U.S. DEPARTMENT OF
ENERGY

Smart Grid System Report

2018 Report to Congress

November 2018

United States Department of Energy
Washington, DC 20585

Message from the Assistant Secretary

I am pleased to present the 2018 Smart Grid System Report, which is intended to provide a status of smart grid deployments nationwide, resulting benefits, and the challenges yet remaining as we move forward with the modernization of the electric grid. It covers smart grid developments since the prior Smart Grid System Report submitted in August 2014. Over the past ten years, we have witnessed the accelerated deployment of technologies meant to improve the reliability and efficiency of utility operations, including the deployment of systems and practices to better engage utility customers in the management of energy. Throughout this time, the Department has worked closely with both utilities and state regulators to convey best practices and enable a better understanding of the potential value of smart grid systems. However, we also recognize that the application of smart grid technology depends largely on the specific needs of utilities, the preferences of their customers, and the respective policies of state and local jurisdictions. As a result, the pace and scope of smart grid technology deployment is occurring differently across the country as local needs may dictate.

Smart grid deployment is traditionally based on improving utility operations at both the transmission and distribution grid levels. Since 2010, we have seen accelerated deployments of advanced metering infrastructure, systems to improve voltage and outage management, and synchrophasor technology to enhance situational awareness. However, in the past five years, we are now witnessing the rapid adoption of distributed technologies, such as photovoltaic systems, and increasing ownership of these distributed assets by utility customers and third-party merchants. The proliferation of distributed devices is driven largely by state policies, lowering technology costs, and changing customer expectations and is not occurring consistently across the country. Where it is happening, the rise in the number of distributed technologies and their ownership by entities other than utilities significantly increases the complexity of grid operations and poses challenges to traditional approaches for grid planning and market designs.

Addressing the emerging complexity will require the deployment of advanced grid capabilities based largely on the application of smart grid technology. This will include the continued development of a variety of technologies and improved strategies for grid sensing, information management, communications, control, and coordination. In this effort, we will also need to ensure the affordability, reliability, resilience, and security of the electric grid. The Department will continue to work closely with the electric utility industry and federal and state agencies to determine prudent approaches for deploying smart grid technologies.

Pursuant to statutory requirements, we are providing this report to the following members of Congress:

- **The Honorable Rodney Frelinghuysen**
  Chairman, House Committee on Appropriations

- **The Honorable Nita Lowey**
  Ranking Member, House Committee on Appropriations

- **The Honorable Michael Simpson**
  Chairman, Subcommittee on Energy and Water Development
  House Committee on Appropriations

- **The Honorable Marcy Kaptur**
  Ranking Member, Subcommittee on Energy and Water Development
  House Committee on Appropriations

- **The Honorable Richard Shelby**
  Chairman, Senate Committee on Appropriations

- **The Honorable Patrick Leahy**
  Vice Chairman, Senate Committee on Appropriations

- **The Honorable Lamar Alexander**
  Chairman, Subcommittee on Energy and Water Development
  Senate Committee on Appropriations

- **The Honorable Dianne Feinstein**
  Ranking Member, Subcommittee on Energy and Water Development
  Senate Committee on Appropriations

If you have any questions or need additional information, please contact me or Ms. Bridget Forcier, Associate Director of External Coordination, Office of Chief Financial Officer, at (202) 586-0176.

Sincerely,

Bruce J. Walker
Office of Electricity

Executive Summary

This report conveys the status of smart grid deployments across the nation, the capabilities they provide, and the challenges yet remaining as we move forward with the modernization of the electric grid. Under Title XIII of the Energy Independence and Security Act of 2007 (Public Law 110-140), the DOE Office of Electricity is required to provide the status of smart grid deployments and related challenges every two years.

Over the past ten years, we have witnessed the accelerated deployment of technologies meant to improve the reliability and efficiency of utility operations, including the deployment of systems and practices to better engage utility customers in the management of energy. This has included increased deployments of advanced metering infrastructure, systems to improve voltage and outage management, and synchrophasor technology to enhance situational awareness. However, more recently, we are witnessing the rapid adoption of distributed technologies, such as photovoltaic systems, and increasing ownership of these distributed assets by utility customers and third-party merchants. The effective integration of the grid with distributed assets presents a more complex and, potentially, transformative situation that will require the deployment of advanced grid capabilities based largely on the application of smart grid technology.

The smart grid is enabled by digital technology applied in devices and systems that allows for enhanced sensing and control of grid elements, more widespread information sharing and communication, more powerful computing, and finer control. The integration of digital structure with the physical structure of the grid is evolving rapidly due to the enhanced performance and declining costs of digital technology. Digital networks will eventually lead to greater levels of information exchange between utilities and their customers, as well as the convergence of the electric grid with other infrastructures such as buildings, transportation, and telecommunications.

U.S. utilities invested approximately $144 billion in electricity generation, transmission, and distribution infrastructure in 2016 (the latest year of available data). Investor-owned utilities, serving 73% of U.S. electricity customers, spent $21 billion and $27 billion in 2016 on transmission and distribution delivery infrastructure, respectively. Annual smart grid investments rose 41% between 2014 and 2016 from $3.4 billion to $4.8 billion and are expected to rise to $13.8 billion in 2024. The high capital costs and long lifespans of transmission and distribution infrastructure make it vitally important that investments made today can support an evolving grid for decades to come.

This report discusses in greater detail the key findings and recommendations given here:

1. Smart grid technology is being deployed to improve operational efficiency, reliability and resilience, but also to address the integration and utilization of distributed energy resources (DERs) where they are being adopted.

2. The integration of information technologies and operational technologies (IT/OT integration), cloud computing, and information networks represent major aspects of smart grid deployment. Standards and protocols, such as IEC 61850 and IEEE 1547, are being developed and applied with significant efforts by the private sector and industry-led groups to ensure interoperability and security. However, continued assessment by the federal government is recommended to ensure that interoperability and cybersecurity standards evolve and are implemented at a pace sufficient to support needed technology deployment.
3. A combination of federal and state policies, improvements in technology performance and costs, and customer preferences for generating and managing energy is challenging traditional approaches for grid planning, operations, market design, and business models. These forces will require a transformation in the structure and functional capabilities of the electric grid and drive a need for holistic approaches in determining smart grid technology deployment strategies.
4. In 2017, 39 states plus the District of Columbia took a total of 288 policy and deployment actions related to grid modernization, integrated resource planning, the application of DERs as non-wires alternatives, utility business models, rate reform, and the application of advanced metering infrastructure, energy storage systems, and microgrids. Progressive state policies, combined with favorable business incentives, have promoted the rapid adoption of DERs. Where this is occurring, the rate of technological change can outpace the ability of regulators and utilities to develop informed grid modernization strategies, especially because smart grid implementation decisions need to enable an effective transition from legacy systems to grids with more advanced capabilities.
5. The increasing presence of renewable generation and the proliferation of customer- and merchant-owned DERs are introducing significantly greater levels of variability and uncertainty in both the supply of electricity and the demand for it. Generation and load profiles, which have been predictable in the past, can now vary instantaneously and are subject to the behavior of consumers where DERs are present. This new situation requires improved visibility into resources not owned by utilities, the ability to control and coordinate an increasing number of assets and endpoints, and grid systems that can readily adapt to conditions within sub-second timeframes.
6. State regulators and utilities will need comprehensive strategies for implementing smart grid technologies to address this complexity. Toward this end, efforts by the Department to assist regulators and utilities in better understanding the structural and functional requirements for an advanced grid should continue, including advancing the practice of grid architecture as a discipline to impart a holistic planning capability. Grid architecture helps to understand the interrelationships between the cyber, physical, industry, market, and regulatory structures to enable the implementation of scalable and coherent grid designs.

7. Integrated planning approaches are needed to achieve a coordinated strategy for smart grid technology deployment across the transmission, distribution and customer domains. This is important where high levels of DERs are deployed, as they present operational issues, yet also provide value in terms of generating capacity, energy, frequency support, and other grid services. Cross-jurisdictional coordination is required to effectively implement the appropriate mix of control schemes and market mechanisms.

8. As utilities, customers, and third-party merchants begin to share responsibilities in the provision of grid services, the traditional business model, especially at the distribution system level, will change. This will require re-defining respective roles and responsibilities; transitional strategies are currently being examined but do not yet exist due, in part, to the lack of fair compensation practices for both utilities and other participants. In addition, regulators, utilities, and the various participants will need to define the rules governing the interfaces between devices. These rules would cover physical, electrical, control, and communication requirements, along with business terms. Such coordination mechanisms will present requirements for smart grid systems.

9. Increasing digital connections between utilities, customers, and various service providers creates new entry points that may expose the electric grid to new cyber risks. However, smart grid technologies can also build in resilience, adding visibility and adaptable controls that can support cyber attack detection and response. Building cybersecurity into smart grid devices and networks as they evolve requires advanced R&D that anticipates future grid scenarios, improved cybersecurity and interoperability standards and guidelines, and coordinated approaches for addressing cyber system restoration.

10. To address the demands envisioned for a future grid, advances in technology are required. Key technological efforts include the development of:

    a. Modeling and analysis tools for both planning and operations purposes that address variability and uncertainty and apply probabilistic and predictive approaches for reducing risk. The tools needed will consume vastly greater amounts of data, operate at higher speeds, enable the determination of a range of optimal solutions, and permit automated control.

    b. Control capabilities based on real-time situational awareness and that enable the effective dispatching of resources.

    c. Solid-state hardware components that are more dynamic, adaptable, and robust, particularly power electronics devices that can control the direction and magnitude of power flow.

    d. Inexpensive and high-performing energy storage technologies that can provide significant flexibility and resilience for grid operations.

   e. Advanced cybersecurity technologies and next-generation resilient and adaptive control system designs that can automatically prevent, reject, and withstand cyber intrusions, allowing critical functions to continue operating, even while under attack.

11. The retention of qualified and diverse employees is a challenge many now see as outpacing the issue of an aging workforce, as skills requirements are changing rapidly due to grid modernization. The application of digital technology, in particular, is requiring a greater number of highly technical workers and engineers that can build, manage, and protect these systems. As a result, the electric industry is continuing to face challenges in attracting, recruiting, and hiring qualified applicants.

SMART GRID SYSTEM REPORT

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Acknowledgments

The Smart Grid System Report was sponsored by the U.S. Department of Energy (DOE), Office of Electricity (OE). The OE program lead for report development is Joe Paladino, DOE Technical Advisor in OE. Significant contributions were provided by: Lindsay Kishter, John Izevbigie, Annie Best, and Patrick Siebenlist of Nexight Group; Juliet Homer, Jeffrey Taft, and Mark Weimar of Pacific Northwest National Laboratory; Paul De Martini of Newport Consulting; and Gil Bindewald of DOE OE.

I. Legislative Language

According to Title XIII of the Energy Independence and Security Act of 2007 (EISA),[a] "[i]t is the policy of the United States to support the modernization of the Nation's electricity transmission and distribution system to maintain a reliable and secure electricity infrastructure that can meet future demand growth and to achieve [a set of requirements that] together characterize a Smart Grid." The U.S. Department of Energy (DOE) Office of Electricity (OE) prepared this Smart Grid System Report for Congress as required by Section 1302 of EISA, which directs the Secretary of Energy, acting through the Assistant Secretary of OE, to:

> **"report to Congress concerning the status of smart grid deployments nationwide and any regulatory or government barriers to continued deployment. The report shall provide the current status and prospects of smart grid development, including information on technology penetration, communications network capabilities, costs, and obstacles. It may include recommendations for State and Federal policies or actions helpful to facilitate the transition to a smart grid."**

This 2018 Smart Grid System Report includes input from the DOE Electricity Advisory Committee (EAC) and staff from other federal agencies in Federal Smart Grid Task Force, including the U.S. Department of Homeland Security (DHS), the Federal Energy Regulatory Commission (FERC), and the National Institute of Standards and Technology (NIST). This report covers developments in the national smart grid landscape since the prior Smart Grid System Report submitted in August 2014.

II. Introduction: Making the Grid "Smart"

A. What Has Changed?

Since the 2014 Smart Grid System Report:

- Cost-shared government and industry investments under the American Recovery and Reinvestment Act (ARRA) concluded in 2015, creating valuable lessons learned.[b]
- Rapid deployment of several smart grid technologies has occurred, with an upward trend of investment expected given new technologies and state policies.
- Falling prices and supportive policies have spurred rapid adoption in some regions of renewable and distributed energy resources (DERs), creating some challenges in grid operations.

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[a] Title XIII resides within Sections 1301 – 1309 of EISA. Energy Independence and Security Act of 2007, Public L. No. 110-140, 121 Stat. 1492 (2007).

[b] The numerous reports and findings generated through the ARRA-funded smart grid projects can be found at: https://www.energy.gov/oe/information-center/recovery-act

- State regulators and policymakers have approached DOE and the national laboratories for technical assistance regarding smart grid technology business cases, regulatory approaches, and planning strategies.
- State-, national- and international-level discussions are taking place on the transformation of the electric grid, especially at the distribution system level, with respect to future structural and functional requirements, prudent technology investment strategies, utility business models, and coordinated planning and operations across the transmission, distribution, and customer boundaries.

B. What Makes the Grid Smart?

In short, the digital technology that allows for enhanced sensing and control of grid elements, more widespread information sharing and communication, more powerful computing, and finer control is what makes the grid smart. In much the same way that the Internet and smart devices have impacted many aspects of our lives and changed the way we access and apply information, digital technology enhances operational control and decision-making. It also enables the intelligent networking of grid systems with other infrastructures, such as buildings and transportation systems.

Smart grid systems consist of digitally based sensing, information management, communications, computing, and control technologies and field devices that function to coordinate multiple electric grid processes. The application of information technology (IT) systems enables utilities to handle greater quantities of data that allow for more effective and dynamic grid operations. Smart grid deployments include three key elements:

1. **Smart field devices and sensors within the physical grid infrastructure that can monitor or measure processes, communicate data back to operations centers, and often respond to digital commands or function automatically to adjust a process.** Utilities are installing millions of digital devices, such as smart meters, phasor measurement units[c] and intelligent electronic devices,[d] throughout the transmission and distribution grid for sensing and control purposes.
2. **Communications networks that share data among devices and systems.** Communications networks with the right speed and size are foundational investments that can serve multiple existing and future smart grid applications.
3. **Information management and computing systems that can process, analyze, and help operators access and apply the data coming from digital technologies throughout the grid.** Using smart grid technologies to their full potential often requires utilities to substantially upgrade and integrate multiple information management systems.

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[c] A phasor measurement unit (PMU) is a device that measures voltage and frequency at a point on the grid and provides time-stamped data many times per second.

[d] An intelligent electronic device (IED) is a term used in the electric power industry to describe microprocessor-based controllers of power system equipment, such as circuit breakers, transformers and capacitor banks.

Advancements in modeling and analysis are moving toward the application of probabilistic and predictive approaches for grid management.

A smart grid uses digital technology to improve the reliability, flexibility, security, and efficiency of the electricity system—key ingredients in the ongoing modernization of the electricity delivery infrastructure. EISA Title XIII makes it U.S. policy to support grid modernization to achieve the following smart grid characteristics:

1. Increased use of digital information and controls technology to improve reliability, security, and efficiency of the electric grid.
2. Dynamic optimization of grid operations and resources, with full cybersecurity.
3. Deployment and integration of distributed resources and generation, including renewable resources.
4. Development and incorporation of demand response, demand-side resources, and energy-efficiency resources.
5. Deployment of "smart" technologies (real-time, automated, interactive technologies that optimize the physical operation of appliances and consumer devices) for metering, communications concerning grid operations and status, and distribution automation.
6. Integration of "smart" appliances and consumer devices.
7. Deployment and integration of advanced electricity storage and peak-shaving technologies, including plug-in electric and hybrid electric vehicles, and thermal-storage air conditioning.
8. Provision to consumers of timely information and control options.
9. Development of standards for communication and interoperability of appliances and equipment connected to the electric grid, including the infrastructure serving the grid.
10. Identification and lowering of unreasonable or unnecessary barriers to adoption of smart grid technologies, practices, and services.

Smart grid technology is the essential ingredient that enables a diverse energy mix, increased participation by customers, and resilient and reliable grid operations.

III. Evolution of Grid Intelligence

The many definitions of a "smart grid" typically define the characteristics or capabilities that it enables. For example, the Electric Power Research Institute (EPRI) defines a smart grid as follows:

"A smart grid is one that incorporates information and communications technology into every aspect of electricity generation, delivery, and consumption in order to minimize environmental impact, enhance markets, improve reliability and service, and reduce costs and improve efficiency."[1]

A smart grid applies digital technology to the sensing, communication, computing, control, and information management functions of the electric grid. The digital technology is embodied within microprocessors that interface with physical devices, communications systems that transmit and share data, solid-state devices that can manipulate voltage and current, and computers that process and display information. The use of digital technology has greatly improved the operational performance of the grid, and is providing new capabilities and insights through the enhanced management, analysis, and sharing of information. With the application of digital technology in the workings of the grid's electromechanical systems, it is now meaningful to consider a digital cyber layer and a physical layer as an integrated "cyber-physical" set. The extension of the cyber layer to electricity customers and third-party service providers permits a shared approach in grid operations, as well as operational convergence with other infrastructures, such as buildings, transportation, and various other utility-based infrastructures (e.g., water and natural gas systems).[2]

The integration of digital technology with the grid's electromechanical systems has evolved over several decades. The beginning of this integration occurred in the 1960s when engineers began to deploy supervisory control and data acquisition (SCADA) systems to automate the monitoring and control processes associated with complex industrial or manufacturing operations. The introduction of SCADA in transmission and distribution substations began in earnest during the late 1970s. These SCADA systems employed microprocessors that directly interfaced with devices in the physical world, telemetry-providing communications, and computers situated at master stations in transmission and distribution control centers.[3]

SCADA systems, including other distribution management systems, have advanced from using vendor-based proprietary protocols to applying open communications standards and protocols (e.g., the Internet Protocol Suite[e]) enabling such systems to interface with devices from multiple vendors, as well as take advantage of advancements in improved techniques for system analysis and operations. SCADA technology is now integrated with other systems (e.g., outage management systems), collectively referred to as operations technology (OT), which are

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[e] The Internet Protocol Suite is the conceptual model and set of protocols that enables a standardized approach for supporting communications between devices. IP-based communications (networking) systems can use fiber-optic, radio and other means for conveying data. Use of the IP suite does not necessarily imply use of the internet itself.

responsible for monitoring and controlling field devices connected to the electric grid.[f] Such operations will become increasingly complex as we increase the number of devices connected to the grid. Various OT functions include:

- Outage management functions, including fault location, isolation and system restoration (FLISR).
- Voltage and reactive power management.
- System monitoring, control and protection, including state estimation.
- Dispatch and control of grid devices, such as circuit breakers, field switches, and power electronics.[g]
- Dispatch and control of resources including central power generation units and DERs.[h]

In parallel with OT deployment, utilities have applied enterprise information technology (IT) to manage business processes, such as billing and revenue collection, asset tracking and depreciation, and workforce management. The IT systems, based on company enterprise and personal computing technology, apply software systems that permit many users to access utility-wide data through a variety of applications. The convergence of IT and OT systems is providing new analytical capabilities and significant operational benefits, leading to an information-driven electric grid. The range of technology developments associated with IT/OT convergence include the following:[4]

- Technology costs to collect and transmit operational data continue to decrease.
- The software underlying many OT applications uses standard IT computing platforms, making it possible to merge these resources, including options to employ cloud computing with higher-scale computing capacity.
- The application of "middleware"[i] is making it possible to link and integrate disparate sets of data, enabling advanced data analysis.

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[f] OT systems used by transmission grid operators are called energy management systems (EMS), while those used by distribution grid operators are called distribution management systems (DMS).

[g] Power electronics represent a class of devices that apply solid-state technology to manipulate current, voltage, and frequency in electrical systems, thereby managing the character and flow of power.

[h] The National Association of Regulatory Utility Commissioners (NARUC) defines a DER as "a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE)." NARUC, *Distributed Energy Resources Rate Design and Compensation*, 2016.

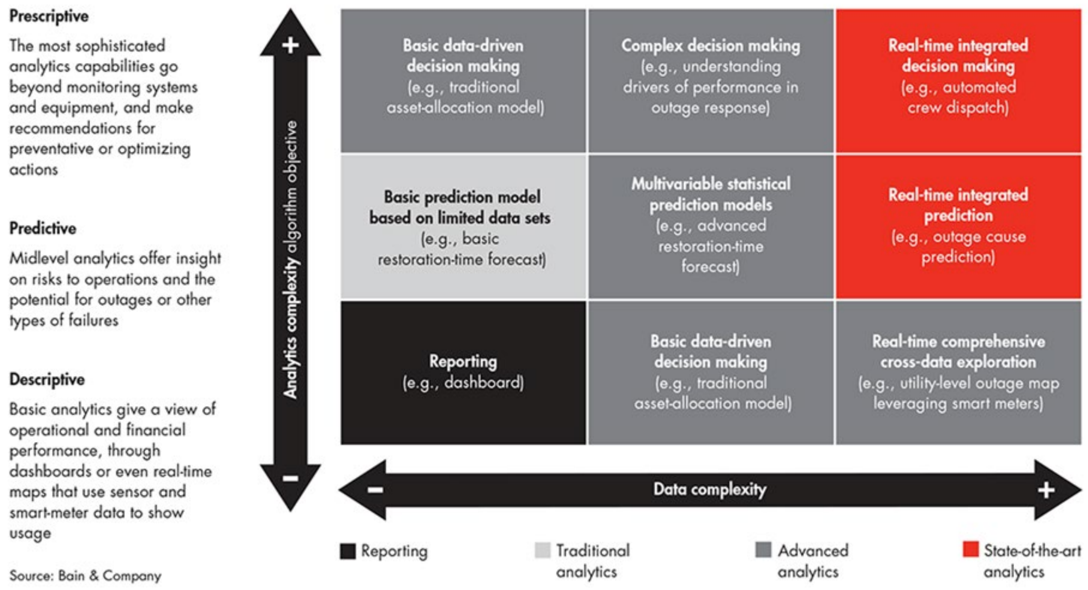
[i] Middleware represents the hardware and software solutions that allow existing applications to communicate and share information.

- Interoperability standards have been developed and employed, although further maturation of such standards is crucial to facilitating further IT/OT convergence. Several organizations, including the International Electrochemical Commission (IEC) and the Institute for Electrical and Electronics Engineers (IEEE), are developing smart grid interoperability standards.
- The escalation in mobile computing, data access, and even digital photography is providing field crews with more access to operational data, some in real time, which is substantially changing distribution activities such as inspections, field resource optimization, and inventory tracking.

This convergence is not occurring at the same pace across the industry, but rather is being driven by exogenous factors that are accelerating grid modernization. However, utilities are seeing many benefits that result from IT/OT convergence. For example, the sharing of historical and real-time data across utility processes that were traditionally siloed provides a new set of opportunities. An emerging technological capability is the advanced distribution management system (ADMS) which is a software platform that supports the full suite of distribution management functions. This includes historical operational data for planning, operational engineering data for system protection, and real-time operations support, including power flow control, automated outage restoration, voltage management, asset management, and DER dispatch and control. The information shared across these functions combined with a knowledge of grid assets provided through geographic systems, current conditions through network models, and customer behavior through advanced metering data, provides significant operational intelligence and efficiency to utilities.

The collection and analysis of system data will improve utilities' ability to economically manage assets, improve load forecasting and planning, provide intelligence to minimize faults and outages, and enable more proactive customer services. The market for utility data analytics in the United States is expected to reach $1.4 billion with a 60% market share by 2022 ($3.8 billion worldwide), as compared to $300 million in 2012.[5] As shown in Figure 1, the field of data analytics is expected to progress from applying data for basic reporting to providing utilities a predictive capability and, beyond that, enabling self-learning and optimization through the application of artificial intelligence and other machine-learning techniques.[6] This will involve collecting and synthesizing massive amounts of data from millions of smart sensors and devices to make timely decisions on how to best allocate resources.[7]

FIGURE 1. EVOLVING CAPABILITIES AND COMPLEXITY OF DATA ANALYTICS



Source: Guille and Stephan, "How Utilities Are Deploying Data Analytics Now," *Bain & Company,* 2016.

Grid modernization involves more than IT/OT integration because the essential structure of the grid is changing due to customer adoption of DERs and public policies driving utilization of DERs as grid resources. As a result, regulators and utilities are re-thinking the design and operation of the grid to create more open and transactive electric networks. This would lead to the development of open networks to enable the interaction of intelligent devices on the grid and the ability for consumers, utilities and other entities to participate and transact. Such networks can provide significant value through optimization and enhanced services as has been observed in the telecommunications industry.[j] Furthermore, additional value can be derived from the convergence of two or more networks or systems by sharing resources and enabling new value streams.[8] The convergence of the electric grid with building and transportation infrastructures is an example where shared resources, e.g., communication systems and computing, can enable more integrated and efficient operations, while fostering the growth of value-added services, such as applications to coordinate electric vehicle logistics.

In this discussion, it is important to note that grid modernization is advancing at different rates across the country based largely on state policies and where deployment of advanced technologies makes economic sense. Also, the adoption and application of DERs by utility customers and various merchants will impact grid operations and require the use of more advanced sensing, communication, computing and control capabilities. As a result, regulators and utilities are faced with determining prudent strategies for the deployment of advanced grid capabilities to address this challenge.

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[j] A conceptual value model (Metcalfe's Law) put forward by Robert Metcalfe in 2007 states that the potential value of a network is proportional to the square of the number of connected users of the system. Hence, network value increases exponentially as we increase the number of nodes that can communicate on the system.

Chapter Endnotes

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[1] EPRI, "Smart Grid Resource Center," n.d.

[2] De Martini and Taft (for PNNL), *Value Creation through Integrated Networks and Convergence,* 2015.

[3] Ujvarosi, "Evolution of SCADA Systems," 2016.

[4] Taylor, "IT/OT convergence," 2014.

[5] Greentech Media Research and SAS, *The Soft Grid 2013-2020* (research excerpt), 2012.

[6] Guille and Zech, "How Utilities Are Deploying Data Analytics," 2016.

[7] Wolfe, "How Artificial Intelligence Will Revolutionize the Energy Industry," 2017.

[8] Taft (for PNNL), *Grid Architecture 2,* 2016.

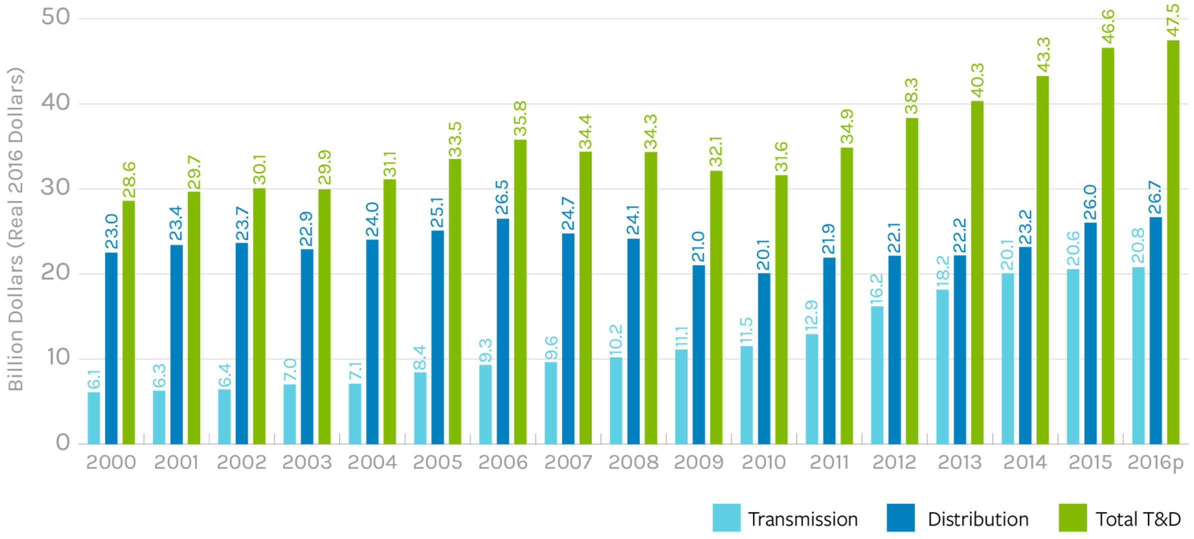
IV. Smart Grid Investment and Deployment

A. Decade of Increasing Grid Infrastructure Investment

Despite relatively flat growth in electricity demand, capital infrastructure investment in the electric power industry is nearly twice what it was a decade ago,[9] as utilities continue to invest in new renewable and natural gas generation resources, upgrade and harden aging physical infrastructure, expand transmission capacity and flexibility, and build in more intelligent systems.

