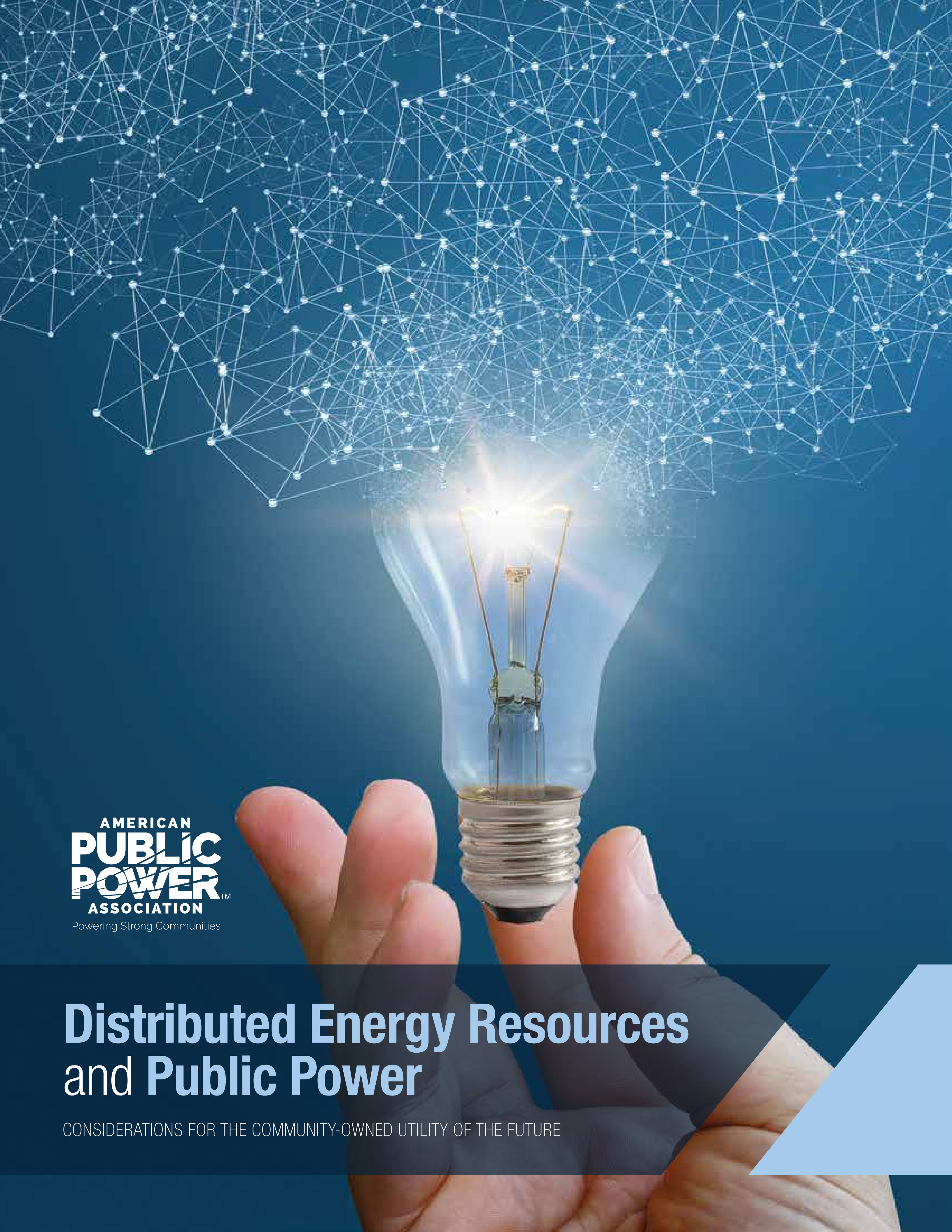

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Distributed Energy Resources and Public Power

CONSIDERATIONS FOR THE COMMUNITY-OWNED UTILITY OF THE FUTURE

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The American Public Power Association is the voice of not-for-profit, community-owned utilities that power 2,000 towns and cities nationwide. We represent public power before the federal government to protect the interests of the more than 49 million people that public power utilities serve, and the 93,000 people they employ. Our association advocates and advises on electricity policy, technology, trends, training, and operations. Our members strengthen their communities by providing superior service, engaging citizens, and instilling pride in community-owned power.

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INTRODUCTION

The electric industry continues to undergo rapid technological changes due to government policy and market changes. Recent developments in technology and policy, particularly related to rooftop solar photovoltaic (PV) installations, are changing how electric utilities operate.

Distributed energy resources (DER), including energy storage, microgrids, and electric vehicles, increasingly impact load management, electric rates, and customer interaction with the electric utility.

Policy developments, particularly at the state level, focus on reforming rate design, net metering, community solar, and other DER-related topics. States including New York, Massachusetts, and Minnesota have begun to reform the traditional electric utility model to better incorporate DER. Nearly every other state has introduced legislation concerning DER, particularly the rate and revenue impacts of increased deployment. As these policies are being explored, this report offers an informative review of the opportunities and challenges of different DER, implications of each technology on utility operations, and case studies from public power utilities that have implemented specific aspects of DER integration.

When the American Public Power Association (Association) published a report on policy developments related to distributed generation (DG) four years ago, the report focused on some of the operational and revenue challenges rooftop solar systems pose.[1] This report revisits the core concepts and issues discussed in the previous report with updated developments with other types of DER, such as storage and electric vehicles. This report also examines state legislation and regulatory proceedings on DER, including broader state proceedings on reforms to the utility business model, including the New York Reforming the Energy Vision (REV).

Ultimately, the technological and policy developments offer a peek into the potential "utility of the future." Staying informed on these developments will help public power utilities to navigate the new complexities DER may bring to the industry.

[1] *Distributed Generation: An Overview of Recent Policy and Market Developments,* published November 2013. Available at http://www.publicpower.org/files/PDFs/Distributed%20Generation-Nov2013.pdf.

THE IMPACTS OF DISTRIBUTED GENERATION

Distributed Generation and Distributed Energy Resources

Distributed generation (DG) refers to power produced at the point of consumption, particularly small-scale energy resources that typically range in size from 3 kilowatts (kW) to 10 megawatts (MW) or larger. Most residential systems are 10 kW or less, while some commercial and industrial systems may exceed 1 MW in capacity.

DG is an element of distributed energy resources (DER). DER, as defined by the Electric Power Research Institute, "are smaller power sources that can be aggregated to provide power necessary to meet regular demand."[2] Broadly speaking, DER comprise a variety of customer-sited technology, including storage, demand response, energy efficiency, and electric vehicles. Though these terms are used interchangeably, in this report DG refers more narrowly to customer-sited generation resources, while DER refer to the broader sweep of customer-sited technology.

The Solar PV Market

The solar market continues to grow. Calendar year 2016 was a record-breaking year for the solar industry, as 14,762 MW of solar PV were installed, approximately double the 2015 total. Spurred by price reductions and tax incentives, 2016 was the first year that solar was the leading source of capacity additions in the United States.[3]

Most new solar capacity was utility-scale solar, representing 10,593 MW of the new capacity. Non-residential installations, especially commercial and industrial projects, accounted for 1,586 MW of new capacity.[4] Residential solar accounted for 2,583 MW of new installed capacity, with noticeable growth in states such as Utah, Texas, and South Carolina.[5]

Because many anticipated the Investment Tax Credit (ITC) to expire at the end of 2016, developers were eager to put new projects in the pipeline. Though the ITC did not expire, solar capacity development has slowed.[6]

The residential PV market has especially slowed as national solar companies pursue new business models in lieu of expanding their customer base.[7] For the first time, year-over-year residential solar PV installations declined in the first quarter of 2017, with deep declines in California due in part to wet weather, and there was a slowdown in overall solar capacity development. A total of 2,044 MW of solar PV were installed in the first quarter of 2017.[8]

While the rate of installations has slowed somewhat in recent months, this follows tremendous growth over the past few years. Some states have had far more development in the rooftop PV marketplace, especially Hawaii and California.

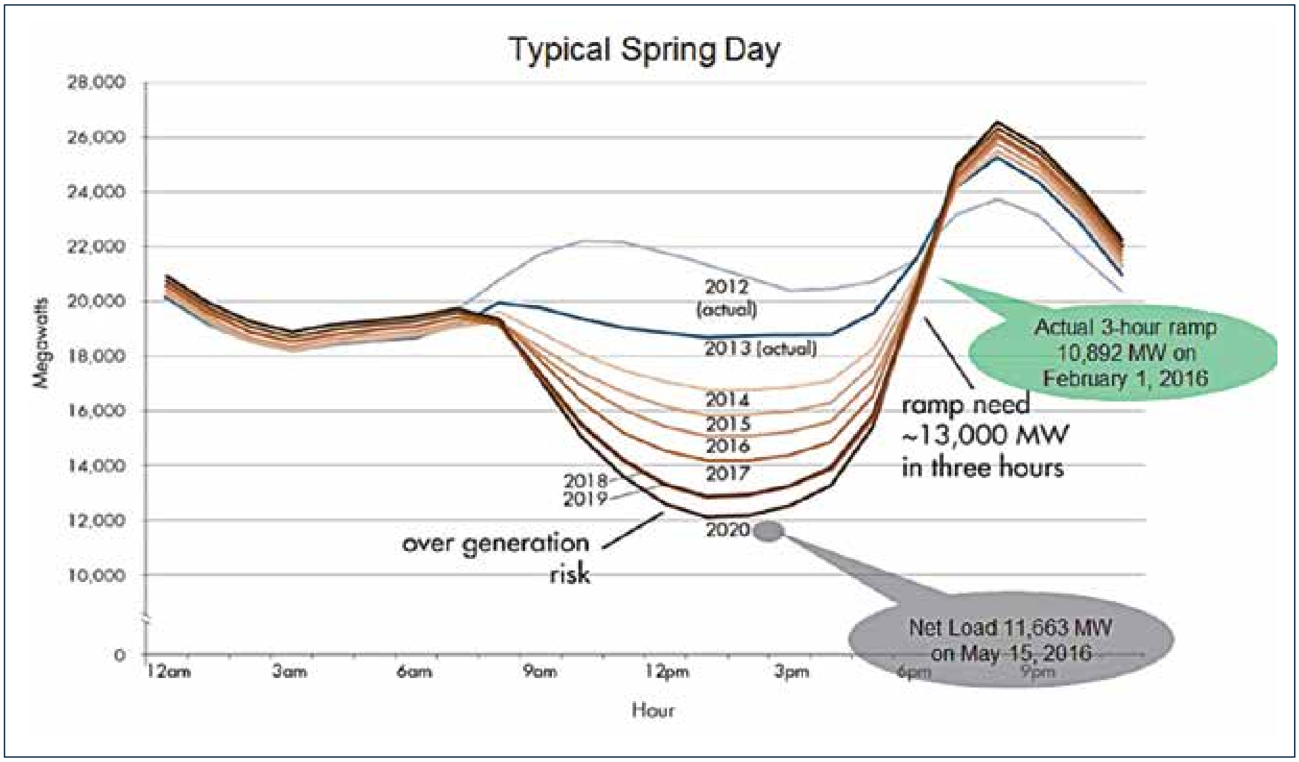
Overall, there are approximately 8,000 MW of residential solar PV capacity installed in the United States, spread out over 1,000,000 residential customers.[9] This capacity is unevenly distributed throughout the United States, with most of the capacity in California, Hawaii, and the southwest, though there is also a considerable amount of solar PV in states such as New Jersey and Massachusetts.

