and the associated levelled rates are calculated and compared to the base rate. The rate impacts are expressed in terms of percentage change in levelled rates relative to no NEM, base case.

In Table 1, the rows designate project scale and the columns indicate the level of NEM payments. Each entry shows the percent change to the 20-year levelled rate for the indicated combination of scale and NEM payment. For example, the first entry of 1.95% shows that if the NEM project is 5% of load and the volumetric payment equals the levelled total rate of \$.12/kWh, the rates to non-solar customers will rise by 1.95% as a result of the NEM project. Reading across the first row, one can see that as the NEM payment declines toward the variable component of the rate, the rate impact is smaller. Reading down the first column, one can see that for the given NEM payment, the rate impact increases as the project scale increases. The rate impacts in the last column are all zero because the NEM payment of \$.07/kWh is equal to the assumed value for avoided cost.

Table 1 not only shows how NEM programs can affect rates paid by non-solar customers, but it also demonstrates that rate design can be an effective tool to address cost shifting. As volumetric rates get closer to avoided costs, rate impacts are mitigated and cost shifting diminishes.

IV – Illustrative Benefit-Cost Analysis

Along with the effects of cost shifting, other key variables — direct project costs, cash flows associated with wholesale market products, societal subsidies and external factors — can cause the economics of solar PV to vary across stakeholder groups.

For example, projects that qualify for a federal investment tax credit (ITC) can yield cash flow benefits to the stakeholder group that invests, but not to society or other stakeholders. Global environmental benefits might appear as positive cash flows for society but not for utility customers — at least not the full amount — because customers will garner only a negligible fraction of the societal benefit. The value of renewable energy credits (RECs) flows to the stakeholder groups that hold the rights, but not to groups that don't. And, alternative procurement models — net metering, utility ownership, or community projects — will affect stakeholder groups differently.

The tables and graphs below use benefit-cost analysis to illustrate how the economics of an NEM project can vary across three principal stakeholder groups — solar customers, non-solar customers, and society, depending on stakeholder perspectives and the treatment of crucial variables. Tables 2 and 3 are laid out in the same way, but they depict different scenarios. It is important to do a scenario analysis because there is uncertainty regarding the values of the key inputs and ambiguity concerning the proper assignment of the variables to stakeholder groups.

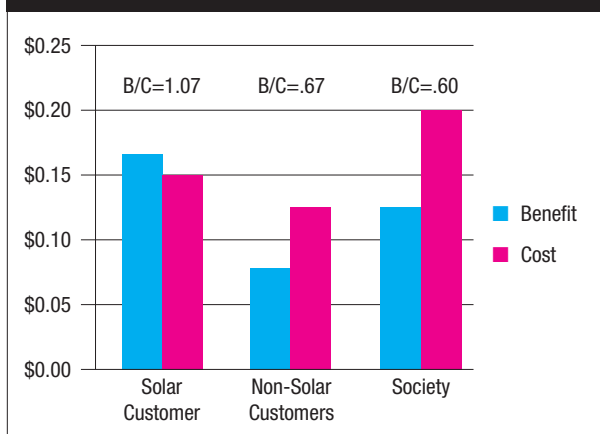
Table 2 - Costs

	(1) Project Cost \$/Kwh	(2) ITC & Other \$/Kwh	(3) NEM Payment \$/Kwh	(4) Total Net Cost \$/Kwh
Solar Customer	\$0.20	(\$0.05)	\$0.00	\$0.15
Non-Solar Customers	\$0.00	\$0.00	\$0.12	\$0.12
Society	\$0.20	\$0.00	\$0.00	\$0.20

Table 2 - Benefits

	(5) Loss & TOU Leveled Energy \$/Kwh	(6) Leveled Capacity \$/Kwh	(7) Leveled REC \$/Kwh	(8) Leveled Transmission \$/Kwh	(9) Leveled Distribution \$/Kwh	(10) Leveled Externalities \$/Kwh	(11) Leveled NEM Revenue \$/Kwh	(12) Leveled Total Benefits \$/Kwh	(13) B/C Ratio
Solar Customer	\$0.00	\$0.00	\$0.04	\$0.00	\$0.00	\$0.00	\$0.12	\$0.16	1.07
Non-Solar Customers	\$0.05	\$0.01	\$0.00	\$0.02	\$0.00	\$0.00	\$0.00	\$0.08	0.67
Society	\$0.05	\$0.01	\$0.00	\$0.02	\$0.00	\$0.04	\$0.00	\$0.12	0.60

Graph 2



The presentation is meant to be illustrative, but the base case values shown in Table 2 are reasonable and within ranges used by others. Given the assumptions underlying Table 2, the NEM project appears to be economic from the perspective of the solar customers, but uneconomic for the non-solar customers and society.

Columns 1–3 in the top section of Table 2 depict individual costs, any one of which may or may not apply to a particular stakeholder group. Costs include the all-in costs to install and maintain the PV system; incentives (federal ITC, grants, etc.) , which are treated as cost offsets to the recipients; and NEM payments to solar customers, which are treated as costs to

the utility and hence costs to non-solar customers.

Columns 5-11 of the bottom section depict individual benefits, which might include avoided energy, capacity, transmission and distribution costs; REC proceeds; avoided environmental external factors; and NEM payments to solar customers . It is assumed that the project produces marketable RECs, the proceeds of which flow to solar customers. The existence and market value of RECs can vary widely across jurisdictions, and also within jurisdictions over time. NEM programs may also be set up so that REC proceeds flow to the utility, and hence to non-solar customers, as opposed to the solar customers.

Solar customers incur the total PV system costs (column 1), but these costs are partially offset by the societal subsidies (federal ITC, accelerated tax depreciation, state tax concessions, grants and other incentives) shown in column 2. The benefits flowing to solar customers include NEM payments (column 11) and REC proceeds (column 7) . The NEM payment is set at \$0.12/kWh, which represents the nationwide average retail rate for residential electric customers . In reality, these payments may, depending on the structure of the NEM program and the utility’s rate design practices, be higher or lower than the utility’s average rate, so this value can vary widely with significant impacts on the B/C ratios. For non-solar customers, total cost, based on the NEM payment made by the utility to the solar customers (column 3), exceeds the total benefits, which comprise avoided

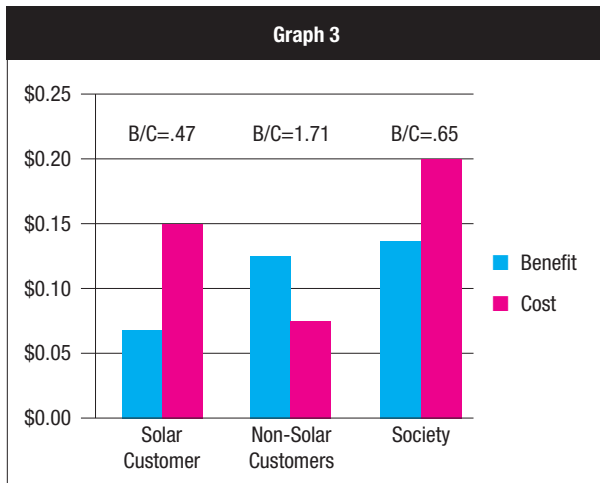
Table 3 - Costs

	(1) Project Cost \$/Kwh	(2) ITC & Other \$/Kwh	(3) NEM Payment \$/Kwh	(4) Total Net Cost \$/Kwh
Solar Customer	\$0.20	(\$0.05)	\$0.00	\$0.15
Non-Solar Customers	\$0.00	\$0.00	\$0.07	\$0.07
Society	\$0.20	\$0.00	\$0.00	\$0.20

Table 2 - Benefits

	(5) Loss & TOU Leveled Energy \$/Kwh	(6) Leveled Capacity \$/Kwh	(7) Leveled REC \$/Kwh	(8) Leveled Transmission \$/Kwh	(9) Leveled Distribution \$/Kwh	(10) Leveled Externalities \$/Kwh	(11) Leveled NEM Revenue \$/Kwh	(12) Leveled Total Benefits \$/Kwh	(13) B/C Ratio
Solar Customer	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.07	\$0.07	0.47
Non-Solar Customers	\$0.05	\$0.01	\$0.04	\$0.02	\$0.00	\$0.00	\$0.00	\$0.12	1.71
Society	\$0.05	\$0.01	\$0.00	\$0.02	\$0.00	\$0.05	\$0.00	\$0.13	0.65

Graph 3



energy, capacity and transmission costs (columns 5, 6 and 8). Consistent with the cost shifting discussion in Section III, it is assumed that the solar customers continue to rely on the utility's distribution system to consume electricity when their facilities are not producing, and to sell electricity during periods of excess production, so the benefits do not include avoided distribution costs.