U.S. utilities—including investor-owned utilities (IOUs), public power providers, and cooperatives—invested about $144.5 billion in electricity generation, transmission, and distribution infrastructure in 2016 (the latest year of available data).[k] Major IOUs alone, which serve about 73% of U.S. electricity customers, spent about $48 billion on the transmission and distribution grid that delivers electricity to customers (about $21 billion and $27 billion, respectively). They spent another $65.5 billion on generation, gas pipeline, and storage infrastructure, environment, and other capital investments, for a total capital expenditure of about $112.5 billion in 2016.[10]

FIGURE 2. CONSTRUCTION EXPENDITURES BY IOUS FOR TRANSMISSION AND DISTRIBUTION, 1990-2016



Source: EEI Statistical Yearbook, 2015 and 2016 Data

The steady uptick in grid investment coincided with rapidly declining wind and solar generation costs, growing supplies of low-cost domestic natural gas, a series of increasingly extreme and costly weather events (including Superstorm Sandy in 2012), and a widening national spotlight

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[k] Based on information reported to DOE from EEI, APPA, and NRECA. EEI reported total expenditures at $112.5 billion for IOUs, APPA reported $7 billion for public power utilities, and NRECA reported $25 billion for electric cooperatives in 2016.

on reliability and resilience as cyber and physical threats grow more severe. Rising capital investments in transmission and distribution infrastructure (see Figure 2) now take up the largest share of total capital spending by major IOUs.[11]

The transmission system, often called the bulk electric system, includes the high-voltage lines that carry large amounts of electricity from generating plants over long geographic distances to distribution substations. The last few years have seen record spending in transmission infrastructure—nearly triple the investment rates of a decade earlier—to expand, upgrade, or replace towers, fixtures, station equipment, overhead conductors, and other components. IOUs invested $20 billion in transmission infrastructure in 2016.

Transmission expansion and upgrades have largely been made to access power from new generation installations (especially renewable resources) and carry it to load centers; replace and harden aging infrastructure; relieve congestion; accommodate regional population and load shifts; improve reliability and security to meet new standards; and access cheaper power available through restructured markets.[12] Increasing labor and construction material costs also contributed to the rise in investment.

Distribution infrastructure investment often cycles as equipment wears out and is replaced. Figure 2 also shows that distribution investments by IOUs have grown incrementally since 2009, reaching a high of $27 billion in 2016. The largest investments were in poles and fixtures, overhead conductors, and station equipment to not only replace but also upgrade and harden the system against outages from the growing frequency of extreme and high-cost weather events, from hurricanes and storms to fires and floods.[13]

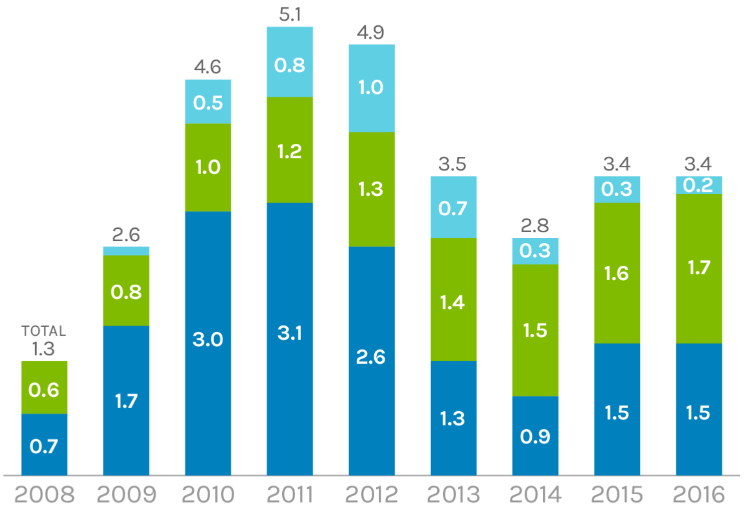
Several out-year projections show high capital investment is expected to continue over the next several years as utilities replace aging components and build in flexibility, intelligence, and resilience.[14] **The high capital costs and long life spans of transmission and distribution infrastructure make it vitally important that investments made today can support an evolving grid for decades to come.** A growing proportion of this investment will go toward smart infrastructure, the intelligent field equipment and the information, communication, and control systems that will allow utilities to operate the grid with greater visibility, flexibility, precision, and speed.

B. Growing Investment in Smart Grid Devices and Systems

There is no one comprehensive source of data on the cost and rates of smart grid technology deployment or projection, and investment categories are often difficult to compare across sources. This section uses several sources to demonstrate a steady rise in smart grid infrastructure investment and the factors that have driven rapid deployment of smart grid technologies that were still considered nascent less than a decade ago.

According to Bloomberg New Energy Finance, U.S. utilities in 2016 invested an estimated $3.4 billion in smart grid technologies at the distribution level, about 13% of the $27 billion spent on distribution infrastructure by large IOUs.[15] Since 2008, U.S. utilities have invested $31.6 billion in distribution-level smart grid technologies (see Figure 3), a higher investment rate than predicted in 2014. Actual spending from 2014 -2016 was roughly 25% higher than forecasted by Bloomberg in 2014.[16]

FIGURE 3. DISTRIBUTION-LEVEL SMART GRID SPENDING, BILLIONS



DISTRIBUTION-LEVEL INVESTMENTS INCLUDE:

SMART METERING

$1.5 BILLION

Smart meters and related communications and IT infrastructure

DISTRIBUTION AUTOMATION

$1.7 BILLION

Feeder and substation automation; distribution management; volt/VAR optimization (VVO); conservation voltage reduction (CVR); fault detection, isolation, and restoration; and outage management

ADVANCED SMART GRID

$0.3 BILLION

Grid applications that go beyond basic DA, including active network management, distributed generation integration, load control, home energy management, and EV charging.

Source: Bloomberg New Energy Finance World Factbook, 2017

The spike in investment starting in 2010 was due largely to $9 billion of public-private investments in smart grid deployment from 2010-2015 under the ARRA.[I]

The Bloomberg estimate in Figure 3 excludes smart grid deployment at the transmission level, along with the costs of new and integrated operational control and management systems, a key upgrade needed to maximize the use of new smart grid devices and data for improved grid control.

A more complete analysis by Newton-Evans estimates that U.S. utilities in 2016 invested a total of $4.8 billion in smart grid technologies and the associated information, communication, and control systems. This represents about 10% of the $47 billion in transmission and distribution infrastructure spending by IOUs.

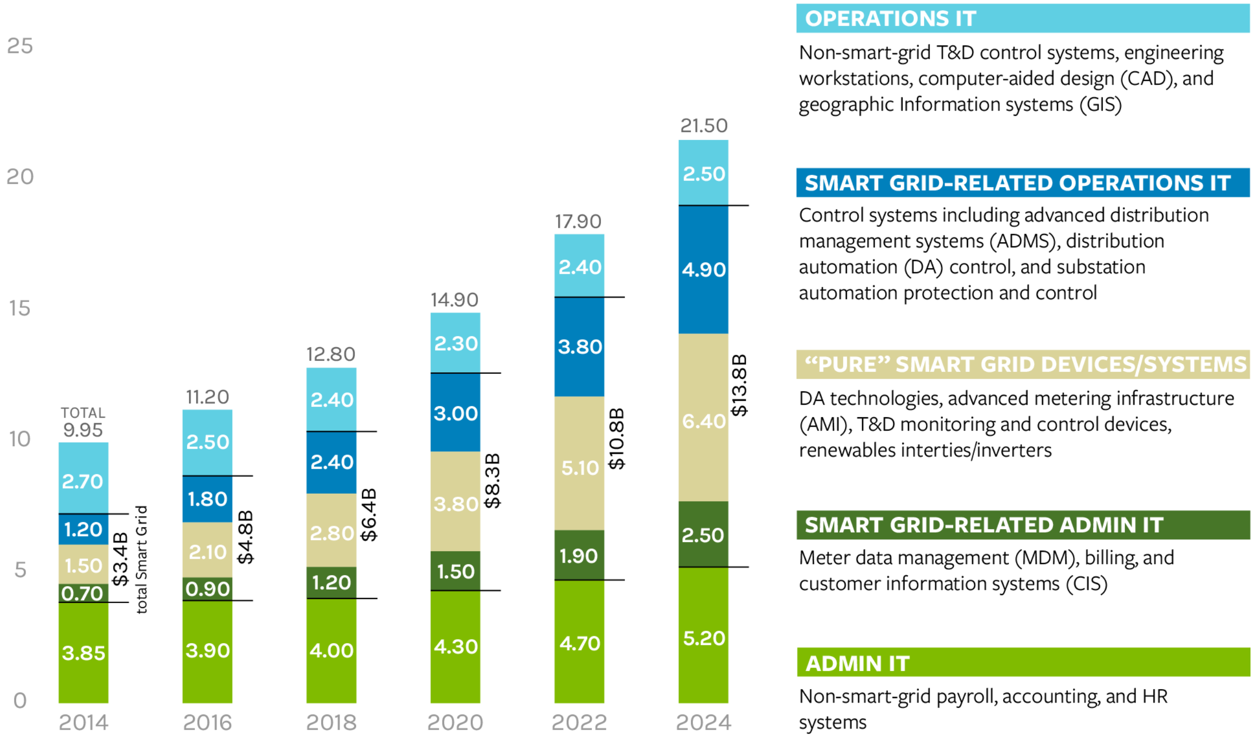
Newton-Evans analysis shows that **annual smart grid investment rose 41% between 2014 and 2016**, from $3.4 billion to $4.8 billion (Figure 4). This analysis makes an important distinction between the **estimated $2.1 billion spent on "pure" smart grid devices** or networks in 2016, and investment in smart-grid-related IT, including **$1.8 billion on smart-grid-related IT for operational systems** (such as substation automation and control systems) and $**0.9 billion on**

[I] DOE's Office of Electricity received $4.5 billion in Recovery Act funding to support smart grid investments, including funding for the Smart Grid Investment Grant (SGIG) and Smart Grid Demonstration Programs, which consisted of 131 cost-shared deployment projects with the energy industry.

smart-grid-related IT for administrative systems (such as smart meter data management and billing systems).

Figure 4 shows how smart grid investments will increasingly converge traditional information technology systems with operational control technology. Newton-Evans forecasts significant growth in utility IT spending over the next decade, and the large majority of that growth will be in "pure" smart grid devices and supporting information management and control technology. The forecast estimates that annual smart grid investment will double between 2014 and 2018, and will double again by 2022. By 2024, annual smart grid spending is expected to be $13.8 billion—making smart grid a more significant portion of total spending on grid assets.

FIGURE 4. ANNUAL SMART GRID INVESTMENT (OF TOTAL GRID INFORMATION AND CONTROL TECHNOLOGY INVESTMENT)



Source: Newton Evans, 2017; Data represents total electricity sector, as extrapolated from market studies and direct surveys representing 10%-30% of U.S. or North American markets, either in terms of customers served, number of substations, or revenues.

Several key factors have driven smart technology investment over the last several years—and may accelerate adoption in the coming decade:

- Cost-shared deployment under the Recovery Act reduced the risk of early investment, put millions of new digital technologies and operational systems on the grid, and supported vendor marketplace maturity, resulting in falling device costs and greater choices.

- Those commitments accelerated utility smart grid plans by as much as a decade, helped train the workforce, advanced conversations on codes and standards, and demonstrated expected benefits and cost savings that were not yet proven—paving the way for wider industry adoption.[17]
- The economy's growing reliance on power requires a more resilient power grid, particularly as weather-related disruptions and cyber threats are on the rise. Utilities are increasingly using automated controls and self-healing functions to prevent major blackouts, limit outages, restore faster, and enable microgrids that can keep powering critical facilities during disruptions.
- Declining prices of distributed technologies like rooftop solar and electric vehicles—particularly in states with high incentives and renewable energy targets—are rapidly requiring faster and more robust control capabilities than current systems allow.

C. Smart Grid Technologies: Deployment Trends and Benefits

This section provides key examples of innovative smart grid deployments and resulting benefits in the following technology areas:

- **Advanced transmission system technologies** for wide-area visibility and control
- **Advanced distribution system technologies** for self-healing automation, equipment health monitoring, and voltage optimization
- **Advanced metering infrastructure**
- **Smart customer devices** and energy management systems that enable demand response

1. ADVANCED TRANSMISSION SYSTEM TECHNOLOGIES

Smart grid advancements in the transmission system are focused on giving operators better system visibility, faster response, more effective decision-making, automated protection, and greater control.

Synchrophasor technology

One of the most impactful innovations has been the widespread deployment of synchrophasor technology which involves the application of PMUs to deliver precise, time-synchronized measurements of voltage and frequency[m] to transmission grid operators. Current SCADA systems deliver observations about grid conditions every 4 to 6 seconds,[18] whereas PMUs can provide observations 30 times or more per second. Each PMU measurement is location- and time-stamped permitting grid operators to better observe power grid dynamics, e.g., changes in

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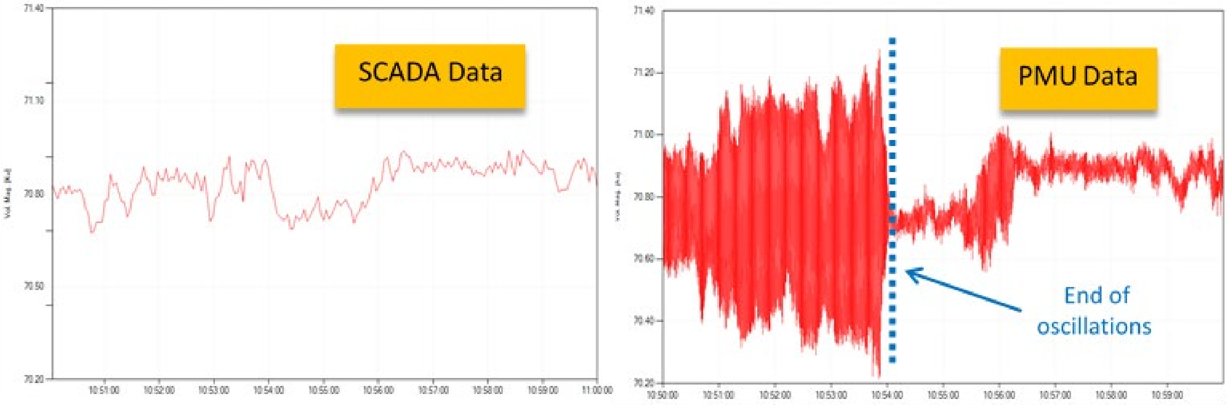
[m] The frequency of the electric grid in the United States is kept tightly at 60 hertz (+/- 0.5 Hz), or 60 cycles per second. One cycle is equivalent to approximately 16 milliseconds. At 60 Hz, the current (movement of electrons) in our (alternating current) wires reverses direction 120 times per second.

frequency and power flow across the system, with microsecond accuracy, which cannot be provided by traditional SCADA. Figure 5 shows how PMU data can more quickly and accurately detect an oscillation, which was then corrected. Such oscillations are indicative of system anomalies that can potentially lead to catastrophic system failure if left unaddressed.

FIGURE 5. TRANSMISSION GRID OSCILLATIONS AS SHOWN BY SCADA DATA VS. PMU DATA



Source: DOE, *Synchrophasor Technologies and their Deployment in the Recovery Act Smart Grid Programs,* 2013.

PMU adoption has accelerated since the ARRA jump-started PMU commercialization and development of updated technical standards and conformance testing. The electric industry is currently in the second round of technical standard updates through IEEE; and several utilities are now installing PMUs as part of regular infrastructure build-outs (rather than as special projects). As a result, synchrophasor technology is gradually shifting from a research and off-line analysis tool to one that actively supports real-time operations, enabling such capabilities as real-time oscillation monitoring and management, linear state estimation, and automated power plant model validation. In 2009, there were fewer than 200 PMUs in the U.S. transmission system, used primarily for research. By 2017, there were more than 2,500 networked synchrophasors, providing visibility across nearly 100% of the U.S. transmission system at varying degrees of resolution.[19]

EMS Advancements

Transmission operators have continued to advance smart grid capabilities that utilize the benefits of IT/OT integration. A good example of this is the Advanced Control Center (AC^2) commissioned in 2011 by PJM.[20] PJM is the regional transmission operator which coordinates electricity across Pennsylvania, New Jersey, Maryland, and 10 additional states and serves over 65 million people. The AC^2 employs a shared architecture platform permitting various applications (associated with the EMS, market management system, and settlements system) to plug into an enterprise service bus and receive and transmit information through it by applying standardized communication protocols and procedures. As a result, it provides a standardized integration platform for applications that differ in technology, design or vendor and can scale to incorporate additional applications and data streams. For example, it can integrate the massive data streams from the increasing number of phasor measurement units being installed across the PJM territory. It also provides an information platform for PJM's members through industry-standard messaging architecture and two-way communications.

2. DISTRIBUTION AUTOMATION

Distribution automation (DA) refers to the application of digital processes to improve the effectiveness and efficiency of distribution system operations, oftentimes to automate operations that were formerly performed manually. This includes automation of fault detection and restoration, equipment health monitoring, and the optimized management of voltage and reactive power.

Automated Location and Isolation of Faults

Fault location, isolation, and service restoration (FLISR) technology can help utilities better isolate faults and restore power where outages have occurred. FLISR devices include fault indicators, line monitors, automated feeder switches, and reclosers. When a fault occurs or a power line is damaged, these technologies work in tandem to detect and clear temporary faults, isolate sustained faults, and automatically re-route power around faults (where possible), often within seconds.

As was observed by several utilities receiving ARRA funds, fully automated switching and validation typically resulted in greater reliability improvements than operator-initiated, remote switching with manual validation. For example, several utilities that deployed FLISR reported a 55% reduction in the number of customers interrupted by sustained outages and a 53% reduction in the number of minutes that they were out of power during those events. In addition, eighteen utilities that deployed FLISR reported avoiding 197,000 truck rolls, equivalent to 3.4 million vehicle miles traveled, from 2011 through 2015. Precise fault location enables operators to dispatch repair crews accurately and notify customers of outage status, which reduces outage length and repair costs, reduces the burden on customers to report outages, and increases customer satisfaction.[21]

Figure 6 shows how automated feeder switching deployed by EPB in Chattanooga restored power within seconds to half of the customers who experienced an outage during a June 2012 derecho (windstorm) which had moved rapidly across the eastern part of the country. The automated switching technology detected the faulted sections of the distribution system and immediately reconfigured the distribution network in such a way as to limit the number of customers experiencing the outage. In Figure 6, the green line shows the outage curve for those experiencing the event, while the blue curve provides an estimate of the outage curve if the technology had not been deployed. EPB estimates that it avoided $23 million in customer damages in this one storm and was able to completely restore the system 17 hours earlier than anticipated.[n]

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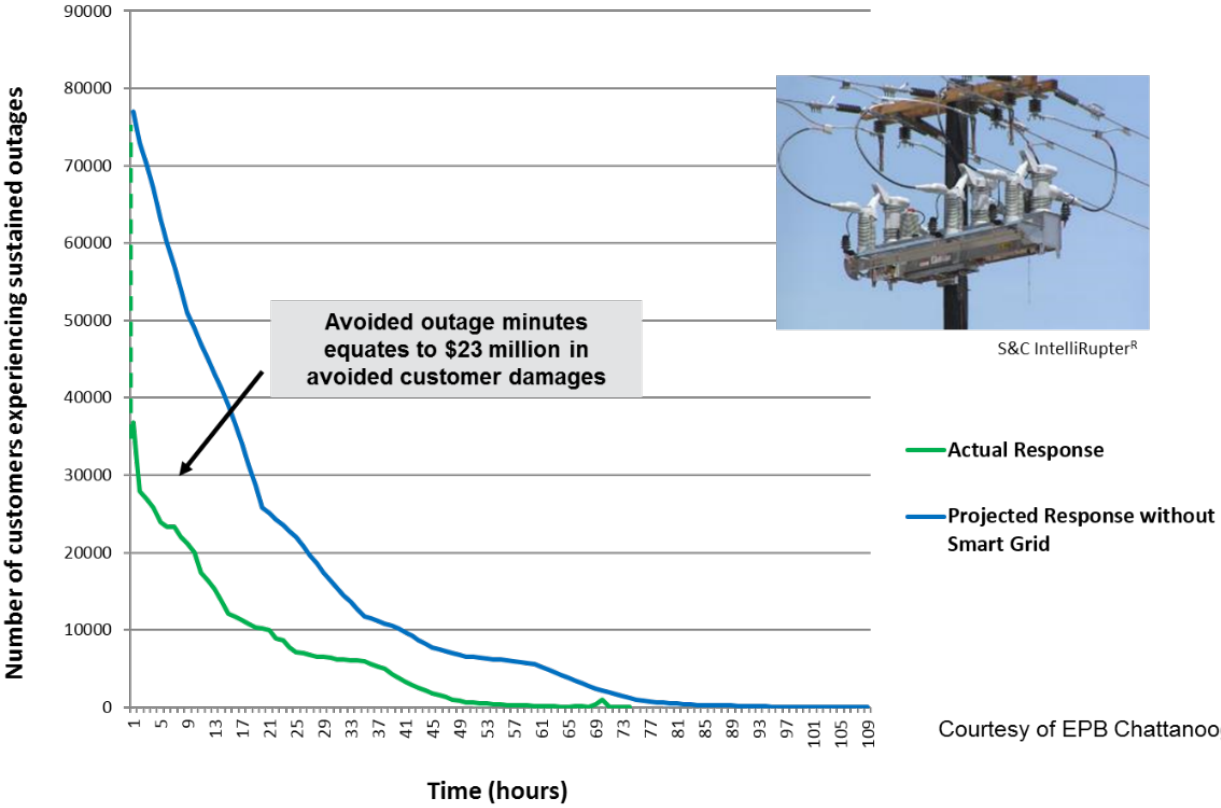
[n] Customer damage estimates were calculated using the Interruption Cost Estimate (ICE) Calculator tool, which applies outage damage costs from numerous utility surveys. See https://icecalculator.com/home.

FIGURE 6. FASTER RESTORATION TIME AT ELECTRIC POWER BOARD OF CHATTANOOGA



Courtesy of EPB Chattanooga

Equipment Health Monitoring and Failure Prevention

Improved sensing capabilities enable operators to measure equipment health parameters and receive real-time alerts for abnormal equipment conditions. Utilities can better anticipate and proactively prevent equipment failures, prioritize repairs and maintenance, and plan preventative maintenance and replacement needs. These technologies and systems also equip grid operators with new capabilities to better dispatch repair crews based on diagnostics data.

For example, Florida Power & Light (FPL) can observe changes in transformer performance based on shifts in voltage output detected by smart meters. FPL can now replace transformers before they fail and, as a result, has significantly reduced outage times experienced by customers through a proactive maintenance program.[22]

Voltage Optimization and Distribution System Efficiency

Several utilities are applying automated methods to adjust voltage and reactive power levels along their distribution circuits to reduce energy losses and conserve energy consumption, especially during peak demand periods. Voltage optimization and conservation voltage reduction (CVR) processes integrate the operations of several devices (load tap changers, voltage regulators and capacitors) and can be performed through a variety of automated approaches. The energy saved in these operations is translated directly into savings for customers and a reduction in energy requirements that can lead to deferring capital expenses, including for generation facilities.

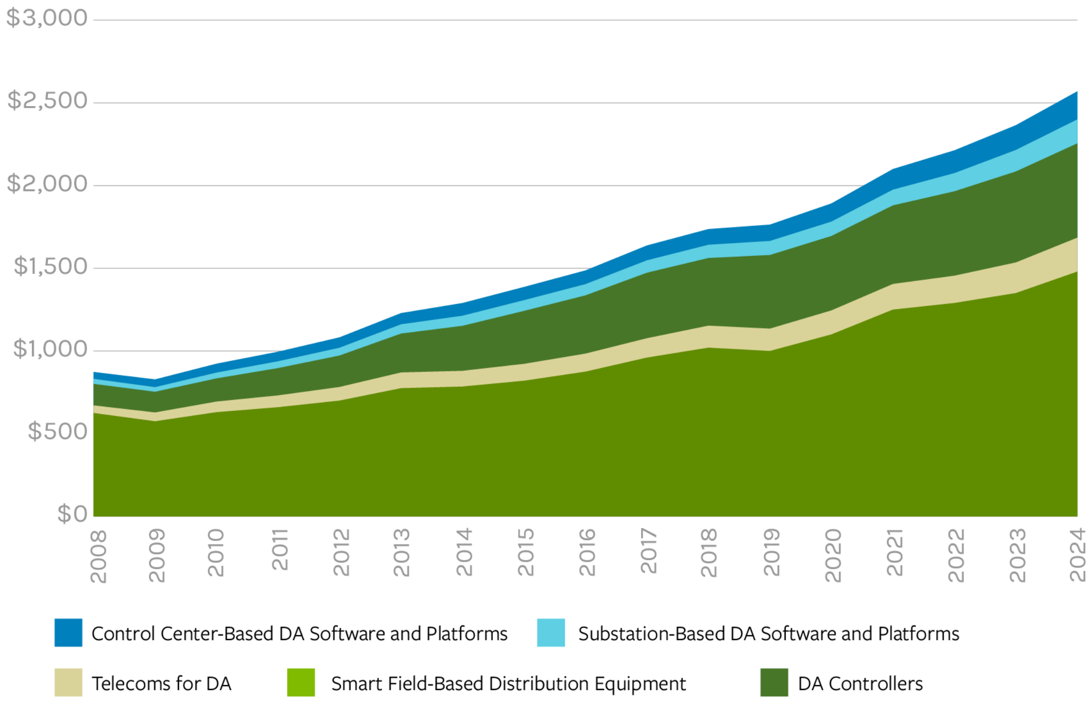
The potential energy savings from voltage optimization varies from circuit to circuit. However, case studies show that even a modest voltage reduction of 1-3% can deliver significant energy and cost savings. Several utilities participating in ARRA-funded projects realized energy savings of 2%-4% on affected feeders using conservation voltage reduction methods. For example, Duke Energy used integrated volt/VAR controls with an advanced distribution management system to achieve a consistent 1%-1.58% voltage reduction on more than 700 circuits across Ohio.[23] These reductions saved fuel and lowered customer bills, with no detrimental effects on service quality. In 2011, Duke estimated the value of its smart grid investments over a 20-year period at $190.41 million.[24] Duke's continuous voltage reduction strategy—which targeted a 2% voltage reduction—made up the most significant portion of those expected benefits, valued at $155.57 million over 20 years.

Applied system-wide, such techniques could save hundreds of thousands in yearly energy costs, particularly when targeting larger and heavily loaded feeders, although the costs of implementing the technology need to be measured against potential benefits. Also, integrating smart inverters into legacy voltage optimization systems will present a challenge, as utilities and regulators will need to develop strategies to deploy the advanced functionality of smart inverters described in IEEE 1547-2018. Nearly 45,000 circuits now have voltage optimization, or about 22% of all U.S. distribution circuits (as of 2016).[25]

DA Investment and Deployment Trends

Smart grid investments in the coming years will shift more heavily to distribution system intelligence. Many utilities pursuing distribution automation started with small-scale deployments, allowing them to resolve technical and systems integration issues, and assess the potential benefits and savings for utilities and customers alike. As utilities begin to scale up deployment plans, distribution-level smart grid investments are predicted to increase significantly in the coming years, according to Newton-Evans (Figure 7). More than half of spending will go to smart field devices and communications networks, while an increasing percentage will be spent on control equipment and control center and substation-based software and platforms.

FIGURE 7. ESTIMATED HISTORIC AND PROJECTED U.S. INVESTMENTS IN DISTRIBUTION AUTOMATION



Source: Newton Evans, 2017; Data represents total electricity sector, as extrapolated from market studies and direct surveys representing 10%-30% of U.S. or North American markets, either in terms of customers served, number of substations, or revenues. Represents sum of all DA categories, mid-range estimate.

3. SMART METERS AND ADVANCED METERING INFRASTRUCTURE (AMI)

AMI is an integrated system of smart meters, communications networks, and data management systems that provide a two-way digital link between utilities and customers. Nearly half of U.S. customers now have smart meters. For most utilities, smart meters collect data at regular intervals (typically 15 minutes) and deliver it to a local data aggregator in the communications network where it is finally backhauled to an operations center. Because of the vast amount of data, utilities typically backhaul the data three times per day, and use it for customer billing, load forecasting, and system forensics. This information can also be shared with customers to help them better monitor and manage their electricity consumption.

