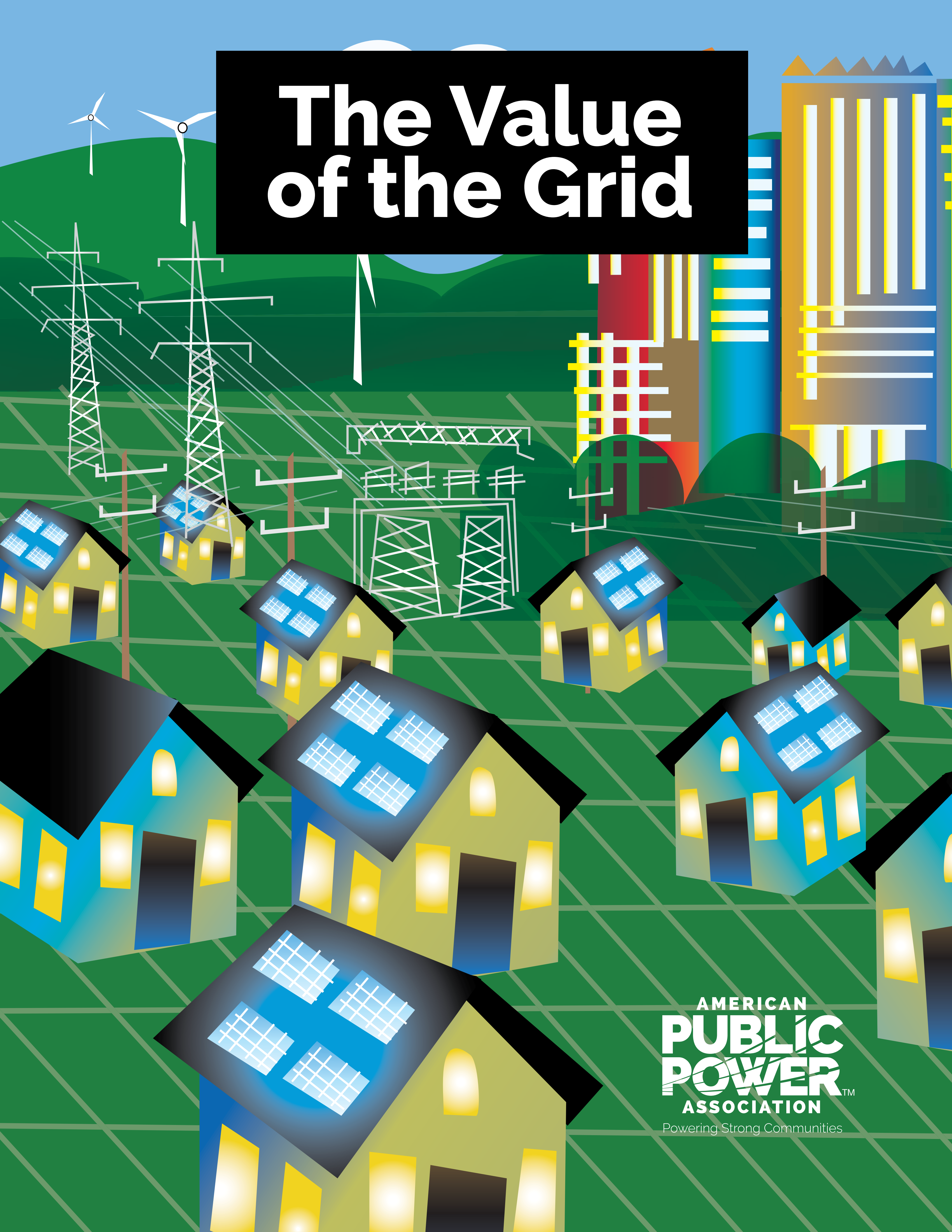
The Value of the Grid



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Introduction

Rapid changes within the electric industry have led to concerns that electric utilities are in peril of becoming obsolete. The rise of distributed energy resources (DERs), particularly rooftop solar generation or distributed generation (DG), as well as energy efficiency, behind-the-meter energy storage, and microgrids have caused declining or stagnant sales. Declining costs for these DER options promise to further erode sales.

Both environmental concerns and economics are driving these changes. Concerned stakeholders seek to move energy production away from fossil fuel generation, and DERs are low or non-carbon emitting resources. Others see an opportunity to promote individual freedom in resource allocation. And others see owning DERs as a way to secure a long-term fixed power price in the face of rising retail rates.

There is still tremendous value in both the electric utility and the electric grid in meeting these evolving customer expectations. Not only will the utility continue to play a role in the future, the grid and the utilities managing it are essential in navigating the evolution of the energy industry.

Complete grid defection, where customers disconnect from all utility service and rely on self-supply, is unlikely and counterproductive to customers seeking low-cost reliability or a decarbonized future.

While DERs become more economical, other factors limit the potential of complete grid defection. Grid defection is made all the less likely due to a countertrend: electrification. The electrification of various items, particularly vehicles, water heating, and home heating, could more than compensate for declining sales due to DERs.

The combination of electrification and distributed technologies requires a platform and entities to manage this platform. The grid will become even more important in a high-DER and electrified future, as these resources will need to be integrated in an efficient manner to ensure reliability. Though different models of grid management will emerge, the electric utility will continue to play an essential role.

Public power utilities are especially suited to thrive in this future. A number of public power utilities are already taking steps to prepare for the new energy future, and exploring new services and business models to lay a groundwork for their future role.

As public power business models adapt to change, the steps and considerations utilities take will help them to thrive in these new roles.

The Value of Distributed Energy Resources and the Cost of Grid Defection

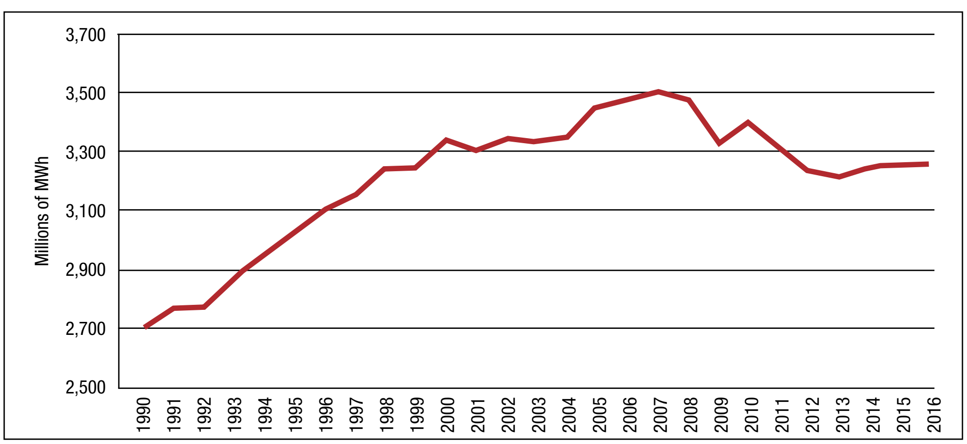
Distributed energy resources have increased their reach over the past decade and have moderately impacted load growth. Since 2008, electricity sales throughout the United States have stagnated. The recession that began in the late 2000s caused a decline in sales, and electricity sales have not rebounded in nearly the same way they have in the aftermath of previous economic downturns. Figure 1 shows historic trends in electric sales, and demonstrates flat growth over the past decade.

The single biggest factor in declining sales is energy efficiency. Efficiency gains in electric appliances, lighting, home insulation, and heating, ventilation, and air conditioning (HVAC) systems have all contributed to lower electricity sales than would be expected, even though Americans continue to use more appliances and devices that use electricity. Demand response programs, where customers are induced to reduce energy use at certain times, have contributed to diminished electric use as well.

Distributed generation, outside of Hawaii, has only had a minimal impact comparatively thus far. But the number of residential and commercial rooftop solar customers has grown to over 1.3 million, with a total capacity of approximately 13,000 megawatts (MW).[1] Hawaii has the widest penetration of DG as a percentage of total load, followed by California. While DG has increased nationwide, currently less than one percent of national load is served by DG.