Society, via the solar customers, incurs the PV system costs, which are not offset by the tax incentives and grants because these items merely represent transfer payments from a societal perspective. Along with avoided energy, capacity and transmission costs, the societal benefits include an

environmental component shown in column 10, which represents the expected reduction in environmental costs when solar production reduces the output of fossil resources. In this scenario, the environmental benefit happens to equal the assumed REC value, but this will not necessarily be the case. Because society incurs the PV system costs without offsetting subsidies, societal costs exceed the net costs to the solar customers. At the same time, societal benefits in the form of avoided production costs are assumed to be below the NEM payment, and the societal environmental benefit is equal to the solar customers' REC benefit. Thus, relative to the solar customers, societal costs are higher and benefits are lower, so the project appears uneconomic for society but economic for solar customers.

As shown by the B/C ratios (column 13) Table 2 indicates that in this scenario, the NEM project is cost effective (B/C 1.07) only for solar customers. The project is not cost-effective for non-solar customers (B/C 0.67) and for society as a whole (B/C 0.60). The project is least cost effective from a societal perspective.

An alternative scenario is presented on Table/Graph 3. In this case, the project appears economic for non-solar customers but not for solar customers or society.

In Table 3, the NEM payment is set equal to the utility's avoided cost (\$0.07/kWh versus \$0.12/kWh in Table 2). The REC proceeds are allocated to the utility, and hence to the non-solar customers. The social environmental benefit

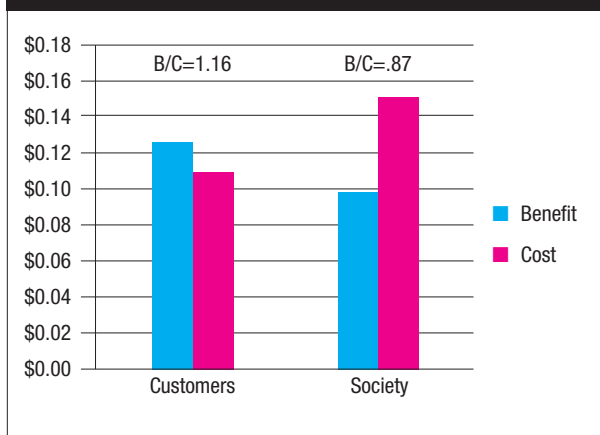
Table 4 - Costs

	(1) Project Cost \$/Kwh	(2) ITC & Other \$/Kwh	(3) NEM Payment \$/Kwh	(4) Total Net Cost \$/Kwh
Customers	\$0.15	(\$0.04)	\$0.00	\$0.11
Society	\$0.15	\$0.00	\$0.00	\$0.15

Table 4 - Benefits

	(5) Loss & TOU Leveled Energy \$/Kwh	(6) Leveled Capacity \$/Kwh	(7) Leveled REC \$/Kwh	(8) Leveled Transmission \$/Kwh	(9) Leveled Distribution \$/Kwh	(10) Leveled Externalities \$/Kwh	(11) Leveled NEM Revenue \$/Kwh	(12) Leveled Total Benefits \$/Kwh	(13) B/C Ratio
Customers	\$0.05	\$0.01	\$0.05	\$0.02	\$0.00	\$0.00	\$0.00	\$0.13	1.16
Society	\$0.05	\$0.01	\$0.00	\$0.02	\$0.00	\$0.05	\$0.00	\$0.13	0.87

Graph 4



is set at \$0.05/kWh versus \$0.04/kWh in Table 2. These inputs lead to a reordering of the relative economics across stakeholder groups, as shown by the B/C ratios presented in column 13 and on Graph 3. The B/C ratios for non-solar customers, society, and the solar customers are, respectively, 1.71, 0.47 and 0.65. Thus, the project now appears economic for non-solar customers but not for solar customers or society. The societal economics have improved, but the B/C ratio is still less than one, indicating that the project remains uneconomic.

Other cases yielding different results can be easily developed, and this framework allows one to evaluate project economics

based on one's own assumptions, expectations, and notions about which variables should be considered. In addition, it allows one to describe what circumstances would have to prevail to bring about various outcomes, like an "everyone wins" scenario where the benefit-cost ratios are greater than one for all stakeholders.

V- Utility-Scale Projects

Tables 2 and 3 depict alternative outcomes for small-scale, net-metered projects. As illustrated in Table/Graph 4, this same framework can also be used to evaluate the type of larger PV projects generally undertaken by utilities as opposed to individual customers. Two important differences between utility-scale and small-scale NEM projects are apparent. First, the larger projects display lower, unitized all-in costs. Second, although under many circumstances average utility rates will increase with utility projects, as they do with net metered projects, the magnitude will be less and the cost shifting between customers is eliminated. The overall increase will be less, other things equal, because utility sales do not decline and thus fixed costs are spread over more billing units. The tension between solar and non-solar customers is eliminated because all customers will be solar customers.

Table 4 depicts results for a utility-scale project. There are only two stakeholder groups, customers (all customers) and society. Given these particular assumptions, the project appears economic for customers but not for society, primarily

because of the societal subsidies. Again, the results vary with the assumptions and it is up to users to determine the assumptions that align with their expectations.

VI – Managing Outcomes

More than just a mechanical technique for estimating outcomes, the process of altering inputs and comparing scenario results illuminates the key dynamics and the inherent trade-offs among interest groups that accompany the adoption of solar PV as an energy resource. Obviously, one would hope for a “win-win-win” case where the B/C ratios were greater than one for all stakeholders, indicating positive economic benefits for all, but that would be unlikely under current circumstances. So, in order to accommodate increasing amounts of solar PV, decision makers will have to balance the interests of the different stakeholders.

In situations like those depicted in the Tables 2 and 3, where the expected levelized cost of electricity with rooftop solar PV exceeds the projected market value of the output, subsidies and/or cost shifting will be necessary to encourage development of these systems, because without the subsidies there would be little, if any, economic incentive for customers to invest in them. Even utility-scale projects, which generally exhibit lower unitized costs, will, in most cases, appear uneconomic in the absence of subsidies, REC payments or imputed environmental benefits. As noted above, there may be good reasons for a utility, a community, or broader society to use subsidies and wealth transfers to encourage the adoption and use of any technology, including solar PV, but it is important for public authorities and other decision makers to appreciate the economic constraints and inherent trade-offs, and to explicitly consider what levels of subsidization and cost shifting seem appropriate.

To a large degree, decisions regarding societal subsidies are made at the federal or state levels, although local communities may also create incentives through tax abatement or other economic development programs. Also, in many cases, NEM programs are designed by state lawmakers and/or regulators. Certainly, utilities can influence these policies but they will likely not be the principal architects. However, utilities can directly influence cost shifting and rate impacts, and they can affect the nature and scope of solar resource development in their service territories by pursuing programs that meet overall renewable goals in the most efficient manner possible.

Conventional rate design mechanisms provide familiar tools

for utilities to manage cost shifting and rate impacts. As shown in Section III, for a given scale of NEM program, the degree of cost shifting is directly related to the divergence between the NEM payments to solar customers and the actual costs avoided when the NEM production displaces utility output. In many cases, but not all, NEM payments are based on the utility’s retail volumetric charges, so a utility can minimize cost shifting by setting the volumetric charges as close as possible to its actual variable costs, while relying more on customer charges and less on usage-sensitive demand charges to recover fixed costs.

Not only does proper rate design address practical rate impact issues, but it can also help prevent ill-informed public perceptions about a utility’s attitude toward renewable resources and energy efficiency. Solar proponents often portray the utilities as calcified monopoly institutions intent on killing solar power. In certain cases, they have assailed utilities for attempting to mitigate cost shifting by imposing surcharges on NEM production to recover the fixed costs not avoided by the program, likening such proposals to the taxing of customer-installed efficiency measures. Surcharges of this sort may indeed seem inappropriate when portrayed in that way. However, they actually make good economic sense when a significant portion of a utility’s fixed costs – costs not avoided by NEM programs or energy efficiency measures -- are recovered through the utility’s volumetric charges. In such circumstances, a properly designed surcharge would be fair, and economically efficient, but it may not appear that way to a public audience. These surcharges would not be needed if the volumetric charges reflected true avoided costs, and fixed costs were recovered in customer charges and/or less usage-sensitive demand charges.

This is not to suggest that designing rates to better accommodate solar PV would be a simple, non-controversial undertaking. Utility rate structures vary across jurisdictions, companies and customer classes within companies. Rate stability is generally a key rate making goal, and rate redesign, which often creates winners and losers among customer classes, can lead to instability. But, significant penetration of solar PV is also likely to create winners and losers, and it would be best to explicitly address these effects. Intelligent rate design provides a means for utilities to balance various interests as they pursue their business and public policy goals.