Utility Operations and DG

The addition of DG impacts the electric grid in multiple ways, many of which are positive. One of the principal benefits of DG is avoiding building additional generation capacity to the extent energy production, or reduction, is reliably coincident with demand. Distributed resources can take the place of retiring assets, or obviate the need to build new generation resources as reserve margins dwindle. Moreover, the overwhelming majority of new DG

2 http://www2.epri.com/Our-Work/Pages/Distributed-Electricity-Resources.aspx
3 GTM Research. *US Solar Market, 2016 in Review,* p. 5.
4 Ibid., p. 11.
5 Ibid., p. 10.
6 GTM Research. *US Solar Market Insight, Q2 2017,* p. 6.
7 Ibid., p. 7.
8 Ibid., p. 12.
9 Figures deduced by adding 2,044 MW installed in 2016 to 5,444 MW of "net metered" capacity as reported on Form EIA-861, 2015 data.

Figure 1: Duck Curve



Source: California ISO, 2016

is represented by solar PV, which means an increase in the share of non-carbon emitting generation, giving DG valuable environmental attributes. DER can also help reduce transmission-related costs, both because they reduce peak demand and because they are located at or near the load.

A study from Arizona Public Service (APS) identified load reductions attributable to DG would mean APS could procure fewer spinning reserves.[10] Furthermore, DG paired with other technologies could have other benefits including reactive power, power quality, and voltage support.[11]

PV paired with storage creates further opportunities, especially with regards to peak load reduction. Since system peak does not always correspond with solar peak, the ability to offset peak energy use with batteries charged at times of higher solar concentration (and less electric usage) would be of value to the utility and even independent system operators (ISO) and regional transmission organizations (RTO), where applicable.

However, when solar PV is not paired with storage – few DG systems are – utilities experience greater load management issues. As mentioned above, the peak time for solar does not always correspond with the utility's peak. When the peak times correspond, rooftop solar PV helps reduce the peak load. But when they do not correspond, rooftop solar can exacerbate load management issues. This is one of the potential challenges of greater DG penetration.

The "duck curve" (Figure 1) helps illustrate this point. In California, there is a great reduction in load in the late morning and early afternoon. This load is further reduced as rooftop solar PV systems generate at their peak. But as the afternoon rolls on, solar production begins to ramp down at the same time when statewide demand increases.

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

11 K.R.S. Kashyap and B. Dheeraj Reddy. *Ancillary Services and Stability Analysis of Distributed Generation System,* International Journal of Engineering Research and Applications, Vol. 3, Issue 3, May-June 2013, pp. 247-251, available at https://pdfs.semanticscholar.org/0fb8/d7740b21000775c27f90dd621077909b855a.pdf.

Therefore, utility-scale generation must simultaneously make up for the standard increase in demand and the additional demand no longer being met by solar PVs.

This highlights the fundamental operational challenge of solar PV: it is an intermittent resource. Solar panels produce energy only when the sun is shining. The setting sun diminishes production, and afternoon clouds, rainfall, and high temperatures can reduce the efficiency of panels. These factors make it difficult for system operators, particularly since they do not have operational control over DG resources.[12]

There are also safety concerns related to DG. One such concern is unintentional "islanding," which refers to a situation where DG continues to energize a feeder even when the utility is otherwise not supplying power due to an outage. This puts utility workers and the public at risk as they may not realize a circuit is still energized. Other safety issues include high-voltage spikes, which can cause customer equipment damage and even DG-created blackouts (although the latter is only remotely possible at very high DG penetration levels).[13]

Revenue and Cost Recovery

Public power utilities generally undertake cost of service (COS) studies to establish revenue requirements. Though it is difficult to exactly match revenues to cost, the goal is to establish a revenue requirement equal to their COS. Though it is difficult to exactly match revenues to cost, nonmaterial mismatches are not of great concern, and can be accounted for via true-up mechanisms or power cost adjustments.

DG, particularly in a net metering regime, can cause significant revenue shortfalls. Under a standard net metering tariff, customer generation exceeding the customer's energy needs flows back to the electric grid. Excess generation can result in the kilowatt hours displayed on the customer's meter to move backwards, essentially crediting the customer for the excess generation at the retail rate of electricity.

The majority of a residential bill is based on the customer's electricity use. However, a much greater proportion of a utility's costs are fixed – customer service, meters, capital investments – than is reflected on a customer's bill. A typical residential bill has a small ($10 or less per month) customer charge. While DG customers can reduce the utility's variable costs through lower monthly usage, their fixed costs remain the same regardless of usage. The reason net metering leads to this shortfall is because most residential rates are based on variable energy charges.

If revenues dip below the COS, then those lost revenues must be recovered somewhere else. The utility may raise its rates. If it does so, the DG customer's bill may increase, though it would still be lower overall than it had been before the installation of rooftop solar PV. Non-solar customers, on the other hand, would see an overall increase in their monthly bills. Therefore, under most net metering arrangements, non-solar customers are subsidizing solar customers.

Rate Design Options

Utilities have begun implementing or are considering implementing rate design changes to address these imbalances.[14] These options are summarized below.

Residential Demand Charges: Though demand charges are common in commercial and industrial rates, they are atypical for residential tariffs. A demand charge assigns a cost to the customer for the relative strain the individual customer places on system resources. Demand charges are reflective of the fact that customers with a more variable load – meaning one that shifts up and down throughout the day – place more strain on the system than customers with flatter loads.

Demand charges are typically based on a customer's monthly peak kW energy demand. For example, if the demand charge is $5 per kW month, and the peak demand for the month is set at 8 kW, then the demand portion of the bill would be $40. In a three-part tariff including a demand charge, the variable energy charge is reduced, so the overall bill impacts for the entire rate class are meant to be revenue neutral.

There are multiple options for setting a demand charge. A demand charge can be established by the customer's peak usage during any period (non-coincident peak), or only during the utility's peak (coincident peak). The demand charge window can be as short as 15 minutes or as long as

[12] GE Energy. *Impact of Photovoltaic Generation on Distribution Systems.* Schenectady, NY: Distribution Systems Testing Application and Research, 2013.
[13] *Distributed Generation: An Overview of Recent Policy and Market Developments,* pp. 8-14.
[14] American Public Power Association. *Rate Design for Distributed Generation: Net Metering Alternatives with Public Power Case Studies,* June 2015. Available at http://www.publicpower.org/files/PDFs/Rate_Design_for_DG-_Net_Metering_final.pdf.
[15] Naim Dargouth, et al. *Exploring Demand Charge Savings from Residential Solar.* National Renewable Energy Laboratory and Lawrence Berkeley National Lab, January 2017, pp. 25-31.

four hours.[15] If the demand charge is set during a shorter window, PV owners may be subject to higher peak billing demands due to cloudiness. Over a longer window, DG customers can experience even more savings if the demand charge is established during peak periods. The demand charge can be established over a single period, or it can be the average of multiple peaks.[16]

A demand charge enables the utility to recover a greater portion of fixed costs through a quasi-variable rate. Like fixed charges (discussed below), they recover fixed costs, but in a way in which the customer has more direct control. In the context of DG, demand charges help mitigate the problem of cross-customer subsidies. Demand charges for DG customers allow the utility to recover more of the costs associated with serving customers who become net users of electricity at the time of system peak.

Most customers are unfamiliar with demand charges, and therefore may balk at this addition to their monthly bill or may have difficulty understanding how the charge is established. Furthermore, some customers may not be able to control when they use electricity, and could be subject to higher charges than customers with otherwise similar profiles.

One potential impact of a demand charge is increased customer interest in energy storage. A customer who pairs a rooftop PV system with energy storage can reduce their demand at peak times, thus avoiding a potentially high demand charge.[17]

Increased Fixed Charges: Some utilities have begun to recover a greater proportion of their fixed costs through higher monthly fixed customer charges. Though many utilities have been unsuccessful in raising the charge, some utilities have at least been permitted a small or moderate increase.[18]

Increased customer charges are a relatively simple way to recoup fixed costs. Since customers already pay customer charges, they are at least familiar with the concept, unlike demand charges. The customer charge is also a steadier, more consistent stream of revenue.

However, customer advocates tend to dislike increases in fixed charges.[19] Fixed charges adversely impact low-use customers who, in many cases, are low-income customers.[20] However, this is not true in all cases. With some utilities, there is an inverse relationship between usage and income, due in part to differences in access to energy efficiency. Higher customer charges may provide a disincentive for energy efficiency, especially since they are usually paired with lower variable energy charges.

Moreover, high fixed charges may discourage customer investment into certain types of DG, particularly into leased PV systems. And if the customer charge is set too high, it could even lead to grid defection, where customers completely remove themselves from electric utility service, especially if technologies come along to supply the customer with the electricity not furnished by the rooftop system at a cost which is less than the all-in cost of a monthly utility bill.[21]

Another option some utilities have adopted is a hybrid demand-customer charge. Under this approach, the customer charge is tiered based on the customer's peak monthly usage over a year. Therefore, a customer with higher typical usage would have a higher customer charge than one with lower peak usage.

Time-Varying Pricing: Time-of-use (TOU) or time-varying pricing (TVP) are becoming more widespread, even outside the context of DG. Under TVP, the price of electricity more accurately reflects the actual cost of delivering service. As such, prices would be higher at peak periods, while reduced at other times. Some TVP pricing regimes have a simple on-peak, off-peak rate, while others have multiple pricing periods.

In general, TVP rates align utility costs and revenues in a more equitable fashion, as the wholesale price of electricity is much higher during periods of peak usage. In the context of DG, TVP may be beneficial because the excess generation would be credited at a rate potentially more reflective of its actual value.

TVP generally requires the use of advanced metering infrastructure (AMI), so this option is not available to utilities without AMI. In some cases, the benefits of rolling out TVP rates (or even some of the other associated benefits of AMI) may not outweigh the cost of implementing AMI.

16 See *Rate Design Options for Distributed Energy Resources,* pp. 9-12 for a more detailed discussion of setting the demand charge, as well as the pros and cons of establishing one.
17 For an explanation of how solar can be paired with storage, see Daniel Muoio, "Tesla's rechargeable battery can power your home with solar energy – here's how it works, Business Insider, May 12, 2017, available at http://www.businessinsider.com/how-teslas-powerwall-2-works-solar-roof-2017-5.
18 For examples, see *Rate Designs for Distributed Energy Reources.,* p. 13.
19 Janee Briesemeister and Barbara R. Alexander. *Residential Consumers and the Electric Utility of the Future.* American Public Power Association (2016).
20 National Consumer Law Center at http://www.nclc.org/energy-utilities-communications/utility-rate-design.html/.
21 Energy Center of Wisconsin. *Third-Party Distributed Generation: Issues and Challenges for Policymakers,* March 2014, pp. 34-35.

Also, as with demand charges, some customers may not be able to modify their usage to avoid being charged during higher-priced periods. As with demand charges, TVP could make solar paired with storage a more attractive option because storage could be deployed at higher priced periods. Another issue within the DG context is that TVP rates could compound cost recovery issues if fewer peak price events occur than anticipated or if customers reduce usage more than anticipated in response to the peak rates.