These numbers are expected to grow significantly in coming years. The leading cause of this growth is economics: solar panel prices have dropped precipitously, while electric rates have increased modestly. The Rocky Mountain Institute (RMI) observes that grid parity – the point at which solar plus storage costs as much as traditional grid service over the usable life of the technology – has already been achieved in some locations, including Hawaii.[2] RMI projects that grid parity will be achieved in most states by 2025, and for nearly all customers by 2050.[3]

Figure 1. Total sales of electricity in the US, 1990-2016

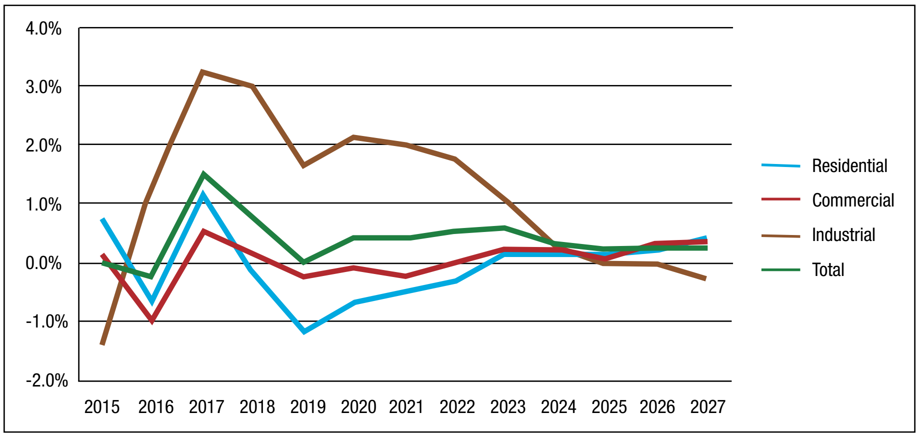


Source: ABB Velocity Suite

The Energy Information Administration (EIA) projects sales growth to be minimal over the short term.

[1] Energy Information Administration (EIA) Form EIA-861, 2016 data.
[2] Peter Bronski et al. *The Economics of Grid Defection.* Boulder, CO: Rocky Mountain Institute, 2014, pp. 7-9.
[3] Ibid., p. 25.

Figure 2. Projected year over year sales growth, by sector, 2015-2027



Source: Energy Information Administration: Annual Energy Outlook, published May 2017

There are non-economic factors influencing this trend. As RMI notes, some have been motivated by extreme events such as Superstorm Sandy to investigate microgrids and other options to improve reliability beyond what is typically delivered by the grid. Large corporations, meanwhile, are seeking to achieve renewable energy goals. Approximately 60 percent of Forbes Fortune 100 companies have a renewable energy goal.[4]

The potential for DERs

There are significant opportunities to increase DG in cities. The National Renewable Energy Laboratory (NREL) studied the technical potential penetration of rooftop solar in 128 cities, including shading, roof tilt, and east-west orientation. The study found that 83 percent of small buildings in the 128 cities had a suitable location for rooftop photovoltaic (PV), but only 26 percent of the total rooftop areas of these buildings were suitable for development. The study also found that most medium and large buildings have at least 10 square meters of suitable roof space, and 99 percent have at least one qualifying roof plane. The total rooftop space of medium-sized buildings suitable for PV was determined to be 49 percent, and 66 percent for large buildings. [5]

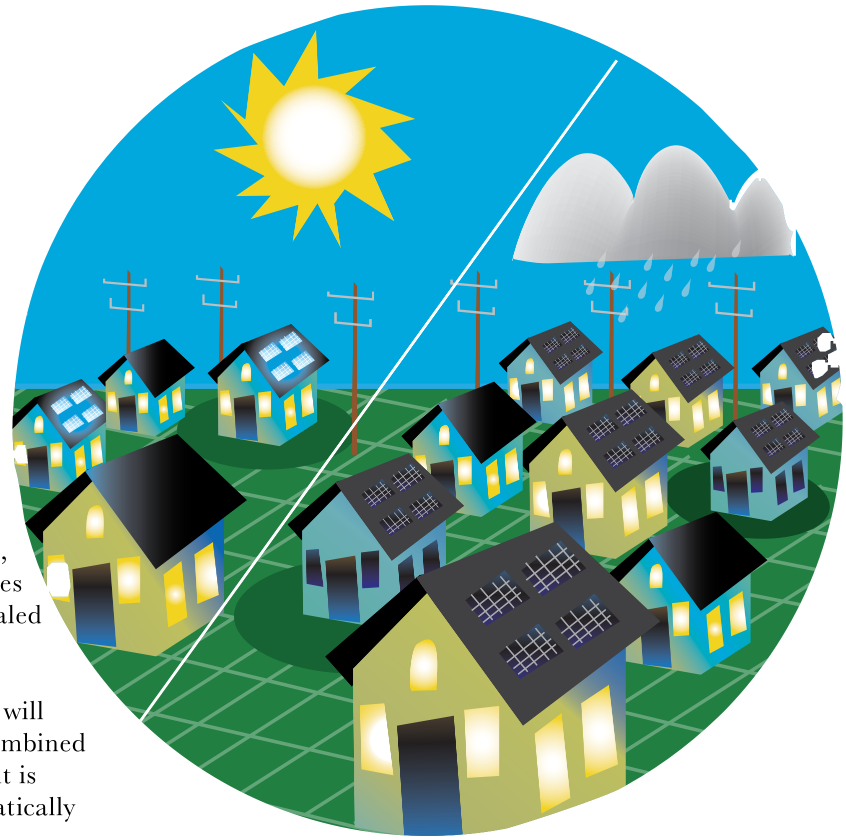
The technical potential for rooftop solar is not the same throughout the country. Mission Viejo, California, had the highest amount of suitable roof space at 88 percent, in contrast with only 18 percent of suitable roof space in New York and Washington, DC. [6] Ultimately, NREL concluded that 26 percent of the total rooftop space of small buildings was suitable for rooftop PV deployment, accounting for potentially 731 gigawatts (GW) of PV capacity, generating 926

[4] Ibid., pp. 14-16

[5] Peter Gagon, Robert Margolis, Jennifer Melius, Caleb Phillips, and Ryan Elmore. *Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment.* Golden, CO: National Renewable Energy Laboratory, 2016, p. 12.

[6] Ibid., pp. 19-20.

The Value of Distributed Energy Resources and the Cost of Grid Defection



Terawatt-hours (TWh) annually. Medium and large buildings in the study had a potential capacity for 386 GW and 506 TWh of annual production. [7] To put that in perspective, in 2016, the total nameplate capacity in the United States was 1,177 GW, and total electric generation totaled almost 4,145 TWh. [8]

Both the RMI and NREL reports posit that DG will play an increasing role in the electric sector. Combined with declining costs in energy storage systems, it is becoming more possible for customers to dramatically reduce their dependence on the grid, and even completely defect from it.

The cost of DERs

Grid defection is not the only cause for concern for utilities. Even if DG customers remain tied to the grid, they use less power than non-DG customers, thus cutting into electric sales. Electric utilities – especially public power utilities who are not seeking a rate of return – could be indifferent to lower sales if rate design equitably reflected cost causation. Net energy metering (NEM), the most common rate design for DG customers, creates subsidies between customers in the same class. [9,10] This is because though a high proportion of a utility's costs are fixed, however, 90 percent or more of utility revenue is normally recovered through variable charges. Therefore, the recovery of fixed costs through variable charges creates an imbalance where net metered customers are compensated (or credited) for their excess generation at retail rates, and non-DG customers pay a greater share of the cost through the variable charges.

As utilities move towards alternative rate designs, it is possible that some rate strategies may exacerbate revenue recovery problems or spark more grid defection. For instance, if a new rate design causes DG customers' rates to increase to the point where a solar plus storage option represents a significant financial discount, it could induce them to completely move away from the utility. On the other hand, it is possible for DG customers that stay connected to the grid to game certain rate options, especially peak charges in a time-of-use rate. A customer who owns a solar plus storage system (or even just a solar PV system) who injects power onto the grid to offset their peak charge avoids the utility's peak charges while earning credits for power generated at a much more expensive time of the day.

Despite these developments, there are countervailing trends which mitigate the potential for grid defection. While NREL's study suggests high growth potential for PV, not all rooftop space is suitable. Moreover, it is unlikely that all the suitable space will be used. An analysis of the NREL study performed by the Brattle Group stated that "100 percent realization of NREL's

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[7] Ibid., p. 38.

[8] 2016 data from the Energy Information Administration, Form EIA-860 for capacity and Forms EIA-861 and EIA-923 for generation.