Along with proper rate design, it should be recognized that to the extent solar PV is being pursued to fulfill renewable

portfolio standard requirements or to satisfy customer or community interests, as opposed to meeting NEM mandates, utilities may be able to reduce cost shifting and overall adverse rate impacts, by meeting their solar goals with larger utility-scale projects that cost less on a unit basis and avoid cost shifting among utility customers.

VII - Conclusion

As noted at the outset, solar PV has been growing rapidly in recent years, spurred by decreasing costs, RPS requirements, mandated NEM programs, consumer preferences and utility integrated resource plan initiatives. But, the rapid growth does not, by itself, demonstrate the economic viability of solar PV as a power resource. It is clear that the penetration of solar PV has been aided by direct subsidies, and indirect subsidization in the form of higher utility rates and cost shifting among utility customers. These incentives may be rooted in laudable public policy goals, but they, along with other factors, can complicate the economic analysis of solar PV, causing the assessments to differ for different stakeholder groups. Decision makers, both public authorities and utility managers, will have to balance different constituent interests when setting and pursuing renewable goals. The foregoing discussion provides a framework for explicitly identifying trade-offs and evaluating the economics of solar PV from alternative perspectives.

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- i SEIA, U.S. Solar Market Insight 2012 Year in Review (<http://www.seia.org/research-resources/us-solar-market-insight-2012-year-review>), last visited 05/09/2014.
 - ii Actually, to the extent that NEM customers are net purchasers from the utility, they will help make up a small portion of the shortfall through higher rates as well.
 - iii In the case of NEM the solar customer would most likely be the investor and thus capture the benefit. For utility-scale projects the ITC would not be available to government owned electric utilities and in many cases it would be difficult for even for Investor owned utilities to directly capture the benefit. However, both could reap at least a portion of the benefit by either partnering with a tax investor or by procuring the output through a purchase power arrangement with a third party that is able to utilize the benefit.
 - iv See Rocky Mountain Institute, A Review of Solar PV Benefit and Cost Studies, second edition September, 2013 (www.rmi.org/elab) last visited 05/09/2014; VT Public Service Department, Evaluation of Net Metering in Vermont, January 15, 2013; EEI. A Policy Framework for Designing Distributed Generation Tariffs, November 2013; and California Solar Initiative Cost-Effectiveness Evaluation, prepared for California Public Utilities Commission, April 2011; Edison Electric Institute, Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business, January 2013.
 - v All values are leveled over the planning horizon. Energy and capacity values should be adjusted for line losses and any pertinent seasonal/time-of-use characteristics. For range of values used in other studies see supra note iv.
 - vi The variable in the table represents the total value of all incentives, including federal and state tax incentives, grants etc. This value can vary greatly depending on the nature and timing of the project, the type of investor, region of the country and utility jurisdiction. While the federal ITC may not be directly available to all investors (including government-owned utilities or private investors with limited tax appetite), a portion of the benefits may be obtainable through arrangements with third parties. For present purposes, a proxy value equal to 25% of installed cost is used to capture all societal subsidies.
 - vii This particular layout is chosen for ease of exposition, but clearly since variables can be arranged on either side of an equation by switching signs, different configurations, are possible, and perhaps preferable for some. For example, as opposed to showing the federal ITC as a cost offset (cost item with a negative sign) one could depict it as a positive benefit cash flow.
 - viii EIA, Electric Power Monthly, February 2014. (<http://www.eia.gov/electricity/monthly/update/>), last visited 05/09/2014





Rate Design for Distributed Generation

NET METERING ALTERNATIVES

With Public Power Case Studies



Rate Design for Distributed Generation

NET METERING ALTERNATIVES

With Public Power Case Studies

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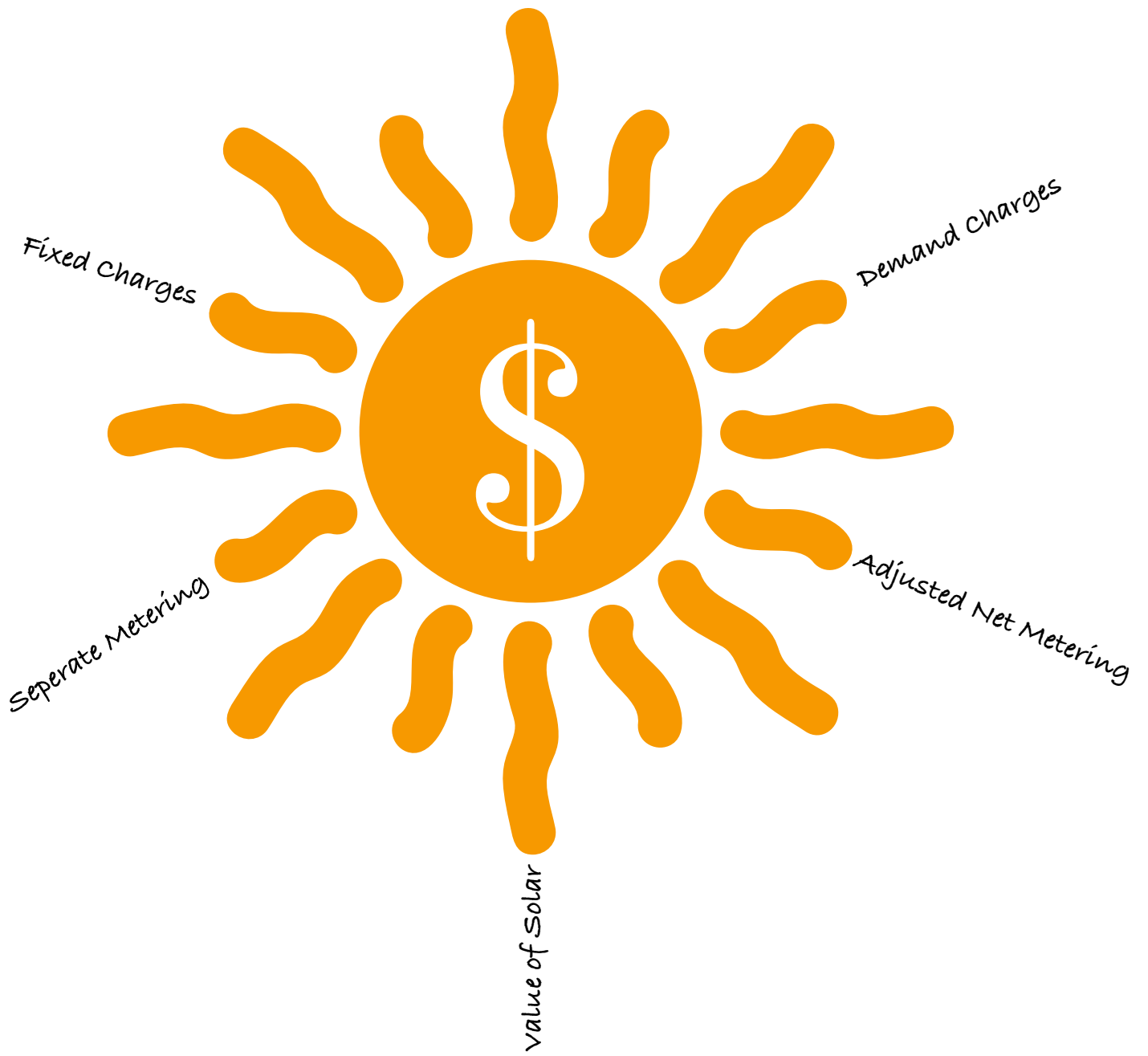


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Executive Summary

The American Public Power Association's "Rate Design for Distributed Generation" report examines rate design options for solar and other distributed generation (DG), using public power utility case studies. The report discusses how utilities have educated customers about new rates, and how DG and non-DG customers responded. While the rate design options have some drawbacks, and might not be technically feasible for all utilities, they offer the industry new models that account for the rate impacts of distributed generation.

The use of DG, particularly rooftop solar photovoltaic (PV), is growing fast. As of October 2014, just under 8,000 megawatts (MW) of solar capacity was installed on residential and business rooftops across the United States (U.S.).¹

The growth of DG has been spurred by environmental concerns and economic considerations. Federal and state tax incentives are a driving force behind solar PV installations and can together cover up to 70 percent of the total cost of solar panels in some states.² Declining solar panel prices have also fueled growth in rooftop solar. Utility rate structures for distributed generation have provided a significant benefit to solar customers.

As DG becomes more widespread, rate analysts and researchers are developing new rate designs to help ensure that utilities recover their cost of service, encouraging while providing appropriate incentives for rooftop solar deployment.

Utilities can no longer afford to take a wait and see approach in rate design for DG, nor should they assume that old rate designs adopted before the escalation in DG installations will work in the future.