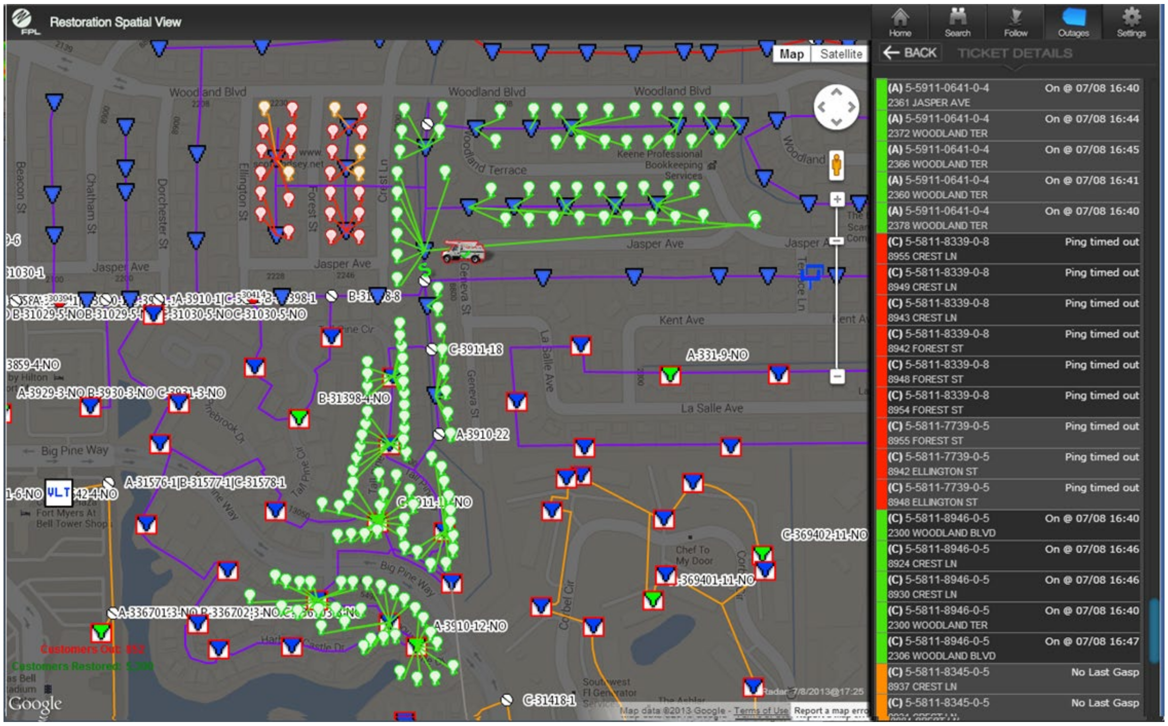
AMI provides significant operational benefits, which translate to utility cost savings and convenience to customers. AMI can:

- Significantly reduce operating costs by remotely reading meters, connecting/disconnecting service, and identifying outages—all previously manual functions.
- Generate more accurate bills faster and enable utilities to provide customers digital access to their usage information. About 26% of U.S. customers now have daily digital access to their usage data.[26]
- Detect meter tampering and electricity theft to enhance revenue collection.

- Send "last-gasp" alerts when service is disrupted, enabling utilities to isolate outages faster and dispatch repair crews more precisely. This capability is most valuable when smart meter data is integrated with outage management systems and restoration operations.
- Enable utilities to send time-based price signals to customers and incentivize demand reduction during peak periods. (See Dynamic Pricing and Demand Response on page 33).
- Support voltage management activities when smart meters are used as sensors.

Florida Power & Light has deployed a mobile application called the Restoration Spatial View (RSV) tool for use on tablets and smartphones to assist the utility's field crews in power restoration efforts. The application combines AMI information and data from a variety of sources to provide GPS-assisted street views and driving directions, weather data and storm tracking, maps showing real-time information on fault locations and smart meter outage activity, customer usage and voltage history, and restoration confirmation. The RSV tool, serving as an information platform, has greatly aided field crews in restoration operations; the restoration confirmation function ensures there are no embedded outages prior to leaving a site.

FIGURE 8. VIEW OF A SCREEN IMAGE FROM FPL'S RESTORATION SPATIAL VIEW TOOL



(A) 5-5911-0641-0-4	2361 JASPER AVE	On @ 07/08 16:40
(A) 5-5911-0641-0-4	2372 WOODLAND TER	On @ 07/08 16:44
(A) 5-5911-0641-0-4	2366 WOODLAND TER	On @ 07/08 16:45
(A) 5-5911-0641-0-4	2360 WOODLAND TER	On @ 07/08 16:41
(A) 5-5911-0641-0-4	2378 WOODLAND TER	On @ 07/08 16:40
(C) 5-5811-8339-0-8	8955 CREST LN	Ping timed out
(C) 5-5811-8339-0-8	8949 CREST LN	Ping timed out
(C) 5-5811-8339-0-8	8943 CREST LN	Ping timed out
(C) 5-5811-8339-0-8	8942 FOREST ST	Ping timed out
(C) 5-5811-8339-0-8	8948 FOREST ST	Ping timed out
(C) 5-5811-8339-0-8	8954 FOREST ST	Ping timed out
(C) 5-5811-7739-0-5	8955 FOREST ST	Ping timed out
(C) 5-5811-7739-0-5	8942 ELLINGTON ST	Ping timed out
(C) 5-5811-7739-0-5	8948 ELLINGTON ST	Ping timed out
(C) 5-5811-8946-0-5	2300 WOODLAND BLVD	On @ 07/08 16:40
(C) 5-5811-8946-0-5	8924 CREST LN	On @ 07/08 16:46
(C) 5-5811-8946-0-5	8930 CREST LN	On @ 07/08 16:46
(C) 5-5811-8946-0-5	2300 WOODLAND TER	On @ 07/08 16:40
(C) 5-5811-8946-0-5	2306 WOODLAND BLVD	On @ 07/08 16:47
(C) 5-5811-8345-0-5	8937 CREST LN	No Last Gasp
(C) 5-5811-8345-0-5		No Last Gasp

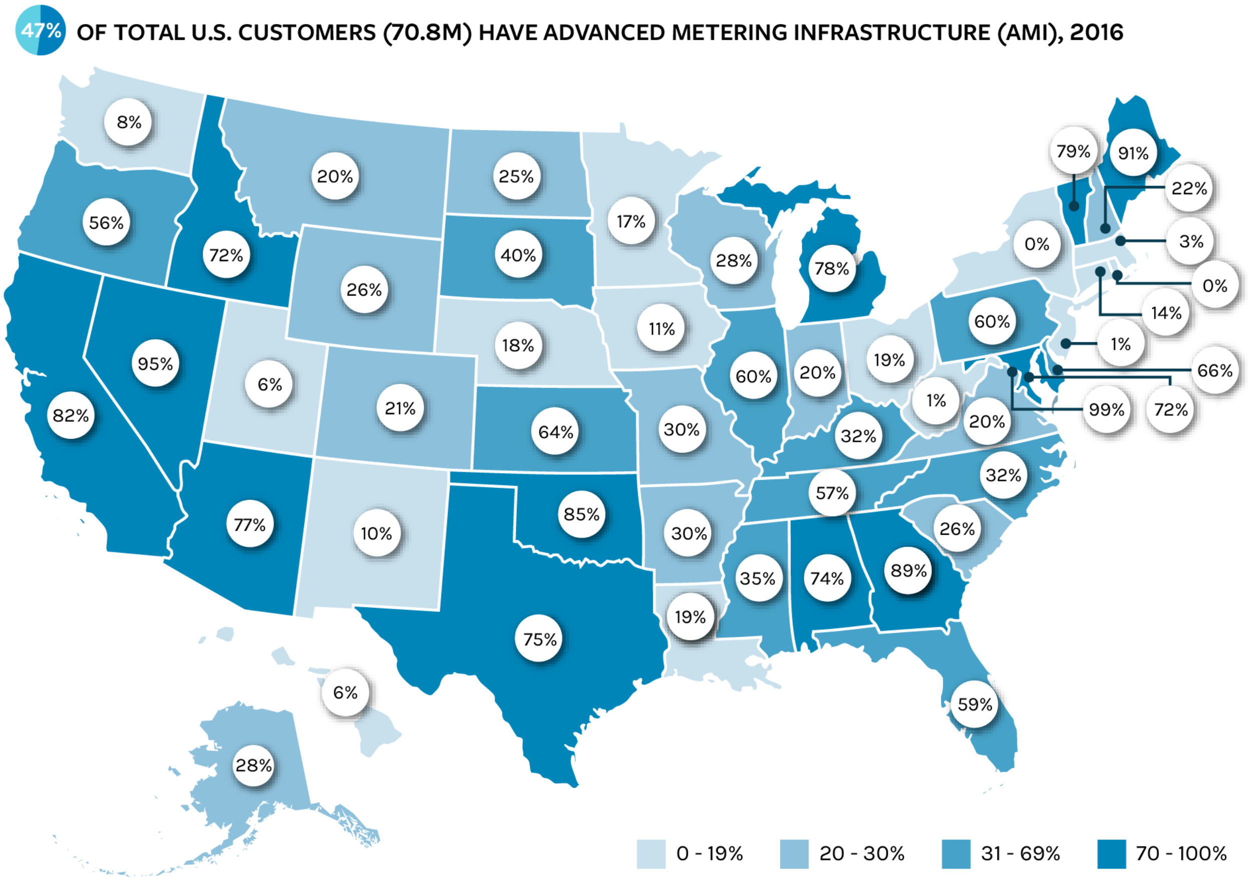
Image courtesy of LaMargo Sweezer-Fischer, Florida Power & Light.

AMI Investment and Deployment Trends

From 2007 to 2016, the number of advanced meters has grown ten-fold. About 70.8 million meters out of a total of 151.3 million meters were smart meters as of 2016, representing about 47% of U.S. electricity customers (Figure 9). Bloomberg estimates that number has risen to 51% by the start of 2018.[27] This is a significant increase compared to 14% of customers with smart meters in 2010 and only 2% in 2007.[28]

Recovery Act investments contributed to this sharp rise, as cost-shared investments deployed 1/3 of all smart meters added between 2010-2015 (16 million meters). Individual states and utilities often have vastly different rates of smart grid deployment, as the business case varies widely. The largest number of smart meters were installed in California and Texas, states with deliberate AMI polices. These policies created less risk for utilities to recover costs and reduced the administrative burden for processing rate cases before AMI benefits were widely proven.

FIGURE 9. PERCENT OF U.S. CUSTOMERS WITH SMART METERS



47% OF TOTAL U.S. CUSTOMERS (70.8M) HAVE ADVANCED METERING INFRASTRUCTURE (AMI), 2016

Source: EIA, "Electric power sales, revenue, and energy efficiency: Form EIA-861," 2016 data.

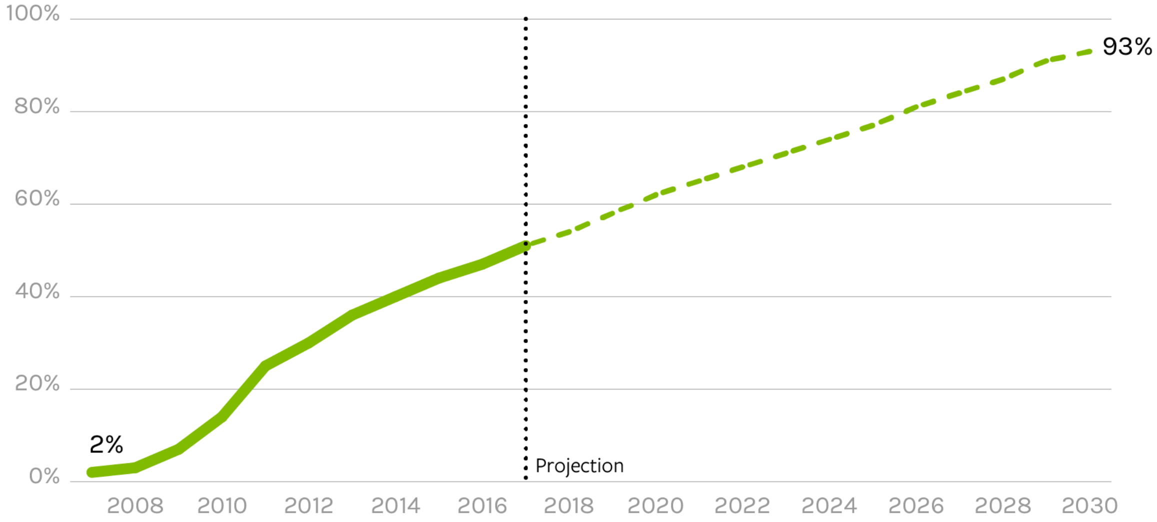
Differences in AMI deployment rates are often driven by state legislation or utility regulation, as some states require that regulators approve utilities' cost recovery mechanisms.

AMI investment rates are expected to slow in the years ahead (see Figure 10). Half of all meters are now smart meters, and another 25% are meters with automated meter reading (AMR) functionality—a smart meter precursor that improves the efficiency of meter reading.[29] Because the operational and maintenance savings from automated metering make up about 65%-80% of expected AMI benefits,[30] utilities with AMR find it difficult to justify AMI upgrades ahead of expected replacement periods.

Operations and maintenance (O&M) savings derived from AMI deployments are highest for utilities with low customer densities over large geographic regions, or with significant weather-related outages. For utilities with small-scale metering (e.g., under 750,000 meters), the cost of back-office software systems can sometimes outweigh the benefits. Aside from O&M savings, the ability of AMI to provide timely customer use data is most attractive to utilities and states with strong support for time-of-use rates or where demand response has a high value.

Going forward, investment will likely center on more holistic grid modernization investments, like grid sensing and multi-purpose communications throughout the distribution grid, rather than point solutions like AMI. Stronger business cases are emerging that are not centered around automated billing. Future AMI systems will apply smart meters that act as grid sensors, distributed computing platforms, and control points for DER.[31] Next-generation smart meters are now becoming commercially available; they will have computing capabilities and permit distributed decision-making.

FIGURE 10. GROWTH IN U.S. CUSTOMERS WITH ADVANCED METERING INFRASTRUCTURE (AMI), 2007-2030



Source: Actuals through 2016 from EIA, “Electric power sales, revenue, and energy efficiency: Form EIA-861,” 2016 data; projections from BNEF, provided directly to DOE.

4. CUSTOMER AUTOMATION AND ENERGY MANAGEMENT SYSTEMS

With rising AMI deployments, more than a quarter of U.S. customers now have daily access to their digital energy usage information through their energy providers using mobile apps and web interfaces. Customers can use this information to make smarter energy decisions over time, but a real sea change is coming from advanced control technologies that allow customers to automate changes to their energy use in response to price signals or other inputs.

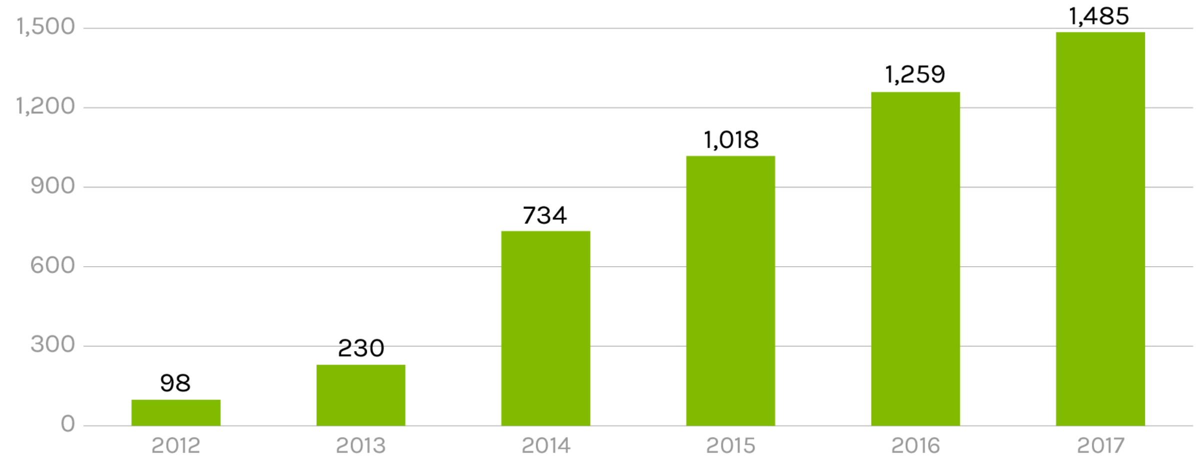
The set-it-and-forget-it nature of smart thermostats makes it easier for customers to participate in demand response and dynamic pricing. Smart home devices, like NEST, Amazon's Echo, and Google's Home, go even further, allowing users to connect and automate a growing number of technologies (such as lights, thermostats, security cameras, and door locks) with a single device.

NEST, for example, links multiple smart home devices on a network, and can activate lights when security cameras detect motion, or turn down lights to save energy when the house is empty. NEST also connects to the utility's metering system through Wi-Fi to respond to time-of-use signals and adjust electric-based heating and cooling systems during peak periods.

Amazon's Echo uses voice recognition to check the news, play music, search the web, or purchase services through connected businesses. Capabilities can be expanded by downloading "skills" in the Alexa app from other businesses—including some energy utilities. TXU Energy, a Texas-based energy provider, launched two new Alexa skills in November 2017: one that allows customers to see and manage their account, and one that allows them to control their TXU thermostats with Alexa, rather than adjusting the device manually.[32]

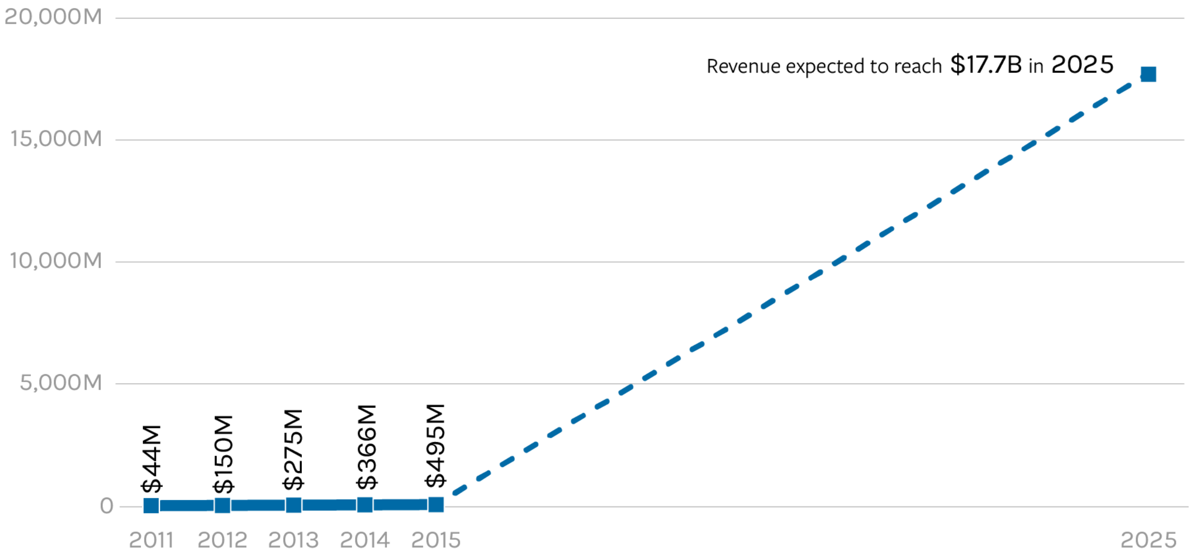
Of about 117 million U.S. homes in 2016, about 17 million had some type of smart home device. By 2020, 40 million smart thermostats are expected in U.S. homes with 50 million smart light bulbs, and 12 million smart water leak detectors.[33] Sales of connected home technologies grew almost 1500% from 2012 to 2017, [34] and explosive growth is slated to continue as competition increases and vendors expand how devices interact with other businesses and services (see Figure 11 and Figure 12).

FIGURE 11. CONNECTED HOME TECHNOLOGY SALES, MILLIONS



Source: Statista, "Connected home technologies sales in the United States from 2012 to 2017," 2018.

FIGURE 12. GROWTH IN HOME ENERGY MANAGEMENT SYSTEM REVENUE

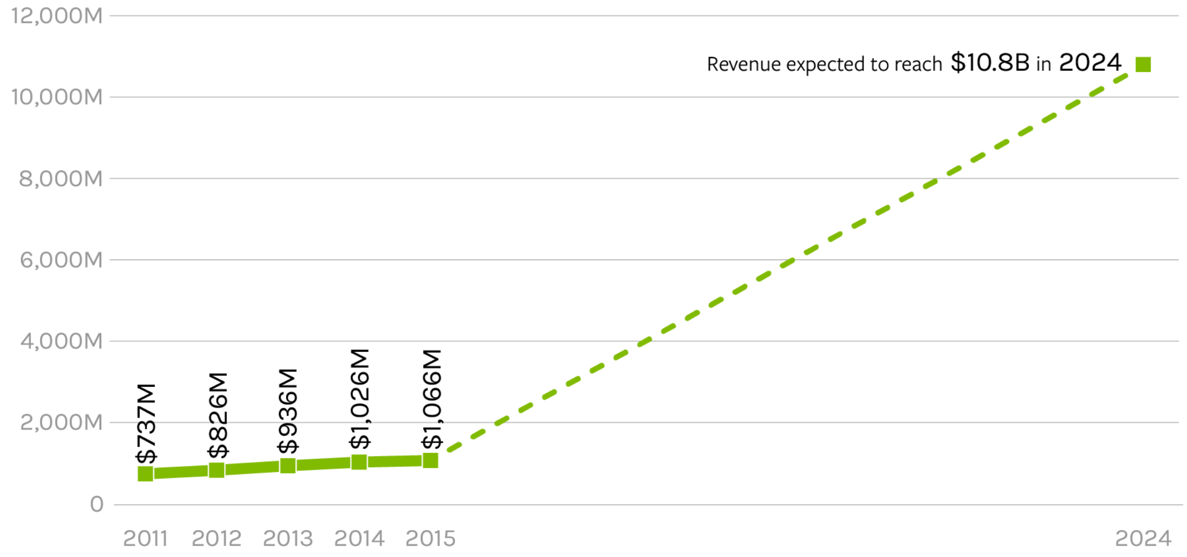


Source: Advanced Energy Now, *2017 Market Report*, prepared by Navigant Research, 2017.

Though connected home technologies are increasing in availability and popularity, none are yet fully "plug and play" to easily enable energy savings or load shifting. Integrating devices such as Amazon Echo and Google Home into home energy systems can be cumbersome and often requires the purchase of additional appliances to fully realize potential cost savings. Nevertheless, the technology maturity (e.g., user interface, controls) is beginning to come together with declining costs to enable future widespread use.

Business owners are also beginning to adopt building energy management systems that allow more precise control and automatic settings to drive down energy use and costs. Since 2011, the market for building energy management systems has grown from $737 million to more than $1 billion, and is expected to grow faster—more than ten-fold—in the next decade (see Figure 13). These systems employ control technologies to manage appliances, HVAC, and lighting systems, automatically turning them on and off to optimize efficiency or respond to load conditions or pricing forecasts.

FIGURE 13. GROWTH IN BUILDING ENERGY MANAGEMENT SYSTEM REVENUE



Source: Advanced Energy Now, *2017 Market Report*, prepared by Navigant Research, 2017.

Building and home energy management capabilities must be designed to seamlessly coordinate with grid management systems to be effective. Integration will require utilities to foster true bi-directional communication networks that can send and receive price signals, commands, and other data in standard, interoperable formats. Customer privacy and data protection is a growing consideration, as both smart meters and customer-based technologies allow utilities and third-party service providers to collect and analyze vast amounts of energy usage data.

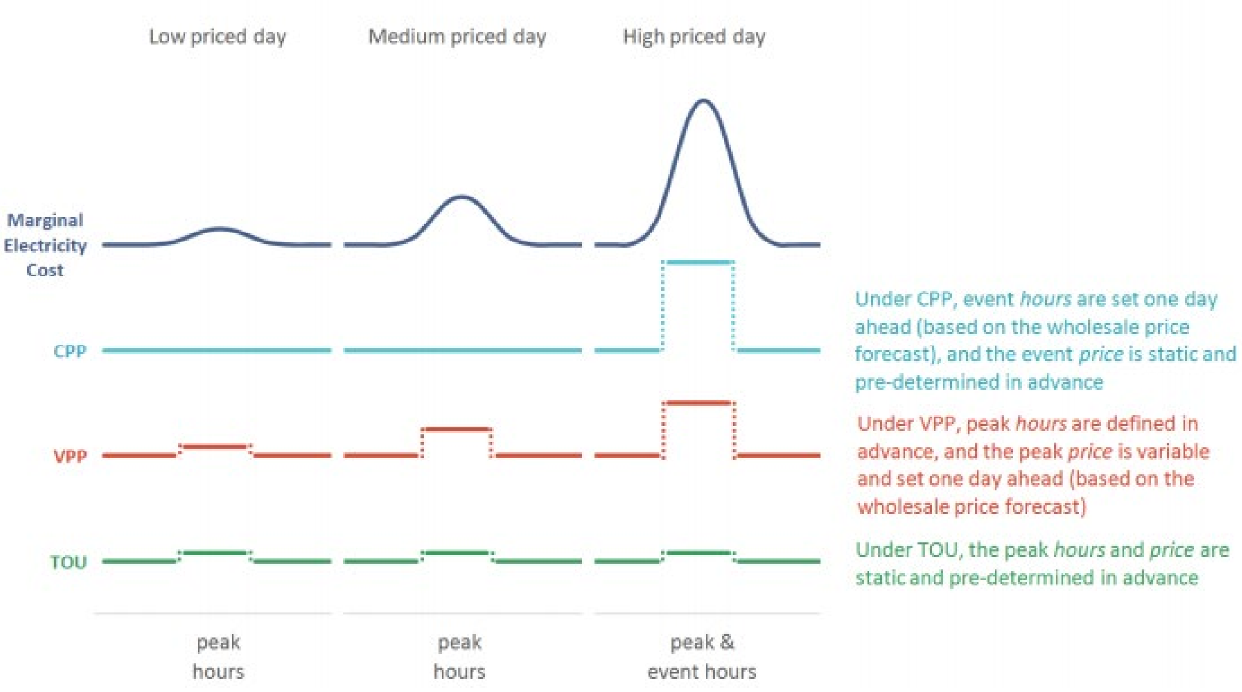
5. DYNAMIC PRICING AND DEMAND RESPONSE

The combination of AMI and smart customer devices enables customers to effortlessly change their energy use in response to dynamic rates. Time-based rates, or dynamic pricing, include a variety of options for utilities to charge higher rates during peak hours or critical events, and lower rates during off-peak hours (see Figure 14). While the electricity industry has been exploring time-based rate options for decades, smart grid technologies make it possible to use dynamic pricing to incentivize significant shifts in customer load during peak periods.

Customers can use smart devices to automatically reduce their energy use during peak hours to save money. Direct load control devices—installed in energy-intensive appliances like air conditioners and water heaters—also allow utilities to temporarily turn appliances off during peak periods, often in return for bill credits.

Only 5% of U.S. customers participate in dynamic pricing today, as the enabling technologies are being put into place and utilities test program designs.[35] Recent studies show significant promise. Twenty-six utilities who tested various rate programs with more than 400,000 customers under their SGIG projects found that customers reduced their peak demand by up to 23.5%.[36] Peak demand reductions can help utilities defer capital investments in peaking power plants.

FIGURE 14 - ILLUSTRATION OF TIME-BASED RATE DESIGNS



Under CPP, event *hours* are set one day ahead (based on the wholesale price forecast), and the event *price* is static and pre-determined in advance

Under VPP, peak *hours* are defined in advance, and the peak *price* is variable and set one day ahead (based on the wholesale price forecast)

Under TOU, the peak *hours* and *price* are static and pre-determined in advance

Source: DOE, Customer Acceptance, Retention, and Response, 2016.