[9] American Public Power Association. *Distributed Generation: An Overview of Recent Policy Developments*, 2014

[10] American Public Power Association, *Rate Design Options for Distributed Energy Resources*, 2016.

technical potential is unlikely, and even if achieved, utility sales of electricity would still represent over 60 percent of overall electricity production." [11]

While RMI's analysis focuses on the economic case for grid defection, it largely ignores technical considerations. While it may be economically beneficial in the abstract to use the grid as an energy account balancing entity, most customers will not have the technical ability to truly separate, and those who can defect might choose not to. Moreover, a simplistic economic analysis of the cost to implement a solar plus storage system compared with electric rates minimizes other economic factors, especially the value of having the electric grid available as a backup battery.

Even where the economics and technical specifications work together to make grid defection feasible, other considerations may give customers pause. Poor weather may impinge on the ability of solar plus storage systems to provide 100 percent of all power needs. If a location experiences several overcast, rainy, or non-windy days in a row, followed by one sunny and windy day and then five more rainy days – what Charles Bayless terms the "Cleveland Effect" – then the customer would need five days of battery storage and six days of generation (one for load on the sunny day, and five to charge the battery). In other words, 500 percent battery and 500 percent generation reserves would be needed. [12]

These factors cause Brattle to conclude that wide defection is not likely. "Even with significant increases in solar PV efficiency and deployment of distributed storage systems, the amount of power the typical residential roof can generate will not be sufficient to power all use of electricity in the home. So even for houses with suitable roofs, a fully autonomous electric production system is likely not feasible." [13]

The likeliest scenario for the future is some grid defection, and a greater penetration of solar plus storage behind the meter, and most DER customers remaining tied to the grid because of the tremendous value of the grid as a reliable and valuable backup source of electricity. This presents several options for electric utilities: to be a provider and owner of DERs, an energy services company managing an integrated grid, or some combination of these two. In any case, the electric utility will have a core function in a high-DER future. This is even truer if the developments analyzed in the next section bear fruit.

Even with significant increases in solar PV efficiency and deployment of distributed storage systems, the amount of power the typical residential roof can generate will not be sufficient to power all use of electricity in the home.

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[11] Jurgen Weiss, Ryan Hledik, Michael Hagerty, and Will Gorman. *Electrification: Emerging Opportunities for Utility Growth.* The Brattle Group, 2017, p. 3.

[12] Charles Bayless, "Renewables are Cheaper than the Existing Grid," *Public Utilities Fortnightly,* February 2018, p. 41.

[13] Weiss, et al, *Electrification,* p. 8.

Electrification

Items traditionally energized by fossil fuels – vehicles, water heating, and home heating – are being electrified, both for environmental and efficiency reasons.

The electric sector represents a growing portion of the total United States energy sector. In 2017, the electric sector accounted for approximately 38 percent of total energy use.[14] As recently as 1979, electricity represented less than 30 percent of the energy sector. In 2010, electricity's proportion of energy consumption reached 40.6 percent, and has hovered in the high 30s since.

There is potential for even greater growth in the electric sector of the economy. Items traditionally energized by fossil fuels – vehicles, water heating, and home heating – are being electrified, both for environmental and efficiency reasons.

Electric vehicles

The greatest opportunity for electrification resides in the transportation sector. Plug-in hybrid electric vehicle (PHEV) and electric vehicle (EV) sales have increased significantly in recent years. In 2017, a record 200,000 EVs were sold in the United States, which marked a 26 percent increase over 2016 sales, the previous record high year for EV sales.[15] EVs are projected to be an increasing share of the vehicle market, and depends on a number of factors, including tax benefits and credits, battery prices, changes in fuel economy standards, and the development of charging infrastructure.

[14] Energy Information Administration, *Monthly Energy Review,* March 2018, Table 2.1: Energy Consumption by Sector. Accessed at: https://www.eia.gov/totalenergy/data/monthly/

[15] Jonathan M. Gitlin, "2017 was the best year ever for electric sales in the US," ars Technica, January 4, 2018, accessed at https://arstechnica.com/cars/2018/01/2017-was-the-best-year-ever-for-electric-vehicle-sales-in-the-us/

The Electric Power Research Institute (EPRI) projects that light-duty EVs and PHEVs will account for 75 percent of new vehicle sales by 2050. Though EVs are expected to remain more expensive than internal combustion engine (ICE) vehicles, lower fuel and maintenance costs will make EVs less expensive on a total cost basis by the early 2020s.[16] Demand for electric heavy duty transport vehicles such as buses and trucks, which comprise about 10 percent of the market, is expected to reach 40 percent by 2050.[17]

In the short-term, EV sales projections are more varied. EPRI's reference case suggests EVs will represent 25 percent of miles traveled in 2030, but this projection depends on the factors outlined above.[18] Navigant also predicts steady growth, projecting sales of more than 700,000 EVs annually, with as many as 3.5 million EVs on the road across the United States by 2021. Navigant also projects that by 2025, EV electricity consumption will be over thirteen times the consumption from EVs 2016.[19]

Electric vehicles are three times as efficient as their ICE counterparts. EVs use 59-62 percent of the electricity used to charge them, as opposed to ICE vehicles, which use 17-21 percent of the gas they are fueled by.[20] To put that in terms of energy used, an EV driven 12,000 miles will have used 33 million British Thermal Units (MMBtu) whereas a comparative ICE vehicle will have used 86 MMBtu.[21] This efficiency advantage means that by 2050, there would be a 60 percent reduction in total energy use despite a 30 percent projected increase in vehicle miles traveled.[22] These efficiency improvements have environmental benefits.

Electric water heating

Another potential for greater electrification is in the water heating sector. There is already a large market for electric water heaters – 43 percent of homes in the United States currently have electric water heaters. But only a small proportion of these water heaters use a specific technology called heat pump water heating, which is a more efficient but also a more expensive mechanism.[23]

In addition to being more efficient, electric water systems can also effectively function as a battery. As explained by the Brattle Group, "By heating the water in the tank to store thermal energy, water heaters can be controlled in real-time to shift electric consumption from higher-priced hours when less efficient generating units are on the margin to lower-priced hours when in some cases there may be excess supply of energy from renewables."[24]

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[16] Electric Power Research Institute. *U.S. National Electrification Assessment.* Palo Alto, CA: EPRI, 2018, p. 27.
[17] Ibid., p. 30.
[18] Ibid., p. 28.
[19] American Public Power Association. *A Public Power Guide to Understanding the U.S. Plug-in Electric Vehicle Market,* prepared by Navigant, 2017; available at https://www.publicpower.org/system/files/documents/understanding_the_us_plug-in_electric_vehicle_market_2017_digital_final.pdf/
[20] S. David Freeman and Leah Y. Parks. *All Electric America.* Solar Free Press, 2015, p. 11.
[21] EPRI, *National Electrification Assessment,* p. 15
[22] Ibid., p. 27.
[23] Ibid., p. 34. There are two primary types of water heaters: electric resistance water heaters (ERWH), which use an electric element to directly heat water, and heat pump water heaters (HPWH), which use the surrounding air to heat the water. See Ryan Hledik, Judy Chang, and Roger Lueken. *The Hidden Battery: Opportunities in Electric Water Heating.* The Brattle Group, January 2016, p. 4.
[24] Hledik, et al, *The Hidden Battery,* p. 1.

An all-electric system would be 39 percent more efficient than the current system.

Electric water heaters also present an opportunity to smooth out the effects of the duck curve.[25] As outlined by the Regulatory Assistance Project (RAP), "each controlled water heater can provide the flexibility needed for about 2 kW of wind or solar generation."[26] Furthermore, "control of one million electric water heaters means that up to 4,400 MW of load could be 'turned on' as needed to absorb wind or solar energy, and that up to 1,000 MW of water heating load that occurs during periods of high demand could be 'turned off' as needed to manage peak loads."[27] In other words, being able to control the functions of electric water heaters on short notice can smooth out the variability effects of renewable generation, which would allow for more renewable generation on the grid without sacrificing reliability.

Building heating

Building space heating currently accounts for 12 percent of energy use, the second largest application of energy.[28] Electric heat pumps and electric resistance heating are already in use, and both have greater usage in the residential sector – 15 percent for heat pumps, and 19 percent for resistance heaters.

Heat pumps can provide an efficient method for end users to reduce emissions, depending on the local energy mix. Heat pump space and water heating systems are typically 200 to 400 percent efficient. In other words, for every unit of power consumed, the heat pump produces two to four times that amount by taking heat out of the ambient air.[29] Though generally more efficient than natural gas heating, heat pumps can have problems with low airflow, leaky ducts, and

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[25] A phenomenon, already prevalent in California, where solar energy production peaks in the late afternoon, slightly before the system peak. When the system peaks, solar production ramps down, necessitating a quick ramping up of other resources. Plotted on a curve, it looks strangely like a duck.