Most utilities in the U.S. use net metering to measure and compensate customers for the generation they produce. However net metering has several shortcomings and results in non-DG customers subsidizing DG customers.

Utilities have options other than traditional net metering. Many public power utilities have adopted new rate designs to serve DG customers. Some of these rate designs supplement net metering by recouping more of their fixed costs through fixed charges, while other designs provide comprehensive alternatives to net metering.

Utility rate setters must balance between simplicity and accuracy, align costs and prices, support environmental stewardship, and ensure that rate designs are well suited to customers. Customer communication and engagement are essential components of the rate-setting process.

This report does not examine every rate design option, nor does it suggest a single best option. It offers alternatives to traditional net metering, with case studies. Utilities can consider how they can adapt rate designs to suit their community's needs, factoring in market structure, state policies, and other considerations.

¹ Mike Taylor, Joyce McLaren, Karlynn Cory, Ted Davidovich, John Sterling, and Miriam Makhyounl, Value of Solar: Program Design and Implementation Consideration (NREL/TP-6A20-62361. Golden, CO: National Renewable Energy Laboratory, 2015), 1.

² American Public Power Association, Distributed Generation: An Overview of Recent Market and Policy Developments (Washington, DC: American Public Power Association, 2013), 6.

Traditional Rate Design and Costs

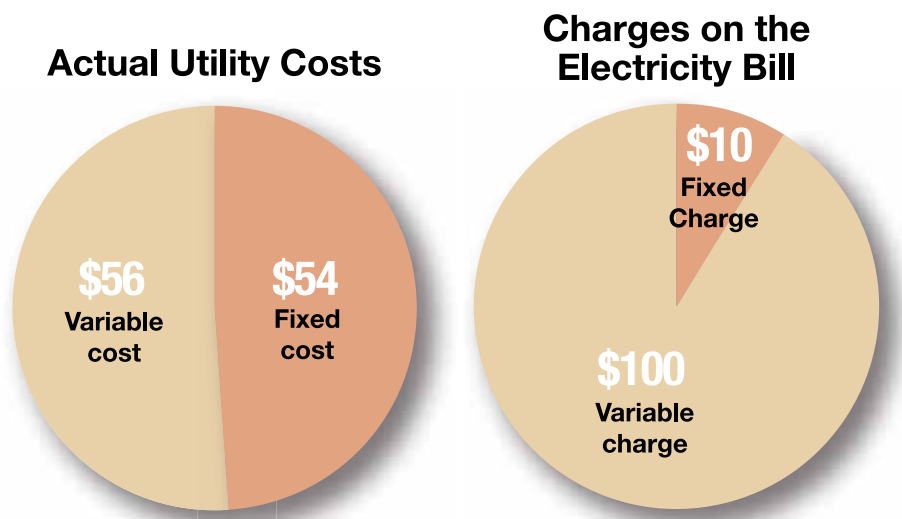
Most utilities follow a traditional cost-of-service model to set electricity rates. They have been guided by the principles established by James Bonbright³ that rates should:

- Provide adequate and stable revenues to the utility.
- Be stable, predictable, and easy for customers to understand.
- Reflect fair cost allocation to rate classes.
- Reflect present and future private and social costs.
- Discourage wasteful use of service.
- Avoid undue discrimination in rate relationships (i.e. be subsidy free with no inter-customer burdens).
- Promote dynamic efficiency and innovation.

Utility rate analysts must forecast utility revenue requirements and allocate costs to each customer class. Traditional rate design has attempted to meet these allocated revenue requirements through a fairly simple method. Residential utility bills typically have two components — a fixed monthly customer charge and a variable energy charge based on kWh usage.⁴ The variable energy charge typically makes up the lion's share of the bill.

The energy charge has traditionally been a flat \$/kWh charge although a utility's cost to serve a customer varies greatly by time of day and season. Some utilities have introduced seasonal charges, with summer and winter rates set slightly higher than rates at other times of the year. Other utilities implement time-of-use rates— mostly a two-tiered rate, with charges for peak hours (e.g. 3 – 7 pm) set considerably higher. Some utilities use complicated formulas, such as critical peak pricing, with a very high charge for absolute peak hours, a slightly lower charge for less congested times, and a very low rate for off-peak hours such as the late evening.

Utilities recoup a large portion of their costs from residential customers through variable energy rates even though a high percentage of costs is fixed.



³ James C. Bonbright, et al., *Principles of Public Utility Rates*, 2 nd ed. (Arlington, VA: Public Utilities Reports, Inc., 1988).

⁴ Commercial and industrial customers usually have an additional demand charge based on peak usage, generally measured in dollars per kilowatt (kW) month. Utilities may have additional riders to their residential, commercial, and industrial tariffs, including fuel adjustment clauses.

A study by the Electric Power Research Institute (EPRI) shows that a typical residential customer uses 982 kWh of electricity per month, with a bill averaging \$110. The bill is made up of three cost components — \$70 can be allocated to generation, \$30 to distribution, and \$10 to transmission. Nearly all the distribution and transmission costs are fixed (or capacity-type) costs that do not vary based on hourly customer loads, while approximately 80 percent of generation costs are variable. This means that \$54 of the typical bill is related to capacity or fixed costs, and \$56 can be attributed to energy-related, or variable costs.⁵ Yet a typical residential fixed charge is around \$10 per month. So the utility recovers most of its fixed costs through variable rates.

Utilities have depended on variable charges to recover costs because:

- Analog meters can only record the customer’s usage over a given time period, not the usage at a specific time of the day.
- Complex rate structures can overwhelm and confuse customers. A pilot study of time-of-use rates in California showed that while customers were able to grasp general concepts, such as prices being higher during peak periods on critical days, they did not understand basic rate structures.⁶

Time of use retail rates more accurately reflect the utility’s actual cost to generate or purchase energy. Demand rates can be adjusted to align with the customer’s contribution to the coincident system peak, and include a demand ratchet⁷. But such options add a layer of complexity to the rates.

No rate design will perfectly match costs and rates. Utility rate analysts have to determine how far they want to go to better align costs with rates. As Michael O’Boyle puts it:

Even if perfect cost causation was possible, it would overwhelm the consumer with information. Rates should approximate cost causation relative to other customers, with other public policy goals left to resolve the imperfections or justify certain cross subsidies over others.⁸

Customer outreach and education are an essential aspect of any new rate design. Whatever the rate design, pilot programs have shown that customers will shave energy usage during peak periods if given a price signal to do so.

But even when customers have greater knowledge about rates, other tradeoffs exist. While higher fixed charges might provide adequate and stable revenues to the utility, they may not discourage wasteful use of service (some Bonbright principles are contradictory). Higher fixed monthly customer charges generally favor high-use customers, and might discourage conservation. Higher energy charges benefit low-use customers.⁹

Utilities have tried to balance these issues for a number of years. While perfect alignment between costs and rates has not been possible, cost of service analysis has helped utilities set rates that meet their revenue requirements.

DG has thrown a wrinkle in this equation. Net metering, the most common method of compensating distributed generators, has created severe problems.

⁵ Electric Power Research Institute, *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources* (Palo Alto, CA: EPRI, 2014), 21-22.

⁶ Ahmed Faruqui and Ryan Hledik, *Transitioning to Dynamic Pricing* (Washington, DC: Brattle Group, 2009), 8.

⁷ A demand ratchet is a mechanism incorporated into some commercial and industrial tariffs and is based upon historical demand. For example, if a customer records a peak usage of 100 kW during a billing cycle, if the demand ratchet was 50 percent, minimum billing demand would be 50 kW over the next year regardless of what the actual demand was during that period. The purpose of the demand ratchet is to protect against customers who have large demand swings.

⁸ Michael O’Boyle, *An Adaptive Approach to Promote System Optimization*. Paper released through SEPA 51st State Project, 2015. Accessed at <http://sepa51.org/submissions.php>.

⁹ Larry Blank and Doug Gegax, “Residential Winners and Losers behind the Energy versus Customer Charge Debate,” *Electricity Journal* Volume 27, Issue 4 (2014), 32.

Net Metering

Most utilities in the U.S. use net metering to measure the net monthly usage or surplus generation of customers with solar power.

Net metering is a basic mechanism. The meter runs forward when the customer takes electricity from the grid. It stops when the customer generates and consumes the same amount of electricity. The meter runs backwards when the customer puts any surplus electricity they generate from rooftop solar back into the grid.

If, at the end of the billing period, the customer has consumed more power than they've generated, the utility bills the customer the net usage amount in kilowatt-hours (kWh). If the consumer has produced more power than they've consumed, the utility credits the consumer for the excess kWh. Utilities have adopted a variety of policies regarding how long the credits roll over, if and when they expire, and whether or not the customer receives payment for excess generation at the end of the year.