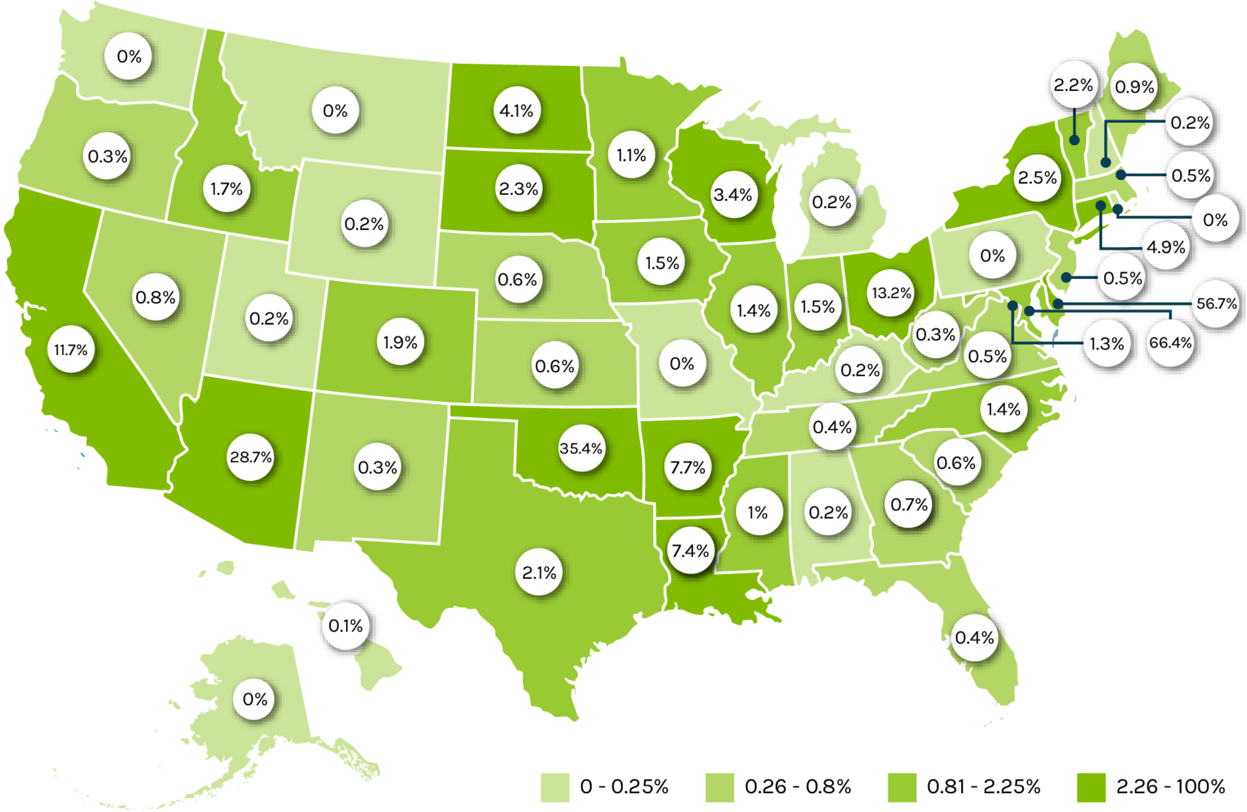
In a set of rigorously controlled variable pricing studies undertaken through ARRA efforts with 10 utilities, participants found that customers that applied control technologies, such as programmable communicating thermostats (PCTs), reduced peak demand to a greater extent than those customers that just received information from utilities through in-home displays.[37] Such thermostats provide customers the additional convenience of setting their comfort preferences and then letting their heating and cooling systems function automatically to signals provided by the utility. Although the results were variable, some utilities have continued to expand their time-varying rate programs based on the success of the pilot projects conducted under DOE's SGIG program:

- In 2015, California's legislature directed the state's investor-owned utilities to adopt and implement time-of-use rates as a default,[38] after examining their potential for beneficial load shifts. Encouraging results from the Sacramento Municipal Utility District's (SMUD)

Consumer Behavior Study[39] under DOE SGIG helped justify this decision. SMUD observed an average peak demand reduction of 26% for those customers on a critical peak pricing program (without the use of a PCT).

- Oklahoma Gas and Electric's Smart Study TOGETHER project evaluated various enabling technologies with time-based rate programs, and its impacts on energy consumption and peak demand. The pilot program used a multi-tiered rate structure (low, standard, high, and critical). Residential customers averaged annual savings of $191.78 and commercial customers averaged $570.02 annual savings.[40] Based on study results, OG&E expanded the use of time-based rates to nearly 20% of its customers,[41] which are achieving 147 MW of peak demand reduction and helped defer investment into two 165 MW plants originally planned for construction in 2015/16.[42]

FIGURE 15. PERCENT OF U.S. CUSTOMERS WITH DYNAMIC PRICING BY STATE, 2016



Source: EIA, "Electric power sales, revenue, and energy efficiency: Form EIA-861," 2016 data; includes customers participating in one of the following pricing programs: Real time, Time of Use, Variable Peak, Critical Peak, Critical Rebate Pricing.

Chapter Endnotes

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[9] EEI, *Delivering America's Energy Future,* 2017.

[10] EEI, *Industry Capital Expenditures,* 2017.

[11] EEI, *Industry Capital Expenditures,* 2017; Deloitte, *From growth to modernization*, 2016.

[12] EEI, *Delivering America's Energy Future,* 2017; EIA, "Investment in electricity transmission infrastructure shows steady increase," 2014; Deloitte, *From growth to modernization*, 2016.

[13] Deloitte, *From growth to modernization*, 2016.

[14] EEI, *Industry Capital Expenditures,* 2017; DOE, *Quadrennial Energy Review*, 2015.

[15] BNEF and BCSE, *2017 Sustainable Energy in America Factbook*, 2017.

[16] Expected 2014-2016 funding: $7.7 billion; actual: $9.6 billion. BNEF and BCSE, *Sustainable Energy in America*, 2015 and 2017.

[17] Electricity Advisory Committee, *Grid Modernization,* 2015; DOE, *SGIG Program Final Report,* 2016.

[18] NERC, *Real-Time Application of Synchrophasors for Improving Reliability*, 2010.

[19] NASPI, "Synchrophasors & The Grid," 2017.

[20] Boston, "PJM Implements the Advanced Control Center," 2013.

[21] DOE, *Distribution Automation*, 2016.

[22] "Big Data – Using Smart Grid to Improve Operation and Reliability", LaMargo Sweezer-Fischer, Florida Power and Light, presented at the IEEE Power and Energy Society Conference, Washington, DC, July 2014.

[23] Simms, "Duke Energy Production Experience with CVR," 2016.

[24] DOE, *Distribution Automation*, 2016; Estimates from a third-party evaluation by the Public Utilities Commission of Ohio: MetaVu, *Duke Energy Ohio Smart Grid Audit and Assessment*, 2011.

[25] EIA, "Electric power sales, revenue, and energy efficiency: Form EIA-861," 2016 data.

[26] EIA, "Electric power sales, revenue, and energy efficiency: Form EIA-861," 2016 data.

[27] BNEF and BCSE, 2018 Sustainable Energy in America Factbook, 2018.

[28] EIA, "Electric power sales, revenue, and energy efficiency: Form EIA-861," 2016 data.

[29] EIA, "Electric power sales, revenue, and energy efficiency: Form EIA-861," 2016 data.

[30] Analysis provided to DOE by Paul DeMartini, 2018.

[31] Analysis provided to DOE by Paul DeMartini, 2018.

[32] TXU Energy, "TXU Energy Enables Customers to Adjust Smart Thermostat," 2017.

[33] St. John, "100 Million US Homes Lack Smart Devices," 2017.

[34] Stubbe, "Consumers Getting Hot for Smart Thermostats," 2018.

[35] EIA, "Electric power sales, revenue, and energy efficiency: Form EIA-861," 2016 data.

[36] DOE, *AMI and Customer Systems*, 2016.

[37] DOE, Customer Acceptance, Retention, and Response, 2016.

[38] CPUC, "Decision on Residential Rate Reform," 2015.

[39] Sacramento Municipal Utility District, *SGIG Consumer Behavior Study,* 2013.

[40] DOE, *AMI and Customer Systems*, 2016.

[41] DOE, "Reducing Peak Demand to Defer Power Plant Construction in Oklahoma," n.d.

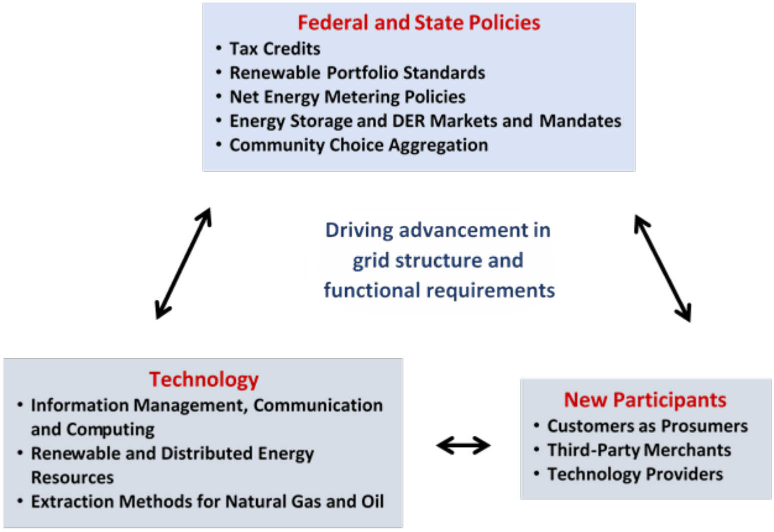
[42] DOE, *Customer Acceptance, Retention, and Response,* 2016.

V. Drivers of Grid Transformation

The electric grid has faced technological and institutional challenges throughout its history; however, we are currently facing a dramatic structural transformation. Three tightly interconnected forces are collectively driving grid transformation, imposing requirements for advanced functional capabilities, and ultimately shaping how individual utilities and states adopt and deploy smart grid technologies:

1. Federal, state, and local policies favoring the adoption of renewables and DERs and for enabling greater customer choice.
2. Advancements that are driving down the costs of information management, computing, and communication technologies, as well as for renewables and DERs, and offering new capabilities to utilities and customers, as a result.
3. The emergence of new participants, such as utility customers as prosumers,[o] energy service providers, and technology firms, in the management and generation of electricity and as providers of grid services.

FIGURE 16. FORCES INFLUENCING GRID MODERNIZATION



Utilities will continue to apply advances in information management, computing and communication technologies to improve grid reliability, resilience and efficiency. However, the advent of DERs, most notably PV over the past few years, introduces challenges (e.g., the bi-directional flow of power) the electric grid was never designed to accommodate. The increase in the uptake and mixture of DERs, combined with the fact that entities other than utilities will own them, introduces considerable variability and uncertainty in the supply and consumption of electricity over the broadest range of timescales (sub-seconds to years). This increased level

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[o] A customer that both consumes and produces electricity, enabled by the increased proliferation of home technology devices and distributed energy resources.

of complexity will require significant advances in smart grid systems and fundamentally change the way we conduct grid planning and operations, as well as incorporate market structures.

DERs are energy resources on the distribution grid that can generate electricity, store energy, or reduce or impact customer load. The National Association of Regulatory Utility Commissioners (NARUC) defines a DER as "a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE)."[43]

Figure 17 describes the various types of DERs and their characteristics with respect to how they interact with the grid (i.e., whether they consume, store, or deliver energy). Energy storage devices can interact in all of these ways.

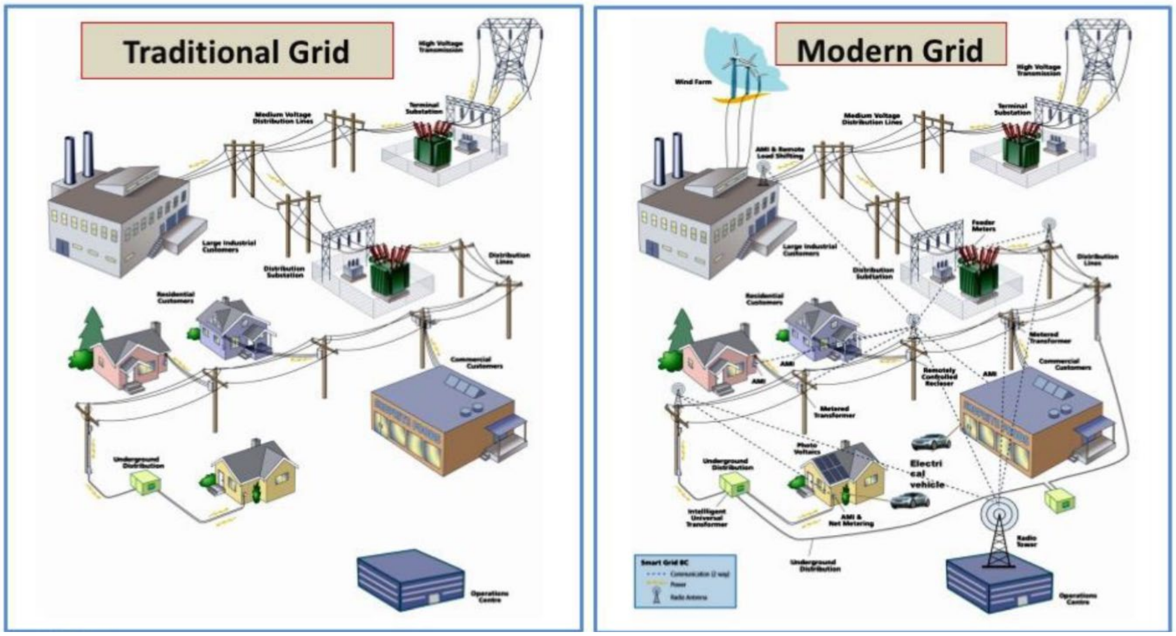
FIGURE 17: DER TYPES, OWNERS, AND GRID CHARACTERISTICS

DER Type	Primary Owner	Characteristics
Photovoltaic (PV) System	Utility, merchant, or customer	Provides electricity to customers, microgrids, and/or utility grids; power output depends on the intensity of solar irradiation
Energy storage system	Utility, merchant, or customer (aggregator may be involved)	Consumes, stores and delivers electricity to customers, microgrids, and/or utility grids; often used to enhance system flexibility
Combined-heat-and-power systems	Utility, merchant or customer	Provides district heating (steam) and electricity to customers, microgrids and/or utilities
Energy efficiency	Customer (sometimes aggregator involved)	Use of energy efficient technology to reduce electricity consumption; often promoted in utility programs
Demand response	Customer (often aggregator involved)	Often associated with utility programs where customers are compensated for reducing demand (load) during peak periods of electricity usage
Variable rates	Utility/customer	Utilities may impose variable rates to customers to incentivize behavior that reduces overall energy usage or demand during peak periods

DER Type	Primary Owner	Characteristics
Electric vehicles	Customer	Consumes electricity and methods for delivering electricity back to the grid are being investigated
Building energy management system	Customer	Optimizes energy use for the building owner
Microgrid	Utility, customer, or merchant	A grid system providing electricity services to a set of customers or buildings (e.g., a university campus); optimizes energy use within its domain, provides backup power, and offers energy or other services (e.g., frequency regulation) back to the utility grid

The manner in which they operate will depend upon their performance capabilities, as well as the operational objectives of their particular owners. As shown in Figure 18, the emergence of DERs and improved networking capabilities are pushing the evolution of the grid from one where centralized power is delivered in one direction to customers to a more integrated and distributed structure with the coordination of power flow, information, and services conducted across the domains of grid operators, customers, and service providers.

FIGURE 18. GRID TRANSFORMATION INTRODUCES COMPLEX RESOURCES

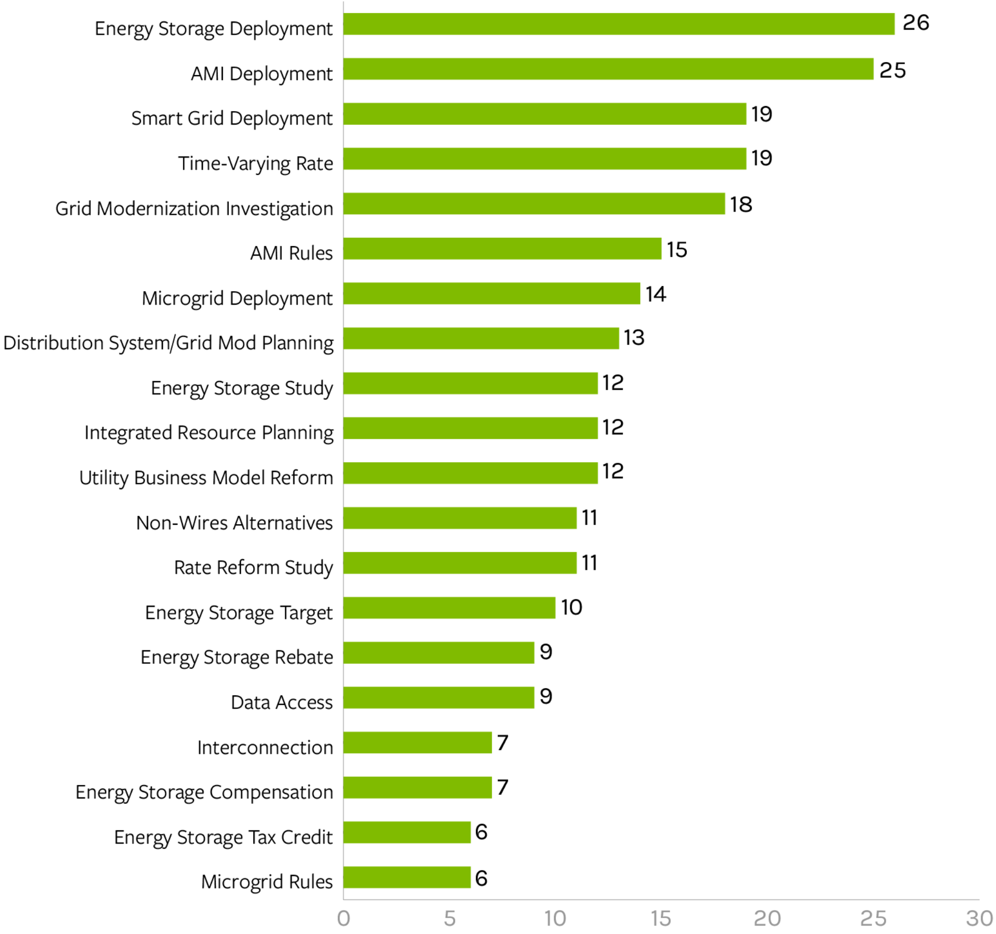


Source: IEEE, *Electric Power Grid Modernization Trends, Challenges, and Opportunities*, 2017.

The transformation to a more distributed future is not happening consistently across the country, but rather is occurring in a patchwork manner driven by favorable policies, patterns of customer adoption, and business practices influenced by increasingly affordable and mature technologies. Where these forces come together, the rate of technology uptake can be rapid and even outpace the ability of regulators and utilities to manage a smooth integration. As a result, holistic strategies for the deployment of advanced technologies are needed to effectively address the increased level of complexity. Smart grid technologies that offer increased visibility, more precise control, automation, and the computing power for fast data processing and decision-making will all be required to manage a grid with a high level of renewable and distributed resources.

Recent policies and deployment actions show the range of grid modernization activities at the state level, from technology deployment, to utility business model and rate forum, and DER integration and valuation strategies. In 2017, 39 states plus the District of Columbia (DC) took a total of 288 policy and deployment actions related to grid modernization (see Figure 19).[44]

FIGURE 19. TOP GRID MODERNIZATION ACTIONS OF 2017



Source: NC Clean Energy Technology Center, *50 States of Grid Modernization*, 2018. Chart refers to total actions, not total states for each action.

The remainder of this chapter presents the technology, policy, and participant forces that are driving grid transformation. Following this chapter, the remainder of the report discusses the issues that this grid transformation presents (Chapter VI) and approaches being undertaken to address them moving forward (Chapter VII).

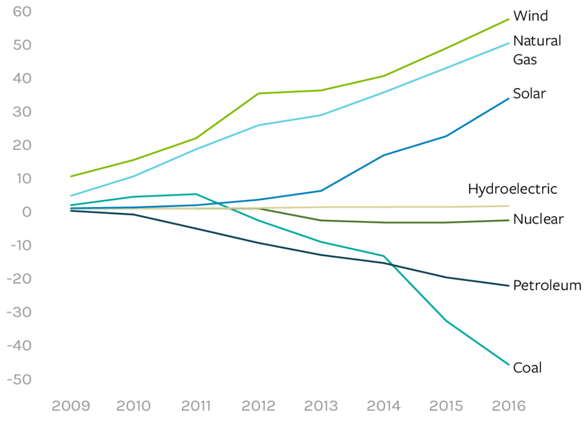
A. Evolving Energy Resource Mix: Gas and Renewable Energy Lead Capacity Additions

The last decade has seen a significant shift in the U.S. energy resource mix, with traditional fuel generation retirements that are largely replaced by natural gas, wind, and solar capacity additions (see Figure 20).

Improved natural gas extraction techniques have led to larger domestic gas resources and lower natural gas prices. Natural gas-fired power plants are also more efficient than other fossil fuels and offer more flexibility, able to ramp up in minutes during peak periods and to provide essential back up to intermittent wind and solar resources. Natural gas capacity additions continue to out-pace projections; on-peak natural-gas-fired capacity has increased 10% (447 GW) from 2009 levels (401 GW).[45] Between 2011 and 2015, 51 gigawatts (GW) of coal-fired capacity retired or converted to another energy source, and an additional 33 GW of retirements are planned between 2017 and 2027.[46]

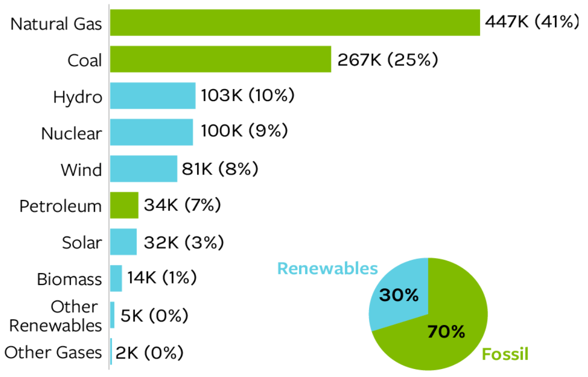
Meanwhile, declining installation costs, favorable policies and incentives, and corporate and public interest have triggered a rapid uptick in renewable energy deployments. U.S. renewable energy capacity (including hydropower and nuclear) has grown 33% since 2010, and now accounts for about 30% of total U.S. generation. Wind and solar together account for about 11% of U.S. generation (see Figure 21).[47]

FIGURE 20. CUMULATIVE NET CAPACITY GAIN (GW), 2009 - 2016



Source: EIA, "Electric power sales, revenue, and energy efficiency: Form EIA-861," 2016 data.

FIGURE 21. TOTAL ENERGY CAPACITY BY FUEL TYPE (MW), 2016



Source: EIA, "2016 Electric Power Annual, Table 4.2A and 4.2B."

Resources such as wind and solar—with production levels dependent on weather patterns—can introduce considerable variability in generation profiles, while customer-based generation can make demand curves more unpredictable. The result of this shift in resources is a complex mix of characteristics and constraints that affect everything from long-term planning to day-to-day operations and minute-by-minute control and coordination.

B. Rapid Rise of Utility-Scale and Distributed Solar

In under 10 years, solar photovoltaic (PV) systems have seen a near meteoric capacity growth of more than 2,900% (from 1,102 MW in 2010 to 32,954 MW in 2016). This swift rise was driven by maturing technologies, falling installation costs, favorable policies and incentives, and a growing demand—from individual customers to major corporations—for cleaner energy technologies and on-site generation. Solar PV installations range from large, utility-scale (greater than 1 MW) projects to smaller, distributed projects (less than 1 MW), which often consist of residential, commercial, and industrial rooftop projects.

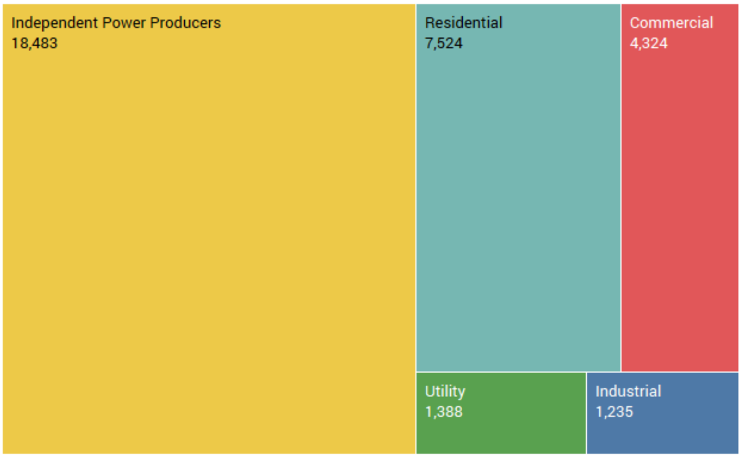
1. SOLAR TECHNOLOGY MATURITY AND AFFORDABILITY

The average solar installation cost—across utility and customer installations—fell 68% since 2010. Decreasing installation costs are a result of increased module efficiency, low-cost imported panels, and reduced profit margins in an increasingly competitive space. Module efficiency increased from 13.8% in 2010 to 17.5% in 2016; module power capacity increased 27.5% from 225 W in 2010 to 287 W in 2016.

Cost decreases and capacity additions were most pronounced for larger-scale installations (see Figure 23). The 80% cost reduction for utility-scale projects was especially pronounced, as costs fell from $4.78/W in 2010 to $0.97/W in 2017.[48] With the sharpest price decrease, utility-scale photovoltaic solar has also grown most significantly—from 393 MW in 2010 to over 20,192 MW in 2016—and more than quadrupled between 2013-2016 alone. About 50% of grid-scale capacity is owned and operated by independent power producers (see Figure 22).

While annual solar installations may drop slightly in 2017 and 2018 due to policy uncertainty, SEIA expects that cost improvements, policy incentives, and corporate demand will drive annual capacity additions near 16 gigawatts (GW) by 2022. If solar adoption continues apace, solar technologies will account for 5% of U.S. generation by 2022, up from 2% today.[49]

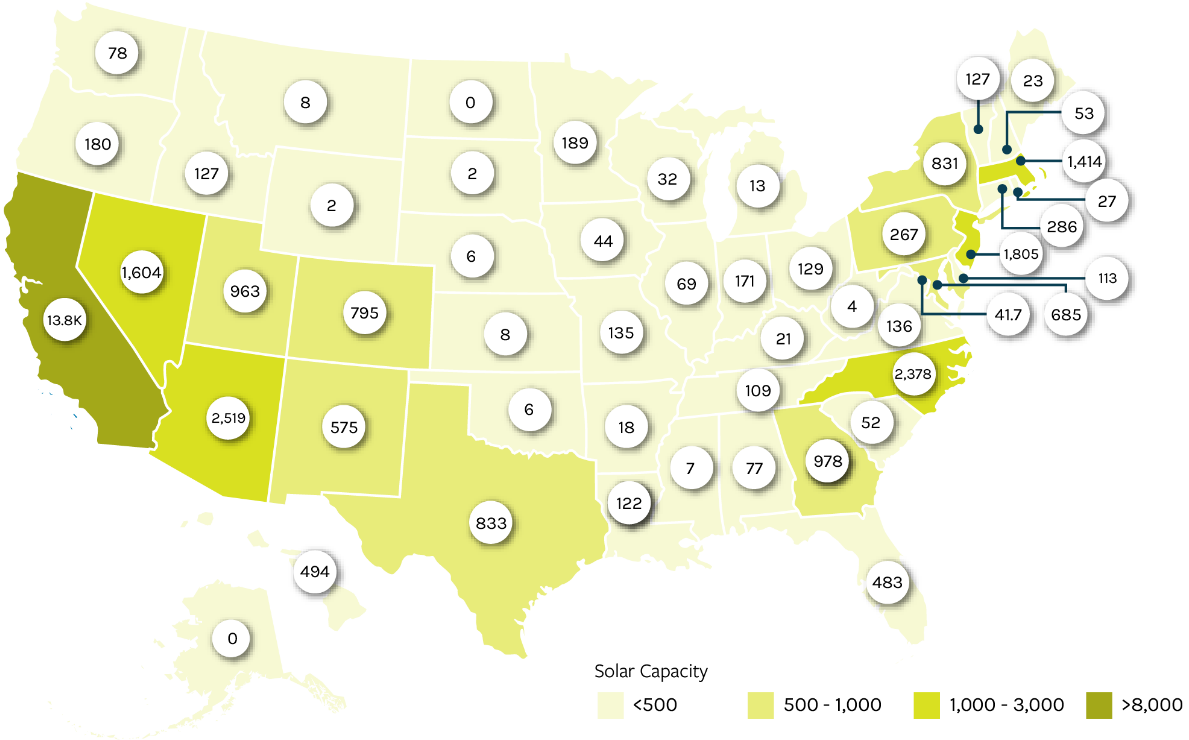
FIGURE 22. SOLAR CAPACITY BY SECTOR (MW), 2016



Source: EIA, *2016 Electric Power Annual*, Table 4.2B and 2016 EIA-861 Survey Data Files.