Net Billing: Under a net billing scenario, the utility measures the amount of energy used by the customer from the utility on one meter, and then separately measures the amount of excess generation supplied by the customer to the utility on another meter. These amounts are then netted against each other to determine the customer's monthly bill. In lieu of net metering – where DG customers are compensated for excess generation at the retail rate – utilities with net billing may issue credits at the wholesale power cost of supply, avoided cost, or some other predetermined credit rate.

Buy-All, Sell-All: As with net billing, the credit rate for customer-side generation is made to be different than the retail rate of electricity delivered to the customer. As opposed to net billing, however, all electricity consumed by the customer and all electricity generated is accounted for, with separate meters accounting for consumption and generation. All the electricity consumed by the customer – whether supplied at the customer's residence or by the utility – is billed at the retail rate, while all customer-side generation – whether consumed by the customer or sent to the grid – is credited at a separate rate. At the end of the month, these amounts are netted out.

From a utility's cost recovery perspective, buy-all, sell-all may be preferable to net billing. Consider a hypothetical customer who consumes 1000 kWh of electricity a month. The customer purchases 400 kWh from the utility, uses 600 kWh of self-generated power, and generates an excess 400 kWh. The retail rate is $0.10, and the rate for generation is set at $0.06.

Under net billing, the customer's energy bill would be $16: $40 charged (400 kWh purchased from the utility at 10 cents) minus $24 credited (400 kWh generation exported to the grid at 6 cents). Under buy-all, sell-all, the customer's energy bill would be $40: $100 charged based on total consumption of 1000 kWh at a rate of 10 cents against a credit of $60, based on total generation of 1000 kWh at a rate of 6 cents.

Value of Solar: The value of solar (VOS) approach is an effort to assign a quantifiable benefit to each kWh of solar energy exported to the electric grid. It is similar to the buy-all, sell-all mechanism, though the generation value is established through a more robust calculation.

Typically, VOS evaluations include:

- Energy
- Emissions
- Transmission and distribution loss savings
- Generation capacity
- Transmission and distribution capacity
- Ancillary services
- Other costs and benefits, including environmental, fuel price hedging, operation and maintenance expenses, and others.[22]

The benefit of a VOS rate design is that the credit for solar production would be reflective of the actual value of solar to the system. A utility could provide a detailed analysis that explains the VOS rate, which could provide customers some assurance that the utility has done its due diligence in setting a fair rate.

A VOS rate does not necessitate a system-wide meter upgrade, as only customers on the VOS tariff would require a second meter.

One drawback to VOS rates is they do require more meticulous calculations than other rate design options. Even if all stakeholders agree upon the general costs and benefits to measure, they may disagree over certain assigned values, such as the environmental benefits of solar generation.

Impacts of Changing Rate Design

Each rate design option affects various stakeholders in different ways. For the utility, smart rate design can close the gap between costs and revenues. Most of the rate design options described above would ease the burden on non-DG customers and shift costs back to DG customers.

Moving away from net metering could discourage further DG deployment. The National Renewable Energy

[22] Mike Taylor, et al. *Value of Solar: Program Design and Implementation Considerations*. (Golden, CO: National Renewable Energy Laboratory, 2015), p. 10.

Laboratory (NREL) ran modeling scenarios to predict the future rate of DG deployment without net metering. In the ten states with the most DG deployment up to now, NREL projects a 62 percent reduction in residential DG deployment if net metering is eliminated, versus a 123 percent increase if net metering is kept in place.[23]

Not all rate designs have the same impact on DG customers. NREL investigated scenarios under different rate designs, each with differing impacts depending on the severity of the charge. High fixed charges and demand rates tend to decrease savings for DG customers, thus lengthening the payback periods. On the other hand, NREL found that TVP generally increased bill savings for DG customers, though that depended in part on the wholesale market structure. And even when DG customers generally benefitted, some fared worse under TVP.[24]

[23] Glen Barbose, et al. *On the Path to SunShot: Utility Regulatory and Business Model Reforms for Addressing the Financial Impacts of Distributed Solar on Utilities.* National Renewable Energy Laboratory and Lawrence Berkeley National Lab, May 2016, p. 33.
[24] Ibid., pp. 36-40.

OVERVIEW OF DER TECHNOLOGIES

There are numerous types of DER: community solar, utility-scale and customer energy storage, and plug-in electric vehicles. Certain technologies, such as microgrids and blockchain tie to DER and may be useful to the operations of the utility of the future. This chapter explores each of these concepts, including cost, benefits and drawbacks, operational considerations, and potential rate design.

Community Solar

Community solar projects are solar PV installations that are jointly owned or leased by community members. If owned by a third party, participating members receive shared benefits, including bill credits. Community solar helps bring the benefits of solar power to customers who may lack the financial means to purchase rooftop solar, whose rooftops may not accommodate solar, or who are renters. It also offers utilities a means of entering the solar marketplace without taking on the risks of a large utility-scale project.

As described in the Association's ***Community Solar A-Z: Guide for Public Power Utilities,***[25] there are multiple options for program design and ownership structure. In many cases, because public power utilities cannot use the investment tax credit (ITC) for solar, a third party finances the system installation, the utility enters a power purchase agreement (PPA), and then in turn enrolls customers into the program.

There are two primary pricing options for customers to participate in community solar: capacity-based pricing and energy-based pricing. Under a capacity-based program, participants can own, lease, or subscribe to a certain number of panels or a proportion of the project. In return, participants receive bill credits proportioned to their share of the project.[26] Normally participants pay upfront, before the project's completion, and retain an ownership portion for the life of the system.

With energy-based pricing, or pay-as-you-go, the participant pays for the system through a per-kWh charge determined by the cost of energy from the solar project. This rate is typically priced at a premium over the current retail rate. Since the rate is normally locked in, this solar rate may fall below the retail rate should the utility's rates increase in the future, as is likely. The solar project rate is billed to the customer for the energy allocated from the project to the customer.

The number of community solar projects has increased markedly over the past few years, and many public power utilities have announced plans to install their first projects or to expand their current portfolio. The Sacramento Municipal Utility District (SMUD) in California, for example, anticipates having more than 100 MW of capacity for its SolarShares program by the end of 2017.[27]

Moorhead Public Service (MPS) in Minnesota established the Capture the Sun program to promote the community solar concept.[28] MPS sited the community solar project where infrastructure was already in place to connect the system to the grid, between two wind turbines near a retired power plant. Customers could purchase 310 watt panels at $470, or 12 monthly installments totaling $480. Customers who own arrays receive an annual credit for their share of production, as MPS determined that the administrative burden was too great to bill monthly. In the first phase of the project, three arrays totaling over 60 kW completely sold out. There were enough customers on a wait list to green light construction of at least one or two more arrays, totaling just over 20 kW each, in 2017.

Energy Storage

Energy storage is a unique technology that has both generator and load attributes. For example, in times of low demand or excess renewable energy generation, an energy storage system can act like a load by absorbing and storing the excess energy. When that energy is needed,

[25] Paul Zummo. *Community Solar A-Z: Guide for Public Power Utilities.* American Public Power Association, November 2016.
[26] David Feldman, Anna M. Brockway, Elaine Ulrich, and Robert Margolis. *Shared Solar: Current Landscape, Market Potential, and the Impact of Federal Securities Regulation.* Golden, CO: National Renewable Energy Laboratory (April 2015), p.7.
[27] Paul Ciampoli, "SMUD, NYPA officials detail customer strategies with growth of DERs," *Public Power Daily,* July 31, 2017. Available at http://www.publicpower.org/Media/daily/ArticleDetail.cfm?ItemNumber=48603
[28] Community Solar A-Z, p. 8.

perhaps because of high demand or an outage, the energy storage system discharges energy, like a generator.

A variety of technologies fit into the energy storage umbrella. In the electrochemical category, there are batteries, either solid-state or flow. There are also electromechanical technologies, like compressed air, flywheels, and pumped hydro. Thermal energy and electrochemical capacitors are additional types of energy storage. While pumped hydro represents the majority of current energy storage capacity in the United States, batteries, specifically lithium-ion batteries, represent the largest share of new projects.[29] The expanded manufacturing market for lithium-ion has helped lower costs. Moreover, most electric vehicles (EVs) use lithium-ion batteries, so as the EV market grows, it helps advance the technology and decrease costs.[30]

Energy storage can be used for a variety of services that can benefit customers, utilities, independent system operators (ISOs) and regional transmission organizations (RTOs), or some combination of the three.[31] Many services tie back to the underlying theme of maintaining grid stability and resiliency. Customers and utilities may install energy storage for backup power or to support a microgrid, boosting resiliency. Customers can benefit from energy storage because of increased consumption of self-generation, reduced demand charges, and TOU bill management. Public power utilities can use energy storage for resource adequacy and renewable resource integration. In restructured markets, energy storage can support ancillary services like black start, voltage support, spinning or non-spinning reserves, frequency regulation, and energy arbitrage. Energy storage can also defer infrastructure investments at the distribution and transmission level by helping to shift demand and shave peak demand.

The economics of energy storage are complex due to a variety of technical and regulatory factors. Costs and technical limitations, such as capacity and power rating, have curbed widespread adoption. However, GTM Research projects that by 2022, energy storage will grow to 2.6 GW and be worth $3.2 billion in the United States.[32] Key economic considerations are factors such as the type of technology, location, status of grid assets, customer base, and rates.[33] Stacking value streams by having multiple use cases can make the technology more economically feasible, but this can be challenging to achieve in some markets.[34] Analysis of the levelized cost of storage indicate the cost per megawatt-hour remains high for certain technologies in specific applications. For example, using a flywheel for frequency regulation could equate to a levelized cost of $598-$1,251 per megawatt-hour, and using a lithium-ion battery to support a distribution substation could result in a levelized cost of $345-$657 per megawatt-hour.[35]

State actions related to energy storage include mandates, targets, funding, tax incentives, and analysis on regulatory reform. States that have energy storage mandates or targets include California, Massachusetts, and Oregon.[36,37,38] Funding for energy storage projects is available in California, Connecticut, Massachusetts, New Jersey,

29 DOE Office of Electricity Delivery & Energy Reliability. "DOE Global Energy Storage Database." Accessed July 26, 2017.

30 Miriam Makhyoun and Mike Taylor. *Electric Utilities, Energy Storage and Solar: Trends in Technologies, Applications and Costs.* Solar Electric Power Association, May 2014, p. 17.

31 Garret Fitzgerald et al. *The Economics of Battery Energy Storage.* Rocky Mountain Institute, October 2015, pp. 14-16. Available at https://rmi.org/insights/reports/economics-battery-energy-storage/
See also Edison Electric Institute. Harnessing the Potential of Energy Storage: Storage Technologies, Services, and Policy Recommendations. May 2017.

32 GTM Research/ESA. *U.S. Energy Storage Monitor: Q2 2017 Executive Summary.* June 2017, pp.11-12.

33 David Frankel and Amy Wagner. "Battery storage: The next disruptive technology in the power sector." *McKinsey & Company,* June 2017. Available at http://www.mckinsey.com/business-functions/sustainability-and-resource-productivity/our-insights/battery-storage-the-next-disruptive-technology-in-the-power-sector

34 Garret Fitzgerald et al. *The Economics of Battery Energy Storage.* Rocky Mountain Institute, October 2015, p. 22. Available at https://rmi.org/insights/reports/economics-battery-energy-storage/

35 Lazard. *Lazards's Levelized Cost of Storage-Version 2.0.* December 2016, p. 11. Available at https://www.lazard.com/media/438042/lazard-levelized-cost-of-storage-v20.pdf

36 National Renewable Energy Laboratory. *Issue Brief: A Survey of State Policies to Support Utility-Scale and Distrusted-Energy Storage.* September 2014, p. 2.