[26] Jim Lazar. *Teaching the "Duck" to Fly*, 2nd Edition. Montpelier, VT: The Regulatory Assistance Project, February 2016, p. 20.

[27] Ibid.

[28] EPRI, *National Electrification Assessment*, p. 31.

[29] Single Package Vertical Air Conditioners and Single Package Vertical Heat Pumps Final Rule, Department of Energy, Minimum coefficients of Performance

incorrect refrigerant charge. Additionally, natural gas is cheaper than electricity on a Btu basis, meaning heat pumps are deployed primarily in mild climates with lower electric prices.[30] With increased efficiency improvements, EPRI projects that electric space heating will account for 50 percent of residential heating by 2050, leading to a 25 percent decline in total residential energy use in this sector.[31]

Efficiency and environmental benefits

A common thread among the electric uses highlighted above is that they are more efficient than other energy uses. According to a Stanford University study, an all-electric system would be 39 percent more efficient than the current system.[32] EPRI projects that if its reference case numbers are met, total energy use in the United States would be reduced by 22 percent by 2050.[33]

Efficient use of electrification has enormous potential environmental benefits, and may be necessary to achieve economy-wide carbon reduction goals. In California, for example, the transportation and non-electric space and water heating sectors account for three times the greenhouse gas emissions of the electric sector.[34]

EPRI's projections for overall energy use reductions would translate into emissions reductions across the country. In its reference case, EPRI projects emissions reductions of 20 to 70 percent of current levels by 2050, depending on the level of electrification and if policies are enacted to induce further cuts in emissions.[35]

RAP terms this emissions efficiency. Even though more kilowatt-hours (kWh) are produced, the total number of joules of energy are reduced.[36] Emissions are reduced even absent the retirement of all fossil fuel generation. In fact, natural gas use is projected to grow in every model EPRI used for its national assessment, while emissions were projected to decrease due to more efficient overall use of energy.[37]

Other organizations have also projected reduced carbon emissions due in part to electrification. The Institute for Sustainable Development and International Relations (IDDRI) includes electrification as one of its pathways to deep decarbonization. Along with efficient end use of energy in buildings, transportation, and industry, as well as decarbonization of fuel sources in the electric sector, IDDRI and the Sustainable Development Solutions Network found that electrification of end uses leads to as much as an 85 percent reduction in total emissions by 2050.[38]

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[30] EPRI, *National Electrification Assessment,* p. 31.
[31] Ibid. As with all other technologies, projections are much higher in aggressive technology cases.
[32] https://news.stanford.edu/pr/2015/pr-50states-renewable-energy-060815.html
[33] EPRI, National Electrification Assessment, p. 40.
[34] Southern California Edison, *The Clean Power and Electrification Pathway: Realizing California's Environmental Goals,* November 2017, p. 1.
[35] EPRI, *National Electrification Assessment,* p. 46.
[36] Ken Colburn, "Beneficial Electrification," presented at Minnesota Rural Electric Association 2017 Energy Issues Summit, St Cloud, MN, August 10, 2017.
[37] EPRI, *National Electrification Assessment,* p. 42.
[38] J.H. Williams, B. Haley, F. Kahrl, J. Moore, A.D. Jones, M.S. Torn, H. McJeon. *Pathways to Deep Decarbonization.* The U.S. report of the Deep Decarbonization Project of the Sustainable Development Solutions Network and the Institute for Sustainable Development and International Relations, 2014, p. 22.

Both DERs and electrified energy end uses require integration and management. A decentralized grid does not provide the appropriate platform for these resources to reach their full potential. Utility management of a centralized grid enables more efficient operation of these technologies.

While overall energy usage and carbon emissions decline, electric power consumption would increase with electrification gains. Full electrification of the transportation sector would lead to a 56 percent increase in electric demand by 2050, and full electrification in the space heating sector would increase electric sales by 40 percent, or a 3,560 TWh increase.[39]

Full electrification of these sectors is unlikely. EPRI's reference case projects 1.2 percent annual load growth through 2050, though this increases to 2.7 percent annual growth in its "Transformation" case.[40] These figures demonstrate the growth potential of the electric industry despite the rise of DERs. Moreover, Brattle projected that even if 50 percent of all rooftop solar generation potential is realized by 2050, electric utility sales would double.[41]

Though electrification provides opportunities for environmental benefits and utility load growth, there are potential challenges to this growth. One example of a technology causing load growth is bitcoin mining. Mining operations use enormous computing power, and have popped up in towns served by public power utilities with low electric rates. Bitcoin mining can present challenges to public health and safety, reliability, rates, and billing. For example, "rogue" bitcoin miners can overload circuits. From a reliability perspective, this can impact power quality. Further, the significant increase in demand can strain infrastructure and require upgrades to distribution and transmission assets. Utilities examining how to accommodate this increased demand are determining the appropriate rate schedule and fees for bitcoin miners.[42]

Utilities might have to adopt different strategies to accommodate new load. The Sacramento Municipal Utility District (SMUD) did an analysis of its distribution system that showed its EV charging rates, which encouraged charging from midnight to six in the morning, could cause up to 17 percent of its service transformers to be overloaded.[43]

This example shows that increased electrification can bring up operational concerns, but it also demonstrates the importance of utility analysis and management. Both DERs and electrified energy end uses require integration and management. A decentralized grid does not provide the appropriate platform for these resources to reach their full potential. Utility management of a centralized grid enables more efficient operation of these technologies.

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39 Weiss, et al, *Electrification,* p. 6.
40 EPRI, *National Electrification Assessment,* p. 38.
41 Ibid., p. 7.
42 For a detailed examination of bitcoin mining, see Paul Roberts, "This Is What Happens When Bitcoin Miners Take Over Your Town, Politico, March/April 2018, accessed at https://www.politico.com/magazine/story/2018/03/09/bitcoin-mining-energy-prices-smalltown-feature-217230
43 Dan Wilson, Karlynn Cory, Daisy Chung, and Vazjen Kassakhian. *Beyond the Meter: Planning the Distributed Energy Future, Volume II.* Black and Veatch, prepared for the Smart Electric Power Alliance, May 2017, p. 23.

The Value of the Grid

It is impossible to precisely predict the levels of DER penetration and electrification in the future. Unforeseen technological developments, public policy changes, and shifts in priorities will all impact how much of these resources are deployed. What is certain is that a paradigm shift is occurring in both the electric and overall energy sectors.

Far from suggesting a diminished role for electric utilities, these changes require an altered yet extremely important function for electric utilities. To fully unlock the potential of these new technologies requires planning, integration, investment, and enhanced operational awareness. Disaggregating these functions may make sense in some circumstances, but generally, communities would be better served having utilities play a central part. Moreover, the value of the existing grid will be made manifest as we work to integrate these resources and assure the continued reliable functioning of the electric system.

Unlocking the value of the grid

Over a century ago, as electricity became widely available to the public, two models emerged for electric generation and distribution. The typical model was to have a series of microgrids located throughout a service territory. Generating plants were small facilities that distributed electricity over small distances. Samuel Insull established the second model, which dominated the 20th century: large, centralized generation resources with a sprawling distribution network delivering power to customers over a large territory. Insull realized the value of economies of scale, as power produced in this way was much cheaper for the utilities, and therefore for customers.

Table 1. Estimated Interruption Cost per Event, by duration and customer class, 2013

Interruption Cost	Interruption Duration					
	Momentary	30 Minutes	1 Hour	4 Hours	8 Hours	16 Hours
Medium and Large C&I (Over 50,000 Annual kWh)						
Cost per Event	$12,952	$15,241	$17,804	$39,458	$84,083	$165.482
Cost per Average kW	$15.9	$18.7	$21.8	$48.4	$103.2	$203.0
Cost per Unserved kWh	$190.7	$37.4	$21.8	$12.1	$12.9	$12.7
Small C&I (Under 50,000 Annual kWh)						
Cost per Event	$412	$520	$647	$1,880	$4,690	$9,055
Cost per Average kW	$187.9	$237.0	$295.0	$857.1	$2,138.1	$4,128.3
Cost per Unserved kWh	$2,254.6	$474.1	$295.0	$214.3	$267.3	$258.0
Residential						
Cost per Event	$3.9	$4.5	$5.1	$9.5	$17.2	$32.4
Cost per Average kW	$2.6	$2.9	$3.3	$6.2	$11.3	$21.2
Cost per Unserved kWh	$30.9	$5.9	$3.3	$1.6	$1.4	$1.3

Source: Lawrence Berkeley National Laboratory

Grid Defection: At What Cost?