FIGURE 23. SOLAR CAPACITY AND COST DATA

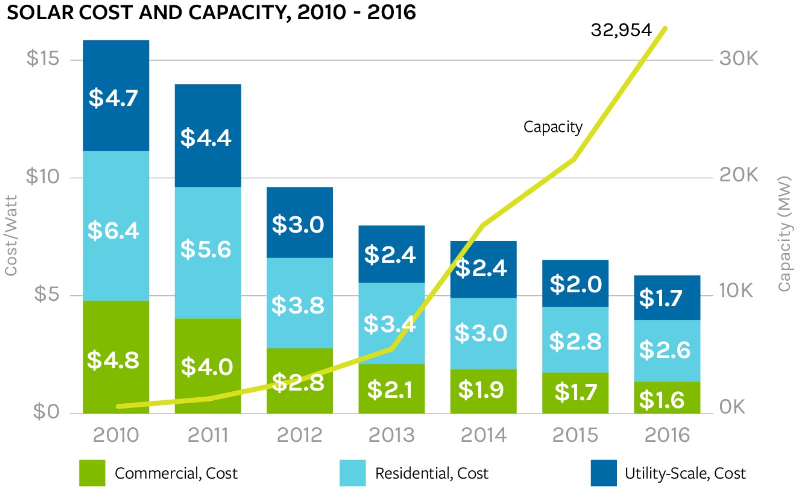
TOTAL SOLAR CAPACITY (32,954 MW), 2016



TOP TEN STATES BY SOLAR CAPACITY (MW), 2016

California	13,880
Arizona	2,519
North Carolina	2,378
New Jersey	1,805
Nevada	1,604
Massachusetts	1,414
Georgia	978
Utah	963
Texas	833
New York	831

SOLAR COST AND CAPACITY, 2010 - 2016



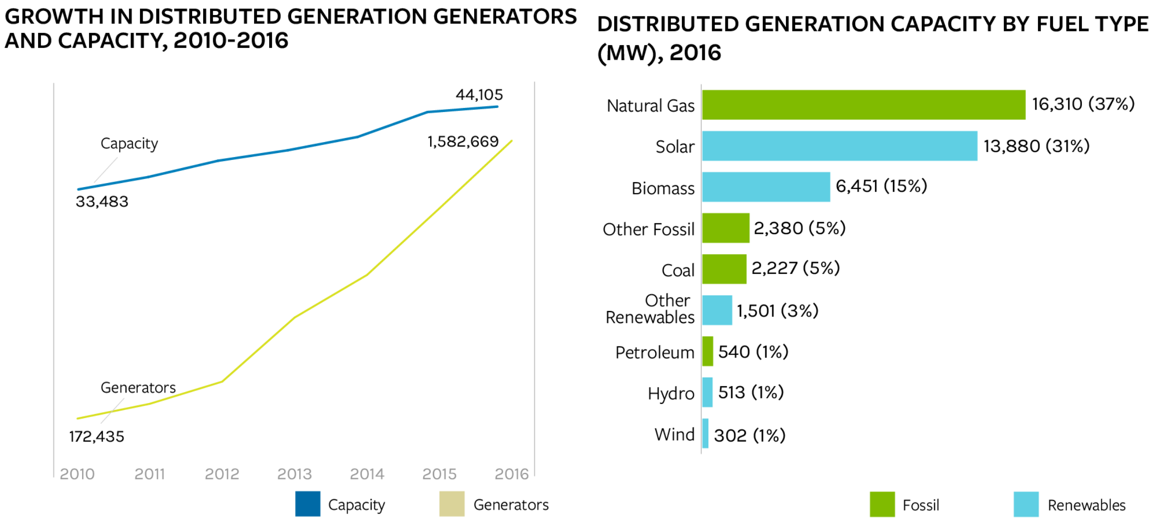
Residential: 3-10 kW; Commercial (rooftop systems, ballasted racking): 10 kW – 2 MW; Utility (ground-mount systems, fixed tilt): >2 MW Capacity. **Source**: Solar Cost – Fu et al. (for NREL), *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017,* 2017. Capacity Timeline and State Breakdown – EIA, February 2017 Electric Power Monthly," 2017.

Solar's biggest grid impact may come from smaller-scale installations, which introduce thousands or millions of new distribution-level endpoints that introduce two-way power flows and disrupt traditional energy market designs, as some customers can now buy *and* produce power. Distributed solar capacity alone grew by more than 687% (from 1,622 MW in 2010 to 12,765 MW in 2016),[50] making it the most rapidly expanding technology market.

Solar PV is the fastest growing type of small-scale distributed generation (DG). Figure 24 shows distributed generation capacity by fuel type, including both renewable resources and fossil-fuel-powered generators, which include combined heat and power at commercial and industrial facilities. Slightly less than half of distributed generators are fossil-fueled generators.[p]

While these small-scale systems often do not contribute significantly to capacity, they have introduced hundreds of thousands of new generation points into the distribution grid, which operators must safely integrate and manage. The number of individual distributed generators grew by 818%, from fewer than 200,000 units in 2010 to more than 1.5 million in 2016. This added complexity challenges current models for grid planning, operations, and markets.

FIGURE 24. DISTRIBUTED GENERATION CAPACITY DATA (ALL FUEL SOURCES)


GROWTH IN DISTRIBUTED GENERATION GENERATORS AND CAPACITY, 2010-2016

DISTRIBUTED GENERATION CAPACITY BY FUEL TYPE (MW), 2016

Sources: EIA, "Form EIA-861," 2016 data; EIA, "Form EIA-860," 2016 data.

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[p] Figure 24 considers distributed generation to include the following types, as reported to EIA by power industry entities on Forms 860 and 861: net-metered generators (Form 861), non-net-metered generators (less than 1 MW; Form 861); and generators directly serving commercial or industrial facilities, including combined heat and power (CHP) facilities (Form 860).

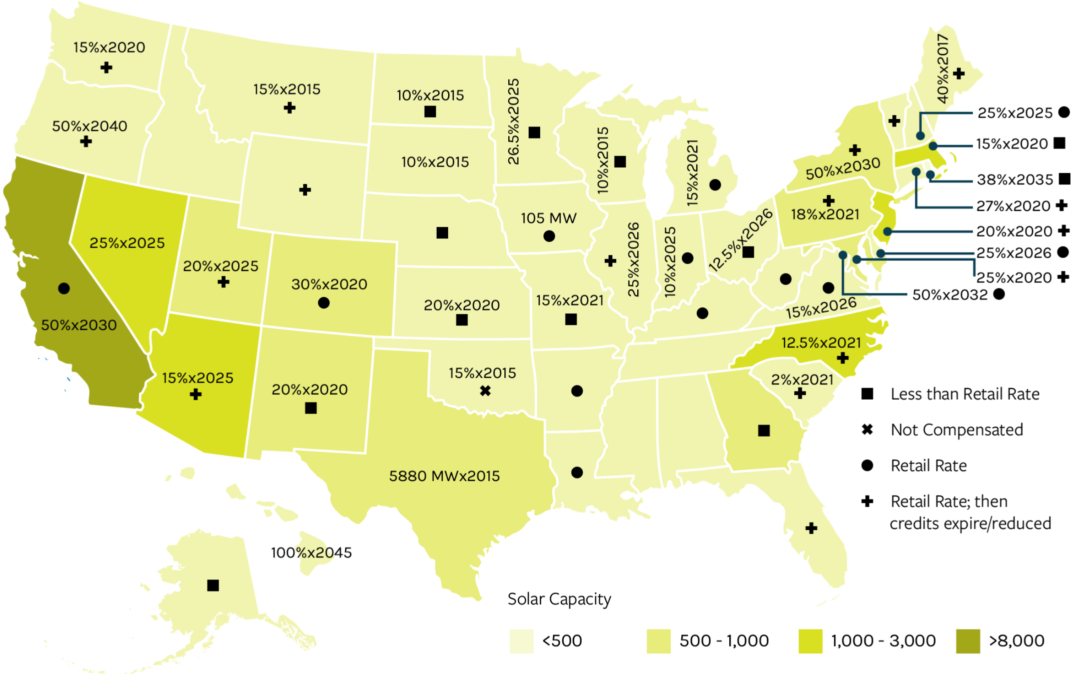
2. POLICIES AND INCENTIVES DRIVING SOLAR UPTAKE

Policies and incentives at the federal, state, and local levels are favoring the adoption of renewable energy generation at the bulk and distribution system levels. These include renewable portfolio standards, energy efficiency targets, incentives and tax credits for renewable technologies, net energy metering rules, and community solar policies.

Renewable portfolio standards (RPS) are state-level regulations that mandate a target percentage of electricity production must come from renewable resources by a certain date. State legislatures typically establish these standards, and public utility commissions (PUCs) generally translate them into rules that govern what percentage of power electricity utilities must purchase from renewable sources.[51]

As of February 2017, 29 states and DC have a renewable portfolio standard, while another 8 states have voluntary renewable portfolio goals (see Figure 25). RPS vary greatly by state, and many states have more modest near-term targets over the next decade and stretch targets in the decades beyond. Hawaii, for example, recently mandated 100% renewables by 2045, with interim targets of 30% by 2020 and 70% by 2040.

FIGURE 25. STATE-LEVEL RPS AND NEM RULES AND INSTALLED SOLAR PV CAPACITY (2016)



Source: RPS - DSIRE, *Renewable Portfolio Standard Policies,* 2017; NEM - DSIRE, *Net Metering,* 2017; Solar Capacity – SEIA, "Solar State by State," 2017.

In addition, 26 U.S. states have established **energy efficiency resource standards (EERS)**, which are binding, long-term (typically 3+ year) targets for utilities or program administrators to improve energy efficiency, and may be coupled with a state's RPS. Utilities can meet targets through more efficient generation as well as energy-efficiency and demand-side management programs, such as time-based rates and demand response.[52]

State and federal renewable energy tax credits offer residential, commercial, and industrial customers attractive capital incentives to develop renewable energy projects. The federal Business Energy Investment Tax Credit (ITC) provides a 30% tax credit for solar, fuel cell, and some wind installations. The credit drops to 26% in 2020, 22% in 2021, and sunsets at 10% in 2022. The Renewable Electricity Production Tax Credit (PTC) offers a 10-year, per-kWh credit for wind and other renewable systems; the PTC expires December 31, 2019, for wind technologies, and expired in 2017 for all other technologies.

Net energy metering (NEM) rules define how customers are credited for the electricity they generate and may require utilities to buy any excess electricity customers add back to the grid. In several states, these credits helped to tip the economic scale in favor of onsite solar, particularly as customer installation costs fell quickly over the last five years. However, several states have revised, eliminated, or are reviewing their NEM rules as DER adoption rises to avoid cross-subsidization.

Most states have traditionally compensated customers at the full retail rate—the same rate they pay the utility per kWh of electricity—resulting in very low or even zeroed-out bills for some customers. As a result, some argue that customers with PV may not fairly pay for fixed infrastructure costs, leaving non-PV customers to take on a larger share of those costs. Others argue that distributed PV increases societal and system benefits at an equal or higher rate than the NEM credits. [53] Many states are reviewing NEM rules, and in several states, PUCs have removed or revised NEM rules so that they credit customers below the retail rate and/or create a minimum monthly service charge for PV customers.

As of 2017, 38 states plus DC enforce mandatory NEM rules, down from 43 states plus DC in 2010 (see Figure 25).[q][54] More than 1.4 million U.S. customers now participate in net energy metering—an almost five-fold increase from 2010—with installations totaling more than 13.5 MW in generating capacity nationwide.[55]

Communities and cities are increasingly seeking energy options to address economic development and environmental and resiliency objectives. In certain states, individuals can form a non-profit group, known as a **Community Choice Aggregator**, to secure renewable electricity contracts on behalf of a community. Legislated in seven states[r], community choice aggregation (CCA) is a powerful tool to drive growth in renewable energy; aggregators can procure clean power from the open market and/or partner with community solar subscriber organizations. In 2013, CCAs procured over 9 million MWh of renewable generation for approximately 2.4 million customers.[56]

The **community solar model** is another method of leveraging multiple customer accounts for energy procurement. Community solar policies are driving distributed PV adoption by

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[q] Six states (Utah, Arizona, Georgia, Indiana, Maine, and Hawaii) no longer enforce mandatory NEM rules; one state (South Carolina) has added mandatory NEM rules since 2010.

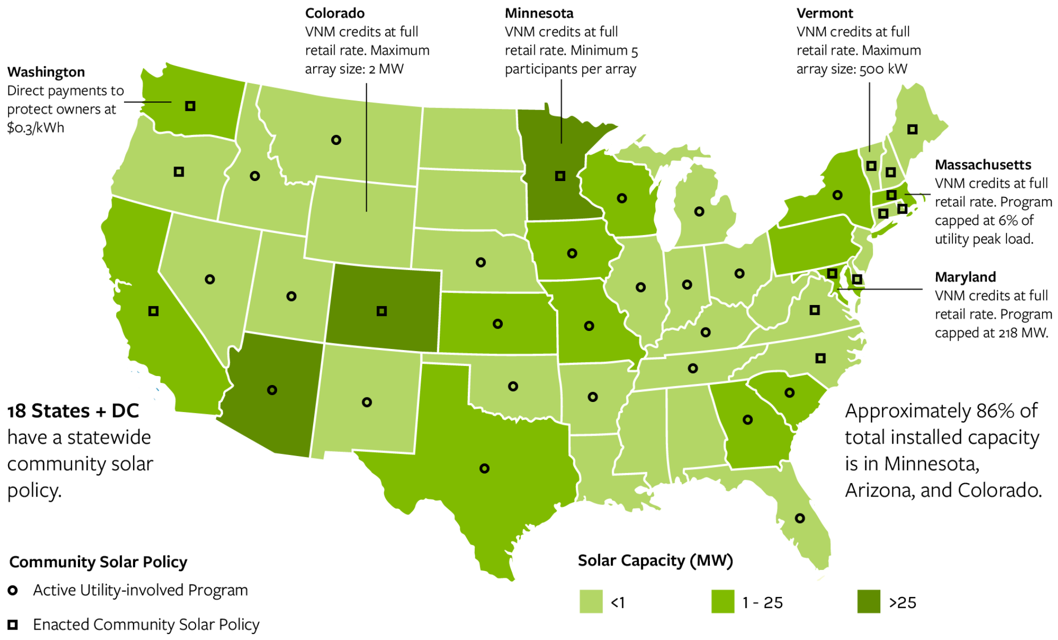
[r] Massachusetts, New York, Ohio, California, New Jersey, Rhode Island, and Illinois passed CCA laws in the late 1990s and early 2000s.

providing solar access to a large pool of customers not suitable for onsite PV use. A community solar project is a shared solar PV array. Participants either pay for a share of the project or subscribe to a portion of its electricity output, which flows directly into the distribution grid. In exchange, the participant's share of the electricity generated is compensated, typically through a credit to their electricity bill, much like NEM. Utilities, businesses, local governments, and community groups can host community solar projects anywhere from public buildings to private land.

A recent study found that almost half of all U.S. households are currently unable to host a rooftop solar system.[57] By reaching those customers, it is estimated that community solar could compose 32% to 49% of the distributed solar market by 2020, while attracting up to $16.3 billion in investment.[58] Annual community solar installations have increased 410% since 2010, with present total installed capacity close to 800 MW.[59]

Policies vary by state, but most enable bill crediting through virtual net metering, an innovative policy that allows participants to deduct a credit from their own electricity bill based on the electricity generated by their portion of the community solar array (see Figure 26). The ability to develop shared solar projects may be inhibited or prohibited if the state regulations do not allow for virtual net metering.

FIGURE 26 – STATES WITH COMMUNITY SOLAR PROGRAMS AND POLICIES



Source: Capacity – Community Solar Hub, "Community Solar Project Map;" Carey et al. *Community solar: Share the sun rooflessly.* 2017. Policy – 50 States of Solar Report, October 2017. Program details are examples, not comprehensive.

Some states, including California, Delaware, Minnesota, Maine, Massachusetts, New Hampshire, and Vermont, have specifically allowed for virtual net metering through legislation.[60] Other state policies may define the size of projects, along with how many and who can participate.

C. Energy Storage Technologies in the DER Mix

Energy storage technologies can consume, store, and deliver power, providing a flexible resource unlike other classes of DER technologies. They can provide emergency back-up power, frequency response, and generation capacity, and help balance highly variable electricity supply and demand. For these reasons, storage has long been an attractive resource to support grid operations, but high cost has been a severe limiting factor until recent years. Lithium-ion batteries have dominated new energy storage projects since 2011 because of rapidly declining costs. Other types of energy storage technologies, such as flow batteries, are also becoming more economically feasible and finding commercial applicability.

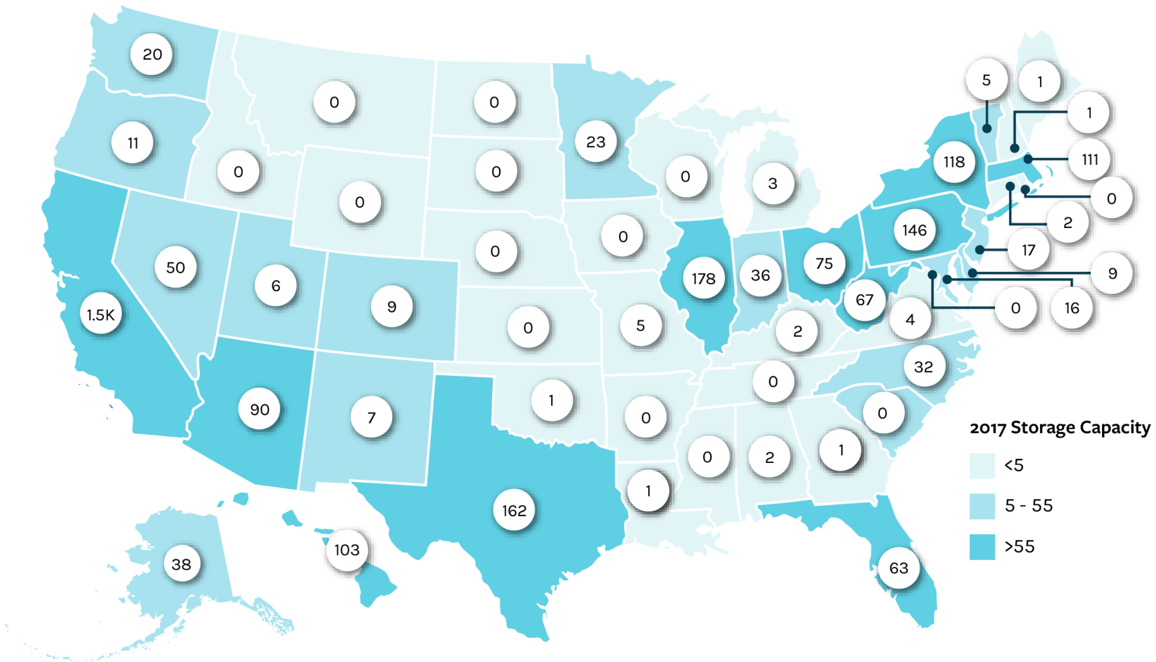
Due largely to rapidly declining battery costs and state incentives, utilities interconnected about 207 MW of grid-tied battery storage in 2016 across 829 new installations. Residential deployments accounted for about 4.5 MW; non-residential accounted for about 54 MW; and utility-scale accounted for about 151 MW of these additions. Total installed battery storage nationwide is now 541 MW (as of December 31, 2016).[61]

While costs are still relatively high, the business case for storage is stronger where it can be used for multiple applications. With rising solar deployments, particularly in the distribution grid, battery storage technologies are even more attractive for their ability to smooth out generation variability by storing electricity during times of overgeneration and dispatching it when needed for grid support. In addition, battery storage technologies have the ability to ramp up quickly to respond to frequency regulation needs for short-duration events.

Energy storage mandates or incentives are relatively new, and aim at driving adoption as costs rapidly decrease. Massachusetts and Oregon have energy storage mandates, while at least five other states have energy storage incentives or investment programs (see Figure 27). California leads the nation with an aggressive mandate requiring utilities to add 1.3 GW by 2019, as well as a self-generation incentive program which provides more than $420 million through 2019 to support development of residential storage projects. Some solar customers in states like Arizona, Nevada, and Hawaii that no longer receive full retail rate for excess generation are turning to battery storage to better utilize their solar systems.

Wholesale market rules can also drive utility storage deployments. California and PJM are among the organized markets that facilitate storage participation through energy, ancillary, and capacity market participation models. Roughly three-quarters of non-hydro utility deployments to date are concentrated in these regions. In February 2018, FERC issued Order 841 that proposed to remove barriers that prevent electric storage resources from participating in organized wholesale electricity markets.

FIGURE 27. ENERGY STORAGE CAPACITY AND INSTALLATIONS



Oregon Mandate
2015-enacted HB 2193 utilities to each have a minimum 5 MWh of energy storage by 1/2020

California Mandate
2 GW x 2020

California Incentive
$166 million annual budget for SGIP through 2020 for storage and other technologies

Nevada Incentive
2017-enacted SB 1045 mandates the PUC to establish energy storage incentives

Maryland Incentive
30% tax credit for energy storage systems

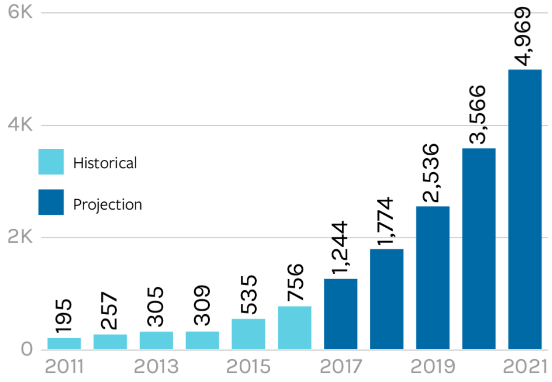
Arizona Mandate
3 GW x 2020

Massachusetts Mandate
3 GW x 2020

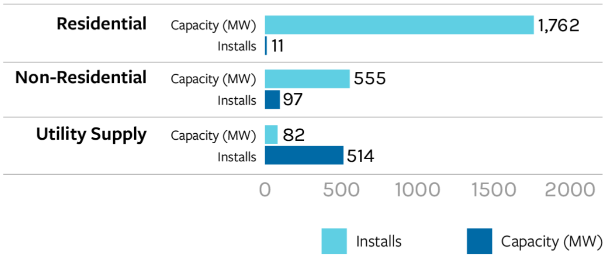
New York Mandate
1.5 GW x 2020

New Jersey Incentive
$300 per kwH for storage projects connected to a renewable project ($300K or 30% of project cost limit)

HISTORICAL AND PROJECTED ENERGY STORAGE CAPACITY (MW)



CUMULATIVE ENERGY STORAGE CAPACITY AND INSTALLATIONS BY MARKET SEGMENT, 2016



Source: Cumulative storage capacity and installs, mandates, and incentives – Chew et al., *2017 Utility Energy Storage Market Snapshot,* 2017. State-level capacity – Frith et al., *Energy Storage Market Outlook, 2018.* Historical and Projected Energy Storage Capacity – GTM, *Energy Storage Monitor, 2017.*

Please note the discrepancy between the storage map, historical and projected capacity, and market segment breakdown. The map is sourced from a 2018 Bloomberg Report and provides the most up-to-date storage capacities; the market breakdown is sourced from a 2017 SEPA report; the historical and projected energy is sourced from GTM. The discrepancies can be attributed to data collection methodology and years analyzed. Nevertheless, the graphs bring attention to key storage markets, scale of projected growth, and market demarcation.

D. Rising Electric Vehicle Adoption Impacts Distribution Load

Improved battery technologies also continue to drive EV manufacturing costs lower, encouraging more auto manufacturers to enter the EV market and develop competitive models. Since 2010, prices for lithium-ion battery packs have decreased 73% while their energy density has doubled—allowing EVs to travel further on a single charge.[62] Large-scale manufacturing of EV batteries has improved economies of scale and driven costs down, with some manufacturers striving to bring prices well below DOE's target price of $125 per kWh.[63]

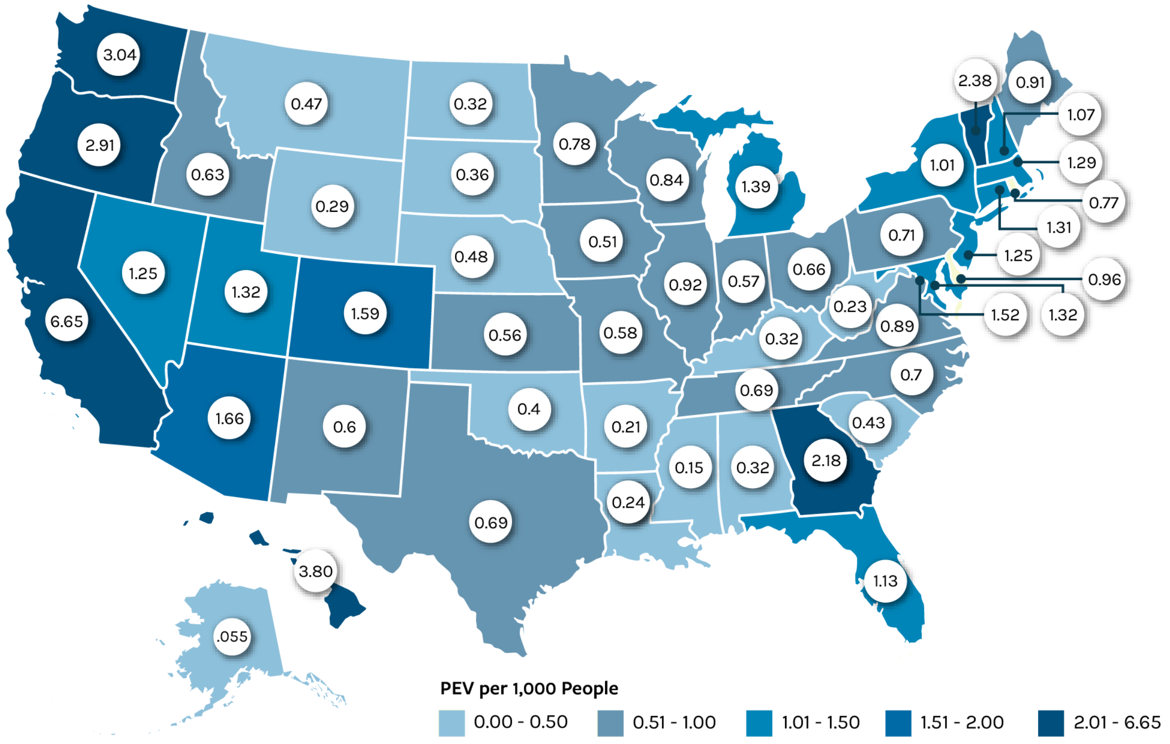
By 2016, there were nearly 700,000 EVs on U.S. roads, compared to 30,000 in 2011, a growth rate of 87%.[64] Nearly 10 million EVs are expected on U.S. roads by 2025.[65] Increasing competitiveness has improved customer choice and increased sales. In 2011, there were only four reported models of PEVs available, with annual sales below 18,000. By 2016, the number of models more than quadrupled, with annual sales at nearly 150,000 units across more than 20 models. [66]

Federal and state incentives, gasoline prices, and an increasing number of EV charging stations have also driven customer adoption. All-electric and plug-in hybrid cars purchased after 2010 are eligible for a federal income tax credit of up to $7,500. State-level incentives may include tax credits and rebates; sales and use tax exemptions; reduced license, registration, or title fees; and non-financial incentives, like use of HOV lanes or special parking permits.

EVs are forecasted to account for more than 35% of the U.S. car fleet by 2050, with battery electric vehicles (BEVs) accounting for more than 80% of the EV market. The rise in EV deployment may significantly increase electricity demand during peak charging times, particularly where concentrations are high (see Figure 28). **High adoption of EVs can both create and alleviate operational challenges.** EV owners may be able to help balance supply and demand simply by charging during periods of heavy solar generation, which can alleviate the risk of overgeneration in regions with high solar adoption, like Hawaii and California. [67] The California Public Utilities Commission found that by offering time-of-use rates, utilities were successful in encouraging customers to shift EV charging times to off-peak hours, when electricity costs were lower.[68] In the future, EVs may also be able to reduce peak demand by temporarily discharging power back to the grid—much like energy storage—when the car is plugged in but not in use.

FIGURE 28. ELECTRIC VEHICLE ADOPTION AND INCENTIVES

PEV REGISTRATIONS PER 1,000 PEOPLE BY STATE



PEV REGISTRATIONS PER 1,000 PEOPLE BY STATE

California	6.65
Hawaii	3.80
Washington	3.04
Oregon	2.91
Vermont	2.38
Georgia	2.18
Arizona	1.66
Colorado	1.59
District of Columbia	1.52
Michigan	1.39

INCENTIVES FOR EV PURCHASE BY STATE

Rebate	California	2,500
	Connecticut	3,000
	Delaware	3,500
	Massachusetts	2,500
	New York	2,000
	Oregon	750
	Pennsylvania	1,750
Tax Credit	Colorado	5,000
	Louisana	2,500
	Maryland	3,000

Source: PEV Registrations – Ayre, "Top State in US for Electric Vehicle Concentrations – California," 2017. EV Incentives – Tesla, "Vehicle Incentives," 2018.[s]

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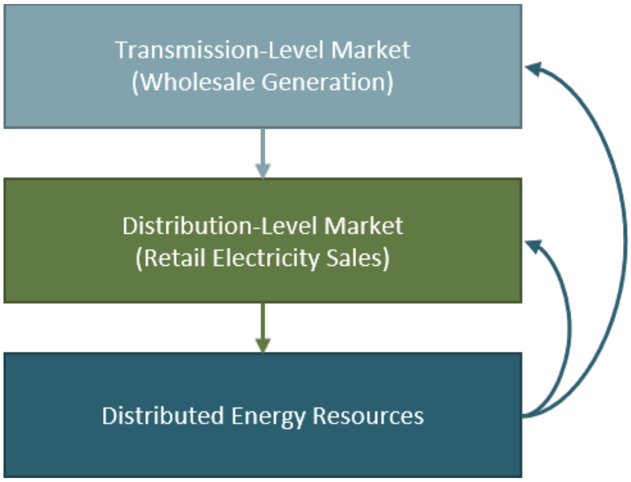
[s] Please note the "Incentives for EV Purchase by State" has caveats regarding income levels and cost of vehicles.
Income level restrictions: California.
Vehicle cost restrictions: Connecticut; Delaware; Maryland; Maryland; New York; Pennsylvania.