37 Executive Office of Energy and Environmental Affairs. "Baker-Polito Administration Sets 200 Megawatt-Hour Energy Storage Target." June 30, 2017. Available at http://www.mass.gov/eea/pr-2017/doer-sets-200-megawatt-hour-energy-storage-target.html

38 Oregon Legislative Assembly. *House Bill 2193.* 2015. Available at: https://olis.leg.state.or.us/liz/2015R1/Downloads/MeasureDocument/HB2193

Nevada, and Washington, among others.[39, 40, 41, 42, 43, 44] In June 2017, Maryland became the first state to provide a tax credit for energy storage systems. At the federal level, three entities within the Department of Energy are involved with different aspects of energy storage systems.[45] The Federal Energy Regulatory Commission (FERC) is examining electric storage participation in markets operated by RTOs and ISOs, and issued a Notice of Proposed Rulemaking in November 2016.[46] The DOE's Office of Electricity Delivery and Energy Reliability runs a program that supports research and development for energy storage in coordination with industry and state players.[47] And the Advanced Research Projects Agency provides energy storage researchers with funding and technical assistance.

Energy storage is included in key energy legislation introduced in the 115th Congress by Sen. Lisa Murkowski, R-Alaska, chairman of the Senate Energy and Natural Resources Committee, and Maria Cantwell, D-Wash., the committee's ranking member. The Energy and Natural Resources Act of 2017, which was introduced in June 2017,features DOE research, development, and demonstration related to energy storage and calls for FERC to study barriers to pumped hydro storage projects.[48]

Public power utilities are already installing energy storage systems to support their business functions, enhance customer experiences, and sell services to the markets. The Village of Minster, Ohio partnered with Half Moon Ventures, American Renewable Energy and Power, and S&C Electric Company to bring online a 7 MW LG Chem lithium-ion battery energy storage system to accompany a new 4.2 MW solar field. This project was the first of its kind for a public power utility.[49] The solar field was built in December 2015 and the battery component went online in April 2016. This solar plus storage effort helps integrate renewable energy, reduce demand, improve power quality, and defer other infrastructure improvement projects. In addition, Minster earns capacity credits and receives lower transmission charges. Using a PPA, the cost for solar energy matches the average retail rate for electricity. The utility has earned various awards for this project including Smart Electric Power Alliance's Public Power Utility of the Year award and Renewable Energy World's Renewable Energy Project of the Year.[50,51]

The Sterling Municipal Light Department in Massachusetts is another public power utility demonstrating the benefits of energy storage. The SMLD project has also garnered international attention In 2016, the utility added a NEC Energy Solutions 2 MW, 3.9 MWh lithium-ion battery to help reduce peak load, lower capacity payments, regulate system frequency, and enhance resilience. The battery, along with existing solar generation, supports the utility microgrid and provides mission critical support to the local police station and dispatch center.[52] Sterling received a 2017 Grid Edge award from Greentech Media.

Plug-In Electric Vehicles

Longer driving ranges, lower costs, and incentives are boosting momentum for plug-in electric vehicles (PEV)

39 California Public Utilities Commission. "Self-Generation Incentive Program." 2017. Available at http://www.cpuc.ca.gov/sgip/.

40 NC Clean Energy Technology Center. "Connecticut Clean Energy Fund." June 7, 2017. Available at http://programs.dsireusa.org/system/program/detail/157

41 Massachusetts Executive Office of Energy and Environmental Affairs. "Energy Storage Initiative (ESI)." 2017. Available at http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/energy-storage-initiative/

42 New Jersey Board of Public Utilities. "NJ Energy Resilience Bank Now Accepting Applications." October 20, 2014. Available at http://www.state.nj.us/bpu/newsroom/announcements/pdf/20141020_erb_press.pdf.

43 Office of the Governor. "Sandoval Signs 29 Bills Including Multiple Energy Measures." June 1, 2017. Available at http://gov.nv.gov/News-and-Media/Press/2017/Sandoval-Signs-29-Bills-Including-Multiple-Energy-Measures/

44 Department of Commerce. "Washington State Clean Energy Fund." Available at http://www.commerce.wa.gov/growing-the-economy/energy/clean-energy-fund/

45 David K Burton et al. "Maryland Enacts First in the Nation Energy Storage Tax Credit." Tax Equity Times. May 10, 2017. Available at https://www.taxequitytimes.com/2017/05/maryland-passes-first-in-the-nation-energy-storage-tax-credit/

46 American Public Power Association. *Comments of the American Public Power Association and the National Rural Electric Cooperative Association on Notice Of Proposed Rulemaking.* February 13, 2017, p. 1. Available at http://www.publicpower.org/files/2-17-17%20APPA%20Storage%20DER%20NOPR%20Comments.pdf

47 Department of Energy. "Energy Storage." Available at https://energy.gov/oe/services/technology-development/energy-storage

48 Senate Energy & Natural Resources Committee. *Energy and Natural Resources Act Of 2017 S. 1460: Joint Staff Section-By-Section Summary.* July 2017, p. 12 and 15. Available at: https://www.energy.senate.gov/public/index.cfm/files/serve?File_id=BD4EFDD0-5B1A-47EA-BA5D-B02C2ADFA619

49 Herman K. Trabish. "Inside the first municipal solar-plus-storage project in the US." *Utility Dive.* July 5, 2016. Available at http://www.utilitydive.com/news/inside-the-first-municipal-solar-plus-storage-project-in-the-us/421470/

50 Anderson, Jeannine. "Village of Minster gets SEPA's 'Public Power Utility of the Year' award." *PublicPowerDaily.* September 6, 2016. Available at http://www.publicpower.org/Media/daily/ArticleDetail.cfm?ItemNumber=46582.

51 Jennifer Runyon. "Village of Minster Energy Storage Project is Renewable Project of the Year." *Renewable Energy World.* December 13, 2016. Available at http://www.renewableenergyworld.com/articles/2016/12/village-of-minster-energy-storage-project-is-renewable-project-of-the-year.html

52 Todd Olinsky. "Energy Storage in Sterling: A Massachusetts Municipal Microgrid." Webinar by the Clean Energy States Alliance, October 25, 2016.

on a global scale.[53] PEV sales increased 37 percent in 2016, and sales are expected to continue to grow both internationally and domestically.[54] By 2021, Navigant Research conservatively estimates that PEV sales will hit 700,000 units in the US alone.[55]

PEVs increase electric demand, which is an opportunity for utility load growth in a time of flat demand and revenues. PEVs provide other benefits, including environmental benefits from lower greenhouse gas emissions. Cost comparisons of electric vehicles, electric vehicle hybrids, and traditional combustion engine vehicles show that electric vehicles have the lowest drive costs for consumers. Further, automated vehicle technology is better suited for electric vehicles because of reduced operational and maintenance costs.[56] As automated vehicle technology takes off, it may drive expansion of the PEV market.

PEV sales are higher in states with incentives, such as California, Oregon, and Washington.[57] For example, California has policies and regulations such as the zero-emissions vehicle (ZEV) mandate that requires automakers to sell a certain portion of ZEVs as a total of all sales.[58] In the Multi-State ZEV Action Plan, Oregon, Massachusetts, Connecticut, Maryland, Rhode Island, and New York have called for a combined 3.3 million ZEVs on their roads by 2025.[59]

Obstacles to customer adoption include costs, charging infrastructure availability, and model availability. Costs are predicted to decrease as the cost of lithium-ion batteries is projected to decline. Batteries represent a significant portion of the total cost of a PEV. For example, a Chevrolet Bolt's battery is 43 percent of the base price.[60] Navigant Research forecasts the price of lithium-ion packs to decrease from an average of $14,240 in 2015 to $10,123 by 2024.[61] Tax incentives can also help defray costs. The US provides up to a $7,500 tax credit and select states also offer tax credits for people who purchase PEVs. The federal tax credit ties back to the original equipment manufacturer (e.g., Tesla), and only applies to 200,000 credits per manufacturer.

Expanding the existing charging infrastructure may help customers conquer range anxiety. Charging stations come in four categories:

- Alternating Current (AC) Level 1 (1.4 kW maximum)
- AC Level 2 (3.3-19.2 kW)
- Direct current (DC) fast charging (50-150 kW)
- DC ultrafast charging (up to 400 kW)

AC charging is most prevalent, but DC charging provides a faster recharge. Charging options also depend on the vehicle, as many plug-in hybrid electric vehicles are not suited for DC charging.

Public power can advance electric vehicle adoption through customer education, pilot programs, and adding charging infrastructure in their community. In May 2017, the Massachusetts Municipal Wholesale Electric Company (MMWEC) launched a program in partnership with Nissan for customers and utility employees of select public power members to receive a $10,000 rebate off purchases of the 2017 Nissan Leaf.[62] Customers also can benefit from the federal tax incentive and the state's $2,500 tax incentive. Additionally, some MMWEC members have partnered with ChargePoint to provide PEV owners with Level 2 chargers at either a reduced fee or completely free.

Volkswagen's Electrify America program is investing $2 billion into electric charging infrastructure and education programs over the next 10 years. The program's goal is to deploy 2,500 non-proprietary chargers at over 450 stations across the country along high traffic routes. The Association continues to engage with Electrify America on ways to support public power communities.

The most significant PEV challenge for utilities is load management. If PEV customers choose to charge when they get home from work in the evening, they will increase demand during the utility's peak demand period. This spike in demand in the evening could also lead to ramping issues with higher PEV penetration. Many PEV owners charge at home because of limited charging options

53 Navigant Research. *Market Data: Electric Vehicle Markets Forecasts.* 2016.
54 Navigant Research. *Market Data: Electric Vehicle Markets Forecasts.* 2016.
55 Ibid.
56 Navigant Research. *Market Data: Automated Driving Vehicles.* 2017
57 Navigant Research. *Electric Vehicle Geographic Forecasts.* 2016
58 State of California. *2013 ZEV Action Plan.* February 2013.
59 "Multi-State ZEV Task Force." Available at https://www.zevstates.us/.
60 John Voelcker. "How much is a replacement Chevy Bolt EV electric-car battery?" *Green Car Reports.* See also Chevrolet. "2017 Bolt EV FWD LT."
61 Navigant Research. *Advanced Energy Storage for Automotive Applications.* 2015
62 MMWEC. "EV Program Offers Vehicle Discounts, Charger Incentive." *Joint Action News.* Summer 2017.

during the work day. To help address this, utilities can investigate how many of their customers own PEVs, forecast future ownership, and explore when and where they plan to charge. Utilities can also help manage load through demand response, or changing rate structures to incorporate TVP or TOU.

Microgrids

The Department of Energy defines a microgrid as "a local energy grid with control capability, which means it can disconnect from the traditional grid and operate autonomously."[63] Microgrids are versatile in that they can operate connected to the grid, or separately as an island. The microgrid and main grid are linked to one another through a point of common coupling. When a microgrid has islanded, the voltage and frequency must be regulated and maintained by the microgrid operator. When a microgrid is connected to the main grid, voltage and frequency can be managed by an ISO. In some cases, when the microgrid is connected to the main grid, excess power could be exported from the microgrid to the main grid, and revenue could be collected by net metering or feed-in tariffs.