While there are different methods for crediting excess generation,¹⁰ under a net metering system, distributed generation is generally treated in effect as a retail transaction. A kWh exported to the grid is given the same value as a kWh consumed at a residence or place of business.

Net metering is simple, easy to understand, and available to utilities of all sizes and technological capabilities. However, paying the customer for solar generation at the retail energy charge implies that energy charges are only collecting the utility's variable generation costs. As utilities must also recover a combination of generation, transmission, and distribution capacity costs through their energy charges, net metering creates a revenue shortfall for the utility. The net shortfall is made up through higher energy charges for all DG and non-DG customers.¹¹

As more customers install DG systems, the cost-revenue disparity grows wider, leading to even more cross-subsidization. This could cause a calamitous spiral — non-DG customers who pay higher rates may turn to self-generation, which further reduces utility revenue.

Ashley Brown explains that net metering did not develop “as part of a fully and deliberately reasoned pricing policy.”¹² Net metering became the de facto pricing mechanism out of convenience and lack of careful study.

Most meters lacked the ability to do anything more than go backwards and forwards, so utilities could only measure net consumption. With the slow penetration of DG initially, only a small number of utilities felt the revenue impacts of net metering. Most utilities have only a handful of net-metered customers, so they have not yet felt the need to consider alternative rate designs.

As Brown points out, these reasons are less applicable to present-day realities. Advanced meters can track usage on a more granular level, enabling more complicated rate mechanisms. With an increasing number of DG installations and customers, utilities are starting to see the revenue loss and non-DG customers are feeling the rate impacts.

An example provided by Southern California Public Power Authority (SCPPA) Rate Design Working Group helps explain why net metering creates a revenue shortfall.¹³

Even if the fixed cost percentage is less than in the above example, the problem remains. **As utilities typically recover such a high proportion of fixed costs through variable rates, reductions in energy usage by DG customers creates a revenue shortfall that other customers have to make up.**

¹⁰ For a summary of net metering programs at the largest public power utilities, see American Public Power Association, Public Power Utilities: Net Metering Programs, 2014, accessed at: http://publicpower.org/files/PDFs/Public_Power_Net_Metering_Programs.pdf/.

¹¹ For a more detailed discussion of cross-subsidies, see American Public Power Association, Solar Photovoltaic Power: Assessing the Benefits & Costs, 2014, accessed at: <http://publicpower.org/files/PDFs/74%20Solar-Photovoltaic%20Power.pdf>.

¹² Ashley Brown, “Net Metering: The Dark Cloud in a Sunny Sky,” May 27, 2015 Accessed at <http://blog.publicpower.org/sme/?p=576>.

¹³ Southern California Public Power Authority Rate Design Working Group. Updating Traditional Rate Design in the Electric Utility Industry, November 2014, 7.

Utility rate	=	12 cents/kWh (5 cents/kWh energy + 7 cents/kWh fixed)
Consumption reduced by 1 million kWh	=	Revenue reduced by \$120,000
Avoided cost with reduced consumption	=	\$50,000 (1 million kWh x 5 cents/kWh)
Fixed costs remaining with reduced consumption	=	\$70,000 (1 million kWh x 7 cents/kWh)

The fixed costs are borne by the remaining, non-DG customers, thus creating a cross-subsidy.

Estimates of the total cross-class subsidy vary, but one study put the total subsidy for California ratepayers alone at \$1.1 billion by 2020. As solar panels are typically more prevalent in more affluent neighborhoods, less affluent customers are subsidizing wealthier customers.¹⁴

When fixed costs are recovered through a variable charge, “the utility can be exposed to a revenue loss that exceeds the fuel and O&M expenses that were avoided — because customers reduced their energy consumption.”¹⁵ This leads to further rate increases, upsetting remaining customers. SCPPA states:

Without structural changes to traditional rates, utilities will be required to increase their rates more frequently in order to maintain existing reliability standards and meet financial responsibilities contained in their bond covenants.¹⁶

Ashley Brown observes another form of subsidy. If in a day-ahead market, the distributor relies on solar DG to cover some proportion of total system load, and the solar energy becomes unavailable due to weather conditions, then the distributor will have to make high-cost spot purchases to make up for the lost solar production. These costs are then passed on to the remaining customers. If the distributor financially hedges this exposure to the spot market, these costs also are passed onto customers. Almost none of the costs are being passed on to the cost causer.¹⁷

Net metering causes revenue shortfalls for utilities, and creates a situation where one class of customers is subsidizing another. In the long run, this is untenable, especially as more customers install DG systems. Utilities should consider modified approaches to net metering, or completely new billing arrangements, some of which are described in section 3.

¹⁴ Robert Borlick and Lisa Wood, Net Energy Metering: Subsidy Issues and Regulatory Solutions (Washington, DC: Edison Foundation: Institute for Electric Innovation, 2014), 3. The report further notes that when customers lease solar systems, the leasing company gets the lion’s share of the subsidy rather than the customer.

¹⁵ SCPPA, Updating Traditional Rate Design, 6.

¹⁶ Ibid., 6.

¹⁷ Brown, “Net Metering”

Alternatives to Traditional Net Metering



Value of Solar

Austin Energy in Texas is the only utility in the U.S. to have implemented a value of solar (VOS) rate but the concept has generated much discussion. The state of Minnesota has mandated that its investor-owned utilities adopt a VOS rate, and has set a formula.¹⁸ Other utilities have conducted VOS studies to measure the costs and benefits of distributed solar energy.¹⁹

What is value of solar? It is a measure of electric system attributes such as transmission costs, generation costs, environmental externalities, and other inputs, and of how distributed solar energy positively and negatively affects each. **VOS is an effort to associate a quantifiable benefit with each kWh of distributed solar exported to the grid.** Presumably, that number would become the kWh rate at which solar DG would be compensated.

VOS represents a departure from net metering. Austin Energy's VOS rate is based on a "buy-all, sell-all" approach where the DG customer buys all of the electricity it consumes from the distribution utility at one rate, and then separately sells all of its distributed generation output to the utility at the VOS rate.

CASE STUDY

Austin Energy's Buy-all, Sell-all Value of Solar Rate

Austin Energy worked with Clean Power Research (CPR) to develop a VOS rate. A study evaluated various cost and benefit components in an attempt to establish a more equitable rate for solar PV customers.

Austin Energy's VOS tariff is based on an algorithm that incorporates six value components:

- **Loss savings:** Reduction in line losses by producing power where it is generated.
- **Energy savings:** The offset of wholesale purchases.
- **Generation capacity savings:** Added capacity that DG brings to the utility's resource portfolio.
- **Fuel price hedge value:** No fuel price uncertainty associated with solar PV.
- **Transmission and distribution capacity savings:** Reduced peak loading on the T&D system, postponing the need for capital investments.
- **Environmental benefits:** Environmental footprint of solar PV is less than that of traditional fossil-fuel generation.²⁰

¹⁸ See Dan Haugen, "Minnesota becomes first state to set 'value of solar' tariff," Midwest Energy News, March 12, 2014, accessed at <http://www.midwestenergynews.com/2014/03/12/minnesota-becomes-first-state-to-set-value-of-solar-tariff/>.

¹⁹ See, for example, Xcel Energy Services, Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System, (Denver, Co: Xcel Energy, 2013). For a broader survey of that looks at the value of solar on a national level, see Steven Fine, Ankit Saraf, Kiran Kuaraswamy, and Alex Anich, The True Value of Solar, ICF International, 2014.

²⁰ Karl R. Rabago, Leslie Libby, Tim Harvey, Benjamin L. Norris, and Thomas E. Hoff, Designing Austin Energy's Solar Tariff Using a Distributive PV Value Calculation (Austin, TX: Austin Energy, 2013), 2.

As explained by those who designed the rate, Austin Energy's VOS rate represents a "break-even value for a specific kind of distributed generation resource and a value at which the utility is economically neutral, whether it supplies such a unit of energy or obtains it from the customer."²¹

Proponents of VOS tout several benefits:

- A fairer, more accurate rate.
- A reduction in the payback period for solar customers.
- Conservation and efficiency encouraged by decoupling the credit from customer's consumption of energy.
- Greater assurance that Austin Energy is charging for the full cost of serving customers.²²

The customer is billed for total consumption and then receives a credit from Austin Energy for PV production at the VOS rate. If the customer's production exceeds consumption in a given billing cycle, the customer receives a credit, which is rolled over to the next billing cycle.

Austin Energy implemented the VOS tariff in 2012 and has reviewed it every year. The value has fluctuated, declining from 2012 to 2013 and increasing a bit in 2014. The primary cause of the fluctuation is the variability of natural gas futures prices, as this impacts the energy savings and fuel price hedge value components within the algorithm.