	Connected 	Not Connected 
Energy use	10,766 kWh/year, 897 kWh/month	
Daily peak consumption	7kWh	
Power source	The grid	5.5 kW solar system and 7 kW home battery
Cost	$114/month, or $1,368/year	$15,000-$23,000, after tax credits
Reliably has power	99.99% of the time	On sunny days, and up to one day after a sunny day
Reliability services	Included in monthly cost	$165-430/month additional

Today, this model is getting reexamined. With modern technology, in some cases microgrids of renewable generation and DERs can deliver electricity more economically and in a more environmentally friendly manner. However, it would be counterproductive to undo the value wrought by the reliability of the existing electric grid.

Perhaps the most important value of the grid is its reliability. Energy Information Administration (EIA) data for 2016 show that a typical customer in the United States is without power a few hours per year, with the average annual system interruption being slightly more than 300 minutes.[44] In other words, power is available to customers well over 99 percent of the time. Catastrophic events which knock out power for multiple days do occur, but these extreme weather events are unusual, and even then, power is generally restored fairly quickly.

It is possible to put a dollar value to this reliability. Research shows that even minimal outage durations can have significant impacts on both residential customers and businesses. In a 2015 report on the cost of interruptions to customers, Lawrence Berkeley National Laboratory (LBNL) researchers estimated that the cost of an interruption can be quite high.[45] As shown in Table 1, the cost of an outage increases the longer customers remain unserved.

Note that the cost per unserved kWh is relatively high for a momentary interruption because the expected amount of unserved kWh over a 5-minute period is relatively low. The outage cost numbers in Table 1 are derived from utility customer surveys and include over 105,000 responses collected from 1989-2012.

The table does not show how customer interruption costs vary by season and time of day. In general, high reliability during times of high demand is more valuable.

Despite lowering cost and improving technology, using a combination of solar and storage to power a typical house is still a relatively unattractive option. Economically speaking, common residential storage devices only store about $1.50 worth of energy, yet cost several thousand to acquire and install. The resulting system is expensive, provides some backup power, but without expansion is ineffective at providing a typical home's energy needs for any significant amount of time.

The question for policy planners is: what would be the cost to reproduce this reliability metric outside of the context of the modern grid? Or, for any customer or set of customers seeking to defect from the grid, what is the true investment needed to achieve 99.9 percent reliability?

A typical home uses 10,766 kWh per year, which is an average of 897 kWh per month.[46] In this example, the home has the potential to consume up to 24kW of energy from the grid, but typically only has a peak consumption of 7kW on any given day.

Tesla Powerwalls typically have a peak capacity of 7 kW, with 5 kW of capacity continuously available, and can discharge 13.5 kWh. If paired with a 5.5 kW solar PV system with a 15.8 percent capacity factor, the solar system will produce 13.51 kWh/day in December. This combination allows for the example home to have enough energy on a typical sunny day during the least sunny part of the year in the northern hemisphere, and accounts for system losses of 14.08 percent.

[44] Form EIA-861, 2016 data, Reliability.
[45] http://eta-publications.lbl.gov/sites/default/files/lbnl-6941e.pdf
[46] https://www.eia.gov/tools/faqs/faq.php?id=97&t=3

The installed cost of solar arrays varies between $2.71 and $3.75 per watt[47], therefore a 5.5 kW solar system is likely to cost between $10,000 and $12,000 after tax credits. A 7 kW Tesla Powerwall costs between $5,000 and $8,000.[48] Therefore, a minimally sized solar plus storage system will cost somewhere between $15,000 and $23,000.

This system would do relatively well with most conditions, but for higher reliability under all conditions (for example, hot days when cooling load is highest or for larger families in a less energy efficient home), it may be necessary to install at least two Powerwalls and double the size of the solar capacity.

Assuming the minimally sized solar plus storage system will cost $20,000, a larger system will easily exceed $30,000 in most locations. Compared to the average residential electric bill of $114 per month,[49] it would take the customer 10-15 years to realize a return on their investment for a minimally sized system, and longer for bigger systems. Customers in regions where the cost of electricity is higher may realize returns on their investment sooner.

Though it may become economically feasible to install solar plus storage systems for many individual households, there is no assurance of consistent solar energy to power those systems 365 days a year, and the sun doesn't shine 24 hours a day. Without connection to a grid supplying nearly continuous power, a DER customer will have to make additional investments to ensure reliability, and these investments might outweigh the economic advantage of an unconnected solar plus storage installation.

The grid's value to DER customers is not solely as a reliable battery resource for DER customers. The electric grid is a network in which electricity flows in a safe and consistent manner. Voltage regulation is as vital a component of the transmission and distribution system as any other aspect. Moreover, whether in the vertically integrated markets of the south and upper Midwest or the deregulated markets which predominate in the northeast and central regions, grid operators oversee the flows of electricity and work to harmonize all elements of the electric system. This is lost with grid defection.

EPRI summarized the value of staying connected to the grid to DER customers:

> Absent redundancy provided by the grid connection, the reliability and capability of the consumer's power system is diminished. Grid capacity provides needed power for overload capacity, may absorb energy during overgeneration, and supports stable voltage and frequency.[50]

[47] https://news.energysage.com/how-much-does-the-average-solar-panel-installation-cost-in-the-u-s/
[48] https://www.energysage.com/solar/solar-energy-storage/tesla-powerwall-home-battery/
[49] https://www.eia.gov/electricity/sales_revenue_price/pdf/table5_a.pdf
[50] EPRI. *The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources.* Palo Alto, CA: Electric Power Research Institute, Inc, 2014, p. 16.

EPRI outlined five benefits of the grid to DER customers:

1. reliability,
2. startup power,
3. voltage quality,
4. efficiency, and
5. energy transaction (the ability to connect a DER to the grid).[51]

Startup power deserves special mention. Large devices such as air compressors, air conditioners, and transformers require a significant in-rush current to run. Standalone PV systems may not have the requisite power to start these devices unless they are significantly oversized. For a residential air conditioner, the peak current measured to start the device "is six to eight times the standard operating current."[52] Therefore, most PV systems need the grid connection and the power supplied by the grid to start these larger devices.

In terms of voltage quality, another benefit to the grid is its limiting of harmonic distortion. Absent a grid connection, DERs are prone to harmonic distortion, which in turn could lead to devices malfunctioning or shortening their useful life. Low voltage quality also leads to a reduction in system efficiency.[53]