Onsite generation is a central component of a microgrid system. Generation for a microgrid can vary from traditional fossil fuel energy sources to renewables such as solar and wind. Solar power is the most common renewable energy used in microgrids.[64] Historically, combined heat and power is the main generation type paired with microgrids. Further, energy storage is a component in half of all microgrids.[65] Storage can create a reserve of excess generation, prolonging the microgrid's ability to function in island mode. Storage also assists with the integration of DER in a microgrid, as these types of resources are intermittent and do not always supply power in concert with a community's peak demand.

A recent report by the Electric Power Research Institute (EPRI) and the Smart Electric Power Alliance identifies DER integration among the primary reasons for microgrid development. The report also lists resiliency, grid services, emissions reduction, and investment deferral as drivers for developing microgrids.[66] This potential for added resilience gained attention in the aftermath of Hurricane Sandy, which caused widespread power outages in October 2012. Microgrids may also fit into the larger picture of smart grid and the "utility of the future." However, the concept and implementation of microgrids is not new. Public power is notably familiar with microgrids, since many systems began as microgrids generating their own power for the communities they serve.

Utilities are key players in the future of microgrid deployments because they can develop their service territory into a microgrid, and have the option to help customers with their own microgrids. Utilities can be involved with the ownership, financing, and operations of a microgrid. If utilities do not get involved in microgrid development, third parties and end users may look to fill this role.

Technical challenges associated with microgrids include power quality assurance, implementing inverter based systems, and accommodating bidirectional power flow. Compounding these challenges is the lack of clarity on safety codes and regulations specific to microgrids. Future regulations and policies are unknown, making it difficult to determine incentives, needs, economics, and interest in microgrid deployment. Despite these challenges, microgrid capacity is expected to grow, and GTM reports that the US is expected to reach 4.3 GW by 2020.[68] As of 2016, there were 160 microgrids with 1,649 MW of capacity.[64] Renewable energy will contribute 45 percent of microgrid capacity when current and planned projects are operational, though renewable energy represented only 10 percent of microgrid capacity in 2016.[69] As of 2016, microgrids are most prominent in New York, California, Texas, Georgia, Maryland, Alaska, and Oklahoma.[70]

There are three microgrid business models, two of which can involve a utility. In an integrated utility model, a utility owns and operates the microgrid. A second option is the unbundled model, where either a utility, third party, or end user own the microgrid, and a different entity oversees

63 Department of Energy. "How Microgrids Work." June 17, 2014. Accessed September 6, 2017 at https://www.energy.gov/articles/how-microgrids-work.

64 "US Microgrid Market Growing Faster than Previously Thought: New GTM Research." *Microgrid Knowledge.* August 29, 2016. Available at https://microgridknowledge.com/us-microgrid-market-gtm/.

65 Ibid.

66 Nadav Enbar et al. *Microgrids: Expanding Applications, Implementations, and Business Structures.* Electric Power Research Institute & Smart Electric Power Alliance, p. 7. December 2016.

67 Ibid.

68 Ibid.

69 Olivia Chen. "US Microgrid Growth Beats Estimates: 2020 Capacity Forecast Now Exceeds 3.7 Gigawatts." *GTM.* June 1, 2016. Available at https://www.greentechmedia.com/articles/read/u.s.-microgrid-growth-beats-analyst-estimates-revised-2020-capacity-project

70 "US Microgrid Market Growing Faster than Previously Thought: New GTM Research." *Microgrid Knowledge.* August 29, 2016. Available at https://microgridknowledge.com/us-microgrid-market-gtm/.

operations. With a third-party model, the end user owns the microgrid and the end user or their provider control microgrid operations. Though the third-party model is the most common, the number of microgrids using the integrated utility model is rising. The public power business model embraces local interests, and often has fewer regulatory burdens than investor-owned utilities (IOUs), which makes microgrid ownership and operation an opportunity for systems with interested communities.

The New York Power Authority (NYPA) is on the forefront of microgrid deployments, which fits into the organization's 2014-2019 Strategic Vision to promote resiliency and environmental improvement.[71] Gil Quiniones, NYPA's president and CEO, explained that "Microgrids are an essential component of Governor Cuomo's Reforming the Energy Vision plan. This is not a niche program. This is the state's energy future."[72] NYPA is partnering with the New York State Office of General Services on a new 16 MW combined heat and power microgrid system that will provide power to a plaza in Albany, NY, which includes government buildings and the New York State Museum. This effort is expected to result in $2.7 million in annual energy savings.[73] Another NYPA partnership with the State University of New York will install a $1.4 million solar generation and battery storage system to power part of Etling Gymnasium.[74] This project will improve resilience in times of high demand and during natural disasters, as the American Red Cross uses the facility as an emergency shelter.[75]

While NYPA demonstrates microgrid developments for specific public power customers, Easton Utilities Commission in Maryland represents the option of an entire utility's service territory being able to island and function as a microgrid. Easton can use its diesel engines and combustion turbines to generate power and disconnect from the PJM Interconnection during periods of high demand and electricity prices.[76]

Blockchain

A blockchain is a digital encrypted network of distributed records. This distributed ledger cannot be modified and its history is traceable. Anonymous nodes of replicated data are used to enhance data reliability across the network. The blockchain construct does not have the traditional central point of authority or intermediaries, like financial institutions, that conduct trades and charge for their services. Instead, blockchain transactions occur peer-to-peer, are recorded across the network, and happen in real-time without transaction fees, making them more efficient.[77] The transactions themselves are facilitated by "smart contracts," which have specific rules to match customers with providers.[78]

The concept of blockchain technology dates back to 2008.[79] Since then, interest in the technology has grown because of its ability to change the norm for how transactions and records are managed. Blockchain is commonly associated with "Bitcoin," which is a cryptocurrency that uses blockchain technology. There are several potential applications for blockchain technology in the energy sector. Proponents of blockchain technology believe it could be revolutionary for energy trading.[80] For example, blockchain could support the buying and selling of electricity from DER. The platform is believed to be highly secure and could support, theoretically, unlimited users. Therefore, blockchain could empower customers, or their equipment, to play a larger role in energy management at the distribution level. Additional applications of blockchain include asset management, documentation of renewable

71 New York Power Authority. *Strategic Vision 2014-2019.* PP. 3, 5. Available at http://www.nypa.gov/-/media/nypa/documents/document-library/governance/strategic-vision-2014-2019.pdf

72 New York Power Authority. "Transmission Projects." Accessed June 19, 2017 at http://www.nypa.gov/power/transmission/transmission-projects.

73 New York State. "Governor Cuomo Announces New Locally Sourced Microgrid to Power the Empire State Plaza." May 22, 2017. Available at https://www.governor.ny.gov/news/governor-cuomo-announces-new-locally-sourced-microgrid-power-empire-state-plaza.

74 New York Power Authority. *2016 Year in Review.* P. 24. Available at http://www.nypa.gov/-/media/nypa/documents/document-library/annual-reports/nypa-2016-year-in-review.pdf.

75 Ibid.

76 Easton Utilities Commission. *Annual Report 2016.* P 11. Available at http://eastonutilities.com/wp-content/uploads/2017/06/EastonUtilities-Annual-Report-2016.pdf

77 Keith Townsend. *Blockchain Technology Impact on Energy Market Transformation: Secured Distributed Energy Transactions in the Cloud.* Georgetown Law Technology Review, (2017, pp. 469-476. Available at https://perma.cc/78RH-8R6N.

78 PwC global power & utilities. *Blockchain – an opportunity for energy producers and consumers?* 2016, p. 1. Available at https://www.pwc.ch/en/2017/pdf/pwc_blockchain_opportunity_for_energy_producers_and_consumers_en.pdf.

79 Jesse Yli-Huumo et al. *Where is Current Research on Blockchain Technology?—A Systematic Review.* PLoS One 11, no. 10 (October 3, 2016), pp. 1-2. Available at http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0163477.

80 *Blockchain Technology: Will It Make a Difference?* The Electricity Journal 3, no. 30, (April 2017): pp. 86-87. Available at https://doi.org/10.1016/j.tej.2017.04.007.

energy certificates and emissions allowances, metering, and billing.[81] All of these applications could support an electric utility's transition to a smarter and cleaner grid.

New partnerships and businesses that tackle blockchain integration with the energy sector are emerging. In February 2017, companies joined forces to launch the Enterprise Ethereum Alliance to advance blockchain technology.[82] Also in 2017, the Rocky Mountain Institute and Grid Singularity launched the global Energy Web Foundation, which focuses on blockchain in the energy sector.[83]

Energy applications of blockchain are transitioning from the theoretical to the real world. Demonstration projects are underway in the United States, Germany, and Austria.[84] In the US, Siemens and LO3 Energy partnered for a blockchain pilot in a Brooklyn, NY microgrid, where households with rooftop solar sell excess power to their neighbors.[85] This example is touted as a successful demonstration of blockchain's ability to facilitate energy trading.

Blockchain technology and its applications remain in the early stages, with some serious challenges ahead. One major obstacle is that blockchain transactions require significant computational power.[86] This ties to other issues, including limited throughput (transactions per second), latency in completing a single transaction, and scalability. Though some advocates believe blockchain will be highly secure, there are still cybersecurity concerns about the records. For blockchain to be widely accepted and adopted, these technological challenges will need to be addressed. Moreover, the legal and regulatory landscape for this technology has yet to be established.

[81] PwC global power & utilities. *Blockchain – an opportunity for energy producers and consumers?* 2016, p. 1. Available at https://www.pwc.ch/en/2017/pdf/pwc_blockchain_opportunity_for_energy_producers_and_consumers_en.pdf.
[82] Keith Townsend. *Blockchain Technology Impact on Energy Market Transformation: Secured Distributed Energy Transactions in the Cloud.* Georgetown Law Technology Review, (2017), p. 473. Available at https://perma.cc/78RH-8R6N.
[83] *Blockchain Technology: Will It Make a Difference?* The Electricity Journal 3, no. 30 (April 2017): p. 87. Available at https://doi.org/10.1016/j.tej.2017.04.007.
[84] James Basden and Michael Cottrell. *How Utilities are Using Blockchain to Modernize the Grid.* Harvard Business Review, March 27, 2017. Available at https://hbr.org/2017/03/how-utilities-are-using-blockchain-to-modernize-the-grid.
[85] Ibid.
[86] Jesse Yli-Huumo et al. Where is Current Research on Blockchain Technology?—A Systematic Review. PLoS One 11, no. 10 (October 3, 2016), pp. 2-4. Available at http://journals.plos.org/plosone/article?id=10.1371/journal.pone.0163477.

STATE POLICIES

The next two chapters explore state actions. This chapter discusses specific legislative and regulatory actions with regards to DER, particularly concerning rate design.