E. Capturing DER Value in Transmission and Distribution Markets

Wholesale electric markets exist for certain types of DERs, yet are evolving to capture their potential value. Distribution level markets are now being explored and emerging through efforts in New York and other states. Regulators, utilities, and legislators are examining how to develop market-based structures that appropriately price the services that DERs provide to the power system, leading to grid modernization strategies that maximizes their potential for grid capacity, flexibility, and operational support. As DERs effectively play into these markets, grid planners and operators will need to effectively coordinate across the transmission-distribution interface to determine how they are dispatched to ensure reliable grid operations. Capturing this value requires advanced control capabilities and improved analytical techniques for forecasting the rate of DER adoption, assessing the ability of distribution grids to host DERs, and determining the locational benefits that DERs provide.

FIGURE 29. INCREASING MARKET COMPLEXITY



Wholesale electric market operators began using demand response about 15 years ago; regulators today are working to make wholesale markets more efficient for integrating new types of DERs. Transmission market maturity for DERs as non-wires alternatives (NWA), such as demand response and energy storage, varies depending on the transmission system operator.[69]

In November 2016, FERC issued a notice of proposed rulemaking (NOPR) that proposed to remove barriers that prevent electric storage resources and DER aggregators from participating in organized wholesale electricity markets. In the NOPR, FERC preliminarily found that resource participation in organized wholesale electric markets is often governed by market rules that (1) do not recognize the physical and operational characteristics of electric storage resources and (2) limit the opportunities for DER aggregation to participate. For example, the Midcontinent Independent System Operator's (MISO) capacity market limits participation to resources that can sustain output for four consecutive hours each day, which could exclude energy storage resources that do not meet these requirements. The NOPR proposed to allow electric storage resources to de-rate their capacity to allow them to meet such minimum run times.

In February 2018, after considering comments on the NOPR, FERC issued Order 841 to remove barriers to participation of electric storage resources in the RTO and ISO markets.[t] It directs RTOs and ISOs to develop wholesale market rules that (1) ensure a storage resource is eligible to provide all the services it is technically capable of providing; (2) ensure storage can be dispatched and set wholesale clearing prices as both a buyer and a seller; (3) account for the physical and operational characteristics of electric storage resources through bidding parameters or other means; (4) establish a minimum participation size for electric storage resources that does not exceed 100 kW; and (5) ensure that the sale of electric energy from the RTO and ISO markets to an electric storage resource that the resource then resells back to those markets is at the wholesale price.

While the 2016 NOPR also proposed revising organized wholesale electric market participation models to include DER aggregation, FERC determined more information is still needed. It opened a new rulemaking proceeding RM18-9-000 in February 2018 to continue reviewing the DER aggregation proposals in the November 2016 NOPR.

States are actively examining the development of distribution system level markets for DERs through analyses that examine the locational value they can provide. Avoiding costly transmission and distribution upgrades presents the largest potential value stream. California, Hawaii, Minnesota, and New York have begun considering the use of DER as an alternative to long-term costs associated with retail level "wires" investments. An example is the Brooklyn-Queens project in New York City where Consolidated Edison (ConEdison) is procuring demand response services from local merchants to avoid costly capacity upgrades. ConEdison deferred $1.2 billion in substation improvements by investing $200 million on customer-side and non-traditional utility-side solutions in the Brooklyn-Queens region to shave 52 MW off peak demand.[70] As DERs are examined for their value as non-wires alternatives, distribution system level markets may expand to include services providing voltage and frequency control and real-time operational flexibility where grid dynamics are particularly fast.

F. Increasing Customer Participation and Evolving Utility Business Models

Residential, commercial, and industrial customers are seeking greater control over their energy supply, and becoming active market players in the process. These factors are changing the traditional roles of distribution utilities, raising questions about future business models for grid investment and cost recovery.

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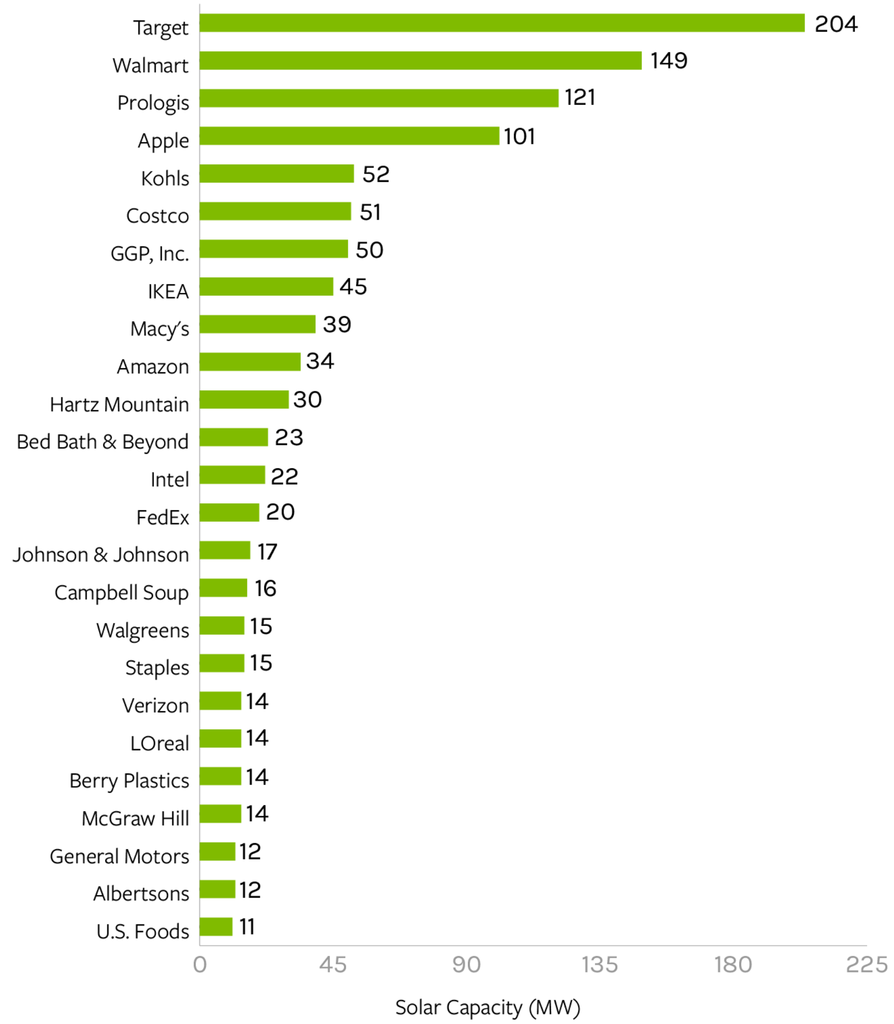
[t] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 841, 162 FERC ¶ 61,127 (2018).

Customers Leading Renewable and Distributed Energy Adoption

More than 1 million homeowners now have solar PV, and 90% of those installations have come online since 2010.[71] Growing solar adoption has increased the number of net metering solar participants from just under 198,255 in 2011 to almost 1,321,277 in 2017.[72] Commercial and industrial businesses in particular are leading renewable and distributed energy adoption to save money, improve their energy independence, and appeal to customers. In 2016, 71 Fortune 100 companies had set renewable energy or sustainability targets – up from 60 two years before.[73] A total of 22 Fortune 500 companies have embraced 100% green energy goals. With their high energy use and access to capital, corporations can support financing for new renewable energy projects of significant size (see Figure 30).

Walmart is a prime example. Since announcing a 100% renewable energy target in 2005, Walmart has been installing solar panels on its stores' rooftops to save money and promote its environmental sustainability policy. The company is recognized as a leading corporate installer of solar power; in fact, it now has more solar capacity than 39 individual states and the District of Columbia.[74] In less than a decade, the company aims to double its current renewable energy consumption to 50% by 2025.[75]

FIGURE 30. TOP 25 COMPANIES BY SOLAR CAPACITY, 2017



Source: SEIA, *Solar Means Business*, 2018 (2017 data).

Customer Participation on Open Markets

Several major corporations have also reached agreements to purchase renewable power directly from open markets, rather than from their distribution utility, while continuing to use distribution services. These changes are disrupting existing transmission and distribution energy and capacity markets, driving regulatory and market evolution to permit new participation models and effectively value and integrate DERs.

In July 2017, Microsoft reached an agreement with Puget Sound Energy (PSE) allowing the company to buy its own power from renewable sources on the open market. The move was facilitated by a tariff created by PSE in 2016 allowing large industrial or commercial customers to acquire energy from suppliers on the open market, and Microsoft will pay a transition fee of $23.6 million.

This followed a trend of casinos that received approval to buy cleaner or cheaper electricity on the open market. In one of the largest defections from an American utility by a commercial customer, MGM Resorts International stopped purchasing electricity from Nevada Power in 2016.[76] Accounting for almost 5% of the utility's power sales, MGM agreed to pay an $87 million exit fee that compensates the utility for investments made to serve their disproportionate load. Other Las Vegas casinos have subsequently followed suit—Wynn and Caesars now purchase electricity directly from Exelon and Tenaska respectively.[77]

This trend raises questions over how utility business models will evolve, allowing utilities to recover investments in distribution delivery and control infrastructure as they shift roles from an electricity provider to a system coordinator.[u]

Emergent Cost Recovery and Business Model Challenges

Utility cost recovery will become more complex as more and more market players use and depend on a reliable energy delivery infrastructure, while purchasing less and less energy directly from the utility. Traditionally, utilities build and maintain the distribution grid to achieve high reliability, and recover those costs through service charges built into rates. While transmission and distribution costs continue to rise, electricity load has remained largely flat within the last decade (see Figure 31), compared to nearly a century of steady load growth.

This is due to a combination of factors, including commercial and industrial energy efficiency improvements, manufacturing outsourcing and efficiencies, and growing onsite customer generation that decreases utility revenues.[78] According to Bloomberg, U.S. investment in energy efficiency doubled from 2008 to 2015, with spending levels reaching $12 billion in 2015.[79]

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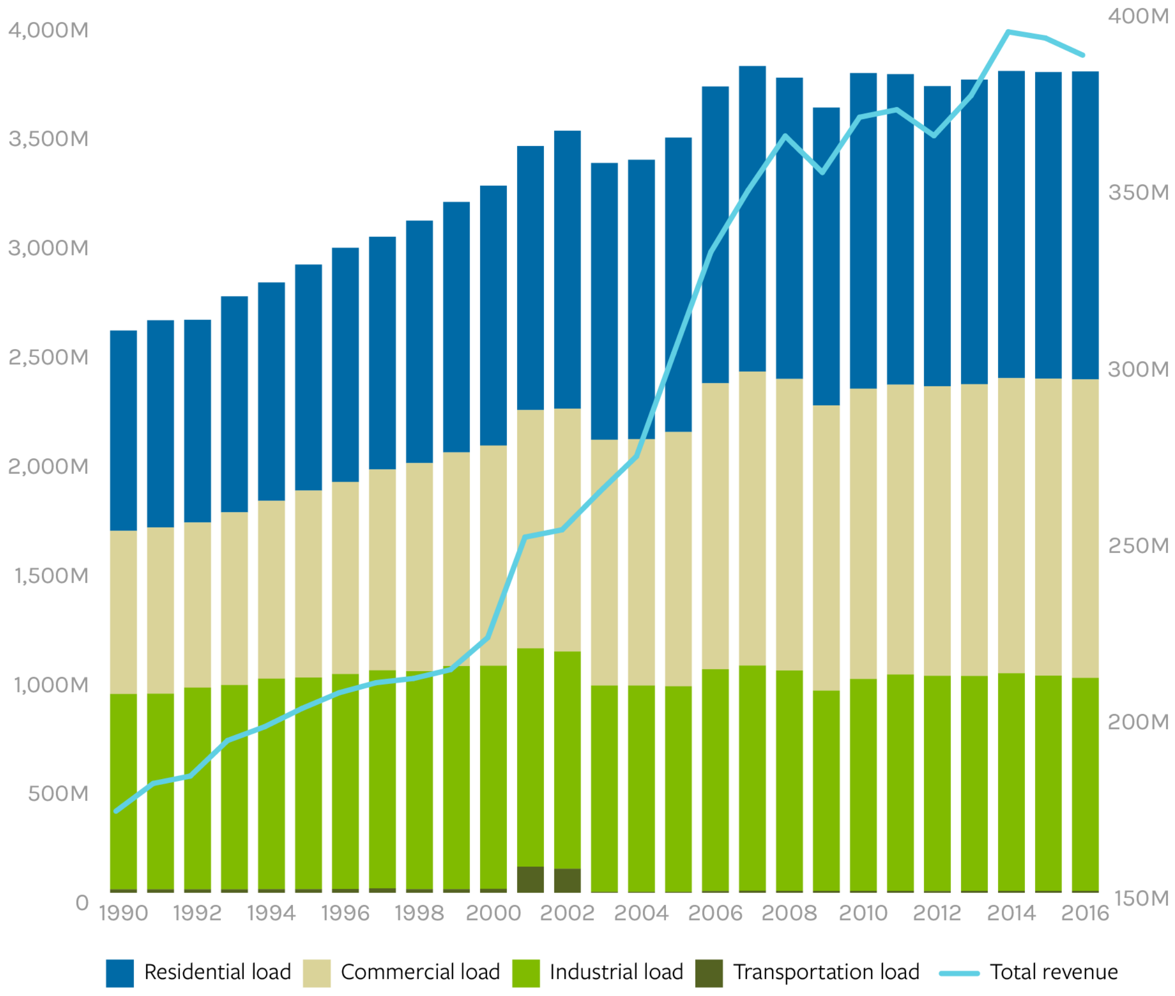
[u] Utilities assume the role of coordinating transactions between multiple energy providers and energy consumers.

FIGURE 31. ELECTRICITY LOAD VS. REVENUE, 1990-2016



Source: EIA, "Electric power sales, revenue, and energy efficiency: Form EIA-861," 2016 data. Prior to 2003, sales of electric power transportation (e.g., city subway systems) were included in "Other Sector," but were combined in certain graphics with "Transportation." After 2003, the "Other" Sector was reclassified as Commercial Sector sales. Transportation sector now includes railroads, and roadways, and city subways systems.

Revenue levels are heavily impacted by both retail electricity prices and load. Average electricity prices have remained generally even over the last decade, when accounting for the rate of inflation. This, combined with flat load growth, has decreased revenues, even as the cost of building and maintaining the infrastructure continues to rise. Though power generation costs for most utilities have decreased by 15% since 2006, electricity delivery costs have increased—in 2016 dollars—from 2.2 cents/kWh to 3.2 cents/kWh, offsetting savings from power generation.[80]

Chapter Endnotes

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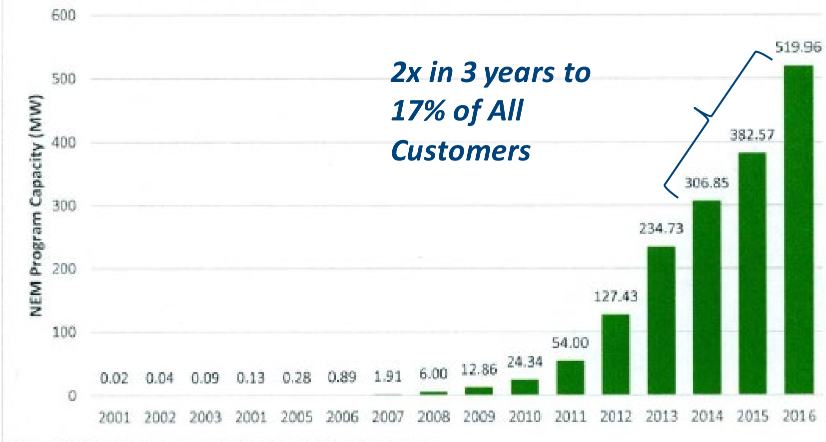
VI. Grid Impacts and Issues

A steady-state condition, where both electricity generation and customer load were fairly predictable over time, has historically supported deterministic approaches for grid planning and operational engineering. As discussed previously, advances in several technological areas are driving the deployment of variable renewable generation and a diverse set of distributed resources at the grid edge. This includes new technologies and related services for electricity customers to manage energy and commercial opportunities for service providers and technology firms. These factors have introduced significant levels of variability and uncertainty in both generation and load profiles and, with this greater complexity, present needs for new grid structures and functional capabilities.

The rate of grid transformation depends upon several factors that differ according to state jurisdiction and region. When top-down drivers (e.g., federal and state policies) combine with bottom-up drivers (e.g., the adoption of technology by customers), the rate can be quick and even outpace the ability of utility and regulatory decision-makers to manage the integration of distributed assets into grid operations. For example, Hawaii witnessed a doubling of PV adoption over the 3-year period from 2013 through 2016 due to the convergence of attractive prices, the commercial availability of PV systems and the state's net energy metering policies (see Figure 32).[81]

FIGURE 32. GROWTH IN HECO CUSTOMERS PARTICIPATING IN NET ENERGY METERING



Note: 2016 total includes approved but not yet installed capacity

Source: Hawaii Public Utilities Commission, Docket No. 2017-0226, 2018.

As shown in Figure 33, the high penetration rate on some distribution feeders in Hawaii caused voltage levels to rise or drop beyond the permissible range due to the effect of electricity flowing back into the grid from customer-owned-PV.[82] Electric grids were not originally designed to accommodate such bi-directional flow which can pose thermal, safety and system protection issues. As a result, the Hawaii Public Utilities Commission revised its NEMs program and is working with the Hawaiian Electric Companies (HECO) to undertake a more holistic approach to DER integration.[83]

FIGURE 33. CUSTOMER-OWNED PV VOLTAGE LEVELS AT HECO

Source: Hawaiian Electric Companies

Image provided courtesy of Hawaiian Electric Companies

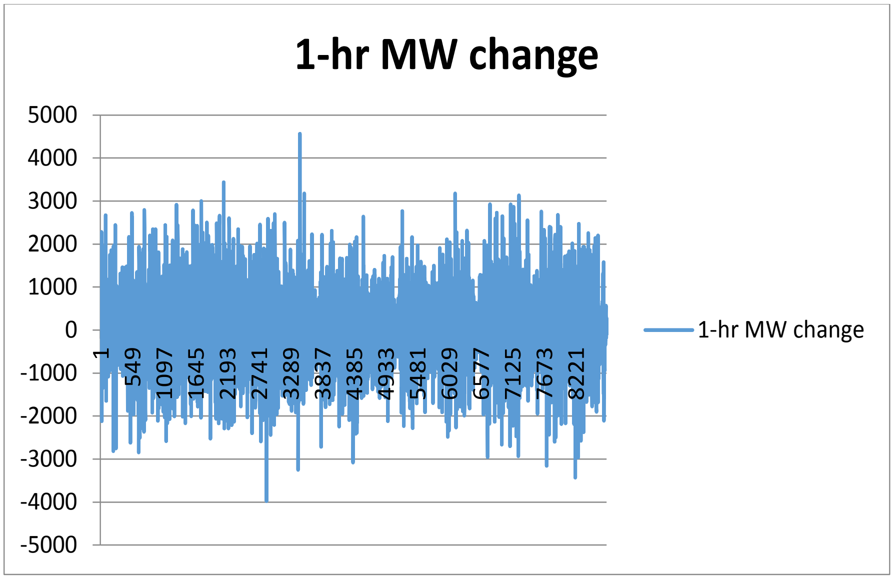
Several factors contribute to the complexity of the electric grid, including:

- The variability and intermittency of renewable generation.
- Decreased frequency response capability and decreasing system inertia.
- Changing load patterns and unpredictability.
- System dynamics becoming both faster and more unexpected.
- The need to manage a vastly increasing number of endpoints.
- Growing cyber attack risks to the electric grid.

A. Variability and Intermittency of Renewable Generation

As opposed to the dispatchable power that is provided by more traditional sources of generation, e.g., coal, natural gas, or nuclear power generation, the intermittency of renewable generation from solar irradiation (e.g., due to ever-changing cloud coverage and the diurnal cycle) or changing wind speeds cause rapid and highly variable fluctuations in power output. This variability can be seen, for example, in the hourly changes in electricity production from wind resources witnessed in the ERCOT interconnection throughout 2017 (see Figure 34). Such variability needs to be factored into grid planning processes to assure that the requisite resources and system flexibility are available at future times to address the uncertainty in generation, as well as for effectively balancing electricity generation and load in real time (over very short time intervals). Effectively integrating large amounts of variable generation will require more flexible grid resources (such as energy storage) and advanced, real-time sensing and control capabilities.

FIGURE 34. HOURLY WIND GENERATION VARIATION AT ERCOT, 2017



Source: ERCOT, "Generation."

B. Decreased Frequency Response Capability and Decreasing System Inertia

To ensure reliability, system frequency must be managed in a very tight band around 60 hertz.[v] Conventional, spinning generation (e.g., coal, nuclear, and gas-fired power plants with rotating electrical generators) are synchronously connected to the grid and provide system inertia, i.e., the ability to maintain system frequency. Deviations in frequency are corrected within seconds by equipment that corrects the rotational speed of conventional generators. However, wind and solar generators, storage devices and non-frequency responsive loads are not synchronously connected to the grid and do not assist in maintaining system inertia. As wind, solar energy, and other non-synchronous DERs replace conventional synchronous generation, we not only reduce total system inertia, but also reduce the number of generating units available to provide frequency response services. Under these operating conditions, the grid may not be able to prevent frequency decline caused by a sudden imbalance between supply and demand and the system will become increasingly vulnerable to blackouts. Advanced inverters and power electronics devices can address frequency response and other power management issues, especially at a local, distribution-system level. As a result, a reduction in the number of rotating generators will require an increase in the use of power electronic devices, rather than electro-mechanical methods, to manage voltage, current, and frequency. Advanced inverters and other power electronics technologies are available but still evolving. Approaches to integrate their advanced capabilities into legacy systems are needed, as well as research efforts to lower their costs.

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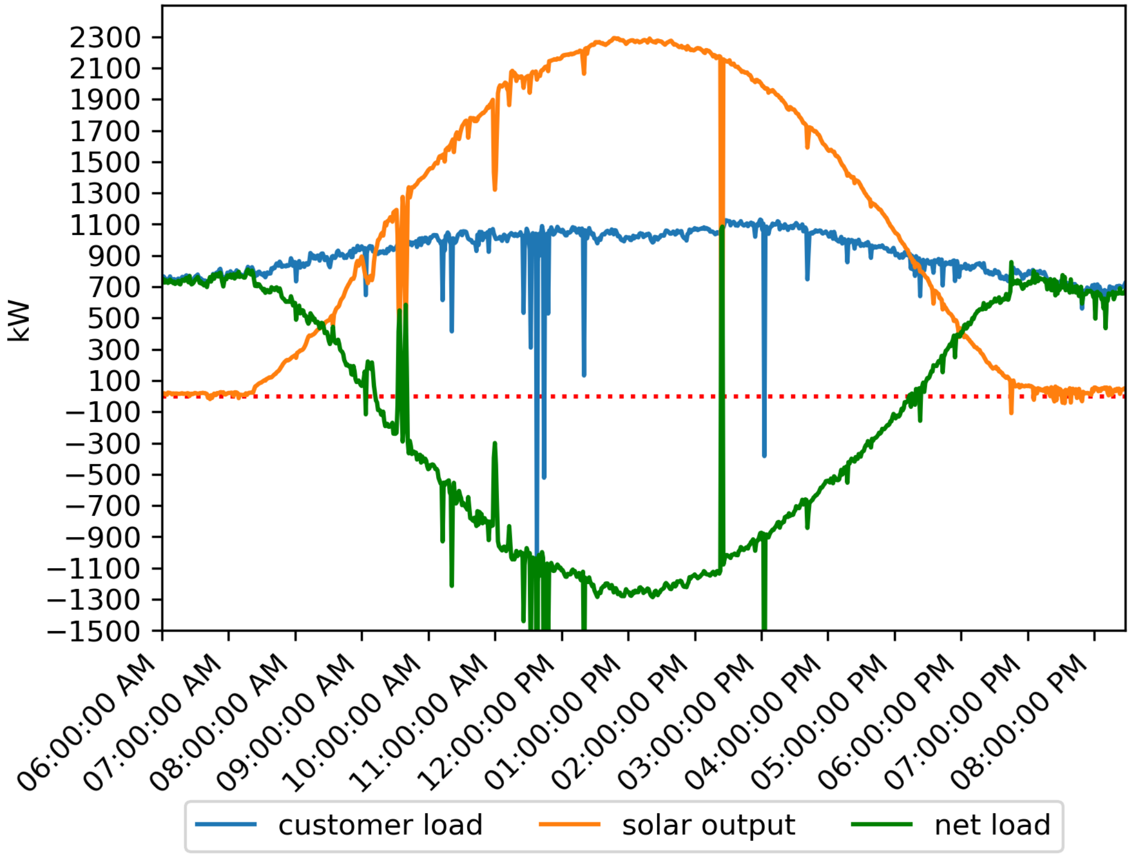
[v] The frequency of the electric grid in the United States is kept tightly at 60 hertz (+/- 0.5 Hz), or 60 cycles per second. One cycle is equivalent to approximately 16 milliseconds. At 60 Hz, the current (movement of electrons) in our wires reverses direction 120 times per second.

C. Changing Load Patterns and Unpredictability

The impact of DERs on net load will be difficult to predict as we increase their number and type. A mixed set of DERs can impact net load in multiple and random ways—some adding power back to the grid, others storing power, others reducing consumption—at various times and locations. In some cases, this will challenge the ability of utilities to predict net load and plan their resource needs, both short- and long-term.

As a result, a mixed set of DERs will lead to a great deal of variability and uncertainty in the net load profile observed by grid operators—even over the course of one day—as shown in Figure 35.[84] In this figure, PV output lowers the net load observed by the utility; in this case, we can see power flow back into the grid. Today, grid operators have limited visibility into DERs located behind customer meters, creating grid control challenges where DERs are increasing. Operators need sensing and control approaches and other observability strategies to monitor and react to the fluctuating power of customer-owned DERs.

FIGURE 35. VARIABILITY AND UNCERTAINTY IN THE DISTRIBUTION NET LOAD PROFILE



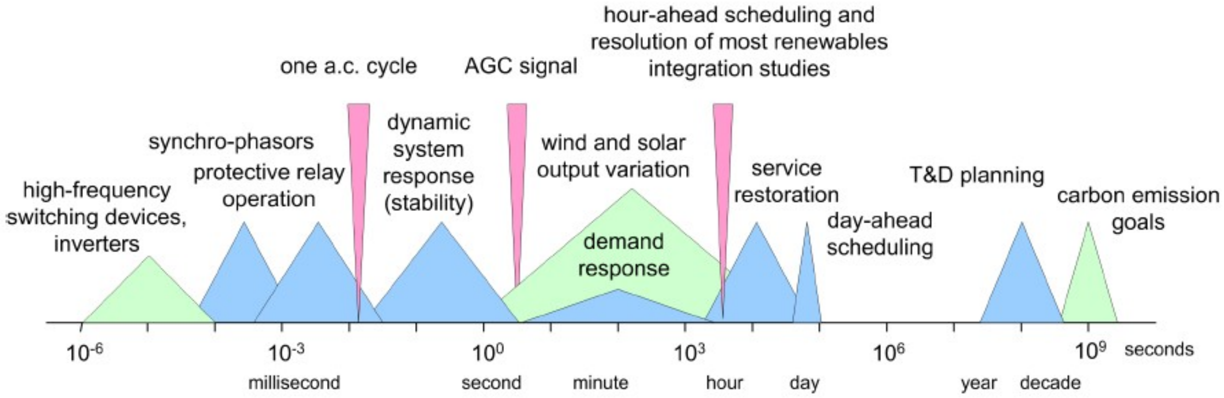
Source: Provided by Emma Stewart of Lawrence Livermore National Laboratory. August 22, 2017 data from a City of Riverside 12 kV distribution feeder with high penetration of solar PV; data from microPMU measurements aggregated to 1-minute data from 120 samples/second.

D. System Dynamics Becoming Both Faster and Unexpected

One of the central challenges in operating electric power systems is that electricity must be generated (or delivered) in the exact moment it is consumed. The fundamental problem that must be addressed by system operators, therefore, is being able to coordinate generation and load in real time. This occurs on multiple levels with control methods appropriate to each timescale.[85]

As shown in Figure 36, the operational time periods in which controls are applied can range from years-to-decades to determine resource requirements through planning processes; days-to-minutes for the scheduling of resources to meet projected short-term demand (mostly through market mechanisms); and sub-second-to-second timeframes for automated control actions. Automated control is required where system behavior occurs too fast for human intervention or where the action needed is unsuitable for remote control due to communication and system latencies.

FIGURE 36. GRID OPERATIONAL TIME PERIODS



Source: Developed by Alexandra von Meier.