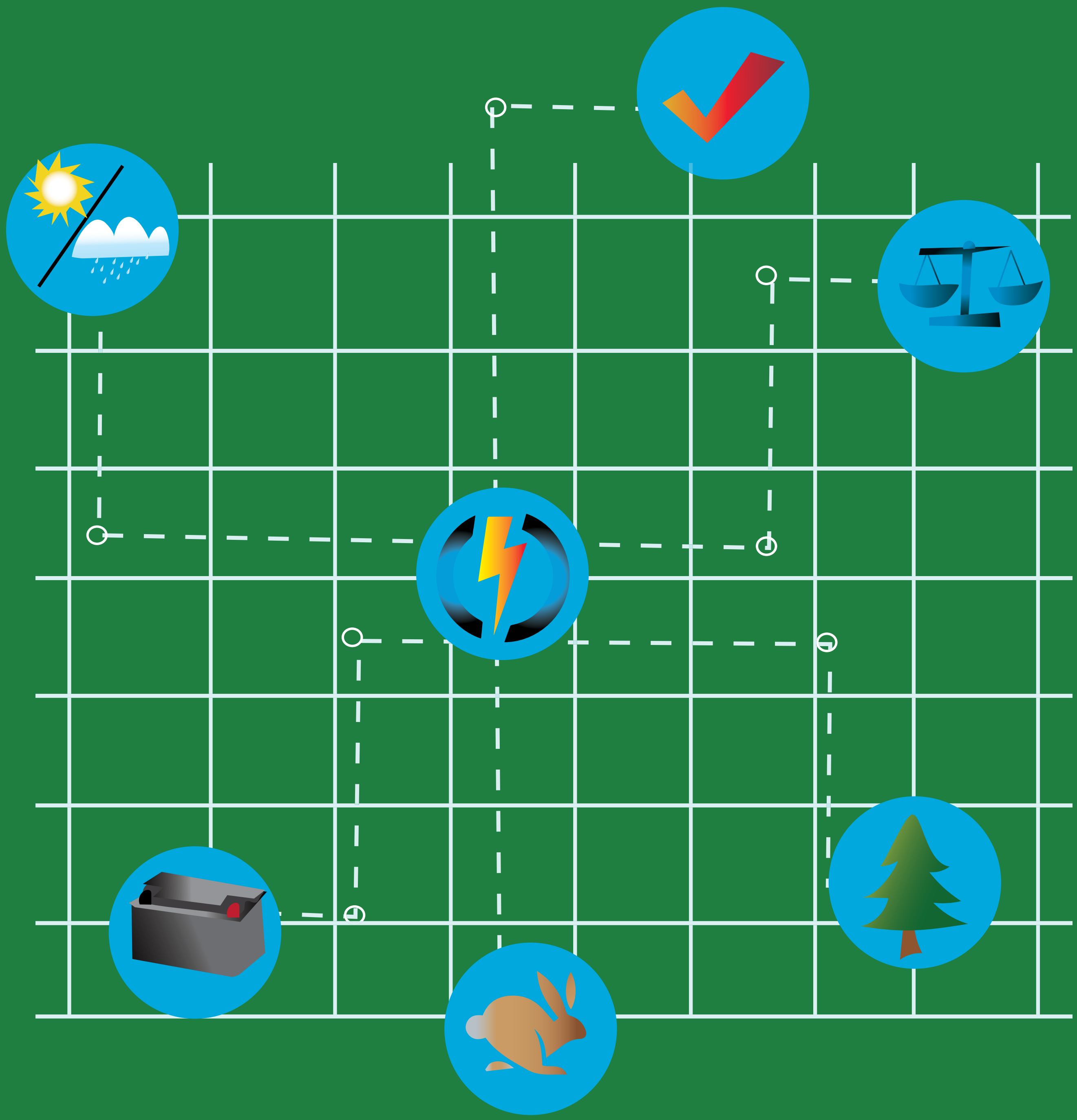
In modeling the full costs for disconnecting from the grid, EPRI noted that DG customers would need additional panels beyond their original requirements, a multi-day storage system "with a dedicated inverter capable of operating in an off-grid capacity," a backup generator that could operate for 100 hours per year, plus other operational and maintenance costs. EPRI concluded that the total cost to re-create grid services would be $275-$430 per month on top of the cost of the original array, though decreases in battery and PV costs could reduce this to $165-$262 per month.[54] Considering an average bill is just above $100 per month, for most customers the economics favor staying on the grid.

Absent a grid connection, DERs are prone to harmonic distortion, which in turn could lead to devices malfunctioning or shortening their useful. life.

Managing the grid

Even if there is widespread acceptance of the importance and value of the existing grid, the status quo is unlikely to hold. Grid architecture will have to evolve to accommodate and integrate DERs and electrified resources.[55] There will need to be enhanced communication systems so that distributed resources can work in sync with each other and with existing resources. The grid will remain essential, but not unchanged.

[51] Ibid.
[52] Ibid., p. 18.
[53] Ibid., p. 19.
[54] Ibid., p. 23.
[55] For work on this topic, see Jeff Taft at Pacific Northwest National Laboratory at https://gridarchitecture.pnnl.gov/



The question that will dominate many policy discussions is: who will be the entity or entities investing in and operating this new infrastructure?

In terms of grid management, several different models have been put forward, each with slightly different roles for the utility. One concept is the distribution system operator (DSO). The DSO would be a balancing agent and coordinator between customers, transmission operators, third party service providers, and distribution utilities.

The precise nature of the DSO is different in various jurisdictions. New York has perhaps the most advanced concept. The state's Department of Public Service (DPS) has rolled out its Reforming the Energy Vision (REV) roadmap, the key component of which is the Distributed System Platform Provider (DSPP). As outlined in a DPS staff report, the DSPP would be a utility that coordinates customer activities to more efficiently run the distribution system. The staff paper adds that "the DSPP will create markets, tariffs, and operational systems to enable behind the meter resource providers to monetize products and services that will provide value to the utility system and thus to all customers."[56] The DSPP would thus be involved in both market and operational functions.

There has been debate about permitting the incumbent utility to function as the DSPP. NRG Energy's comments in the rulemaking establishing REV highlight the opposition to a utility role:

The grid will remain essential, but not unchanged.

> 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.[57]

The DPS has permitted the utility to function as the DSPP for the time being.

Among those who have called for an independent DSO are a group of academics who have designed the Grids with Intelligent Periphery (GRIP) architecture. One of the key components of this design is the Distribution Operator (DO). The DO works in cooperation with load serving entities and other grid resource providers to coordinate activities such as information services, resource management, and infrastructural operations. As conceived in GRIP, "the DO may lease lines, but is not usually an active market participant."[58]

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[56] *Reforming the Energy Vision – NYS Department of Public Service Staff Report and Proposal.* Case 14-M-0101, April 24, 2014, p. 12.

[57] *Reforming the Energy Vision,* comments of NRG Energy, p. 3.

[58] D. Bakken, A. Bose, K.M. Chandy, P.P. Khargonekar, A. Kuh, S. Low, A. von Meir, K. Poolla, P.P. Variya and F. Wu. *GRIP – Grids with Intelligent Periphery: Control Architectures for Grid2050,* Smart Grid Communications, 2011 IEEE Conference, October 2011.

Utilities are in the best position to characterize the needs of the electric grid and identify appropriate investments and deployment.

These are just some of the options that have emerged thus far. At this early stage, there appears to be little consensus on several key issues, including the structure of the DSO, the scope of its jurisdiction and activities, and the appropriate legal and regulatory framework. Under some proposals the DSO or DO would be little more than an aggregator of demand response (DR), energy efficiency (EE), and DG resources interfacing with distribution utilities that retain most of their traditional functions. Other proposals call for much broader functionality where the DSO/DO responsibilities might extend, in some manner, into system planning and operations, communications, metering, interactions with independent system operators (ISOs) and regional transmission organizations (RTOs), financial settlements, and more. The more comprehensive models imply more centralized organizational structures and perhaps consolidation of distribution systems for operational purposes, both of which could pose challenges for traditional distribution utilities, particularly smaller ones.

The benefits of a DSO stem from the evolving nature of the electricity industry. Increasing amounts of DG, EE, and DR resources will require integrated system operations in a changed environment. The integrated grid will have to accommodate new control devices, new generation and load management resources, two-way power and communication flows, increased need for energy balancing and new settlement and ratemaking policies and practices. All while continuing to maintain traditionally high levels of reliability, safety, and customer satisfaction. Though there is disagreement as to how the grid must adapt to accommodate these changes, states with high levels of renewables and DG penetration, such as California and Hawaii, have demonstrated that utilities need improved coordination and system planning.[59]

The utility of the future

Few deny the electric utility any role in this future grid, but there is not a consensus about what that role will be. One vision of the utility's function is to balance and monitor DG, "load management, storage, and coordination of the electricity that will move multi-directionally from the consumer to the utility and to the smart grid and back."[60] In this scenario, the utility is compensated for the services it provides, and not kWh sales.

[59] For a case study examining Hawaii's experience, see Kevin Eber and David Corbus. Hawaii Solar Integration Study: Executive Summary. National Renewable Energy Laboratory, 2013.

[60] Freeman and Parker, p. 52.

DERs provide value to the system by reducing or shifting loads and obviating the need for infrastructure investments. Utilities provide value to DER customers by providing a platform that coordinates the DER's functions and maximizes its output.

Peter Fox-Penner, professor of practice in the Questrom School of Business, expands on this concept with a pair of his own. One version of the utility is as what he terms the Smart Integrator. He describes this model as "a utility that operates a regulated smart grid offering independent power and other services at market prices."[61] The Smart Integrator operates the power grid, but doesn't own or sell power delivered to the grid.[62] Another possibility is for the utility to be organized as an Energy Services Utility. These utilities would be organized like today's vertically integrated utilities, but would employ greater use of "smart grid, dynamic pricing, and decentralized services."[63]

The underlying theme to these concepts is that the utility of the future would serve as a traffic cop, overseeing the smooth functioning of the grid, but with little to no direct involvement other than in providing certain services. While this might be a viable and attractive option under certain circumstances, keeping utilities at an arm's length from direct participation in the markets, and preventing them from owning and operating DERs, might not be best for the development and deployment of these resources.