According to the North Carolina Clean Energy Technology Center, in the first quarter of 2017, some type of policy initiative regarding solar was underway in 40 states and the District of Columbia.[87] In total, 134 actions were identified, and most of them had to do with increased customer charges, investigations into net metering, or valuing solar generation.[88]

What is striking about most of the legislative actions regarding net metering is that they are in the early stages of development. As of March 2017, only a few states have signed legislation or completed regulatory rulemaking.[89] This indicates that there is a lot of discussion surrounding net metering and other topics concerning DER, but many policies are not yet changed and potential alternatives are still being considered. Additionally, almost all the proposed legislation to alter net metering credit rates would grandfather existing net metered customers.

States are also undertaking more value of solar studies. Fourteen states and DC are in the process of examining some aspect of VOS, and 34 states and DC have undertaken some sort of study since 2015.[90] Several of these states have convened working groups to explore the topic. The next chapter will explore the New York VOS proceeding.

With regards to fixed charges, while there have been 44 utility proposals in 23 states to increase fixed charges, no utility has been granted its full request to increase the monthly customer charge, while ten have been granted a partial increase.[91] As for demand charges, there have been 13 proposals in eight states for an implementation of a residential demand charge. Only one decision was made in the first quarter of 2017, and that was the Oklahoma Corporation Commission's rejection of Oklahoma Gas and Electric's residential demand charge.[92]

There has also been some legislative and regulatory activity in relation to both utility ownership and third party ownership of DG. The North Carolina Clean Energy Technology Center identifies nine states which disallow third party ownership or otherwise has legal barriers.[93] Most of these states are in the southeast or south central region of the US. Several of these states have undertaken legislation to legalize third party ownership. Conversely, utilities in four states have taken action on utility-owned rooftop solar programs.[94]

The following section highlights actions in six states: Arizona, California, Indiana, Maine, New Hampshire, and Virginia.

Arizona: In March 2017, the Arizona Corporation Commission (ACC) and Arizona Public Service (APS) reached a rate settlement agreement. APS originally proposed a mandatory demand rate for residential and small commercial customers, but the ACC rejected this request.[95] Among the features of the approved rate tariff were tiered customer charges for non-DG customers. Customers who average 600 kWh or less of usage will be subject to a $10 customer charge (basic service charge). Customers who average between 600 kWh and 1000 kWh will be subject to a $15 basic charge, while customers who average more than 1000 kWh of usage will have a $20 basic charge.[96]

87 North Carolina Clean Energy Technology Center, *50 States of Solar: Q1 2017 Quarterly Report,* April, 2017.
88 GTMIbid., p. 9.
89 Ibid., p. 13.
90 Ibid., p. 31.
91 Ibid., p. 44.
92 Ibid., p. 56.
93 Ibid., p. 65.
94 Ibid., p. 68.
95 Julia Pyper, "Arizona Public Service, Solar Industry Reach Critical Settlement in Contentious Rate Case," *Green Tech Media,* March 1, 2017. Available at: https://www.greentechmedia.com/articles/read/Arizona-Public-Service-Solar-Industry-Reach-Critical-Settlement-in-Content
96 Arizona Corporation Commission. *Arizona Public Service Commission Rate Case, Staff's Notice of Filing Settlement Term Sheet,* Docket No. E-01345A-16-0123, March 1, 2017, p. 6.

The new rate tariff also offers a TOU rate for all customers, including a $13 basic service charge. It also offers up to 10,000 customers to participate in a pilot rate design program that includes features of both TOU and demand rates, with differing on-peak and off-peak winter and summer rates. During the winter, the kW-month demand charge would be $14.25. There is also an off-peak kW charge of $6.50 per kW-month, but only for customers who achieve a peak demand of at least 5 kW during off-peak, non-holiday weekdays.[97]

New DG customers would be able to choose from four rate designs, each with some form of TOU and/or demand charge. They would also be subject to a grid access charge, which will be determined later. The self-consumption rate for solar customers would be approximately $0.12 per kWh, and the export credit would be $0.129 per kWh. The current residential rate for APS customers is approximately $0.13-$0.14 per kWh.[98,99] APS customers who file an interconnection agreement before the final decision would be grandfathered under net metering for 20 years.

Under the settlement, APS will be rolling out a program aimed at expanding rooftop solar access for low and moderate income customers. With the AZ Sun II program, APS will contract with third party developers to install rooftop solar panels on participating customer rooftops. APS would own the generation and all renewable energy certificates, while participating customers would receive a $10-$50 bill credit per month. "Reasonable and prudent" costs incurred by APS in the program would be recoverable through a renewable energy adjustment clause.[100]

California: The California Public Utilities Commission (CPUC) issued a decision mandating that the state's IOUs implement default TOU rates in 2019. As a first step, the utilities have been instructed to narrow their existing rate tiers. In California, most utility rates are set to include steeply inclining block rates. As a means of easing customer adaptation to TOU rates, these tiers would be narrowed and consolidated.[101] The commission further notes that "users in the low tiers pay significantly below the cost of electricity service, while users in the higher tiers pay significantly above cost. These prices are so far from cost that immediate change is necessary." Low-use customers would still pay a lower rate, but the gap would be narrowed. Also, customers who consume 400 percent or more than the average residential electricity in a given zone would be subject to a "super-user" electric surcharge.[102]

Ultimately, the commission directed the IOUs to institute outreach programs to "educate lower tier customers on no-cost and low-cost conservation measures," as well as to begin the process of improving rate comparison tools and educational materials to help customers understand their bills. Finally, the IOUs were directed to begin TOU pilot programs, and to evaluate the results of those pilots in preparation for the roll out of wide-scale TOU implementation.[103]

Though public power utilities are exempt from this rulemaking, SMUD has begun the process of implementing system-wide TOU rates in 2019. SMUD's board of directors approved a residential time-of-day (TOD) rate in June 2017. Some customers will be transitioned to the new rate in 2018, with all customers moved to the new rate by the end of 2019.

Under this TOD program, there will be a summer season (June 1 to September 30) and a non-summer season (the rest of the year). During the summer, there will be peak, off-peak, and mid-peak time periods, while during the rest of the year there will be just the peak and off-peak periods.[104]

Indiana: Legislation signed by Indiana's governor in May 2017 lowered retail rate compensation for net metered systems. For those who have already interconnected or who interconnect through the end of the 2017, the current net metering structure will be in place for 30 more years. Otherwise, the compensation rate will be gradually lowered over the next five years. After 2022, compensation will be the utility's marginal cost plus 25 percent.[105]

Maine: The Maine Public Utilities Commission (PUC) issued a decision in January 2017 to gradually lower the compensation credit for net metered customers. Existing net metering customers, as well as those who install before

97 Ibid., appendix A.
98 Ibid., p. 7.
99 Pyper, "Arizona Public Service, Solar Industry Reach Critical Settlement in Contentious Rate Case."
100 Ibid., pp. 9-10.
101 California Public Utilities Commission. *Decision on Residential Rate Reform for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company and Transition to Time-of-Use Rates,* July 13, 2015, p. 2.
102 Ibid., p. 4.
103 Ibid., p. 5.
104 Jeannine Anderson, "SMUD board approves new Time-of-Day standard residential rates," *Public Power Daily,* June 26, 2017. Available at http://publicpower.org/Media/daily/ArticleDetail.cfm?ItemNumber=48410
105 Robert Walton, "Indiana will phase out retail rate net metering," *Utility Dive,* May 4, 2017. Available at http://www.utilitydive.com/news/indiana-will-phase-out-retail-rate-net-metering/441932/

the end of 2017, will be grandfathered into existing rates for 15 years. For new entrants who sign up over the next ten years, "the netting of the transmission and distribution (T&D) portion of the bill will be gradually decreased to reflect reductions in the costs of small renewable generation technology."[106]

The PUC states that despite the changes in compensation, payback periods for new DG installations should be similar to what they historically have been.

> For a customer installation signed in year one, the full incentive for supply and 90% of the incentive for T&D is received for fifteen years. As the cost of technology declines, the incentive for T&D also declines for new entrants. For a new customer installation in year two, for example, the cost of the solar panels will have declined but the incentive will also decline to 80% for T&D and the full incentive for supply.[107]

New Hampshire: The New Hampshire Public Utilities Commission issued an order in June 2017 to remove limits on net metering, while reducing distribution credits for net metered customers. The order states that solar DG systems of 100 kW or less will still receive 100 percent of energy and transmission credits for excess generation, but only 25 percent of the distribution costs. The order further stipulates that existing net metered customers will be grandfathered at existing compensation rates until December 31, 2040.[108]

Stan Faryniarz of Daymark Energy Advisers filed testimony for the PUC staff. He concluded that net metering did not lead to significant cost shifting at low penetration levels. Staff also suggested that a switch to TOU pricing should be considered by the Commission commission in the long-term.[109]

The commission also agreed with the staff witness that a value of DER study should be a "long-term avoided cost study using marginal concepts and incorporating both TRC and RIM test criteria, and it may also include consideration of demonstrable and quantifiable net benefits associated with relevant externalities (such as environmental or public health benefits), provided that the potential for double-counting of such externalities is adequately mitigated."[110] The commission called for the creation of a working group to oversee the DER value study and deliver a report within eight months of the order's issuance.[111]

Virginia: The governor signed several pieces of energy-related legislation in May 2017, with one focused on community solar. The bill requires Dominion Power and Appalachian Power to conduct community solar pilot projects.[112] These pilot programs are to include facilities that do not exceed 2 MW, and they are not to be constructed by the IOUs, but rather the power is to be purchased through an asset purchase agreement or be subject to a power purchase agreement where the utility purchases the power from a third party.[113]

[106] Maine Public Utilities Commission, *Maine Public Utilities Commission Issued Decision on Customer Net Energy Billing,* January 31, 2017. Available at http://www.maine.gov/tools/whatsnew/index.php?topic=puc-pressreleases&id=729614&v=article08

[107] Ibid.

[108] State of New Hampshire Public Utilities Commission. *Development of New Alternative Net Metering Tariffs and/or Other Regulatory Mechanisms and Tariffs for Customer-Generators: Order Accepting Settlement Provisions, Resolving Settlement Issues, and Adopting a New Alternative Net Metering Tariff,* June 23, 2017, p. 1.

[109] Ibid., p. 18.

[110] Ibid., p. 60.

[111] Ibid., pp. 61-62.

[112] Krysti Shallenberger, "Virginia governor signs 11 energy bills, including solar, pumped hydro proposals," *Utility Dive,* May 9, 2017. Available at http://www.utilitydive.com/news/virginia-governor-signs-11-energy-bills-including-solar-pumped-hydro-prop/442293/

[113] *An Act to amend the Code of Virginia by adding a section numbered 56-858.1:3, relating to electric utility regulation; pilot programs for community solar development,* Approved March 16, 2017. The generating facility may exceed 2 MW of capacity, but no more than 2 MW of the facility can be dedicated to the pilot project.

MAJOR STATE INITIATIVES

Several states have begun regulatory proceedings and other initiatives to examine the future of the electric industry. These proceedings go beyond changes to net metering or laws related to third party ownership. States like New York, Minnesota, Massachusetts, and California have begun investigating wholesale changes to electric markets and the nature of distribution system.