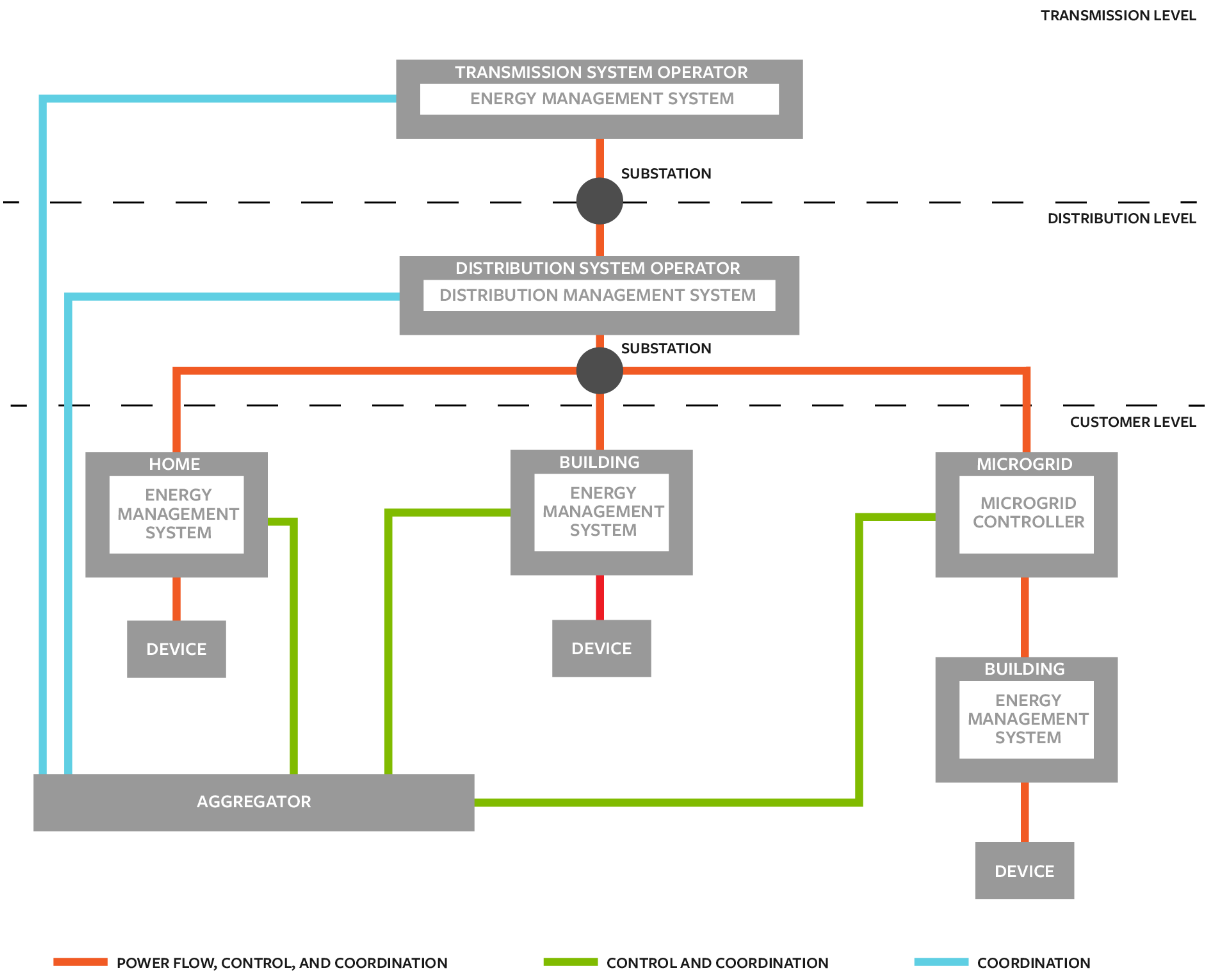
Bulk power systems have employed a variety of control methods as shown in Figure 36. However, the increasing adoption of distributed solar PV and the potential for incorporating additional DERs have introduced greater variability in net load and energy exported into the distribution grid. This results in a more dynamic operating environment resulting in control being pushed out from central stations to substations and distributed devices where automatic or autonomous operations are required. For example, a type of automatic operation is undertaken by automated feeder switching, discussed earlier, which must sense fault currents in milliseconds and undertake operations to reconfigure the topology of a distribution system within seconds.

As we increase variability, various functions, such as voltage management and protection schemes, will need to not only work at faster timescales, but be modified to address the reverse flow of energy from customer or merchant DERs on distribution systems. These systems will need to operate with power electronics devices, such as advanced inverters, to quickly manage power flows and voltage levels. Such requirements are pushing the next generation of field automation and control systems beyond present day capabilities.

E. Need to Manage a Vastly Increasing Number of Endpoints

Widespread DER penetration implies that a grid control system will have to handle thousands or millions of endpoints. The fundamental control problem is to manage bulk energy system resources (e.g., power generation resources) and dispatchable DERs in a way that will not compromise grid operating requirements, e.g., observing constraints on system frequency, voltages, and the operating limits of grid components. This issue becomes more pronounced as we increase the number and types of DERs. In addition, the integration of DERs that are not owned by utilities further complicates the problem shifting it from one of direct control to a combination of control and coordination.[86]

FIGURE 37. COORDINATION AMONG PARTICIPANTS



Coordination is the process that causes or enables a set of decentralized elements to cooperate to solve a common problem, thus becoming a *distributed system*. As shown in Figure 37, the various elements of the system will need to coordinate their activities in a way that does not jeopardize the overall reliability and safety of the grid. Coordination frameworks are required to set the rules governing the interrelationships among the elements (e.g., grid devices and participants) and to enable optimization among them.[87] Understanding how the various participants and grid devices coordinate will be important for ensuring optimal performance during normal operations, but also how they would behave during abnormal operations, such as during an unanticipated outage. In this case, a coordination and control strategy will be needed where a microgrid may wish to isolate itself from the rest of the grid or provide ancillary services needed to maintain system operations.

F. Growing Cyber Attack Risks to the Electric Grid

The growing frequency, sophistication, and effectiveness of cyber attacks over the last decade mark the turning point to an era of politically motivated and nation-state-level targeting of U.S. energy infrastructure. In recent years, the energy sector has seen a dramatic increase in focused cyber probes, data exfiltration, and malware developed for potential attacks.[88] Unlike attacks on business information technology (IT) systems, cyber attacks on grid operational technology (OT) systems have the potential to disrupt power or fuel supplies, damage highly specialized equipment, and threaten human health and safety.

Smart grid technologies present a double-edged sword for cybersecurity. The increasing number of digitally connected devices that interact with grid control systems steadily and significantly expands the potential attack surface by creating new entry points. Utility networks increasingly include digital interfaces to a variety of emerging participants outside the utility boundary. However, smart grid technologies can also build in resilience, adding visibility and adaptable controls that can ultimately enable operators to detect disruptions earlier, restore faster, and operate the grid with more flexibility, including microgrid operations that can keep portions of the grid operating during a disruption.

The integration of evolving IT and OT systems (described in Chapter III, Evolution of Grid Intelligence, on page 13) presents new cyber risks, as any successful cyber attack on business systems can potentially migrate to operational systems. For example, the 2015 cyber attack on Ukrainian electric utilities originated as a spear phishing attack on utility IT systems.[w] Emerging cyber threats also create restoration challenges for digital control systems, which vary widely in design and require highly specialized skills and knowledge to operate. To restore physical infrastructure during a disaster, utilities often rely on mutual aid from other utilities who send crews and equipment to join restoration, which is largely seamless as the skills, terminology, and equipment are common across the industry. Public and private partners in the energy industry are now addressing how to provide cyber mutual aid, defining a set of skills and terminology need to support cyber infrastructure recovery.[89]

The energy industry faces an enormous challenge to build strong cybersecurity into new smart grid technologies from the start, and design in cybersecurity to communication and control

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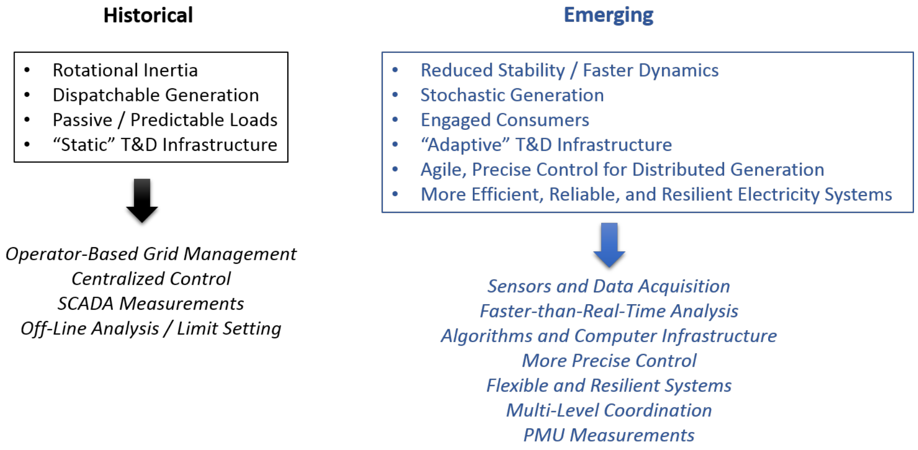
[w] On December 23, 2015, hackers attacked three different electric utilities, resulting in power loss for 225,000 customers for several hours. Attackers used spear phishing emails to gain access to the IT networks.

networks, even as they rapidly evolve. DOE is working with the industry to develop standards, tools, and next-generation communication and control systems that can withstand a cyber attack without losing critical functions. See Cybersecurity on page 77 in Chapter VII for a more complete discussion.

VII. Moving Forward

The evolution of digital technology, including advances in computing and networking capabilities, will ultimately transform the way the electric grid is designed, operated, and connected with other infrastructures. The transition to a more integrated and distributed grid is occurring not only through the application of digital technology, providing intrinsic value to utilities, but also by unpredictable patterns of customer behavior and third parties driving the adoption of DER at the grid edge. As a result, we can anticipate greater levels of variability and uncertainty with regard to both managing energy flows and adapting to the integration of new devices and systems. As shown in Figure 38, addressing this complexity will require new capabilities, including transitioning from deterministic to probabilistic approaches for grid planning and operations.

FIGURE 38. HISTORICAL VS. EMERGING GRID CHARACTERISTICS



Source: DOE, *Quadrennial Technology Review*, 2015.

Advanced smart grid capabilities should result in several performance improvements. **These include both the ability to *adapt* rapidly and optimally to fast-changing conditions, and to *anticipate* them using faster-than-real-time, predictive analysis.** Such capabilities will support risk management approaches to address probabilities and improve resilience.

The electric grid is evolving into an ultra-large-scale system[x][90] as it becomes more decentralized and integrated with a variety of heterogeneous parts, which often have conflicting needs and objectives. The challenge is to institute the appropriate design considerations and processes so we can maintain a stable, coherent, and manageable system as it evolves. To do so will require smart grid advancements that apply grid architecture principles, coordinated planning, and advanced technologies, as discussed in the following sections.

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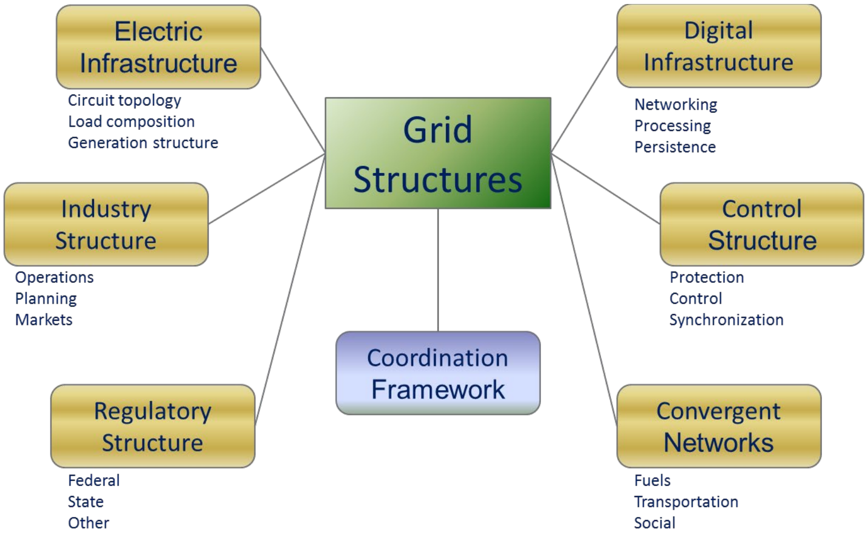
[x] An ultra-large-scale (ULS) system is characterized as a system that is highly decentralized, used by a variety of stakeholders with potentially conflicting needs, evolving continuously, and constructed from heterogeneous parts. Natural ecosystems and cities are examples of ULS systems; they are not necessarily designed through top-down engineering, yet are highly complex and organized, made possible by fundamental components and processes that enable coherent growth.

A. Architectural Considerations

The electric grid is an intricate composite of several structures, including the physical structure, the digital structure, the control structure, the market structure, the industry structure, and the regulatory structure, as shown in Figure 39. Each of these structures interfaces with the others and any modification in one will impact how it may affect the others. The subject of grid architecture is primarily concerned with the integration of these structures and how they are designed to enable advanced grid functions. Beginning with objectives, grid architecture provides a disciplined approach to derive coherent structural designs. Grid modernization strategies need to apply holistic approaches to address complexity and minimize unintended consequences.[91]

FIGURE 39. STRUCTURAL RELATIONS CONSIDERED BY A GRID ARCHITECTURE DISCIPLINE



Source: Provided by Jeffrey Taft, Chief Architect for Electric Grid Transformation, Pacific Northwest National Laboratory.

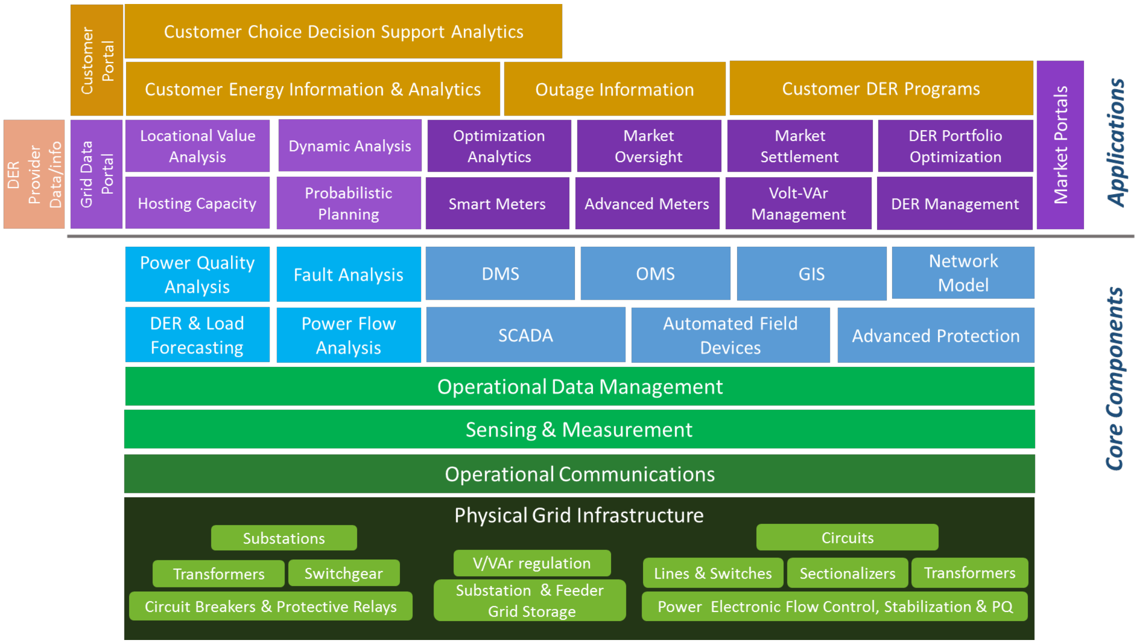
DOE is now working with state commissions and utility partners to develop and apply the discipline of grid architecture to determine the structural and functional requirements of an advanced grid and to help institute holistic planning processes. Through this process, we can better address various issues arising from the integration of DERs, including:

- Developing grid observability strategies and connectivity models.
- Determining approaches for managing, monitoring, controlling, and securing a growing number of grid devices.
- Applying layering, modularity, and interoperability considerations in the way multiple grid systems are used, and in the way they exchange data.
- Designing control models that consider both centralized and distributed approaches.

- Understanding when and under what circumstances to apply market versus control mechanisms.
- Developing coordination frameworks that are scalable and permit local and system optimization.

Grid architecture also helps to simplify grid structure. Certain components of distribution systems can be considered as core, foundational elements and in this way remove the inherent difficulties in trying to integrate siloed operations (see Figure 40). The core components would form a supporting layer or platform, consisting of, for example, information management systems, operational data management, sensing and measurement, operational communications, and the physical grid. Building out the core platform components at the appropriate pace and scale then becomes the chief consideration to enable anticipated future functional capabilities and support new applications as they are needed.

FIGURE 40. DISTRIBUTION SYSTEM PLATFORM



Source: DOE, *Modern Distribution Grid, Volume III*, 2017.

B. Planning and Business Considerations

A high DER future will require sophisticated planning tools and models, as well as new planning approaches that integrate decisions across the transmission, distribution, and customer domains. Existing resource and infrastructure planning tools and approaches were not designed for a complex grid where high levels of DERs can deliver power back to the grid and reduce or shift load in significant ways.

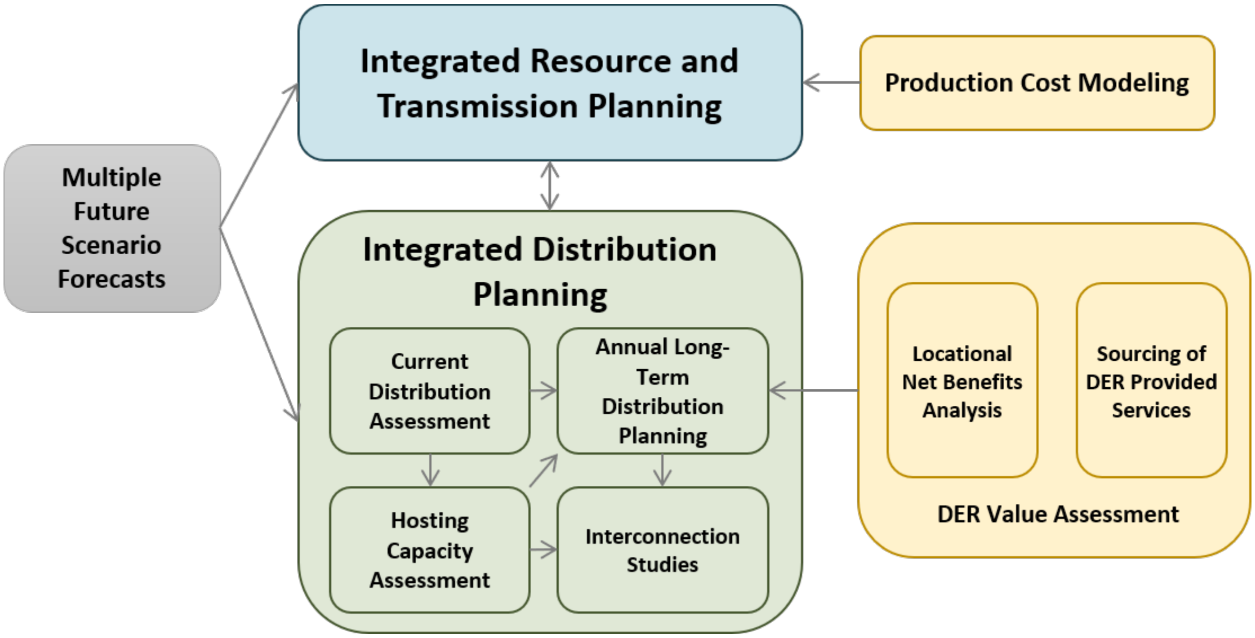
High-levels of DERs can introduce a variety of system issues, yet also offer value by providing generating capacity, electrical energy, and various services like ramping and frequency support.

As a result, integrated planning processes should consider both system issues and value streams for both transmission and distribution operations.

An integrated planning approach, depicted in Figure 41, must include several interconnected analytical processes, including:[92]

- Long-term forecasting of load and DER adoption patterns.
- Hosting capacity analysis to determine what grid upgrades are required and where to support DER integration.
- Automated processes for enabling the rapid DER interconnection processes.
- Analysis of the locational value that DERs provide to distribution systems, recognizing that they can serve as non-wires alternatives to traditional grid upgrades.[y]
- Development of DER sourcing mechanisms that can entice customers and merchants to provide dispatchable DER services.
- Significant coordination between the transmission and distribution planning processes.

FIGURE 41. INTEGRATED PLANNING PROCESSES



Source: Adapted from a figure in: ICF International, *Integrated Distribution Planning,* prepared for the Minnesota Public Utilities Commission, 2016.

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[y] As an example of non-wires alternatives, Con Edison established the Brooklyn-Queens Demand Management (BQDM) project in which a range of demand-side options, obtained through auctions with DER service providers, are being applied to meet a 69 MW shortfall in the growing Brooklyn and Queens boroughs of New York City—rather than spending $1.2 billion for new substations, feeders, and switching stations.

While traditional integrated resource planning is well developed for bulk power systems, planners have few tools to determine how DERs can best contribute to the overall resource mix, and there is growing recognition that transmission and distribution system planning must be more closely coordinated where high DER uptake is occurring.[93]

The analytical methods and tools to support integrated distribution planning processes are evolving and require more sophistication. There are no mature assessment tools today that utilities can use to determine an optimal portfolio of DER non-wires alternatives. However, a growing number of states have policies, dockets, or commission proceedings under way to require detailed planning for grid modernization, DER integration, and integrated distribution system planning (see Figure 42).

FIGURE 42. PLANNING POLICIES FOR GRID MODERNIZATION, DER INTEGRATION, AND DISTRIBUTION SYSTEM PLANNING

Grid Modernization - 28 states			**DER Integration -13 States**			**Distribution System Plans - 15 states**		
AZ	MD	OH	AZ	MA	NY	CA	IN ***	NY
CA	MI	OR	CA	MD	OH	CO	MA	OH
CO	MN	PA	CT*	MI	VT	CT*	MD	OR
CT	MO	RI	HI	MN		HI	MI	RI
DC	NC	TX	IL	NH		IL	MN	WA
FL	NH	UT						
GA	NJ	VT						
HI	NM	WA						
IL	NY							
MA	NV							
* Connecticut - pilot projects ** Florida is expected soon			* Connecticut - pilot projects			* Connecticut - pilot projects *** Indiana - Legislative option to file transmission and distribution plans		

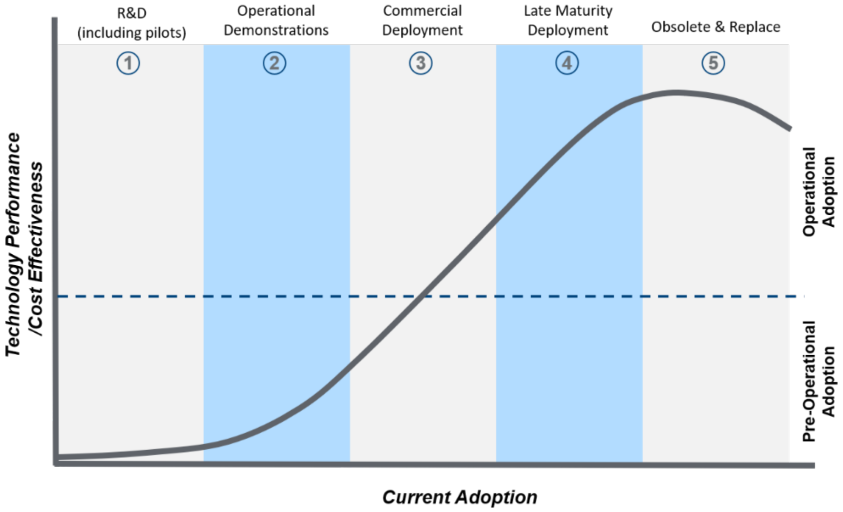
Source: GridWise Alliance, *Grid Modernization Index 4*, 2017; EAC, *Grid Modernization: ARRA Accomplishments and Recommendations for Moving Forward*, 2015.

Grid modernization must also recognize and plan for new technology maturity and adoption lifecycles. Digital operational and control technology innovation now occurs at rates far faster than the traditional utility investment cycle. Legislative, regulatory, and customer expectations of fast adoption for emerging technologies can create friction as utilities must adapt to new technologies and capabilities, often by re-engineering complex business processes with substantial workforce training.

Many of the technologies needed to enable a more integrated and distributed grid are still in early stages of development, while others are much further along the typical technology development curve (see Figure 43). This cycle progresses from research and development

(R&D) through mature deployment, which—depending on the technology and complexity of the upgrade—can take several years. Because the power grid demands very high levels of operational performance, new technologies often must be extensively demonstrated and proven reliable before a utility fully adopts them. Hence, the maturity of technologies is important to consider in setting rational timelines to meet policy objectives.

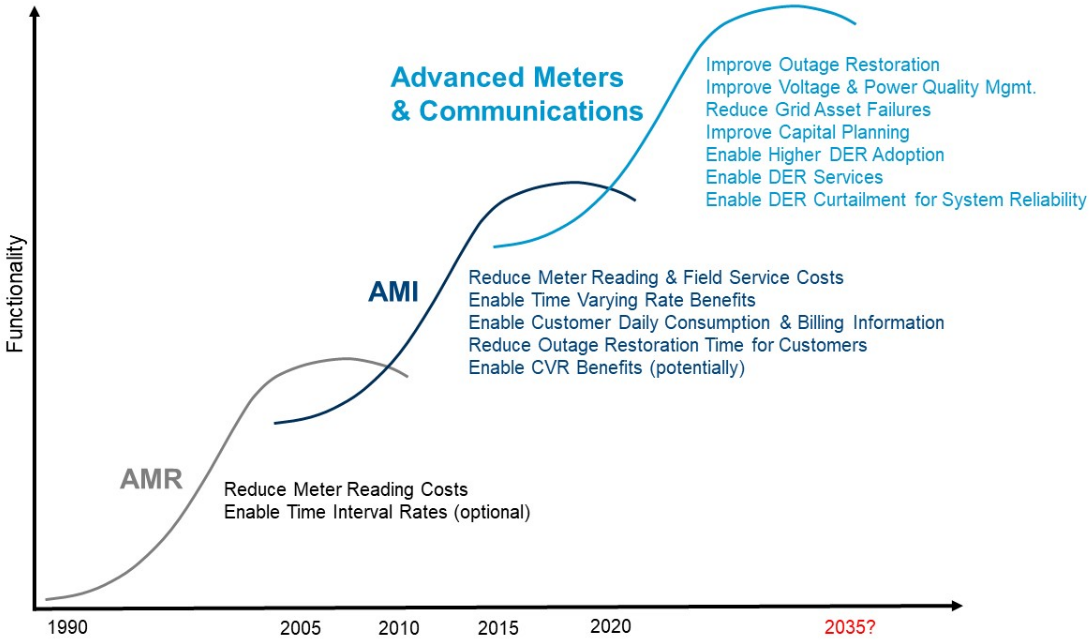
FIGURE 43. TECHNOLOGY DEVELOPMENT S-CURVE



Source: Grid Modernization Considerations: DSPx Phase 2, presented to the New England Conference of Public Utilities Commissioners, April 2018.

Recognition of the maturity of various technologies and how they enable advanced grid capabilities would better inform policymakers, regulators, and utilities in their planning and development of realistic grid modernization strategies. For example, Figure 44 shows a series of technology development S-curves for metering technologies, from automated metering reading (AMR) capabilities, which have been largely superseded by advanced metering infrastructure (AMI) technologies, which will eventually be surpassed by more advanced meters that serve as real-time sensors, which are still in an early stage of maturity today.

FIGURE 44. PRODUCT LIFECYCLE OF METERING SYSTEMS



Source: Grid Modernization Considerations: DSPx Phase 2, presented to the New England Conference of Public Utilities Commissioners, April 2018.