In 2014, Austin Energy modified its review methodology to address concerns about the tariff's volatility. Instead of only looking at natural gas futures prices for one year out, the utility developed a "VOS factor" that incorporates a five-year rolling average. This factor is an average of the forward year plus the four previous years. The aim is to smooth out the tariff and keep the value reasonably stable.

Austin Energy has made other revisions. Originally any unused credits would be "zeroed out" at the end of the year, but now the utility allows credits to roll over for as long as the participant is an Austin Energy customer. The utility has removed the 20 kW cap it had originally placed on residential systems to be eligible for the tariff. Now all residential projects, regardless of size, will be on the VOS tariff. Austin Energy now permits leased systems to receive credits, while previously, only those who owned their systems were eligible.

²¹ Ibid.

²² Ibid., 4.



CASE STUDY

Lincoln Electric System's Value of Solar Study

Lincoln Electric System (LES), a Nebraska utility serving more than 130,000 end-use customers, joined the Southwest Power Pool (SPP) Regional Transmission Organization (RTO) in 2009. In 2014, SPP changed its market design and became an integrated marketplace. SPP pays locational marginal prices (LMP) to LES for its generation, while LES pays SPP the LMP for all energy delivered by SPP to LES to supply its load. Distributed generation can reduce LES' load at certain times of the day, thus decreasing the amount of energy LES needs to buy from SPP.

While LES has not implemented VOS, it engaged in a three-month study to determine a true VOS rate, based in part on its move to the SPP market. The purpose of the study was to provide a "frame of reference" to determine the price point at which the LES renewables program would have no net impact on rates over 20 years.²³ The study examined a base case and a solar case. The solar case was modeled on assumptions of how much solar DG would be installed on the LES system. The goal was to derive a DG compensation figure that would put the cost of the solar on par with the costs incurred in the base case, and fairly compensate solar generators without burdening other customers.

The study examined the costs and benefits of distributed solar generation as it affects various components of LES's LMP-based cost of serving its load, including energy, transmission congestion, and marginal transmission losses, as well as environmental benefits and distribution system benefits.

There was a significant benefit in reduced energy costs (approximately \$35 per MWh, or 3.5 cents per kWh). However, solar DG in the LES service territory actually causes slightly increased charges by SPP for transmission congestion and marginal transmission losses. LES believes this is due to relevant power flows in the SPP marketplace, which currently move predominantly from north to south. The southern part of SPP can't effectively handle all of the northern generation because of congestion. The market deals with this by lowering the LMP in the north, thus reducing the prices paid

to prevailing generation and prices charged to serve load.

This means that Nebraska, which is in the northern part of SPP, is more favorable to load than to generation, and therefore distributed resources create more of a cost than a benefit for the congestion component of the analysis.

After weighing all the costs and benefits, the study estimated the cumulative benefit of DG to be \$37.64 per MWh (or 3.7 cents per kWh) for every MWh generated over a 20-year period. The study concluded that if solar PV owners were compensated at that rate for their excess generation, it would have no net impact on rates over 20 years.

The study also examined LES's one-time capacity payment and concluded that western facing installations contributed more value, particularly during peak periods. Therefore, LES increased its one-time solar capacity payment from \$275 per kW to \$375 per kW for southern facing installations and \$475 per kW for western facing installations.

This study informed Lincoln's new rate structure for renewable generation. As LES developed its rates, it was guided by four principles:

- Projects/programs must "pass a reasonable level of economic scrutiny."
- Projects/programs had to be able to scale up without creating unacceptable financial impacts.
- Projects/programs "should provide incentives and pay energy rates that are reasonably commensurate with the benefits provided to the system."
- LES must migrate to a rate structure that more closely aligns to how it incurs fixed and variable costs.²⁴

²³ See presentation from Scott Benson, Manger, Resource & Transmission Planning for LES, available at https://www.youtube.com/watch?v=Gh_3_tEXSH0&feature=youtu.be

On June 1, 2014, a new rate plan went into effect.

It is a tiered structure system, with a declining payback as certain thresholds are reached. Solar-generating customers with systems smaller than 25 kW will continue to receive net metering credits at the full retail rate. All production from larger systems up to 100 kW, as well as net metering customers with excess generation, will be compensated at the same retail rate. Once 1 MW of cumulative distributed capacity has been installed, DG customers will receive half the retail rate as a credit for surplus generation. LES will establish a rate, as yet to be determined, for anyone who installs DG after 2 MW of aggregate distributed resources have been installed.²⁵ The payment rates for tier I and II customers are guaranteed for at least ten years.

The LES rate study determined that the VOS was below the current retail rate. Therefore, the new renewable generation rates reflect a conscious decision to incent solar and renewable development. LES plans to conduct future studies to re-evaluate the VOS as circumstances change. These studies will inform the net metering credit rate after the 2 MW threshold has been reached.

Lessons Learned

Though LES and Austin Energy diverged in the attributes included in their VOS studies, both provide sound examples of how VOS works and how it can be used to inform utility decision making even if a utility does not implement a VOS-based rate.

The Austin Energy VOS rate was determined to be close to Austin's retail rate, while LES's VOS rate is roughly half of its retail rate — indicating that many factors impact rate analysis. While both utilities are located in an RTO, different market structures, energy prices, and congestion points lead to variations in the value of solar. A kWh of distributed solar provides a greater benefit to Austin Energy relative to its costs than a kWh of distributed solar provides to LES.

The VOS is also significantly dictated by the utility's power purchase arrangements. If a utility has "take or pay" purchase power contracts, declining sales will not reduce fixed costs. A utility that procures a larger portion of its power on the market might better be able to reduce costs through reduced sales²⁶ and derive greater VOS. However, that choice will expose the utility's customers to spot market price volatility.

VOS may vary even within a single system. For example, solar rooftop PV might have more value in a congested urban center than in a less constrained suburban area if solar allows deferral of distribution system upgrades.²⁷ Therefore a utility might consider developing localized factors in its VOS rate, establishing different values for different sub-regions within its system. This would have to be balanced against the desire to have simpler, more easily understood rates.

Even if a utility decides not to immediately implement a VOS rate, there is a value in measuring the costs and benefits of DG. LES was able to quantify the VOS, and decide to incent a certain amount of distributed solar development before reducing the rate close to the VOS rate.

A utility should know what the costs associated with DG are, so it can make informed decisions when establishing rates for DG customers.

²⁴ See presentation from Jason Fortik, Vice President of Power Supply for LES, available at <https://www.youtube.com/watch?v=fOfkxil4G4w&feature=youtu.be>

²⁵ For a detailed summary of LES' net metering rate schedule, see <http://www.les.com/residential/rates/rate-schedules>.

²⁶ American Public Power Association, *Distributed Generation: What Public Power Utilities Need to Know* (Arlington, VA: APPA, 2015), 19.

²⁷ Taylor et al, 46. Technological considerations, including whether the PV system has tracking mechanisms, could also be factored in the VOS.

Demand Charges

Demand charges are typically applied only to commercial and industrial customers, based on each customer's peak usage.²⁸ The demand charge assigns a cost to the customer for the relative strain the customer places on system resources. A customer with flatter demand — using electricity at a more or less constant rate — imposes less of a strain on a utility's capacity resources, and incurs a smaller demand charge as a percentage of the total bill.

Predictability of the customer's usage patterns helps the utility better, procuring power either through purchases or generation to meet the expected demand. Customers with greater variability in their load profiles, particularly those who use a greater amount of electricity at peak system periods, place greater strain on the utility, which must quickly ramp up or ramp down its generation resources to meet the shifting demand.

Residential DG customers have distinct load profiles. On sunny days, they might not consume any electricity from the utility during the day, particularly at peak sun times (late morning to early afternoon in many locations), and in fact, may be net exporters to the utility. The DG customer's net demand intensifies gradually as the sun goes down. The utility's peak system-wide demand may occur after the DG system's peak output, meaning that the DG customer is demanding more utility generation just as other customers are also starting to demand more electricity.

The impact on utility capacity costs of a DG customer's demand may be equivalent to or even greater than that of a typical customer because the DG customers transitions from exporting electricity to the utility to taking electricity from it within a single day.

The cumulative system-wide impact of this phenomenon can be seen in the so-called California duck curve.²⁹ The distribution utility must quickly ramp up its resources to meet not only additional demand, but also compensate for the solar generation that is now being lost. The economic impact of this usage pattern can be **compounded in a capacity market where prices might rise dramatically during periods of congestion and high demand.**

Some utilities have chosen to address these issues by implementing residential demand charges, particularly for DG customers.

²⁸ Typically the charge is based on the maximum kW-demand over a 15-minute interval during the billing cycle.