In terms of the operation of the grid, utilities are in the best position to characterize the needs of the electric grid and identify appropriate investments and deployment. For example, when it comes to electric storage, Jim Lazar, a Senior Advisor at the Regulatory Assistance Project, suggests that "there are targeted locations where electricity storage can be cost effective and should be pursued. These include placement at strategic points where storage provides supplemental generation capacity during some hours, and a place to 'park' surplus generation from high renewable penetration or nuclear generation at times when it is not needed for current demand."[64] While a third party grid operator might develop the technical insight to make these strategic decisions, the incumbent utility already possesses the requisite system knowledge to make informed decisions about where it is best to deploy storage.

The utility could and should function as the hub of the future network, said Jim Laurito, executive vice president of business development at Fortis. "All those devices that people see in smart homes, smart cities, and distributed generation need to be interconnected centrally to the regulated utility for them to work most economically and efficiently," he added.[65]

Even if utilities are acknowledged to be the best entity to operate the grid, many continue to argue against direct utility ownership of DERs. A report from LBNL included the following argument:

> In considering the appropriate roles for regulated utilities and unregulated companies, our primary concern is that regulated utilities should not be competing directly with third-party providers, particularly in the provision of value-added services where these services are readily provided by the competitive market. Utilities have a built-in advantage resulting from their monopoly position.

[61] Peter Fox-Penner. Smart Power: Anniversary Edition (New York: Island Press), 2014, p. 171.
[62] Ibid., p. 175
[63] Ibid., p. 170.
[64] Lazar, *Teaching the Duck to Fly,* p. 34.
[65] Jim Laurito, Executive Vice President, Business Development at Fortis. Quoted in "A Utility Perspective," *Public Utilities Fortnightly,* Mid-February 2018, p. 24.

> This includes lower cost of capital through reliance on ratepayers, existing customer relationships, and superior access to information about their customers and their network.[66]

A counterpoint was offered earlier in the same paper. "Allowing both electric companies and third-party providers to compete to provide these services provides the greatest potential benefit to customers." There will have to be rules and regulations put in place to ensure fairness, but prohibiting utilities from competing "will limit competition and slow the development of the market."[67]

Utilities possess a brand name recognizable to their customers, and might be better able to motivate customers to invest in new technologies or accept changes in service than a new third-party provider. Utilities have a history of providing value-added service to all, "regardless of income, geographic location, or type of customer." Third parties are more likely to ignore certain customer segments – such as those with low credit.[68]

When utilities can offer these services, they are also better able to integrate them. "When electric companies have visibility and oversight of the operation of customer-sited DERs, these resources can provide more benefits. Electric companies are in the best position to leverage customer-sited resources to the benefit of all customers."[69]

Since electric utilities are in the best position to characterize system needs, they should be given visibility of the location, technical capabilities, and performance of DERs within their service territory to evaluate the impact on the energy grid and control to optimize these resources. Operational awareness and control will help ensure reliability, and the utility is best situated to manage this system efficiently.

Utility visibility and control of DERs benefits customers as well. In a report for the Smart Electric Power Alliance, Dr. Carl Pechman, Director of the National Regulatory Research Institute wrote, "The distribution utilities' role as the conduit to the grid will grow in importance with increasing transactive role between customers and the grid."[70] This transactive future will require an enhanced communications network, one which the utilities should be able to develop.[71] In other words, utility control over DERs is critical for enabling DERs to function to their full capabilities.

Utilities and the grid provide value to DER customers, and DER customers provide value to utilities. In a high-DER future, an LBNL report posits that DERs "with appropriate levels of coordination or virtual integration can augment the capabilities of the distribution system and even reduce the amount of capital the utility must invest in." Furthermore, "by substituting for utility investment, customer DERs can help keep utility revenue requirements within the bounds that increasingly price-sensitive customers will pay for."[72] DERs provide value to the system by reducing or shifting loads and obviating the need for infrastructure

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[66] Ryan Katofsky, Benjamin Stafford, and Danny Waggoner, Advanced Energy Economy. *Value-Added Electricity Services: New Roles for Utilities and Third-Party Providers.* Lawrence Berkeley Lab, Future Electric Utility Regulation Series, No. 9, October 2017, p. 30.
[67] Jonathan Blansfield, Institute for Electric Innovation, in *ibid.*, p. 7.
[68] Ibid., p. 8.
[69] Ibid., pp. 8-9.
[70] Carl Pechman. *Scope of the Utility of the Future.* Written for the Smart Electric Power Alliance's *51st State: Phase III* initiative. P. 8.
[71] Ibid., p. 16.
[72] Steve Corneil and Steve Kihm. *Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future.* Lawrence Berkeley Lab, Future Electric Utility Regulation Series, No. 1 November 2015, p. 18.

investments. Utilities provide value to DER customers by providing a platform that coordinates the DER's functions and maximizes its output. This mutually beneficial relationship provides the clearest pathway to a more efficient and cleaner electric grid.

The LBNL report offered an example of how this coordination can work. Customers purchase smart thermostats to save money and to maintain a comfortable environment. A utility that aggregates these thermostats "can provide thermal load management for the distribution system and demand-response based capacity products for the wholesale market." If the aggregator's first concern is saving customers money and keeping them comfortable, and only secondarily optimizing the distribution system, then they are more likely to incent customer involvement and behavior changes. Therefore, appropriate coordination between DERs, the distribution system, and the bulk power system will maximize the value streams of all three entities.[73]

Pechman described how the challenge of this cooperative framework "is how to harvest innovations that benefit customers, financially support the utility, and support development of robust markets, while providing entrepreneurs adequate reward for inventiveness and supporting widespread deployment."[74] Robust competition, which should include utilities in the marketplace, will foster an environment in which new resources thrive.

Ultimately, any market design should keep the needs of local customers at the forefront. Utility involvement in competitive services and operation of the grid is more likely than not to benefit most customers, both in terms of finances and reliability. However, if utilities decide to offer DER services directly, they need to be willing and able to work with customers and provide a full suite of services. To the degree utilities are unable to provide DER services which customers desire, they ought to work closely with third party providers.

There should not be and almost certainly will not be one type of specific model for the electric grid of the future. There will be different rates of adoption of both DER and electrified end-use of energy. Much will hinge on local circumstances and customer interests. In this regard, public power utilities are best positioned to understand these local circumstances and modify their business model accordingly. The next section focuses on how public power utilities can adapt to these changes.

[73] Ibid., p. 23.
[74] Pechman, *Scope of the Utility of the Future,* p. 21.

The Public Power Advantage

Public power utilities have several characteristics which will enable them to transition to this future grid.[75] Peter Fox-Penner observed, "the coming age of decentralized sources and a smart grid will favor community-scale sources located much closer to the grid."[76] According to Fox-Penner, this gives public power and cooperative utilities a potential advantage. In the future grid, public power benefits in several key ways.

Size and local control

The median size of the nation's 2,000 plus public power utilities is approximately 2,000 customers. More than eighty percent of public power utilities have fewer than 10,000 customers. This small size means that these utilities are much closer to their customers than other electric utilities. And all public power utilities, regardless of size, endeavor to provide superior service to their customer-owners. Public power utilities may prove more adept at responding to local needs and circumstances in deploying new technologies.

Flexibility

The relatively small size of most public power utilities provides a sense of flexibility, as does the regulatory framework. In all but a handful of states,[77] public power utilities are not regulated by state power commissions, but rather, are governed by a local governing board (elected or appointed) or a city council. This regulatory framework means public power utilities can act more quickly than investor-owned utilities (IOU).

Reliability

Public power utilities have superior reliability compared to their IOU and cooperative counterparts. Public power customers experience approximately two hours of interrupted service annually, as compared to four hours for customers of IOUs and six hours for cooperative customers.[78] This reliability advantage is important in the context of a new grid adapting DERs and newly electrified resources.

Nonprofit, community-focused

When it comes to adapting to future changes, the most important advantage for public power utilities is the nature of their business models. Because IOUs earn a rate of return for their stockholders on capital and generation investments, they have a financial motivation to make these sorts of investments. Public power utilities have no similar inducement. Generally speaking, they aim to recover their costs, and thus infrastructure investment is only done out of necessity. Therefore, the public power business model is not threatened when customers own DER assets.

The public power business model is not threatened when customers own DER assets.

[75] For a more detailed assessment of the public power advantage, see https://www.publicpower.org/system/files/documents/municipalization-benefits_of_public_power.pdf

[76] Fox-Penner, *Smarter Power,* p. 210.

[77] See http://appanet.files.cms-plus.com/Resources/Rate_Regulation_of_PP_chart_412.pdf for a chart outlining state rate regulation of public power utilities.