Finally, there are no well-developed strategies for transitioning current utility business models to more integrated, participatory systems. Business considerations play into planning processes where the participation of all parties is required. Such business models will need to address mechanisms that can both compensate utilities for deploying the requisite infrastructure and incentivize prudent practices for applying grid services or capabilities provided by non-utility players. Particularly, as utility revenues remain flat or diminishes, the industry will need to examine and apply new mechanisms for recovering fixed infrastructure costs. There are no consistent approaches to determine the appropriate pricing mechanisms to recover the costs of a more complex and distributed grid.[94] In addition, rules will be needed that establish requirements for non-utility market participants to allow DER participation while guaranteeing reliability and affordability objectives. This is especially true for microgrids, which will need to be synchronized with utility systems, yet potentially be required to provide services to customers in the same manner as regulated utilities.[95]

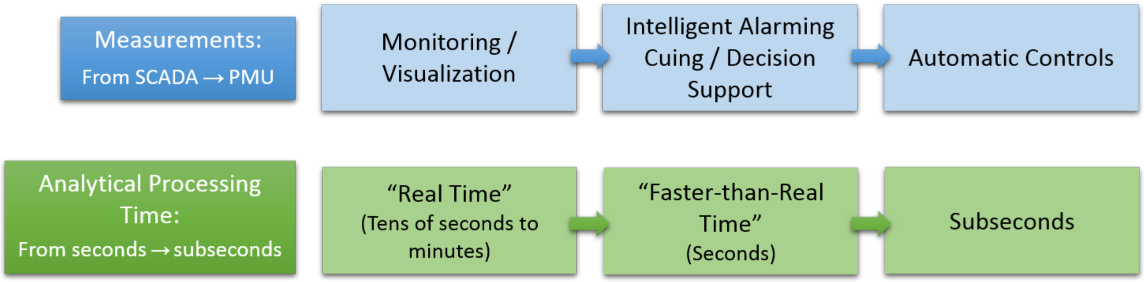
C. Smart Grid Technological Considerations

There are several key technology advancements needed to enable an integrated, complex, distributed system that is reliable and efficient. While a list of discrete research needs is provided in Appendix A, smart grid technology advancements will be needed in five key areas: 1) modeling and analysis, 2) advanced energy management and control, 3) power electronics, 4) energy storage, and 5) cybersecurity.

1. MODELING AND ANALYSIS

The growing interconnectivity, interdependencies, and complexity of the electric power system are requiring tools with enhanced modeling and simulation capabilities for both planning and operational purposes. Current models are used to estimate grid conditions based on the availability and accuracy of data to help operators manage the grid in real time. High-fidelity models and simulation tools are needed, particularly with an increasing number of devices requiring monitoring and control at much faster timescales. Grid planners will need more granular modeling tools that can predict the impacts of the myriad configurations of millions of grid-connected devices, and determine the best technology solutions. Both planning and operating models will need to employ probabilistic analysis using vast amounts of data. Grid operators will require improved sensing and measurement technologies that rapidly feed real-time data into operating models with extremely fast analytical processing rates, from tens of seconds to sub-seconds, enabling them to move beyond monitoring and visualization into automated controls. Modeling, simulation, and data analysis will also help utilities understand the increasingly complex nature of the smart grid, particularly where emergent behavior can surprise designers and operators.

FIGURE 45. PATHWAY TO SPEED IMPROVEMENTS IN ANALYTICAL DECISION MAKING



Source: DOE, *Quadrennial Technology Review*, 2015.

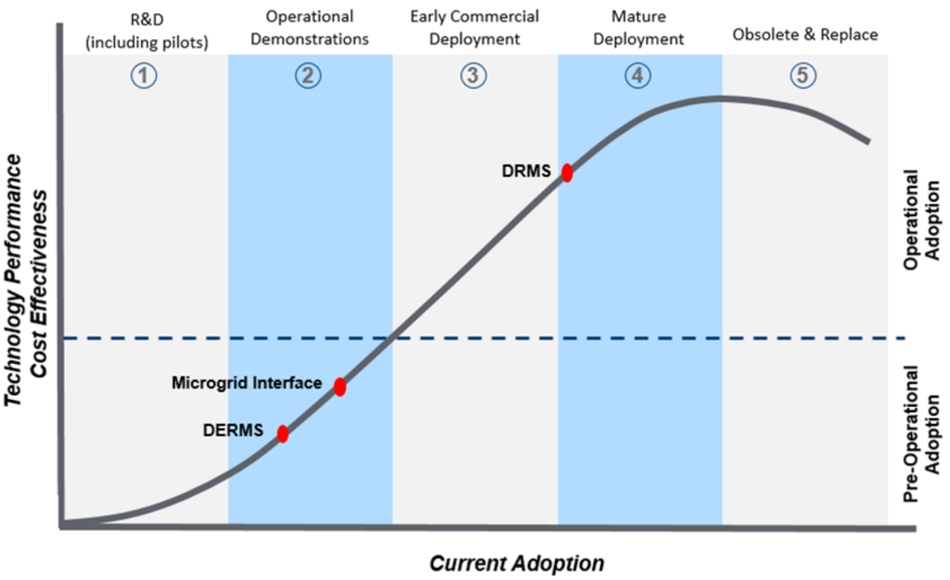
As the grid transitions to one that is analytically driven and controlled, foundational improvements in operational models and simulators becomes even more critical. Validation of models using real-world data and established use cases is needed before automation and model-based control can be fully trusted.

2. ADVANCED ENERGY MANAGEMENT AND CONTROL

Future grid modernization efforts will likely concentrate on designing and demonstrating highly advanced management and control systems, particularly for the distribution system, that integrate enormous amounts of data into real-time operational control. With a growing number of devices and endpoints to manage under tighter timeframes, operators will need advanced control schemes that can manage more complex and unpredictable loads, dispatch resources, and incorporate real-time and predictive analytics that will permit operators to make smarter, faster operating decisions that save time, money, and energy and make the grid more responsive to failures.

Many of these advanced systems are still in early stages of development. For example, as shown in Figure 46, while demand response management systems (DRMS)[z] are commercially available, distributed energy resource management systems (DERMS)[aa] are at an early stage of operational demonstration, particularly as the industry grapples with a single, unified version of the technology. Meanwhile, microgrid interfaces[bb] are in an operational demonstration phase and have not been standardized. Interconnection standards are being updated to address microgrid and DER interfaces.

FIGURE 46. DEMAND RESPONSE, MICROGRID, AND DER MANAGEMENT SYSTEM MATURITY



Source: Grid Modernization Considerations: DSPx Phase 2, presented to the New England Conference of Public Utilities Commissioners, April 2018.

Continued development and operational demonstrations are needed to adopt these and other management and control systems that enable more flexible and automated control decisions.

3. POWER ELECTRONICS

The changing landscape of generation and customer-owned technologies is fundamentally altering the electric power flows and physical phenomena that grid components were designed to accommodate. The pace of grid modernization and system changes demand hardware solutions that are more dynamic, adaptable, and robust. The development and deployment of next-generation grid components, particularly power electronics technologies that incorporate solid-state components, will play a critical role in enabling future grid requirements. Devices,

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[z] A DRMS interfaces with customers enrolled in demand management programs.

[aa] A DERMS is a software solution that incorporates a range of operations to adjust the production and/or consumption levels of disparate DERs directly or through an aggregator.

[bb] A microgrid interface includes load disconnect/reconnect capability; measurement; communications; protection devices that can enable seamless interoperability between interconnected, islanded modes; and synchronized reconnection of a microgrid.

such as solid-state transformers and power flow controllers, can be used in strategic locations to provide instantaneous control over the direction and magnitude of power flow, which will significantly improve the capability and flexibility of the electric grid. New planning strategies are required to integrate power electronics with legacy grid infrastructure; for example, regulators and utilities, with assistance from the Department, are now in the process of addressing how to best deploy smart inverters, which are used to integrate solar PV systems with the utility grid.

In addition, specific research needs are focused on improving the performance, applicability and cost of these grid components, including:[96]

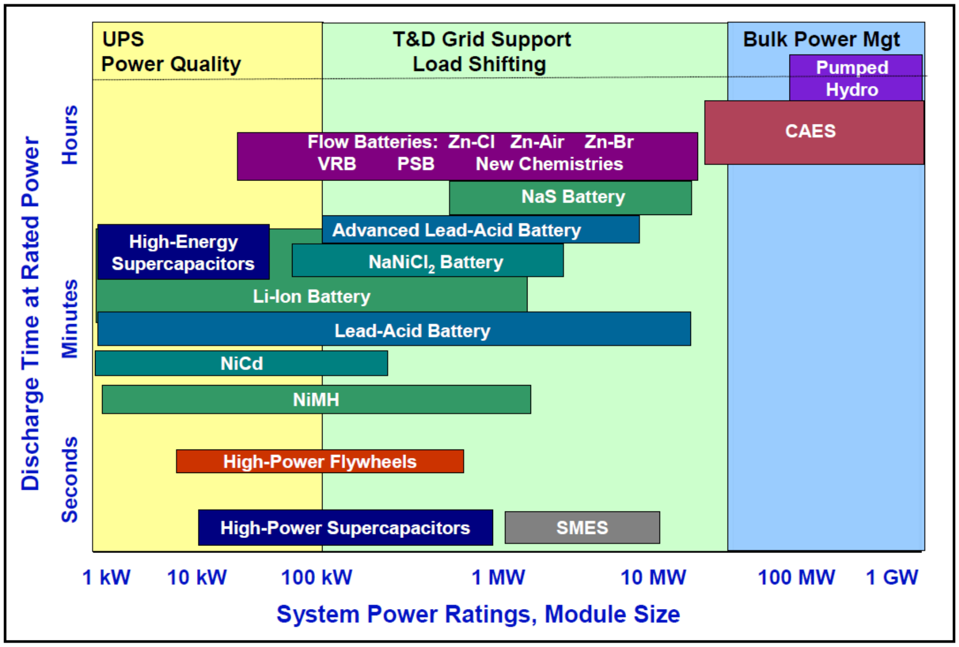
- Improving the performance of current designs by leveraging advances in new materials, such as wide-bandgap semiconductor materials.
- Developing modular and scalable designs, leading to greater standardization and allowing for more cost-effective capacity expansion, as standardized designs do not exist for many grid components.
- Providing local intelligence with embedded sensors, data processing, and communications to enable real-time monitoring and adaptive capabilities.
- Incorporating cyber and physical security measures into the design of each component, rather than added as an afterthought.
- Ensuring customer data privacy given the increasing use and deployment of sensors and the vast amounts of consumer data generated, collected, and analyzed.

4. ENERGY STORAGE

Electric energy storage technologies are characterized by their capability to consume, store, and discharge electric power when needed. These technologies can provide various benefits, such as supporting balancing and ramping requirements, improving the economic dispatch of resources, enhancing power quality and stability, and deferring infrastructure investments. They can also be deployed by customers for backup power and more optimal use of generating assets.

As variability and uncertainty increase, a substantial deployment of energy storage is anticipated to enhance system flexibility and control capabilities. As shown in Figure 47, energy storage technologies have distinct performance characteristics that make them suited to particular grid applications.[97]

FIGURE 47. ENERGY STORAGE PERFORMANCE CHARACTERISTICS



R&D is required in several areas to address cost and technical performance issues, as well as to promote industry acceptance. Targeted research is needed in the development of improved materials and in systems engineering approaches to resolve key technology cost and performance challenges.

Examination of degradation and failure mechanisms, the development of mitigation strategies, and accelerated life testing will help to validate the reliability and safety of energy storage systems. Finally, the development of industry and regulatory agency accepted standards for siting, grid integration, procurement, and performance evaluation will better support the demonstration and deployment in utility systems.

5. CYBERSECURITY

Grid operations grow increasingly complex, while the frequency, scale, and sophistication of cyber threats to the grid are rapidly increasing. Both factors create a growing need for advanced digital sensing and control capabilities. A modern grid requires rapid sensing, fast and predictive analytics, and real-time modeling to make automated decisions; these same capabilities can improve cyber attack detection and response.

The challenge today is building innovative cybersecurity capabilities into smart grid devices and networks as they evolve, while anticipating future grid scenarios and designing next-generation resilient and adaptive control systems. Federal agencies and the energy industry have been working in close partnership since 2005 to reduce the risk of energy disruptions from a cyber attack. Significant work has been done by this public-private partnership to develop cybersecurity standards for smart grid technologies, develop tools and frameworks that bolster utility cybersecurity capabilities, share cyber risk information, and conduct advanced R&D for energy delivery systems—but more is needed, particularly as cyber threats continue to evolve.

For more than a decade, DOE's Cybersecurity for Energy Delivery Systems (CEDS) program has funded a diverse portfolio of cybersecurity R&D led by partnerships of industry, cybersecurity vendors, academia, and national laboratories. To date, CEDS has delivered more than 38 products, tools, and technologies to help secure critical cyber systems and networks, some of which are now in place at thousands of U.S. utilities. As utilities deploy new smart grid devices and networks, innovative and incremental cybersecurity technologies are needed that can prevent, detect, and mitigate a growing range of threats while respecting the needs of existing, legacy systems.

More importantly, advanced RD&D is needed that will build cyber resilience into the next generation of energy management and control systems. CEDS R&D today focuses on anticipating future energy sector attack scenarios and designing cybersecurity into emerging technologies, such as cloud networks for utility data analytics, distribution-level energy management systems that will coordinate microgrid operations, and secure synchrophasor systems to enable real-time control. R&D projects are also examining how to design future power systems and components that automatically detect, reject, or withstand a cyber incident, adapting as needed to keep operating even under attack. Several projects are examining future system designs that recognize and refuse to take any action that does not support grid stability, which limits the damage an attacker can create even if they successfully infiltrate a utility network.

The energy industry will also need advanced tools, standards, and guidelines to build and operate secure smart grid systems. Over the past decade, DOE has worked with the energy industry to design the Cybersecurity Capability Maturity Model (C2M2), a tool that utilities can use to assess and prioritize improvements to their cybersecurity capabilities. DOE also worked with NIST in developing the Cybersecurity Framework, a voluntary framework that aligns with the C2M2, which utilities can use to design or improve their cyber risk management program.

While these tools help utilities strengthen their cyber practices, continued efforts are needed to develop strong cybersecurity standards that utilities and vendors can use in designing and building smart grid networks and systems. Since 2010, DOE has supported NIST and energy industry partners in developing cybersecurity guidelines for smart grid vendors and utilities, but additional work is needed as technologies advance and evolve.

6. INTEROPERABILITY STANDARDS

The application of digital technology has provided an opportunity for enhanced sensing, coordination and control of the various elements that constitute the electric grid. This capability requires the ability of devices and computing platforms to readily share information and operate in a coordinated manner, requiring the development and implementation of industry-accepted interoperability standards and protocols. This is becoming especially important, as devices proliferate at the grid edge, as is being witnessed through the adoption of DERs in various parts of the country.

Over the past five years, significant technological advances in smart grid infrastructure have been implemented, supported by standards development across the entire smart grid arena. Examples include widespread deployment of wireless communication power meters, availability of customer energy usage data through the Green Button initiative, remote sensing for determining real-time transmission and distribution status, and protocols for electric vehicle charging.[98]

Standards and protocols guiding communications and control requirements, such as IEC 61850 and IEEE 1547-2018,[cc] are being developed and applied with significant efforts by the private sector and industry-led groups to ensure interoperability and security. As there are hundreds of standards being developed, continued assessment and coordination by the federal government is recommended to ensure that interoperability and cybersecurity standards evolve and are implemented at a pace sufficient to support needed technology deployment. In addition, significant effort is required to determine how to implement the new or revised standards with respect to legacy technology. For example, DOE has worked closely with IEEE to develop IEEE 2030.7, the *Standard for the Specification of Microgrid Controllers*. DOE is also working with state regulators to assist in the development of strategies for the effective deployment of IEEE 1547-2018, which provides new functions for smart inverters.

The National Institute of Standards and Technology (NIST), within the U.S. Department of Commerce, works collaboratively with the private sector to facilitate and coordinate smart grid interoperability standards development and smart grid-related measurement science and technology. EISA assigns to the National Institute of Standards and Technology (NIST) the "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems…."[99]

Over the past several years, there has been a proliferation of standards development with respect to how devices can effectively integrate with the grid and now there exist hundreds of grid-related standards. These interoperability standards include requirements for the physical performance of the devices, communication protocols and data models to enable the effective integration between grid components, as well as with utility operational and computing systems. For several years, NIST categorized the standards according to the specific domain that they served, e.g., the transmission, distribution, utility and customer domains.[100] However, as the responsibility for sensing and control has migrated across the various domains, and also to devices at the edge of the grid, we are witnessing an overlapping of many standards

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[cc] The IEEE 1547-2018 standard updates the original 1547 standard released in 2003, and significantly expands the functional capabilities (e.g., ride through, anti-islanding, and power quality functions) of inverter technology, enabling the more effective integration of DERs.

development efforts. As a result, NIST has recognized that the traditional approach for parsing standards into the various domains is breaking down.

To illustrate, the revised IEEE 1547 standard now requires smart inverters to be compatible with one of three separate communications protocols and, when combined with the associated data models and other recommendations in the standard, there are more than a dozen different combinations of communications protocols and data models that could bring a smart inverter into compliance with the standard. This interoperability complexity makes it difficult for utilities or the inverter purchaser to ensure an inverter will work within their system even if it is compliant with the current standard. Through their ongoing efforts to develop the next version of an interoperability framework, NIST is reaching out to the industry to address this complexity and clarify performance requirements for communications protocols and data models.

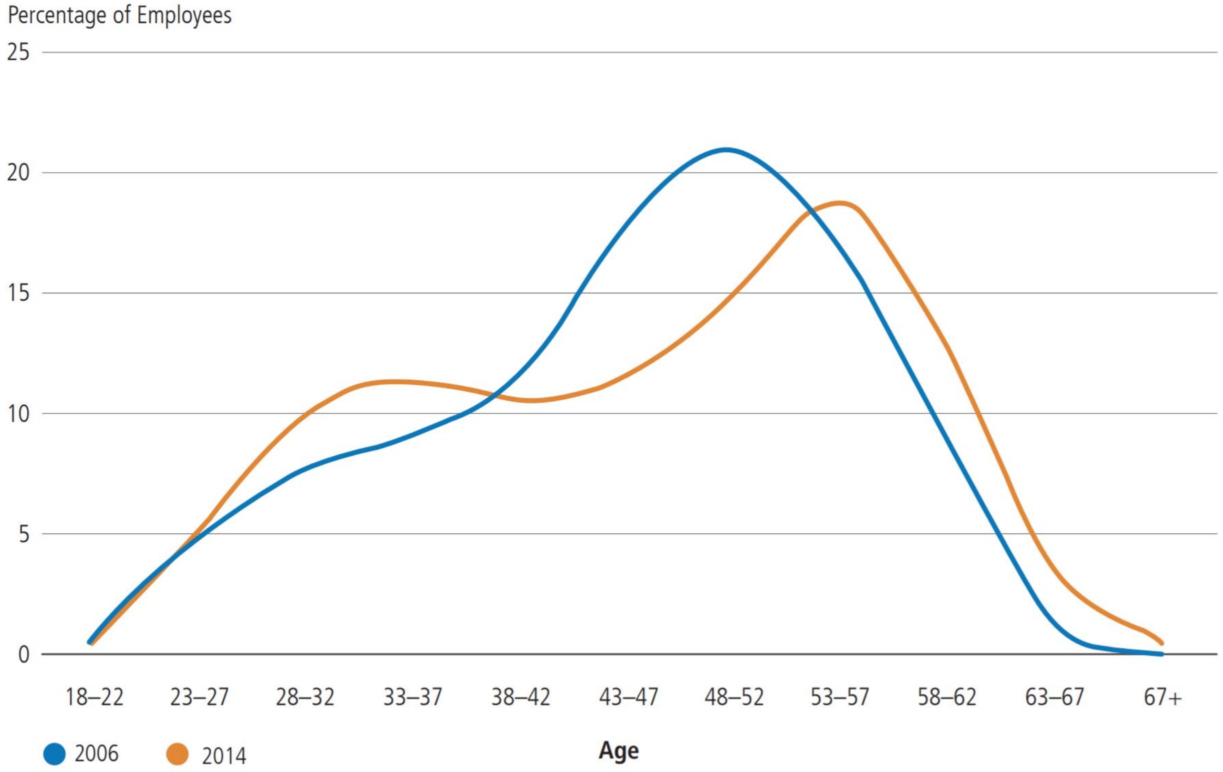
In addition, the majority of the standards and protocols are not accompanied by independent testing and certification programs. This has resulted in the manufacturing of grid devices that do not necessarily comply with the interoperability standards for which they were designed.[101] Without a guarantee of the compliance of devices with standards, the ability to achieve the efficient integration of devices with the grid will become difficult. An approach to address this issue is for NIST to work with the industry to prioritize the set of interoperability standards and identify requirements that would lead to an industry-led program for testing and certification.

D. Workforce Considerations

The electricity industry will need a cross-disciplinary workforce that can comprehend, design, and manage cyber-physical systems, as well as apply risk management, advanced modeling and behavioral science skills. The evolving demands on the electricity industry are causing several workforce challenges for the industry, including a skills gap for deploying and operating newer technologies and changes occurring during a period when the industry is facing high levels of retirements.[102]

Utility executives have reported that replacing their aging workforce continues to be a top priority.[103] This issue has improved somewhat over the past ten years, as shown in Figure 48.[104] However, the retention of qualified and diverse candidates is a challenge many now see as outpacing the issue of an aging workforce, as skills requirements are changing rapidly due to grid modernization. The application of digital technology, in particular, is requiring a greater number of highly technical workers and engineers that can build, manage and protect these systems. As a result, the electric industry is continuing to face challenges in attracting, recruiting, and hiring qualified applicants.[105]

FIGURE 48. AGE DISTRIBUTION IN ELECTRIC AND NATURAL GAS UTILITIES, 2006-2014

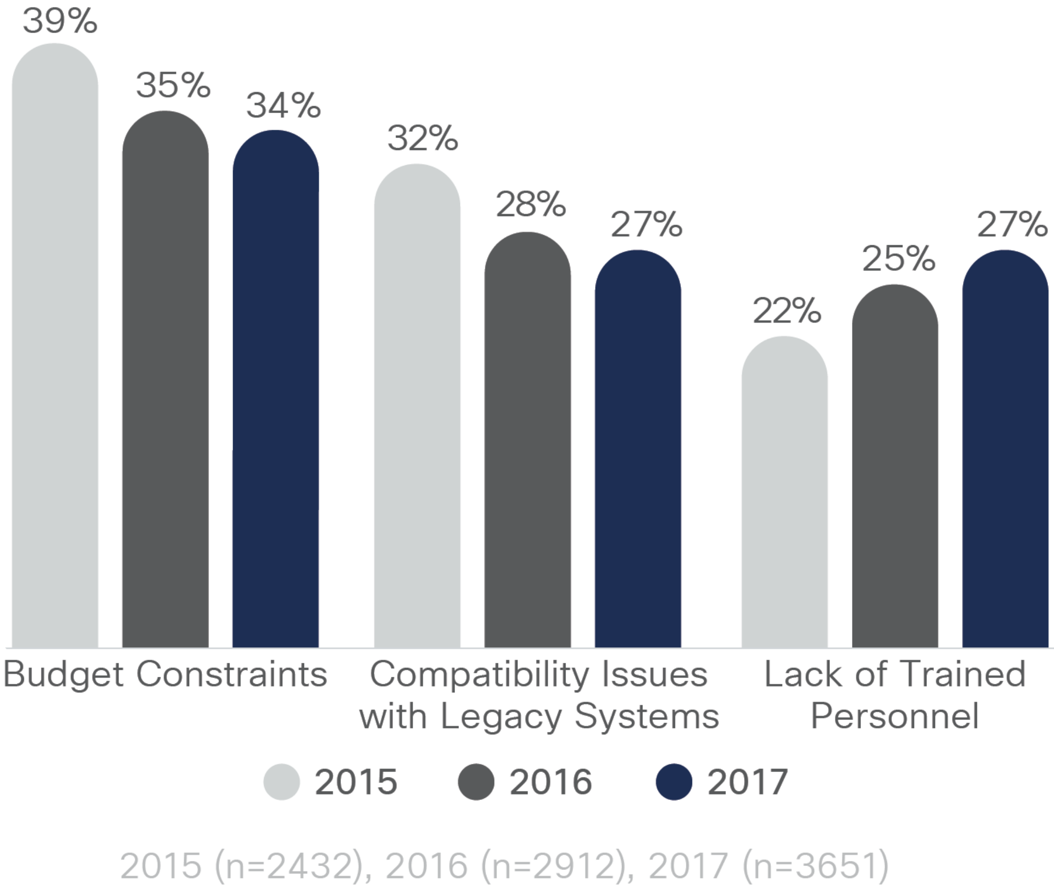


Source: Adapted in the DOE Quadrennial Energy Review from the Center for Energy Workforce Development, *State of the Energy Workforce,* 2016.

One of the significant challenges is filling gaps in the talent pipeline. Training programs and schools that produce the applicant pool still do not reflect the gender and racial diversity in the country.[106] While the long-range prediction of workforce shortages has improved considerably in the past decade, some job classifications, engineers and technicians, especially, continue to face shortages of entry-level and experienced workers.[107] Sixty-eight of the firms surveyed in a study conducted for the Department cited insufficient qualifications, certifications, or education and lack of experience, training, and technical skills as the most reported reasons for difficulty in hiring competent workers.[108]

One of the key skills needed is in cybersecurity. Cisco reports that security professionals cite budget, interoperability, and personnel as their key constraints when managing security (see Figure 49). The lack of trained personnel was identified as a key and growing challenge to adopting advanced security processes and technology across the industries they serve, including the electric power industry.[109]

FIGURE 49. KEY CONSTRAINTS IN MANAGING SECURITY



Source: CISCO, *Annual Cybersecurity Report,* 2018; data from the Cisco 2018 Security Capabilities Benchmark Study

Chapter Endnotes

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VIII. Conclusions

This report conveys the status of smart grid deployments across the nation, the capabilities they provide, and the challenges remaining as we move forward with the modernization of the electric grid. Over the past decade, utilities have deployed smart grid technologies to improve the reliability and efficiency of their operations and to better engage utility customers in the management of energy. However, more recently, we are witnessing the rapid adoption of DERs, such as photovoltaic systems and energy storage technologies, and increasing ownership of distributed assets by utility customers and third-party merchants.

The effective integration of the grid with a mixed set of DERS, combined with the potential for shared ownership of grid services among utilities, customers and merchants, presents a greater level of complexity than the grid was originally designed to accommodate. As a result, we can anticipate a dramatic transformation in the structural and functional aspects of the grid that will require the advancement and use of digitally-based, smart grid technologies. This is now occurring where we can see high levels of DER adoption.

Although the adoption of smart grid technology is not occurring at the same rate across the country, as is appropriate based on local needs for advanced capabilities, one can envision a trend to a more integrated and distributed electric grid where large-scale DER integration will occur. In addition, digital technologies will eventually lead to the formation of information networks that will promote the convergence of the electric grid with other infrastructures, such as buildings, transportation and telecommunications. Given the billions of dollars spent annually on upgrading the electric infrastructure, it is vitally important that investments made today can support an evolving grid for decades to come.

Addressing this challenge will require the application of holistic planning approaches that consider long-range possibilities and integrate the considerations of utilities, customers, grid service providers, and technology developers. It will also require the development and application of technologies that can readily adapt to dynamic conditions, coordinate millions of devices, and provide secure and resilient operations.

IX. Appendix A: Grid Modernization RD&D Needs

The research, development, and demonstration needs identified here come directly from DOE's 2015 *Quadrennial Technology Review*.

FIGURE 50. MOVING FROM TRADITIONAL TO MODERN ELECTRIC POWER SYSTEMS – RD&D NEEDS

Electric Systems	Characteristics		RD&D Needs
	Traditional	**Modern**	
Generation	• Centralized • Dispatchable • Large thermal plants • Mechanically coupled	• Centralized and distributed • More Stochastic • Efficient and flexible units • Electronically coupled	• Planning tools • Energy storage • Control coordination • Flexible thermal generators
Transmission	• SCADA for status visibility (sampling, not high definition) • Operator-based controls (primarily load following and balancing) • Destabilizing effects • Congestion, despite underutilized capacity (limited flow control) • Threats/vulnerabilities not well defined	• High fidelity, time-synchronized measurements • Breadth & depth in visibility • Automatic control • Switchable network relieves capacity constraints • Threats are considered and risks are appropriately managed	• Multi-terminal high-voltage direct current (HVDC) • Low-cost power flow controller technologies • Next-generation energy management systems (EMS) • Integrated planning tools • Security • Low-cost bulk storage
Distribution	• Limited visibility • Limited controllability • Radial design (one-way flow) • Floating on transmission • Increasing fault currents and voltage issues stressing system • Aging assets (unknown effects)	• Enhanced observability • Local, autonomous coordination • Network design and two-way flow • Backbone of delivery system • Self-healing • Active monitoring of asset conditions	• Security • Microgrids • Advanced distribution management systems (DMS) • Distribution and asset sensors • Solid-state transformer • Smart voltage regulation equipment • Community storage
Customers	• Uniformly high reliability, but insensitive to upstream issues • Energy consumers (kWh) • Predictable behavior based on historical needs and weather • Interconnection without integration • Growing intolerance to sustained outages	• Customer-determined reliability/PQ • Prosumers (integrated) • Variable behavior and technology adoption patterns • Plug/play functionality • Kept informed during outages (and before) • Hybrid AC/DC distribution • Data access (outage/usage)	• Single-customer microgrids • Building EMS • DER integration • Security • Transactive controls • Behind-the-meter storage • Low-cost sensors

X. References

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