²⁹ See for example California ISO Fast Fact, accessed at https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf. In California, the combination of night-time wind generation and heavy penetration of solar PV has dramatically increased the morning and late afternoon load ramps that must be met through conventional generation.



CASE STUDY

Lakeland Electric's Residential Demand Charge

Lakeland Electric serves 121,387 customers (more than 100,000 residential customers) in central Florida. Lakeland generates almost all the energy needed to meet its customers' load requirements, operating 218 MWs of coal-fired capacity, 774 MWs of natural gas capacity, and 55 MWs of oil-fired capacity. Lakeland is a winter peaking utility, with a winter peak of 612 MW in 2012, and a summer peak of 590 MW.

Lakeland had been operating under a traditional net metering tariff for a number of years. Customers with solar PV installations were charged for each kWh received from Lakeland during the month, and were given a credit for each kWh sent to Lakeland. The credit was at the same rate as the energy charge. Approximately 100 solar installations were interconnected to Lakeland's system as of December 31, 2014.

Lakeland did not have much DG but conducted a rate analysis to measure the efficacy of its net metering program. The utility wanted to better align its revenue with its costs, and it found that the existing program failed to do so.

As a result of the rate analysis, Lakeland modified its net metering program and established a new tariff. Owners

(or leasers) of PV systems on the new tariff will be on a demand pricing rate schedule. **Residential customers will pay a \$4.80 per kW-month demand rate. Solar output will still be credited at the energy rate, but the energy rate will now be lower.**

The demand charge is based on the customer's "maximum 30-minute integrated kilowatt demand in the month."³⁰ This kilowatt demand is intended to be a fair representation of the capacity that the utility is required to stand ready to supply to the customer.

The new tariff applies to new DG customers who sign an interconnection agreement starting October 1, 2015. Existing net metered DG customers will have ten more years on the current energy-only rate.

The purpose of this modified tariff is to better align revenue to costs. Residential demand charges will ensure solar PV customers receive a billing credit for surplus energy they provide to the utility, while paying a fixed charge for demands they place on the utility system, especially during peak hours.

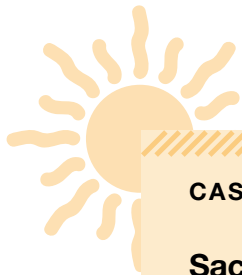
Fixed Charges

Utilities can recover fixed costs by increasing the monthly fixed customer charge. A utility could increase its base customer charge for all customers or elect to add a fixed surcharge to DG customer bills to recoup more of the fixed system costs the utility incurs to serve these customers.

This method is not without controversy as parties have protested proposed increases in several states.³¹ However, it is a mechanism that, if properly applied and accepted, can better align rates with costs.

³⁰ <http://www.lakelandelectric.com/Portals/LakelandElectric/Docs/Publications/Rate%20Tariffs/201502/files/assets/common/downloads/publication.pdf>. See Residential demand service, sheet number 6.3.1.

³¹ See for example the debate in Missouri: <http://www.utilitydive.com/news/utilities-solar-advocates-at-odds-over-missouri-net-metering-bill/386351/>; the controversy of APS's proposal in Arizona: Michael Copley. "Demand charge under APS rooftop solar proposal would add up to \$80 in monthly fees." SNL: Electric Utility Report, July 15, 2013; the Idaho PUC rejecting a customer charge increase: Idaho Public Utilities Commission. "Most of Idaho net metering proposals denied." Case No. IPC-E-12-27, Order No. 32846, July 3, 2013; Louisiana PSC rejecting a customer charge increase: Amanda H. Miller. "Louisiana PSC upholds net metering." Clean Energy Authority, July 1, 2013. Accessed at: <http://www.cleanenergyauthority.com/solar-energy-news/louisiana-psc-upholds-net-metering-070113>; and the discussion around Wisconsin utilities increasing their fixed charge: <http://www.midwestenergynews.com/2014/11/11/wisconsin-fixed-charge-decision-a-sign-of-more-to-come/>.



CASE STUDY

Sacramento Municipal Utility District's Rate Restructuring

The Sacramento Municipal Utility District (SMUD), which serves just over 600,000 customers, of which just under 540,000 are residential customers, increased its fixed charge to recover the cost of service.

SMUD's net metering program was formally adopted by its board in 2008. Like most net metering programs, SMUD credited its solar customers for surplus generation at the same kWh rate that it charged them for electricity it provided to their homes or businesses. SMUD also established a ten-year rebate program — with a stepped payout declining over time — to incent solar development.

Legislation passed in California — AB 920 — discouraged the practice of paying customers at the full retail rate for surplus generation. As a result, SMUD adopted a system where it paid net generators annually at the net metering surplus compensation (NMSC) value. The NMSC value is based on SMUD's wholesale power supply cost, which is about half of the retail rate. Net metered customers retain the option of rolling over their generation credits to cover kWh supplied by SMUD to the customer in the next month.

SMUD also changed its monthly customer charge, also known as a system infrastructure charge, for all customers. In 2011, SMUD determined, based on a cost study, that its marginal cost of serving a customer was about \$26.

The utility wanted to better align rates with costs, so it decided increase its system infrastructure fixed charge for residential and small commercial customers to a point that was closer to the marginal cost. The fixed charge increase was offset by a reduction in energy charges.³² The SMUD Board approved the proposal with a phase-in of the fixed charge over a five-year period.

These changes were made as SMUD began a full rollout of its smart meter plan. Today, virtually all SMUD customers have smart meters. While this does not directly affect how

SMUD charges and credits its DG customers, smart meters provide flexibility to perform analysis on rates and rate structures, which may indirectly affect DG customers.³³

SMUD began redesigning its rate structure in 2011, consolidating its tiered-rate structure down from three to two tiers for residential customers, and introducing time-varying rates for small commercial customers. SMUD also redefined its seasonal period and created a four-month summer period to prepare residential customers for future peak pricing plans.³⁴

In 2013, SMUD began a restructuring of its residential rates that will culminate in universal time-based pricing beginning in 2018. The General Manager report states:

The gradual, multi-year transition will bring all customers in line with the true cost of electricity and will avoid some customers paying more than it costs for SMUD to serve them. SMUD's goal is to gradually transition from tiered pricing, which is the current structure, to time-based pricing. The transition will span four years with full time-based pricing planned to begin in 2018.³⁵

While SMUD's rate changes do not directly address DG, a time-based pricing structure will affect the rate at which DG customers are compensated for excess generation.

SMUD has adopted a **phased-in approach that allows customers to grow accustomed to the new rate design.** Customer education is particularly important when it comes to significant modifications to residential rates that may shift charges from one set of customers to another.

³² For more information on the system infrastructure fixed charge, see <https://www.smud.org/en/about-smud/company-information/document-library/documents/GM-Rate-Report-Addendum-2-06-16-11.pdf>.

³³ See SmartPricing Options Final Evaluation, the final report on pilot design, implementation, and evaluation of the Sacramento Municipal Utility District's Consumer Behavior Study, issued September 5, 2014, available at https://www.smartgrid.gov/sites/default/files/doc/files/SMUD_SmartPricingOptionPilotEvaluationFinalCombo11_5_2014.pdf

³⁴ General Manager's Report and Recommendation on Rates and Services, April 7, 2011, available at <https://www.smud.org/en/about-smud/company-information/document-library/documents/GMRateReport-Vol1-04-07-11.pdf>.

³⁵ General Manager's Report and Recommendation on Rates and Services, May 2, 2013, available at <https://www.smud.org/en/about-smud/company-information/document-library/documents/2013-GM-Rate-Report-Vol-1.pdf>.



CASE STUDY

City of Whitehall's Customer Charge Increase

The City of Whitehall, a public power utility in Wisconsin serving fewer than 1,000 customers, increased its monthly customer charge, shifting recovery of some of its fixed distribution costs away from its variable energy rate.

A cost-of-service study had shown that approximately 29 percent of Whitehall's charges were fixed, but the utility was collecting only 9 percent of its revenue through its monthly customer charge. It therefore sought to increase its customer charge on single-phase residential and general service bills from \$8 to \$16 per month.

In testimony before Wisconsin's Public Service Commission (PSC), the utility explained:

Whitehall's proposal better aligns the fixed charges received from customers with the fixed costs the utility incurs to provide those customers with access to the electric system. Further, Whitehall's proposal more fairly and equitably spreads the costs of service among its residential and general service customers.³⁶

The PSC ultimately agreed to the increase to \$16 only for customers on Whitehall's flat energy rate. For customers on the utility's optional time-of-use plan, the customer charge was increased to only \$10, to see if this would incent other customers to move from the flat rate to the TOU plan.