New York: Reforming the Energy Vision (REV)

New York's REV initiative has received much attention as it stakes out an ambitious vision for the future of the utility business model. In a 2014 staff report, the New York State Department of Public Service (DPS) outlined this vision. This report proposes a platform to transform New York's electric industry, for both regulated and non-regulated participants, with the objective of creating market based, sustainable products and services that drive an increasingly efficient, clean, reliable, and consumer-oriented industry."[114]

One of the major aspects of REV is the creation of the Distribution System Platform Provider (DSPP). The DSPP "will actively coordinate customer activities so that the utility's service area as a whole places more efficient demands on the bulk power system, while reducing the need for expensive investments in the distribution system as well."[115] The report further clarifies that "the DSPP will create markets, tariffs, and operational systems to enable behind the meter resources for providers to monetize products and services that will provide value to the utility system and thus to all customers." Products include energy efficiency, demand response, DG, microgrids, and other technologies. "The DSPP will enable the adoption of information technology and real-time information flow among market participants, and establish a platform to support demand-side markets and technology innovation."[116]

The report states that the utilities are the best fit to serve as DSPP because they have the institutional capabilities to manage the system and construct upgrades to existing distribution infrastructure.[117] However, as the role of the DSPP evolves, there is a possibility that the DSPP could be an independent entity.

On the question of utility ownership of DERs, the report states that it could be in the public interest for utilities to own DER, especially as the competitive market has been slow to bring resources to smaller customers. Therefore, the utilities may be able to provide essential services that the competitive marketplace cannot.[118]

Long-term rate plans of up to eight years may allow for better planning, more certainty, and fewer rate cases, according to the report. The report also discusses input versus outcome-based ratemaking. Input-based ratemaking focuses on past performance, whereas outcome-based rates would be tied to performance which can be measured and quantifiable. Although, as the report indicates, it wouldn't be feasible to move solely to outcome-based rates because of the obligation to serve.[119]

As the REV process has advanced, the state has issued numerous reports, rulings, and orders.[120] Of particular note is a DPS staff report on the value of solar, which sees a need to create more granular price signals and more accuracy in compensating DER.[121] As the report notes, DPS sees a need to create more granular price signals and more accuracy in compensating DERs. These price signals could incent customers to invest in other grid enabling technologies,

[114] *Reforming the Energy Vision – NYS Department of Public Service Staff Report and Proposal.* Case 14-M-0101, April 24, 2014, p. 2.
[115] Ibid., p. 9.
[116] Ibid., pp. 11-12.
[117] Ibid., p. 25.
[118] Ibid., p. 27.
[119] Ibid., pp. 50-51.
[120] See http://www3.dps.ny.gov/W/PSCWeb.nsf/All/C12C0A18F55877E785257E6F005D533E?OpenDocument#Presentations for an extensive list of all REV proceedings.
[121] New York State Department of Public Service, *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding,* 15-E-0751, October 27, 2016.

such as smart inverters, which the department hopes will provide value to all customers by adding value to the transmission and distribution systems.[122]

Furthermore, better price signals would ensure more efficient market operations. "The local marginal pricing applied in the wholesale markets does not segregate out the ancillary supports, load shifting, and environmental and performance benefits that are essential design features of a fully optimized bi-directional power system and decarbonized network."[123] A more granular pricing structure could bolster a market requiring coordination between a DSPP and ISO.

The staff report identified four significant benefits of clean DG: avoided system costs, avoided generation capacity costs, delivery costs, and avoided societal damage/mitigation costs.[124] Staff went into further detail to establish a framework around these four key aspects – or the value stack – of a value of distributed energy resource (VDER) tariff structure. Moreover, the methodology established by the staff is an interim, or Phase One methodology, to be replaced by a more thorough Phase Two methodology, which will be established over the next two years.[125]

Existing net metered customers would be compensated at existing net metering rates for 20 years, unless they opt-in to the rate methodology established in the first phase of the VDER. Once a customer opts-in, the decision is irreversible.[126] Otherwise, mass market systems under 25 kW will remain on net energy metering until 2020, when the second phase of VDER methodology is established.

Minnesota: e21 Initiative

Minnesota kicked off its e21 (21st Century Energy System) Initiative in 2014 to move away from a traditional business model to one where customers have more say in how and where energy is produced and how they use it. The initiative also aims to move to a regulatory structure more reliant on performance-based incentives for utilities.[127]

The initiative issued a report in 2014 to guide stakeholders across four categories of recommendations: performance-based ratemaking, customer option and rate design reforms, planning reforms, and regulatory process reforms.[128]

The initiative issued three whitepapers laying out further details on these components. A paper on performance-based compensation details three models: the current cost-of-service model, a partial shift to performance-based compensation, and a complete shift to a performance-based compensation framework, though it does not mandate a specific course of action. Under a cost-of-service model, any performance-based incentive would be in addition to cost-based revenue. In the partial performance-based framework, the regulator guaranteed return on equity would be reduced, "and utility earnings are driven by a combination of performance outcomes and capital investments." Under a total shift to performance-based compensation, there would be no guaranteed rate of return on equity. Shareholder earnings would be based on a combination of performance goals and "possible new product and service revenue opportunities."[129]

Two other white papers issued under Phase II covered integrated planning and grid modernization, respectively. Among all three papers, several common themes emerged. One such theme was the "value of real-time, multi interest discussion and negotiation in advance of formal proceedings." Other themes included the necessity for new approaches to planning, as well as the need for transparency, streamlining of processes, and a measured approach to reform.[130]

Massachusetts: Grid Modernization Plan

In 2014, the Massachusetts Department of Public Utilities (DPU) issued an order requiring each electric distribution company (IOUs only) to submit a ten-year grid modernization plan (GMP).[131] GMPs were to outline how each company proposes to make progress towards four

122 Ibid., p. 5.
123 Ibid., p. 6.
124 Ibid., p. 7.
125 Ibid., p. 13.
126 Ibid., p. 23.
127 E21 Initiative, *Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota,* December 2014, p. 1.
128 Ibid., p. 2.
129 E21 Initiative, *Phase II Report: On implementing a framework for a 21st century electric system in Minnesota,* December 2016, p. 12.
130 Ibid., p. 19.
131 Massachusetts Department of Public Utilities. *Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid.* D.P.U. 12-76-B, June 12, 2014.

objectives for grid modernization. The four objectives are: "(1) reducing the effects of outages; (2) optimizing demand, which includes reducing system and customer costs; (3) integrating distributed resources; and (4) improving workforce and asset management."

GMPs must outline customer marketing and outreach efforts, research and development plans, and proposed infrastructure and performance metrics.[132] The DPU expressed support for prioritizing AMI in the GMPs, stating, "We continue to view advanced metering functionality as the basic technology platform for grid modernization."

The GMP must also include a five-year short-term investment plan which applies only to capital investments. These investment plans must outline each company's approach to achieving advanced meter functionality within five years of GMP approval. If a business case doesn't justify advanced meter deployment, the plan may include an alternative proposal to achieve advanced meter functionality within a longer timeframe.[133]

The DPU also suggested that time-varying rates (TVR) as well as customer-permitted appliance monitoring and control could facilitate peak shaving by sending appropriate price signals. There are also technology-based opportunities to curb demand, especially volt-VAR optimization (VVO).[134]

The DPU revised its definition of advanced metering functionality, removing VVO and measurement of customers' power quality and voltage, as follows:

(1) the collection of customers' interval usage data, in near real time, usable for settlement in the ISO-NE energy and ancillary services markets; (2) automated outage and restoration notification; (3) two-way communication between customers and the electric distribution company; and (4) with a customer's permission, communication with and control of appliances.[135]

The order further stipulated that GMPs must include one of two types of company-specific metrics: implementation of technologies and systems, and performance progress towards the objectives of grid modernization (i.e., demand reduction or increased reliability).[136]

The DPU clarified that there would be no sharing of customer-specific data with third parties without customer approval. Aggregated data can only be shared after putting in place procedures that ensure de-anonymization cannot occur.[137] Customers will have opt-out provision, which DPU added will ensure greater participation than opt-in.[138]

The IOUs filed their GMPs with the DPU in 2015.[139]

California: Distribution Resources Plan

The California Public Utilities Commission issued a rulemaking in August 2014 for the state's IOUs mandating that they submit distribution resource plans (DRPs), "that recognize, among other things, the need for investment to integrate cost-effective DER and for actively identifying barriers to the deployment of DER such as safety standards related to technology or operation of the distribution circuit."[140] The order further stated that the IOUs must include "methodologies to define locational benefits and optimal locations for DER, augmented or new tariffs and programs to support efficient DER deployment, and the removal of specific barriers to deployment of DER."[141]

The CPUC commission relied in part on a paper, ***More than Smart,*** which laid out some foundational principles for a better integrated grid:

- A comprehensive, multi-stakeholder process for distribution planning.
- Distribution system planning should move to an open, flexible, node-friendly network system instead of a centralized and closed system.

[132] Ibid., p. 2.
[133] Ibid., p. 3.
[134] Ibid., p. 11.
[135] Ibid., pp. 14-15.
[136] Ibid., p. 30.
[137] Ibid., p. 36.
[138] Ibid., p. 37
[139] See http://acadiacenter.org/wp-content/uploads/2015/12/Acadia-Center_GMP-Summary_01072016.pdf for a summary of the plans.
[140] Public Utilities Commission of the State of California. *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.* August 14, 2014, p. 3.
[141] Ibid., p. 5.

- The electric distribution service operators (DSO) "should have an expanded role in utility distribution system operations (with CAISO) and should act as a technology-neutral marketplace coordinator and situational awareness and operational information exchange facilitator while avoiding any operational conflicts of interest." DSO will play an integrating role with CAISO.
- "California should expedite DER participation in wholesale markets and resource adequacy, unbundle distribution grid operations services, create a transparent process to monetize DER services and reduce unnecessary barriers for DER integration."[142]

The DSO is similar in concept to the DSPP of the New York REV initiative. As outlined in the paper, the DSO should evolve past traditional utility functions and toward functions including "managing distributed reliability services involving many types of DER and independent micro-grids providing distributed reliability services to support distribution system operations. The ability of the DSO to utilize locally-provided reliability services will also enable the DSO to maintain more stable and predictable interchange with the BA at the T-D interface." Other minimal DSO functions "include responsibility to [the Balancing Authority] for providing situational awareness involving forecasting, real-time measurement and reconciliation of net load, dispatchable DER resource, and real and reactive power flows from the distribution side of a P-node."[143]

Another DSO function is transmission-distribution interface reliability coordination. This coordination involves ensuring that DER dispatch does not harm the distribution system, and should go beyond forecasting and managing net load. "This does not mean that DSOs will operate balancing markets or an optimal resource dispatch function as done by the balancing authority at the wholesale level." The balancing authority retains sole responsibility of supply-demand balancing. "The DSO will, however, need to coordinate energy delivery schedules to ensure the operational integrity of the distribution system."[144]

In November 2014, Commissioner Michael Picker offered further guidance on the DRPs, laying out three parallel goals of the plans:

- Modernizing the distribution system to accommodate two-way flows of electricity;
- Enabling customer choice of new technology; and
- Animating "opportunities for DER to realize benefits through the provision of grid services."[145]

The commissioner's ruling also defined eight core elements for the DRPs.