[78] See https://www.eia.gov/todayinenergy/detail.php?id=35652. This includes outages caused by major events. Excluding major event outages, the average interruption annually for public power is less than an hour.

Public Power and New Technology

Public power utilities are already providing resources and adapting new technologies to meet evolving customer expectations. Here are just a few examples of public power in action.

Community solar

Numerous public power utilities have developed community solar programs. Several joint action agencies – including the Indiana Municipal Power Authority, Delaware Municipal Electric Corporation, and American Municipal Power – have worked with member distribution utilities to install solar PV in their service territory, while other utilities have established stand-alone programs.[79]

Orlando Utilities Commission in Florida implemented several community solar projects, including the 400 kW Gardenia project. The project produces 540,000 kWh of electricity annually, enough to power about 40 homes. Residential and small business customers can purchase up to 15 kW blocks from the project, at a rate of 13 cents per kWh produced.[80]

Electric vehicles

Several public power utilities, especially in California, have rolled out EV rates and incentives.[81] For example, the Sacramento Municipal Utility District (SMUD) in California allows customers who purchase or lease EVs to choose from one of two incentives: get $599 to cover two years of free charging, or receive a 240-volt high-powered EV charger. SMUD also offers time-of-use (TOU) rates for EV customers, meaning they can charge their vehicles at home during lower-cost periods.[82]

Energy storage

Public power utilities are beginning to explore the potential for energy storage.[83] The Sterling Municipal Light Department received funding from the Massachusetts Department of Energy Resources and the U.S. Department of Energy to add an energy storage system in support of the development of a utility microgrid. The utility had experienced longer duration outages from ice storms, but interest in a microgrid solution peaked after Hurricane Sandy. The NEC Energy Solutions 2 MW, 3.9 MWh lithium ion battery will help the utility reduce peak load, lower capacity payments, enhance system resiliency, and regulate system frequency. The utility can also get value from the storage system through energy arbitrage, where energy can be bought low and sold high in the market. A 3 MW solar array also exists within the utility's distribution network. By connecting the storage system with the solar generation in a microgrid, the utility can ensure the capability of providing mission critical services from the local police station and dispatch center. The battery storage system went online in December 2016.

A public power utility could also provide community storage if there is demand from customers.

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79 For more information on public power and community solar, see American Public Power Association. *Community Solar A-Z: Guide for Public Power.* Prepared by Paul Zummo with assistance from Leidos, 2016. Available at https://www.publicpower.org/system/files/documents/ppf_community_solar_a_to_z.pdf (Association members only)

80 Cassandra Corcoran, "Community Solar Heats Up the Sunshine State," *Relay*, accessed at http://relaymagazine.org/community-solar/

81 The Association's EV tracker, highlighting the activity of the nation's largest public power utilities, is available at www.publicpower.org/resource/public-power-ev-activities-tracker

82 More information is available at https://www.smud.org/en/Going-Green/Electric-Vehicles/Residential.

83 See American Public Power Association. *Understanding Energy Storage: Technology, Costs, and Potential Value.* Prepared by Patricia Keane with assistance from NewGen Strategies, 2017; available at https://www.publicpower.org/system/files/documents/understanding-energy-storage.pdf

Rooftop solar

According to 2016 data from the Energy Information Administration, just under 180,000 customers served by public power utilities have rooftop solar installed, accounting for just under 1 GW of capacity. While much of this is concentrated in California, installations are increasing throughout the United States. Some public power utilities have developed innovative programs to meet growing customer interest in rooftop solar PV.

One such example is CPS Energy in San Antonio, Texas and its Solar Host program. Eligible residential customers can host a solar system on their roof, installed by CPS Energy's partner, PowerFin, at no cost. The electricity generated by the panels is sold to CPS Energy. Solar Host customers receive a credit of three cents per kWh generated.[84]

Digitization

The New York Power Authority (NYPA) has been at the forefront of digitization efforts. In 2016, NYPA signed an agreement with GE Power to provide Asset Performance Management software to monitor generation and transmission equipment health "in order to predict potential failures and thereby reduce unplanned downtime, lower maintenance costs and lower operations risks."[85] A year later, NYPA adjusted the agreement to include GE's application development platform Predix to become "NYPA's Industrial Internet of Things platform of choice."[86]

In April 2018, NYPA also announced a "sensor deployment program that will incorporate new technologies to perform online monitoring of power plants, substations and power lines to boost efficiency and productivity and improve resiliency of New York's statewide public power network." It is estimated that the installation work will take four to five years, with the goal of implementing "a robust, secure and scalable sensor communications network in support of NYPA's Vision 2020 Smart Generation and Transmission strategic initiative."[87]

New models for the future

Though public power has certain intrinsic advantages in the future grid, utilities cannot resist adapting their business models. In many cases, it will be possible to keep providing the same services, with some minor changes to accommodate new resources. Other utilities, however, might need to make a fundamental shift from their traditional business model. Each circumstance is unique, but all utilities need to be prepared.

The American Public Power Association outlined four key transition steps public power utilities should take to prepare for the future grid.[88]

- Recognize the real economic costs and risks of alternatives —and reflect them in specific utility rates and service offerings. Subsidies can create an unsustainable, high-DER future.
- Align customer interests with those of the utility and third-party suppliers at the grid edge and

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[84] For more information, see https://www.solarhostsa.com/

[85] Paul Ciampoli, "NYPA effort to become fully digital utility advances with GE agreement, *Public Power Daily*, October 6, 2016, accessed at https://www.publicpower.org/periodical/article/nypa-effort-become-fully-digital-utility-advances-with-ge-agreement

[86] Paul Ciampoli, "NYPA effort to become fully digital utility advances with GE agreement, *Public Power Daily*, October 30, 2017, available at https://www.publicpower.org/periodical/article/nypa-effort-become-fully-digital-utility-advances-with-ge-agreement

[87] Paul Ciampoli, "NYPA board Oks funding for first phase of sensor deployment effort, *Public Power Daily*, April 13, 2018, accessed at https://www.publicpower.org/periodical/article/nypa-board-oks-funding-first-phase-sensor-deployment-effort

[88] American Public Power Association. *APPA's Roadmap to SEPA 51st State – Phase II*. Prepared for SEPA's 51st State Initiative, Phase II, 2016.

wholesale/bulk power levels.
- Capture the benefits of DER integration for customers and utility system planning and operations.
- Develop the utility business and operational technology infrastructures to sustain these offerings over time.

Changes public power utilities should consider for the future include the following.

- Develop new products and value-based pricing mechanisms for platform services to DER customers (e.g., generation dispatch, storage discharge, backup generation, interconnection, data collection and management) and for products provided to the grid by DERs (e.g., energy, capacity, ancillary services).
- Increase deployment of DERs that meet a value test for participating customers, the utility, and the community. This could include structuring NEM programs to compensate DER customers based on the incremental value of the electricity (e.g., value of solar), with proper accounting in rates for the value of the grid to DER customers.
- Increase use of advanced technologies to facilitate communication, system control, resource dispatch, and dynamic pricing.
- Increase deployment of non-utility generation resources on both sides of the meter.
- Manage foreseeable impacts from distribution-level decisions on bulk power system operations and the wholesale market – and vice versa.
- Develop workable industry business standards to support interoperability and the use of new technologies.
- Enhance coordination between distribution-level and bulk-level planning and operations (e.g., consider aggregation of local DERs as substitute for wholesale generation or bulk transmission).

Not all of these changes will be applicable to all public power utilities, and there may be changes beyond those listed. Regardless, public power utilities, to the extent they have not already, need to begin mapping a strategy. On top of the elements listed above, utilities must also identify their customer preferences, develop a risk management strategy that includes price competitiveness and financial risks, and develop a plan for smarter grid infrastructure. In a smarter grid infrastructure plan, utilities should identify the services they plan on offering, third parties with whom they can form strategic partnerships, and their supply options, including community solar and utility-owned solar.

Conclusion

It is impossible to ignore the winds of change circling the electric industry. Increasing deployment of DERs and electrification of certain technologies mean the electric grid is more, not less, important than ever before.

Customer expectations – and their ability to meet some of those expectations on their own – means electric utilities will have to reevaluate their business models. Public power utilities are well-positioned to meet these changing customer expectations. Local control and understanding of local circumstances means public power utilities can adapt based on what their customers want. Public power utilities could serve as a platform, or an essential integrator and provider of technological solutions. No matter which choice is made, the electric utility will continue to play an essential role in the future.