One potential variation to the customer charge is a **minimum bill**. This is not a set charge applied to all customer bills. But a utility could establish a minimum amount, say \$20 per month, for a customer bill. If a customer accrues at least \$20 in variable energy charges, they would not have to pay any portion of that minimum charge. This minimum charge would apply only if the customer's net usage falls under the minimum amount. If the customer's net usage is zero, then the customer would pay exactly \$20 as their minimum bill.³⁷

Separate Metering

An alternative to net metering is a **buy-sell approach in which the customer purchases all energy consumed on site at the utility's retail rate, and then separately sells all its surplus rooftop generation to the utility at avoided cost.**³⁸ This is similar to the VOS approach, in which consumption and generation are treated as completely separate services with different price points and rate designs. The difference is that instead of a detailed methodology to determine a specific rate, the utility would just pay the PV customer the wholesale rate, or some other similar rate, for all energy exported to the utility by the customer.

³⁶ Application at page 3, Application of the City of Whitehall, Trempealeau County, Wisconsin as an Electric Public Utility, for Authority to Increase Rates (Wisconsin Public Service Commission filed March 4, 2015) (Docket No. 6490-ER-106)

³⁷ Jim Kennerly, "The Minimum Bill: A First Step to Fair Utility Rates in a Distributed Energy Age," PV Solar, September 10, 2014, accessed at <http://www.pvsolarreport.com/minimum-bill-first-step-to-fair-utility-rates/>.



CASE STUDY

Santee Cooper's Net Billing Program

The South Carolina Public Service Authority, also known as Santee Cooper, supplies electricity to more than 172,000 retail customers as well as to 27 large industrial facilities, and to other power systems, including the state's 20 electric cooperatives.

Santee Cooper adopted a net billing program in response to the revisions in the Public Utility Regulatory Policy Act (PURPA) made via the Energy Policy Act of 2005. The utility adapted rates for DG customers to minimize cost shifts.

Santee Cooper's net billing rate applies to customer-side generation with a nameplate rating that cannot exceed the estimated maximum monthly kW demand of the residence or 20 kW, whichever is less. Additionally, customers on this rate pay a \$24 per month customer charge as well as an on-peak demand charge of \$11.34/kW per month, and off-peak demand charge of \$4.85/kW per month.

Santee Cooper separately meters electricity supplied to the customer and electricity supplied by the customer. The energy credit to customers for surplus generation and the energy charge paid by customers are based on the time of day. There are different on-peak and off-peak energy charges, with a seasonal component — the summer on-peak charge is different from the winter on-peak charge. **At the end of the billing cycle, Santee Cooper nets all of the charges to the customer against all of the credits that the customer has accumulated.**

Ashley Brown offers a modification to separate metering:

If utilities pay all energy producers, large or small, central or distributed, at the locational market price, it has the advantage of bundling both transmission costs or savings and energy costs. It is a rather level playing field for all generators, with a slight advantage to solar PV DG because, again, it assures purchase without assured delivery.³⁹

Under this rate design, distributed generators would essentially be treated the same as wholesale power producers. This method also has the effect of stripping away the connection between the utility's retail rates and its payments to distributed generators.

Other Net Metering Variations

Without demand or added fixed charges, net metering is an inefficient way to align costs and revenues. However, it can be adjusted in a way that better aligns revenue with costs.

³⁸ Borlick and Wood, Net Energy Metering, 12. =

³⁹ Brown, "Net Metering".



CASE STUDY

Concord Light's Wholesale Credit Rate

Concord Light in Massachusetts serves 8,100 total customers and approximately 6,800 residential customers. The utility credits excess generation at less than the retail rate. Concord subtracts each customer's excess production from the customer's electricity purchases, and bills them the net amount at the end of a billing cycle.

If a customer produces more generation than is purchased in a given month, that customer receives a credit equal to the price that Concord pays the New England Independent System Operator (ISO-NE) for energy on the spot market.

The spot market price in 2012 was under 4 cents per kWh and was projected to be the same for 2013. **This is substantially lower than the residential retail rate,** which ranges from approximately 14 to 17 cents per kWh.⁴⁰

Concord also combines a distribution charge with its net metering tariff. The distribution charge goes up incrementally as the customer PV system size increases. The monthly charge for the smallest unit (2-4 kW) is \$3.60 per month. Twenty percent of each customer bill goes toward maintaining the distribution system and to cover the utility's distribution operating costs. The distribution charge ensures that these costs are shared among all Concord customers, even those who generate some of their own electricity.

New Braunfels Utilities in Texas also combines a monthly customer charge, delivery charge, and cost of power charge with its net metering rate. It also has a minimum monthly bill, which is laid out in its net metering tariff as follows:

The minimum monthly bill shall be the customer charge plus the delivery charge per installed kW of generation, and any special charges or adjustments.⁴¹

⁴⁰ "Concord Light: Residential Solar PV Net Metering Policy Acknowledgement." Accessed at: http://www.concordma.gov/pages/ConcordMA_LightPlant/Netmeteringpolicyacknowledgement081613.pdf

⁴¹ New Braunfels net metering tariff, accessed at <http://www.nbutexas.com/Portals/11/pdf/Electric%20Rates%203-09.pdf>.

Customer Education

Communicating to customers about changes to rates and rate structures is critical, especially for a customer-owned public power utility. In the case of rate design related to DG, both DG and non-DG customers need to understand why the decisions have been made.

Utilities must explain the relationship between costs and rates to gain customer understanding and support. On its website, Concord Light explains why the utility continues to accrue fixed costs to serve its solar customers:

Customers with solar PV systems continue to receive all of the services provided by the electricity distribution system in town and by Concord Light. Customers' adoption of solar does not reduce Concord Light's costs for maintaining local infrastructure and providing services. The customer acknowledges that the distribution charge is a condition of receiving net metering credits from Concord Light.⁴²

Engaging customers helps to gain their acceptance. For example, Lakeland Electric held a series of workshops with elected officials, stakeholders, and citizens' groups and invited public comments before implementing its demand charges. Stakeholder reaction to the increased customer charge and the demand charge has been mostly positive.

After completing its VOS study, LES held public stakeholder meetings to explain the process and ratemaking decision. The meeting videos are posted on YouTube and linked from the LES website.⁴³ The website also contains links to reports and other documents that further explain net metering and solar rooftop PV.

An American Public Power Association guidebook, *Distributed Generation: A Guidebook for Public Power Utilities*,⁴⁴ suggests that utilities should conduct meetings with key stakeholders and customers on contemplated changes to rate design, and communicate strategic plans with lenders and oversight boards.

The guidebook provides details on how to conduct a customer education program on the implications of installing DG. The program should include information on potential rate increases, changes in rate design, standard terms in DG contracts and leases, how to vet third party vendors, DG equipment, and safety and reliability issues connected to DG.

Such programs can benefit the utility, too, as the guidebook notes:

The utility can learn about customers' DG preferences and willingness to pay for currently embedded utility services such as reliability and distribution system maintenance.

⁴² Concord Light: Residential Solar PV Net Metering Policy Acknowledgement.

⁴³ Videos can be accessed at <http://www.les.com/savings-energy/solar-customer-owned-gen>.

⁴⁴ APPEA, 27.

Conclusion

We are beyond the initial stages of DG. More and more customers are installing DG, and there is no sign that this trend will slow in the immediate future.⁴⁵ Utilities can no longer afford to take a wait and see approach when it comes to rate design, nor should they assume that their existing rate design — especially a net metering design that was adopted before the escalation in the number of DG installations — will suffice to recover the utility’s revenue requirements and send good price signals to its customers.

This report describes a variety of rate design options for public power utilities to consider. No single design will work for all utilities. Community needs, market structure, state policies, and myriad other considerations will influence each utility’s ultimate decision.

It is also important to keep in mind that, as is always the case with rate design, there will be tradeoffs. Ken Costello offers advice to regulators that applies equally to utilities:

Public utility regulation always involves compromising different objectives. For example, to improve economic efficiency, how much higher would rates become for certain customers? Are these two outcomes, taken together, fair to all customers and in the public interest? How much would economic efficiency have to increase to compensate for the higher rates? No single rate mechanism is superior to other mechanisms in advancing all of the regulatory objectives.⁴⁶

No single approach is right for rate design. Rate setters must balance between simplicity and accuracy, align costs and prices, promote conservation, and consider many more factors. While some rate designs may be better suited to proper cost alignment, utilities must carefully consider whether they are well suited to customers.

Communication and engagement are essential components of the rate-setting process.

⁴⁵ Although the potential reduction in the solar investment tax credit could dampen the marketplace to some degree.

⁴⁶ Ken Costello, “Evaluating Alternate Rate Mechanisms: A Conceptual Approach for State Utility Commissions,” *Electricity Journal* Volume 27, Issue 4 (2014), 24.



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