1) Integration capacity analysis – IOUs need to perform analysis to determine how much capacity may be available on the distribution network. This should include current system analysis as well as two-year outlooks on planned investments. The DRP must also include a "unified locational net benefits methodology consistent across all three utilities" which will include, among other elements, avoided capital costs, avoided operations and maintenance, and improved distribution system reliability and resiliency.
2) Demonstration and deployment – IOUs are directed to develop proposals for DER-focused demonstration and deployment projects that seek to demonstrate integration of locational benefits analysis into utility distribution planning and operations.
3) Data access – IOUs are to develop data sharing policies and procedures.
4) Tariffs and contracts – DRPs may "propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives." These new or modified tariffs would be limited in their applicability to demonstration projects.
5) Safety considerations – DRPs must identify safety considerations, including if new requirements need to be developed, and how DER can support higher levels of system reliability and safety.

142 Paul DeMartini. *More than Smart: A Framework to Make the Distribution Grid More Open, Efficient and Resilient.* Resnick Institute, 2014, pp. 3-4.
143 Ibid., p. 17
144 Ibid., p. 18.
145 Public Utilities Commission of the State of California. *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769 – Assigned Commissioner's Ruling Re Draft Guidance for Use in Utility AB 327 (2013) Section 769 Distribution Resource Plans,* November, 17, 2014.

6) Barriers to deployments – DRPs shall identify barriers to deployment, of which there are three main categories to consider: barriers to integration/interconnection, barriers that limit the ability of DER to provide benefits, and barriers related to distribution system operational and infrastructure capacity.
7) Coordination with utility general rate cases –DRPs should identify action or investments that may be included in the utility's next general rate case.
8) Phasing of next steps – Since this is just the beginning of a long-term process, utilities should include how DRPs can be updated every two years.[146]

The state's IOUs continue to collaborate with working groups to finalize the DRPs.

146 Ibid., p. 15-23.

MOVING TOWARDS THE UTILITY OF THE FUTURE

State proceedings, as well as other articles, reports, and books, have proposed ways to better integrate renewables, DG, and other technologies to the grid, and have proposed different models for utility involvement in these areas. This extensive discussion about changes to the traditional utility business model has brought forth several ideas for what defines the "utility of the future."

Integrating DER

One of the greatest challenges to DER integration is that multiple participants have different levels of control over generation, transmission, distribution, and load management. This can be especially challenging in markets operated by an RTO or ISO. In such a market, the ISO dispatches DER without having the full operational awareness of the impact on the distribution system, nor can the ISO predict how DER may impact net load. Meanwhile, the distribution operator does not have as much visibility and control over DER as the ISO does with regards to transmission.[147]

These challenges can be more easily overcome with low levels of DER. But in a high DER future, the ISO needs to be able to forecast the behavior of "autonomous DER" – meaning DER not participating in the ISO market. As explained in the ***More than Smart*** paper, there is a need to "specify roles and responsibilities of the ISO, distribution operator, and DER providers in ensuring timely and accurate information is available to produce accurate short-term forecasts."[148]

Some have laid out a market-based approach to integration. One such solution is called transactive energy. Transactive energy is defined as "a vision of an intelligent device-enabled grid where each device can utilize economic signals in order to optimize allocation of resources subject to the constraints of the grid."[149]

In a transactive energy approach, smart devices would be connected in such a way that price signals would be sent to each connected device to ensure they are turned off during peak periods. These price signals would tell the device when it would be optimal to operate.[150] The Electric Power Research Institute (EPRI) forecasts a rapid increase in the number of connected devices, also known as "the internet of things," from 5 billion in 2015 to 25 billion in 2020.[151]

This shift to a world of connected devices will require advances in cybersecurity as well as the integration of information technology (IT) with operational technology (OT). EPRI notes that the Open Automated Demand Response (Open ADR 2.0 b) standard highlights the importance of IT/OT integration. This standard – open to any grid-connected electrical resource – has three important attributes: unlimited use, open and unrestricted access, and anyone can benefit from it.[152]

In terms of security, there are a few routes available to utilities. Network System Management (NSM) is a platform which "can enhance the security of devices, links, and interfaces." NSM incorporates network control, monitoring, and other safety features.[153] Utilities have also addressed the lack of a centralized threat management capability through integrated security operations centers (ISOC). As explained by EPRI, "an ISOC is designed to collect, integrate, and analyze events and logs from these traditionally siloed organizations, providing much greater situational awareness to a utility's security team."[154]

147 More than Smart, *Coordination of T&D,* p. 6.
148 Ibid., p. 11.
149 Nilgun Attanurk and Marzia Zafar. *Transactive Energy: A Surreal Vision or a Necessary and Feasible Solution to Grid Problems?* Prepared for the California Public Utilities Commission Policy & Planning Division, October, 2014, p. 4.
150 Ibid., pp. 11-12.
151 Electric Power Research Institute. *Electric System Connectivity: Challenges and Opportunities.* February, 2016, p. 7.
152 Ibid., p. 12.
153 Ibid., p. 13.
154 Ibid., p. 14.

The Utility's Role

What role does the utility play in this highly integrated future? The New York REV DSPP and the distribution operator of the California PUC's grid integration project are roles that can be fulfilled by the utility. Yet some industry groups protest both the utility role as a DSPP and their ability to own DER assets. The comments of NRG Energy in the rulemaking establishing REV highlight this sentiment:

> Allowing utilities in New York to ratebase DER investment will be incredibly corrosive to the DER marketplace and set innovation in New York's distribution system back immeasurably. DER investment decisions should be driven by end-users and their designated agents, with shareholder dollars at risk.[155]

Solar City expressed similar reservations, and the Alliance for Clean Energy indicated an independent entity could become the DSPP further down the line, and further speculated about potentially creating an Independent Distribution System Operator (IDSO), which would be operationally similar to NYISO.[156]

In terms of the utility's role as a grid manager, Peter Fox-Penner, director of the Institute for Sustainable Energy and professor of practice at Questrom School of Business at Boston University, discussed a couple of different models. Under the "Smart Integrator" scenario, the utility would not own any generation assets, but would instead run a "smart transmission system and/or distribution system that integrates, sets prices for, and balances all types of generation, storage, and demand response."[157]

Alternatively, utilities could be organized as "Energy Services Utilities." These utilities would be organized like today's vertically integrated utilities, but would employ greater use of "smart grid, dynamic pricing, and decentralized services."[158] A hybrid model would be a smart integrator where the DG is owned by their communities.[159]

Fox-Penner also writes of community energy systems (CES). These are similar to public power utilities, "except that a CES is added into an area where the wires may be owned and operated on an open access basis by a separate Smart Integrator." As he describes it, it is the "unlikely child of public power and retail choice."[160]

The Eastern Interconnection States' Planning Council (EISPC) also describes a similar set of models, distinguishing between "platform facilitators" – akin to a traffic cop – "service providers" and "wires providers." The utility could also be a network facilitator, interacting with DG customers as a partner with third parties.[161] As outlined by EISPC, the choice for the utility is between passive and active network management. Utilities engaged in active management take steps to "coordinate the different DG systems so as to maximize the value of integration."[162]

EISPC also addresses the other point of contention: utility ownership of DER assets. As highlighted above, there has been some state legislation aimed at granting utilities more leeway to own rooftop solar systems, but these actions have come under fire by solar and some other third party interest groups. They remain concerned that utility ownership of DG and DER is unfair because utilities already enjoy an incumbency advantage.

EISPC approaches this issue by highlighting the pros and cons from the utility perspective. On the pro side, utility ownership of DG could lead to better economies of scale, and better use of resources. Furthermore, utility ownership of DG could spur further DG development. With utility ownership, the utility recoups lost revenue, the customer does not have to pay any upfront capital costs, and the utility can have greater operational control of the DG facility. In other words, the utility would be placed in a situation where it can promote, rather than obstruct, DG deployment.[163]

155 *Reforming the Energy Vision,* comments of NRG Energy, p. 3.
156 *Reforming the Energy Vision,* comments of Alliance for Clean Energy, p. 15.
157 Peter Fox-Penner. *Smart Power: Anniversary Edition* (New York: Island Press), 2014, p. 170.
158 Ibid.
159 Ibid., p. 172.
160 Ibid., p. 287
161 Eastern Interconnection States' Planning Council. *Utility Involvement in Distributed Generation: Regulatory Considerations White Paper.* National Regulatory Research Institute, February 2015, p. 16.
162 Ibid., p. 17.
163 Ibid., pp. 40-42.

As for disadvantages, the utility's inherent cost advantages could discourage further third party activity in this space. Regulators would have to encourage a level playing field, and as such they would have to ensure that core, non-DG customers are not subsidizing DG asset purchases. They could do this through ring fencing (keeping different company assets financially separated) and prohibit information and employee sharing through the utility, similar to rules proscribed for retail choice.[164] Other concerns include the potential for utilities to leverage their market power in their core business to bolster their DG market activities.[165]

Public Power Forward

Public power utilities will be affected by these changes as much as IOUs, if not more so. The relatively small size of most public power utilities makes it much more challenging for them to adapt these technological innovations. It will become increasingly important for Joint Action Agencies and State Associations to collaborate on these issues with member utilities. The American Public Power Association can also provide resources and guidance as utilities consider new business models for the future.

Public Power Forward is the Association's effort to focus on how the issues surrounding the "utility of the future" impact public power utilities. The Association has produced several white papers on an assortment of topics, including rate design, and other resources, such as research papers, case studies, and educational opportunities and webinars.[166]

The Association laid out a roadmap for this initiative in its submittal to Phase II of the Smart Electric Power Alliance 51st State.[167] The roadmap outlines the steps public power utilities need to take as they respond to changing customer preferences:

- Establishing measures likely to lead to sustainable long-term business practices and customer relationships.
- Experimenting with various approaches to utility controlled community-scale solar to identify business and operational challenges.
- Starting to realign retail customer rates with economic costs and cap exposure to net energy metering regulatory arbitrage.
- Modeling and managing risks to the utility and customers driven by external factors.
- Communicating with governing boards, customers, and community stakeholders on the utility's plans.[168]

The roadmap calls on public power utilities to fully integrate DER into utility operations, develop better use cases, and adopt pilot programs. The roadmap highlights community solar as one avenue through which utilities can deliver solar options to customers who may otherwise lack the means or interest in managing rooftop systems. Community solar also offers utilities an opportunity to gain operational experience.[169]

While the Association's roadmap suggests that many traditional elements of the utility business model will remain relevant in the future, it identifies key elements of the transition to the future state:

- Recognizing the real economic costs and risks of alternatives — and reflecting them in utility specific rates and service offerings. Subsidies can create an unsustainable, high-DER future.
- Aligning customer interests with those of the utility and third-party suppliers at the grid edge and wholesale/bulk power levels.
- Capturing the benefits of DER integration for customers and utility system planning and operations.
- Developing the utility business and operational technology infrastructures to sustain these offerings over time.[170]

In the end, the roadmap suggests a careful integration of core services with new product offerings. While this convergence of new and old business models may prove challenging, it can also present an opportunity for public power utilities to develop new revenue streams and better connect to and engage with customers.

164 Ibid., p. 42.
165 Ibid. pp. 43-44.
166 Public Power Forward. American Public Power Association. http://publicpower.org/Topics/Landing.cfm?ItemNumber=45624
167 American Public Power Association. *APPA's Roadmap to the SEPA 51st State,* April 2016. Available at https://sepa.force.com/CPBase__item?id=a12o000000TOYIXAA5. An infographic summarizing the roadmap is also available at: http://www.publicpower.org/files/Media/images/APPA_Road%20map%20info_2pgv3.jpg
168 Ibid., p. 13.
169 Ibid.
170 Ibid., p. 15.

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